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Pennsylvania Public Utility Commission, et al., v. UGI Utilities, Inc. - Electric Division	Docket No.: R-2022-3037368
Call-In Telephonic Evidentiary Hearing(s)	

Pages 128 - 185

Judge's Chambers
State Office Building
801 Market Street
Philadelphia, PA

June 13, 2023
Commencing at 10:01

INDEX TO EXHIBITS

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Hearing Date: June 13, 2023

NUMBER	FOR IDENTIFICATION	IN EVIDENCE
UGI Exhibit:		
UGI Exhibit Book I	151	162
UGI Electric Statement No. 1, Christopher R. Brown, UGI Electric CRB-1	152	162

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BOOK I

UGI UTILITIES, INC. – ELECTRIC DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI UTILITIES, INC. – ELECTRIC DIVISION
PA P.U.C. NO. 6, SUPPLEMENT NO. 51
PA P.U.C. NO. 2S, SUPPLEMENT NO. 7

DOCKET NO. R-2022-3037368

Issued: January 27, 2023 **Effective: March 28, 2023**

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UGI UTILITIES, INC. – ELECTRIC DIVISION
2023 BASE RATE CASE
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UGI UTILITIES, INC. – ELECTRIC DIVISION
2023 BASE RATE CASE
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Tracy A. Hazenstab UGI Electric Statement No. 2	• Budget Process • Revenue Requirements • Operating Revenues and Expenses • Compliance with PA Act 40 of 2016	TAH-1 – 2
Vivian K. Ressler UGI Electric Statement No. 3	• Accounting Process and Historic Costs • Rate Base • Operating Expense Adjustments	VKR-1
Eric W. Sorber UGI Electric Statement No. 4	• System Operations • System Reliability and Performance • Safety Initiatives • Inflation and Supply Chain Impacts • Proposed Tariff Modifications • Prior Case Compliance Items	EWS-1 – 2
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UGI UTILITIES, INC. – ELECTRIC DIVISION
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Darin T. Espigh UGI Electric Statement No. 8	• Taxes and Tax Adjustments	DTE-1 – 3
Paul R. Moul UGI Electric Statement No. 9	• Capital Structure • Cost of Equity • Rate of Return	PRM-1
Sherry A. Epler UGI Electric Statement No. 10	• Sales and Revenues • Tariff Changes	SAE-1 – 6

STATEMENT OF REASONS

UGI UTILITIES, INC. – ELECTRIC DIVISION
2023 Base Rate Case
Docket No. R-2022-3037368

STATEMENT OF REASONS

I. INTRODUCTION

UGI Utilities, Inc. – Electric Division ("UGI Electric" or "the Company") is filing Proposed Supplement No. 51 to UGI Electric Tariff Pa. P.U.C. No. 6 and Proposed Supplement No. 7 to UGI Electric Tariff Pa. P.U.C. No. 2S, with a proposed effective date of March 28, 2023. The proposed rates will not become effective, however, until October 2023, assuming that the Pennsylvania Public Utility Commission ("PUC" or the "Commission") suspends the effective date for a period of seven months pursuant to its standard practice. The rates set forth therein, if approved by the Commission, would increase UGI Electric's annual jurisdictional distribution operating revenues by $11.4 million based on a fully projected future test year ending September 30, 2024, and would produce an increase in total revenues (distribution and generation charges) of approximately 7.5%.

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

Table 1. Average Monthly Bill Impact

Average Electric Customer Bill Impact

		Total Monthly Bill Impact			
	Average Usage	Current	Proposed	Increase (Decrease)	Total
Residential	1,000 kWh	$192.73	$209.96	$17.23	8.9%
Small Commercial	1,000 kWh	$199.06	$220.49	$21.43	10.8%
Industrial	50,000 kWh	$6,455.07	$6,475.18	$20.11	0.3%

UGI Electric principally makes this tariff filing to: (1) allow it to earn a fair return on investments that are used and useful to serve the public safely and reliably; (2) obtain additional financial support for ongoing Commission-approved infrastructure replacement programs that are designed to enhance safety and reliability and for enhanced information technology ("IT") systems; and (3) recover higher levels of operating expenses that are necessary for the provision of safe and reliable electric distribution service. Without the requested rate relief, the Company's returns on investment will continue to decline and jeopardize the Company's ability to attract the lower cost capital needed to make the system investments necessary to support and ensure continued system reliability, safety, and customer service performance.

Each of these subjects is discussed in more detail in Section II. Section III addresses UGI Electric's management effectiveness and describes the Company's various efforts to control increasing costs and improve service to customers. Section IV provides a more detailed overview of the major components of this rate filing.

II. REASONS FOR THE REQUESTED RATE INCREASE

UGI Electric last received a general rate increase in 2021. Since then, UGI Electric has increased its planned plant investment by $70.5 million in the distribution system to ensure a well-maintained and reliable system that meets the current and future expectations of the Company's customers. UGI Electric intends to invest significant additional capital in the distribution system through 2027 under its Commission-approved Second Long-Term Infrastructure Improvement Plan ("LTIIP"). Through its LTIIP programs, UGI Electric has accelerated and will continue to accelerate investments in the repair, replacement, and improvement of aged and aging distribution infrastructure by over 100% compared to historic baseline levels immediately prior to the Initial LTIIP. Together, UGI Electric's focus on upgrading and modernizing the distribution system, technologies, and facilities supports the Company's efforts to continue providing safe and reliable distribution service and high-quality customer service. Additionally, UGI Electric made reasonable efforts to help control expenses and increase efficiencies to reduce the proposed revenue requirement otherwise needed.

The growth in operating and capital costs, along with relatively stagnant customer usage and growth trends, do not allow UGI Electric to earn a fair rate of return on its investments at present rate levels.

As reflected in UGI Electric Exhibit A (Fully Projected Future), Schedule A-1, the Company's operations are projected to produce an overall return on rate base of 3.77%, which equates to a return on common equity of only 3.28% for the 12 months ending September 30, 2024. As explained by UGI Electric witness Paul R. Moul (UGI Electric Statement No. 9), these returns are not adequate based on applicable financial data and the risks confronted by UGI Electric. Unless UGI Electric receives the requested rate relief, those returns will continue declining, deny the Company an opportunity to earn a fair and reasonable rate of return, and jeopardize the Company's ability to attract the capital needed to make the system investments necessary to support and ensure continued system reliability, safety, and customer service performance.

Through this filing, UGI Electric also proposes to update the terms and conditions of its tariff. Specifically, UGI Electric proposes to keep its Flood Control Power ("FCP") Rate as a separately-identified tariffed rate. This is discussed further in the direct testimony of UGI Electric witness John D. Taylor of Atrium Economics, LLC (UGI Electric Statement No. 6). UGI Electric witness, Eric W. Sorber, supports tariff modifications regarding the market phase out of certain outdoor bulb types and the addition of provisions for customers interested in decorative lighting.

Additionally, UGI Electric witness, Sherry A. Epler, explains other proposed tariff changes that are necessary to update the Company's rate schedules, riders, and terms and conditions of service.

III. MANAGEMENT EFFECTIVENESS

UGI Electric has focused on a number of areas to enhance and improve the quality and effectiveness of its management performance, to reduce expenses, or both. These management efforts include:

- High standards for electric reliability – UGI Electric has had strong reliability performance as measured by the Commission-established Benchmark levels for service reliability. The Company has met or performed better than the PUC Benchmark levels in two of the three categories in 2021 and 2022, with SAIFI being the only outlier.
- Meeting long-term infrastructure improvement targets – Through its recently-approved Second LTIIP, UGI Electric expects to expend significant capital (approximately $50.6 million) and complete numerous projects to enhance distribution system safety and reliability.
- Energy Efficiency and Conservation Plan – UGI Electric's voluntary Energy Efficiency and Conservation ("EE&C") Plan provides education and incentives to UGI Electric's customers to encourage the efficient use of electricity and incents smart appliance purchase decisions. During the most recent EE&C program year, UGI Electric issued $377,870 in rebates to residential and commercial customers and achieved savings of 3,935,000 kWh, resulting in the greenhouse gas benefit of avoiding the release of 2,964 metric tons of CO_2.[1]

[1] This figure was derived from the EPA Greenhouse Gas Equivalencies calculator https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator

- Enhanced customer-service offerings and continued IT system replacements – The Company's investments in IT through the UNITE initiative have promoted customer self-service through the Company's web portal, increased electronic payments, and improved the customer experience. Additionally, in 2022, UGI Electric provided more than $1.25 million in support to customers in need through Low Income Home Energy Assistant Program ("LIHEAP"), Operation Share, and Low Income Usage Reduction Program ("LIURP") grants.
- Safety focus – Safety is a fundamental imperative at UGI Electric. The Company continues to foster a robust safety culture that ensures the safety of its employees, customers, and communities, such as providing electric safety awareness training to local first responders. UGI Electric also provides electrical safety tips, as well as safety and conservation education, through many mediums to the public.
- Community support – UGI Electric supports many projects that benefit communities throughout its service territory. In addition, UGI invests more than $1.5 million annually to support education improvement programs, including $270,000 in the overlapping UGI Electric and UGI Gas service territories.

The identified initiatives, as described by the Company's witnesses, demonstrate UGI Electric's commitment to providing and improving its provision of safe, reliable, and quality distribution services to its customers. The Company believes that its management efforts, system investments, and continued provision of safe and reliable service at reasonable rates, as detailed by the witnesses in this proceeding, all support an additional upward adjustment to the Company's rate of return. This upward adjustment is included in the 11.30% return on common equity requested by the Company and discussed in the direct testimony of Paul R. Moul (UGI Electric Statement No. 9).

IV. OVERVIEW OF FILING

Included with UGI Electric's filing are all of the supporting data required by the Commission's regulations. This information provides data for a historic test year ended September 30, 2022, a future test year ending September 30, 2023, and the fully projected future test year ending September 30, 2024. Because of the adverse impact of regulatory lag when rates are established using a historic test year, the Company has elected to use the fully projected future test year as the basis for its proposed revenue requirement.

UGI Electric has followed Commission ratemaking practice and precedent in preparing its claims for rate base, operating revenues, and operating expenses. Rate base was determined based on depreciated original cost values for projected plant in service at the end of the fully projected future test year ending September 30, 2024, inclusive of the Company's LTIIP accelerated replacement capital, IT investments, and other used and useful infrastructure to support growth and service reliability as detailed in the direct testimony of Vicky A. Schappell (UGI Electric Statement No. 5). The Company's rate base claim also includes reasonable estimates for materials and supplies inventory and cash working capital, as well as standard deductions for accumulated depreciation, accumulated deferred income taxes, and customer deposits. The Company's rate base claims are shown in summary form in Schedule C-1 to Exhibit A-1 (Fully Projected Future) and are supported by the direct testimony of Vivian K. Ressler (UGI Electric Statement No. 3).

UGI Electric's *pro forma* test year operating expenses were derived from its fiscal year 2024 operating budget. Based on the analysis of Company witness Tracy A. Hazenstab (UGI Electric Statement No. 2), certain operating expenses were annualized, normalized, and otherwise adjusted in accordance with standard ratemaking practice, as detailed in Section D of Exhibit A (Fully Projected Future). UGI Electric's claim for depreciation and amortization expense is supported by Exhibit C (Fully Projected Future) to the filing, and exhibits developed and supported by John F. Wiedmayer of Gannett Fleming Valuation and Rate Consultants, LLC (UGI Electric Statement No. 7). Mr. Wiedmayer's calculations are based on the straight-line, remaining life method previously approved for UGI Electric's operations by the Commission. Company witnesses Christopher R. Brown (UGI Electric Statement No. 1) and Eric W. Sorber (UGI Electric Statement No. 4) also discuss the Company's efforts to contain costs and obtain efficiencies.

UGI Electric's income tax expense also was calculated using procedures previously accepted by the Commission. The Company's filing reflects, for federal income tax purposes, the normalization of book-tax timing differences related to UGI Electric's use of accelerated depreciation for tax purposes. Other appropriate book-tax timing differences were flowed-through for ratemaking purposes. The Company's tax claims are supported in the direct testimony of Darin T. Espigh (UGI Electric Statement No. 8).

Through this filing, UGI Electric is proposing to allocate the proposed revenue requirement to all customer classes based on the results of a class cost of service study. The proposed revenue allocation moves each rate class closer to the system average rate of return. Details regarding the rate of return are provided in the direct testimony of Paul R. Moul (UGI Electric Statement No. 9). Additional details regarding the Company's cost of service study and revenue allocation are provided in the direct testimony of UGI Electric witness John D. Taylor of Atrium Economics, LLC (UGI Electric Statement No. 6).

With respect to rate design, UGI Electric is proposing to increase the customer charges for Rate R and Rate GS-1. Otherwise, the rates and rate design for the Company's customers will essentially remain the same. Company witness Mr. Taylor sponsors the tariff changes related to the Rate FCP. Mr. Sorber discusses tariff changes regarding the provision of decorative lighting features and the market phase out of certain outdoor lighting bulb types. UGI Electric witness Sherry A. Epler (UGI Electric Statement No. 10) discusses the tariff changes and clarifications included in UGI Electric's Tariff No. 6, Supplement 51, and the minor changes to the Choice Supplier Tariff, which is incorporated into UGI Electric's Tariff No. 2S, Supplement No. 7.

V. <u>CONCLUSION</u>

As set forth in UGI Electric's filing, the proposed revenue increase is the minimum increase necessary for UGI Electric to continue providing safe and reliable service, to maintain the integrity of its existing capital, to attract additional capital at reasonable rates, and to have a reasonable opportunity to earn a fair rate of return on its property used and useful in rendering electric service to the public within its service territory. Moreover, the Company's proposed revenue allocation and rate design and proposed tariff changes are just and reasonable and non-discriminatory. Therefore, the rates, rules, and terms and conditions of service set forth in UGI Electric's Proposed Supplements to Tariff Nos. 6 and 2S should be permitted to become effective as filed.

PLAIN LANGUAGE - STATEMENT OF REASONS

UGI UTILITIES, INC. – ELECTRIC DIVISION
2023 Base Rate Case
Docket No. R-2022-3037368

PLAIN LANGUAGE
STATEMENT OF REASONS

UGI Utilities, Inc. – Electric Division ("UGI Electric") has asked the Pennsylvania Public Utility Commission ("Commission") to approve new rates that would increase annual revenues for its electric distribution service by $11.4 million, or an increase in total revenues of approximately 7.5%.

The main reasons for the rate increase are:

- UGI Electric continues to invest in electric plant needed to provide continued safe and reliable service. From 2022 through 2024, UGI Electric will invest approximately $70.5 million in repair, replacement, and modernization of its aging infrastructure and other necessary improvements. These investments are needed to ensure a well-maintained and reliable system that can meet the current and future expectations of UGI Electric's customers.
- Despite reasonable efforts to help control expenses and increase efficiencies, UGI Electric's costs continue to increase in several areas, including salaries and wages for field and administrative employees and the cost of products and services.
- Without substantial rate relief, UGI Electric will not be able to earn a fair return on its investment used to serve the public and, if not addressed, this could adversely affect the integrity of its financial ratings and its ability to attract the capital needed to make the system investments necessary to support and ensure continued system reliability, safety, and customer service performance.

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

In support of its rate increase, UGI Electric has filed all of the supporting data required by the Commission's regulations, as well as the written statements of 10 witnesses and numerous exhibits prepared by those witnesses. The data, testimony, and exhibits submitted by UGI Electric comply with the Commission's filing requirements. The proposed distribution revenue increase is the minimum increase necessary for UGI Electric to earn a fair rate of return on used and useful property employed to provide safe and reliable service to the public within its service territory.

SECTION 53.52 - FILING REQUIREMENTS

UGI UTILITIES, INC. – ELECTRIC DIVISION

Proposed Changes to UGI Utilities, Inc. – Electric Division
Supplement No. 51 to UGI Electric Pa. P.U.C. No. 6 and
Supplement No. 7 to UGI Electric Pa. P.U.C. No. 2S

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

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

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

UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company") has provided a Statement of Reasons describing the necessity for the changes proposed in this filing.

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

62,877 customers and 9,120 lighting fixtures as of September 30, 2024.

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

Tariff Rate	Customers
R	54,996
BLR	3
GS-1	5,275
GS-4	2,329
GS-5	56
FCP	7
LP	211
Lighting	9,120 (fixtures)

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

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

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

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

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

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

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

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

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

Not applicable.

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

The Company has not undertaken any polls.

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

The Company will notify customers of the proposed changes by direct mailing a printed notice to all customers using the form of notices specified by the Commission at 52 Pa. Code § 53.45. In addition, the Company will issue a press release and paid advertisements on the date of filing as well as posting notices at the Company's headquarters and website at https://www.ugi.com/notices/ .

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

Schedule D-11 of UGI Electric Exhibit A (Fully Projected) includes claims related to uncollectible accounts expense in accordance with the Commission's May 13, 2020 Secretarial Letter regarding COVID-19 Cost Tracking and Creation of Regulatory Asset at Docket No. M-2020-3019775, as discussed in the Direct Testimony of Vivian K. Ressler (UGI Electric Statement No. 3).

(b) Applicable to changes in rates.

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

The Company has provided a Statement of Reasons describing the necessity of this filing. In addition, please see the Direct Testimony of Christopher R. Brown, UGI Electric Statement No. 1, John D. Taylor, UGI Electric Statement No. 6, and Sherry A. Epler, UGI Electric Statement No. 10.

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

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

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

Tariff Rate	Customers
R	54,996
BLR	3
GS-1	5,275
GS-4	2,329
GS-5	56
FCP	7
LP	211
Lighting*	6,826 (Fixtures)

*Partial

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

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

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

Tariff Rate	Customers
Lighting*	2,294 (Fixtures)

*Partial

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

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

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

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

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

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

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

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

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

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

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

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

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

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

None.

I. GENERAL FILING INFORMATION

I-A-1

Request:

Provide a summary discussion of the rate change request, including specific reasons for each increase or decrease. Also provide a breakdown which identifies the revenue requirement value of the major items generating the requested rate change.

Response:

Please refer to UGI Electric Exhibit A (Historic), UGI Electric Exhibit A (Future), and UGI Electric Exhibit A (Fully Projected), Schedules A-1. Also, please see the Direct Testimony of Christopher R. Brown, UGI Electric Statement No. 1.

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

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I-A-2

Request:

Identify the proposed witnesses for all statements and schedules of revenues, expenses, taxes, property, valuation and the like.

Response:

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

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

I-A-3

Request:

Provide a single page summary table showing, at present and at proposed rates, together with references to the filing information, the following as claimed for the fully adjusted test year:

Revenues
Operating Expenses
Operating Income
Rate Base
Rate of Return (produced)

Response:

Please see Attachment I-A-3.

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

UGI Utilities, Inc. - Electric Division
PUC Jurisdictional
Test Year Ended September 30, 2024
(Thousands of Dollars)

	AT PRESENT RATES		AT PROPOSED RATES	
	Amount	**Exhibit A - Fully Projected Future Reference**	**Amount**	**Exhibit A - Fully Projected Future Reference**
Revenue	152,691	Schedule A-1, Col. [3], Line 12	164,116	Schedule A-1, Col. [5], Line 12
Operating Expenses	(145,378)	Schedule A-1, Col. [3], Line 13	(146,304)	Schedule A-1, Col. [5], Line 13
Operating Income	6,490	Schedule A-1, Col. [3], Line 17	14,038	Schedule A-1, Col. [5], Line 17
Rate Base	172,242	Schedule A-1, Col. [3], Line 8	172,242	Schedule A-1, Col. [5], Line 8
Rate of Return	3.768%	Schedule A-1, Col. [3], Line 18	8.150%	Schedule A-1, Col. [5], Line 18

I-A-4

Request:

Whenever a major generating plant is placed in operating service or removed from operating service the utility shall separately indicate the effect of the plant addition or removal from service upon rate base, revenue, expense, tax, income and revenue requirement as it affects the test year.

Response:

As UGI Electric does not own any generation plants, this filing requirement is not applicable to this rate filing.

Prepared by or under the supervision of: Eric W. Sorber

I-B-1

Request:

Provide a corporate history including the dates of original incorporation, subsequent mergers and acquisitions. Indicate all counties, cities and other governmental subdivisions to which service is provided, including service areas outside this Commonwealth, and the total number of customers or billed units in the areas served.

Response:

UGI Utilities, Inc. ("UGI") was organized in 1882 under the name "The United Gas Improvement Company" and changed its name to "UGI Corporation" in 1968. In 1992, UGI adopted its current name when it became, as it remains today, a wholly-owned subsidiary of a newly-formed holding company that adopted the name UGI Corporation.

UGI's electric and gas operations are separated into two operating divisions. UGI's gas operations ("UGI Gas") are headquartered in Denver, Pennsylvania; while UGI's electric operations ("UGI Electric") are headquartered in Wilkes-Barre, Pennsylvania.

UGI Electric can trace its origins to the 1925 acquisition by UGI of the American Gas Co., which owned the Luzerne County Gas and Electric corporation. In 1953, as authorized by a Certificate of Public Convenience issued by the Commission on June 16, 1952, at Docket No. A.78264, all of UGI's Pennsylvania public utility subsidiaries, including the Luzerne County Gas and Electric Company, were merged into UGI.

In 1967, UGI acquired the Harvey's Lake Light Company, whose 113 square mile service territory, along with the electric service territory of the former Luzerne County Gas and Electric Corporation, comprise the current service territory of UGI Electric. That service territory is identified in the list of communities served in UGI Electric's tariff. See UGI Electric Exhibit F. UGI Electric currently provides electric distribution service to approximately 60,000 residential, commercial and industrial electric customers in Luzerne and Wyoming Counties and 35 municipalities.

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

I-B-2

Request:

Provide a description of the property of the utility and an explanation of the system's operation, and supply the following, using available projections if actual data is unavailable:

a. A schedule of generating capability showing for the test year, and for the two consecutive 12-month periods prior to the test year, net dependable capacity in KW by unit, plant capacity factor by unit, and total fuel consumption by type and cost for each unit, if available, or for each station, and operation and maintenance expenses by station.

b. A schedule showing for the test year and for the 12-month period immediately prior to the test year the scheduled and unscheduled outages—in excess of 48 hours—for each station, the equipment or unit involved, the date the outage occurred, duration of the outage, maintenance expenses incurred for each outage, if available, and amounts reimbursable from suppliers or insurance companies.

c. A schedule for each unit retired during the test year or subsequent to the end of the test year, which shows the unit's KW capacity, hours of operation during the test year, net output generated, cents/KWH of maintenance and fuel expenses, and date of retirement.

d. A schedule showing latest projections of capacity additions and retirements—costs and KW— and reserve capacity at the time of peak for at least 10 years beyond the test year, including the inservice dates—actual or expected—and AFDC cutoff dates—if different from inservice dates— for all new generating units coming on line during or subsequent to the test year, if claimed.

Response:

As UGI Electric does not own any generation plants, this filing requirement is not applicable to this rate filing.

Prepared by or under the supervision of: Eric W. Sorber

I-B-3

Request:

Provide an overall system map, including and labeling all generating plants, transmission substations—indicate voltage, transmission system lines—indicate voltage, and all interconnection points with other electric utilities, power pools, and other like systems.

Response:

UGI Electric's overall system map includes Critical Energy Infrastructure Information and is, therefore, not included herein.

Prepared by or under the supervision of: Eric W. Sorber

II. PRIMARY STATEMENT OF RATE BASE & OPERATING INCOME

II-A-1

Request:

Provide a schedule showing the test year rate base and rates of return at original cost less accrued depreciation under present rates and under proposed rates. Claims made on this schedule should be cross-referenced to appropriate supporting schedules.

Response:

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

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

II-A-2

Request:

If the schedule provided in response to item 1, is based upon a future test year, provide a similar schedule which is based upon actual data for the 12-month period immediately prior to the test year.

Response:

Please refer to UGI Electric Exhibit A (Historic), Schedule A-1.

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

II-A-3

Request:

When a utility files a tariff stating a new rate based in whole or in part on the cost of construction, as defined in 66 Pa.C.S. § 1308(f) (relating to voluntary changes in rates), of an electric generating unit, the utility shall identify:

(a) The total cost of the generating unit.

(b) The following costs:

(1) The cost and quantity of each category of major equipment, such as switchgear, pumps or diesel generators and the like.

(2) The cost and quantity of each category of bulk materials, such as concrete, cable and structural steel and the like.

(3) Manual labor.

(4) Direct and indirect costs of architect/engineering services.

(5) Direct and indirect costs of subcontracts or other contracts involving major components or systems such as turbines, generators, nuclear steam supply systems, major structures and the like.

(6) Distributed costs.

(c) A cost increase of $5 million or more, including AFUDC, over the original utility estimates provided under 66 Pa.C.S. § 515(a) (relating to construction cost of electric generating units) and its causes.

(d) Compliance with subsections (a) and (b) will be identical in format and substance as that provided under 52 Pa. Code § 57.103 (relating to estimate of construction costs) for original cost estimates submitted under 66 Pa.C.S. § 515(a).

II-A-3 (Continued)

Response:

As UGI Electric does not own any generation plants, this filing requirement is not applicable to this rate filing.

Prepared by or under the supervision of: Eric W. Sorber

II-B-1

Request:

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

a. A description of the plant or land site and its cost and any accumulated depreciation.

b. The expected date of use for each item claimed.

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

d. The data when each item was acquired.

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

Response:

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

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

II-B-2

Request:

If a claim is made for construction work in progress, provide a supporting schedule which sets forth separately, revenue-producing and nonrevenue producing amounts, and include, for each category a summary of all work orders, amounts expended at the end of the test year and anticipated inservice dates. Indicate if the construction work in progress will result in insurance recoveries, reimbursements, or retirements of existing facilities. Describe in exact detail the necessity of each project claimed if not detailed on the summary page from the work order. Include final completion dates and estimated total amounts to be spent on each project.

Response:

No claim is being made for construction work in progress.

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

II-B-3

Request:

If a claim is made for materials and supplies or fuel inventory provide a supporting schedule for each claim showing the latest actual 13 monthly balances and showing in the case of fuel inventory claims, the type of fuel, and location, as in station, and the quantity and price claimed.

Response:

Please refer to UGI Electric Exhibit A (Historic), UGI Electric Exhibit A (Future), UGI Electric Exhibit A (Fully Projected), Schedule C-8. There is no claim being made for fuel inventory.

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

II-B-4

Request:

If a claim is made for cash working capital provide a supporting schedule setting forth the method and all detailed data utilized to determine the cash working capital requirement. If not provided in the support data provide a lead-lag study of working capital, completed no more than 6 months prior to the rate increase filing.

Response:

Please refer to UGI Electric Exhibit A (Historic), UGI Electric Exhibit A (Future), UGI Electric Exhibit A (Fully Projected), Schedule C-4 for the working capital lead-lag study and the Direct Testimony of Vivian K. Ressler, UGI Electric Statement No. 3.

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

II-B-5

Request:

If a claim is made for compensating bank balances, provide the following information:

a. Name and address of each bank.

b. Types of accounts with each bank—checking, savings, escrow, other services, and the like.

c. Average daily balance in each account.

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

e. Average daily compensating bank balance at each bank.

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

g. Interest earned on each type of account.

h. A calculation showing the average daily float for each bank.

Response:

UGI Electric has no requirements for compensating bank balances with its banks and has not made a claim for this item.

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

II-B-6

Request:

Explain in detail by statement or exhibit the appropriateness of additional claims or the use of a method not previously mentioned, in the claimed rate base.

Response:

Please see UGI Electric Exhibit A (Fully Projected) Schedule C, the Direct Testimony of Eric W. Sorber, UGI Electric Statement No. 4, and the Direct Testimony of Vivian K. Ressler, UGI Electric Statement No. 3, for an explanation and detail of UGI Electric's claim for additional rate base items.

Prepared by or under the supervision of: Eric W. Sorber

II-C-1

Request:

Prepare a Statement of Income including:

a. The book, or budgeted, statement for the test year.

b. Adjustments to annualize and normalize under present rates, including an elimination of the effects on income of the energy cost rate and state tax adjustment surcharge.

c. The income statement under present rates after adjustment.

d. The adjustment for the revenue requested.

e. The income statement under requested rates after adjustment.

Each adjustment, including those relating to adjustment clauses, shall contain an explanation in sufficient clarifying detail to allow a reasonably informed person to understand the method and rationale of the adjustment.

Response:

The information requested in items a. through e. is set forth in UGI Electric Exhibit A (Future), and UGI Electric Exhibit A (Fully Projected). Please see the Direct Testimony of Tracy A. Hazenstab, UGI Electric Statement No. 2, and the Direct Testimony of Sherry A. Epler, UGI Electric Statement No. 10.

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

II-C-2

Request:

If the schedule provided in item 1 is based upon budgeted data for a future test year, provide a similar schedule which is based upon actual data for the 12-month period immediately prior to the test year.

Response:

The information requested is set forth in UGI Electric Exhibit A (Historic). Please see the Direct Testimony of Tracy A. Hazenstab, UGI Electric Statement No. 2, and the Direct Testimony of Sherry A. Epler, UGI Electric Statement No. 10.

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

II-D-1

Request:

Provide a schedule showing all revenues and expenses for the test year and for the 12-month period immediately prior to the test year, together with an explanation for major variances between test year revenues and expenses and those for the previous 12-month period. Revenues and expenses shall be summarized by the major account categories listed below. If budgeted data for a future test year is not readily available by these categories, an analysis of the data for the 12-month period immediately prior to the future test year or for the most recent available calendar year may serve as the basis for ratably allocating the budgeted data into the account categories 400 through 432.

Response:

Please see Attachment II-D-1.

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

UGI UTILITIES, INC. - ELECTRIC DIVISION
SCHEDULE OF REVENUES AND EXPENSES
FUTURE TEST YEAR AND FULLY PROJECTED FUTURE TEST YEAR
(Dollars in Thousands)

		FTY 2023	FPFTY 2024	Increase/ (Decrease)	
	OPERATING REVENUES				
400	**Electric Revenue:**				
	Residential Sales	110,334	111,379	1,045	
	Commercial	29,030	32,053	3,023	A
	Public Street and Highway Lighting	734	748	15	
	Public Authorities	18	19	1	
	Sales for Resale	-	-	-	
	Total Sales Revenue	**140,115**	**144,199**	**4,084**	
	Other Electric Revenue:				
	Forfeited Discounts	520	520	-	
	Misc Service Revenues	16	16	-	
	Rent from Electric Property	567	567	-	
	Other Electric Revenues	10,517	10,323	(194)	
	Total Other Electric Revenue	**11,620**	**11,426**	**(194)**	
	Total Operating Revenue	**151,736**	**155,625**	**3,890**	
	OPERATING EXPENSE				
401-402	**Operation and Maintenance Expense:**				
	Power Purchases	85,651	87,774	2,123	
	Transmission Expenses	8,011	8,254	243	
	Distribution Expenses	12,438	13,259	821	B
	Customer Accounts Expenses	5,245	5,479	234	C
	Customer Service & Information Expenses	32	34	2	
	Sales Expenses	0	0	(0)	
	Administrative and General Expenses	9,961	10,269	309	
	Total Operation & Maintenance Expense	**121,338**	**125,070**	**3,732**	
403-405	Depreciation Expense	9,947	10,751	804	D
408.1	Taxes Other than Income Taxes, utility operating income	9,255	9,523	267	
	Total Operating Expenses Prior to Income Taxes	**140,540**	**145,343**	**4,803**	
	INCOME TAXES, UTILITY OPERATING INCOME				
409.1	Income taxes, utility operating income	2,019	1,312	(708)	E
410.1/411.1	Provision for deferred income taxes, utility operating income	-	-	-	
	Total Income Taxes, Utility Operating Income	**2,019**	**1,312**	**(708)**	
	Operating Income After Income Taxes	**9,176**	**8,970**	**(206)**	
	OTHER INCOME AND DEDUCTIONS				
419	Interest and dividend (income) expense	(20)	(20)	-	
426	Donations and expenditures for civic, political & related	111	112	1	
	Total Other Income & Deductions Expense (Income)	**92**	**93**	**1**	
	INTEREST CHARGES				
427	Interest on Long-term Debt	3,059	3,400	341	F
428	Amortization of Debt Discount and Expense	41	44	3	
431	Other Interest Expenses	532	367	(165)	G
432	Allowance for Borrowed Funds Used During Construction	(208)	(196)	12	
	Total Interest Charges, net	**3,424**	**3,615**	**191**	
	Total Non-Operating Expense Prior to Income Taxes	**3,515**	**3,707**	**192**	

UGI UTILITIES, INC. - ELECTRIC DIVISION
SCHEDULE OF REVENUES AND EXPENSES
FUTURE TEST YEAR AND FULLY PROJECTED FUTURE TEST YEAR
(Dollars in Thousands)

		FTY 2023	FPFTY 2024	Increase/ (Decrease)
	INCOME TAXES, OTHER INCOME AND DEDUCTIONS			
409.2	Income Taxes, other income and deductions	-	-	-
410.2/411.2	Provision for deferred income taxes, other income and deductions	-	-	-
	Total Income Taxes, Other Income and Deductions	-	-	-
	Non-Operating Expense After Income Taxes	**3,515**	**3,707**	**192**
	Net Income	**5,661**	**5,263**	**(398)**

A	The increase in commercial revenue is primarily due to new customer growth.
B	The increase in distribution expenses is due primarily to increases in overhead line maintenance expense.
C	The increase in Customer Accounts Expenses is due primarily to salary, benefit and uncollectible expense increases.
D	The increase in Depreciation Expense is due to additional plant placed in service during 2024, as well as a full year of depreciation in 2024 on the assets placed in service during 2023.
E	The decrease in Income taxes, utility operating income is due to lower pre-tax income.
F	The increase in Interest on Long-term Debt is due to additional debt outstanding in 2024.
G	The decrease in other Interest Expenses is due to a higher short term interest rate in the FTY that is expected to decrease in the FPFTY.

II-D-2

Request:

Provide a summary of test year adjustments which sets forth the effect of the adjustment upon the following: operating revenues, operating expenses, taxes other than income taxes, operating income before income taxes, State income tax, Federal income tax and income available for return. In addition, test year adjustments shall be presented on the basis of the major account categories set out at II-D-1.

Response:

Please see Section D, Schedule D-3 within UGI Electric Exhibit A (Historic), Exhibit A (Future), and Exhibit A (Fully Projected Future).

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

II-D-3

Request:

List and explain all nonrecurring or extraordinary expenses incurred in the test year and all expenses included in the test year which do not occur yearly but are of a nature that they do occur over an extended period of years, for example, nonyearly maintenance programs, and the like.

Response:

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

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

II-D-4

Request:

As a separate item, list extraordinary property losses related to property previously included in cost of service when the gain or loss on this property has occurred or is likely to occur in the future test year. The proposed ratemaking treatment of extraordinary gains and losses must also be disclosed. Sufficient supporting data must be provided.

Response:

No gain or loss was recorded for the 12-month periods ended 9/30/2020, 9/30/2021, or 9/30/2022. No gain or loss is anticipated in either the future or fully projected future test year.

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

II-D-5

Request:

Provide the amount of accumulated reserve for uncollectible accounts, method and rate of accrual, amounts accrued and amounts written off in each of the last 3 calendar years.

Response:

Please see Attachment II-D-5.

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

UGI Utilities, Inc. - Electric Division
Income Statement Supporting Schedules
Schedule of Reserve for Uncollectible Accounts

($ in 000's except for rate of accrual)

	9/30/2020	9/30/2021	9/30/2022
Account 144 - Accumulated Provision for Uncollectible Accounts	$ 1,850	$ 1,948	$ 2,238
Method [1]	Allowance	Allowance	Allowance
Rate of Accrual[2]	2.41%	1.49%	1.70%
Amounts Accrued - Uncollectible Expense[2]	$ 1,015	$ 1,015	$ 2,133
Amounts Written Off (net of recoveries)	$ 1,259	$ 1,232	$ 1,843

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

[2] Fiscal years 2020 and 2021 excludes $1,013 and $315; respectively recorded as a COVID-19 regulatory asset in accordance with the May 13, 2020 Secretarial Letter at Docket No. M-2020-3019775.

II-D-6

Request:

Supply detailed calculations to support the total claim for rate case expense, including supporting data for outside service rendered. Provide the items comprising the estimated rate case expense claim for the current rate case.

Response:

Schedule D-10 of UGI Electric Exhibit A (Fully Projected Future) provides the Company's claim for rate case expense. For further information, please see the Direct Testimony of Tracy A. Hazenstab, UGI Electric Statement No. 2.

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

II-D-7

Request:

Submit schedules for the test year and for the 12-month period immediately prior to the test year showing by major components, if included in claimed test year expenses, the expenses incurred in each of the following expense categories.

a. Miscellaneous general expenses, including account 930.

b. Outside service expenses.

c. Regulatory commission expenses.

d. Advertising expenses, including advertising engaged in by trade associations whenever the utility has claimed a contribution to the trade association as a ratemaking claim—provide explanation of types and purposes of such advertising.

e. Research and development expenses—provide a listing of major projects.

f. Charitable and civic contributions, by recipient and amount.

Explain major variances between the test year expenses and those expenses for the prior 12-month period.

Response:

a. Please see Attachment II-D-7(a).

b. Please see Attachment II-D-7(b).

c. The expenditures associated with Account 928 – Regulatory Commission Expenses are $225,000, $481,000 and $446,000 for 2022, 2023 and 2024, respectively, and are related to costs associated with the most recent rate case and other professional expenses.

d. Please see Attachment II-D-7(d).

II-D-7 (Continued)

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

f. UGI Electric does not claim any charitable or civic contributions in the historic, future, or fully projected future test years.

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

UGI UTILITIES, INC. - ELECTRIC DIVISION
SCHEDULE OF ACCOUNT 930.2 – MISCELLANEOUS GENERAL EXPENSES
FOR THE YEARS ENDING SEPTEMBER 30, 2022 THROUGH 2024

Expenditure Type (*in Thousands*)	**2022**	**2023**	**2024**
ASSOCIATION DUES	79	61	68
EMPLOYEE BUSINESS EXPENSE	23	19	21
OTHER EXPENSES	68	136	157
GRAND TOTAL	170	216	246
Less: 19.95% allocable to Transmission	(34)	(43)	(49)
Portion claimed for Distribution	136	173	197

UGI UTILITIES, INC. - ELECTRIC DIVISION
SCHEDULE OF ACCOUNT 923 – OUTSIDE SERVICES EMPLOYED
FOR THE YEARS ENDING SEPTEMBER 30, 2022 THROUGH 2024

Expenditure Type (*in Thousands*)	**2022**	**2023**	**2024**
CORPORATE ALLOCATION	622	745	760
INFORMATION TECHNOLOGY	283	458	488
LEGAL SERVICES	324	108	116
PROFESSIONAL FEES	222	287	301
INSURANCE	474	734	693
MATERIALS, MAINTENANCE AND EQUIPMENT	18	2	2
OTHER EXPENSES	6	(3)	(3)
GRAND TOTAL	1,949	2,329	2,357
Less: 19.95% allocable to Transmission	(389)	(465)	(470)
Portion claimed for Distribution	1,560	1,865	1,887

UGI UTILITIES, INC. - ELECTRIC DIVISION
ADVERTISING EXPENSE
FOR THE YEARS ENDING SEPTEMBER 30, 2022 THROUGH 2024

Expenditure Type (*in Thousands*)	**2022**	**2023**	**2024**
SUMMARY BY PURPOSE			
CONSERVATION OF ENERGY	23	15	16
EXPLANATION OF BILL PRACTICES, RATES, ETC	33	83	92
PUBLIC HEALTH AND SAFETY	2	2	2
OTHER ADVERTISING PROGRAMS	20	27	30
	78	127	141
SUMMARY BY MEDIA			
PRINT	63	44	48
BILL INSERT	2	16	18
DIGITAL	8	1	1
OTHER	4	66	74
	78	127	141
Less: 19.95% allocable to Transmission	(15)	(25)	(28)
Portion claimed for Distribution	62	102	113

II-D-8

Request:

Provide an analysis by function of charges by affiliates, for the test year and the 12-month period immediately prior to the test year, for services rendered included in the operating expenses of the filing company. Explain the nature of the service and the basis on which charges or allocations are made, including a copy of an applicable contract. Also, explain major variances between the charges for the test year and the corresponding charges for the prior 12-month period.

Response:

Please see Attachment II-D-8.1 for Charges Imposed by Affiliates. For Affiliate Interest Agreements and the applicable contracts, please see Attachment II-D-8.2.

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

UGI UTILITIES, INC. - ELECTRIC DIVISION
CHARGES IMPOSED BY AFFILIATES
FOR THE YEARS ENDED SEPTEMBER 30, 2023 AND 2024
(in Thousands of Dollars)

Charges to Electric Distribution	**FTY 2023**	**FPFTY 2024**
UGI Corporation		
UGI Corporation Allocation		
Administrative services - Allocation	$ 1,747	$ 1,793
Administrative services - Shared Executive Functions	115	118
Administrative services - Shared Service Center	108	111
Insurance Expense	606	619
Other Professional Services Expense	228	232
UGI Amerigas - IT Support	16	16
UGI International - IT Support	10	10
UGI Energy Services - IT Support	86	86
Total	$ 2,917	$ 2,985

UGI UTILITIES, INC. - ELECTRIC DIVISION
List of Affiliated Interest Agreements

Affiliate	Effective Dates	Docket#	Details
UGI Corporation	May 1992	G-00920296	This Agreement sets forth the terms by which Utilities may provide administrative services to or receive services from Holding Company and its unregulated subsidiaries. These services will be provided on a cost basis.
	November 2016	G-2016-2543527	UGI Electric received the right to purchase power through its Commission-approved POLR supply plan and RFP process from any affiliate, and to receive a guarantee from an affiliate (such as UGI Corporation) as performance assurance for any POLR supply contracts with an affiliate (such as UGI Energy Services).
United Valley Insurance Co	June 1993	G-00930344	Affiliate Interest Agreement for insurance coverage through United Valley Insurance Co. Coverage through the affiliate is not mandatory and may be purchased through other independent companies when costs or coverage are more advantageous.

UGI Corporation Affiliated Interest Agreement G-00920296

RECD MAY 22 1992

TMJ-600-0045

COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
P.O. BOX 3265, HARRISBURG, PA 17105-3265

May 21, 1992

IN REPLY PLEASE
REFER TO OUR FILE

G-00920296

RICHARD L BUNN
UGI CORPORATION
PO BOX 13009
READING PA 19612-3009

Affiliated Interest Agreement Between
UGI Corporation and UGI Utilities, Inc.

To Whom It May Concern:

This is to advise you that an Opinion and Order has been adopted by the Commission in Public Meeting on May 21, 1992 in the above entitled proceeding.

An Opinion and Order has been enclosed for your records.

Very truly yours,

John G. Alford

John G. Alford, Secretary

smk
Encls.
Cert.Mail

UGI Corporation Affiliated Interest Agreement G-00920296

Both Copy

UGI CORPORATION

BOX 858 VALLEY FORGE PA. 19482 ▪ 215-337-1000

April 30, 1992

FEDERAL EXPRESS

The Honorable John G. Alford, Secretary
Commonwealth of Pennsylvania
Public Utility Commission
North Office Bldg., Room B-18
P.O. Box 3265
Commonwealth and North Streets
Harrisburg, PA 17120

Re: Administrative Services Agreement between UGI Utilities, Inc. and UGI Corporation, an Affiliated Interest

Dear Secretary Alford:

Enclosed for filing with the Pennsylvania Public Utility Commission ("Commission") pursuant to Section 2102 of the Public Utility Code, 66 Pa.C.S. §2102, are an original and two (2) conformed copies of an Administrative Services Agreement dated May 1, 1992 "(Agreement") between UGI Corporation and UGI Utilities, Inc.

As part of a corporate reorganization pursuant to a Plan of Merger approved by shareholders on April 9, 1992, the former UGI Corporation became a wholly owned subsidiary of New UGI Corporation, a holding company. The reorganization became effective on April 10, 1992. New UGI Corporation changed its name to UGI Corporation and the former UGI Corporation changed its name to UGI Utilities, Inc. In order to avoid potential confusion arising out of the name changes, "new" UGI Corporation is hereafter referred to as "Holding Company" and UGI Utilities is referred to as "Utilities."

Utilities is a public utility subject to the Commission's jurisdiction and is a wholly owned subsidiary of Holding Company. Holding Company is a Pennsylvania corporation and owns all of the outstanding common stock of Utilities. The Agreement sets forth the terms by which Utilities may provide administrative services to or receive services from Holding Company and its unregulated subsidiaries. The administrative services are essentially the same as those historically provided by Utilities to its unregulated subsidiaries prior to the formation of the current holding company structure.

ROUTE 363 AT PENNA. TURNPIKE INTERCHANGE, VALLEY FORGE

The Agreement contemplates that certain of the services formerly provided by Utilities Corporate Headquarters Group may be provided by Holding Company. The method of allocating the costs to be charged for these services is essentially the same as the method traditionally employed by Utilities. This allocation method was reviewed and approved as part of the Commission's Management and Operations Study of Utilities conducted in 1989.

To assist in the Commission's review, the following is a summary of the more significant terms of the Agreement:

- o The administrative services to be provided by Holding Company after full implementation of the Agreement may include management, finance, pension fund management, internal audit, legal, shareholder relations, human resources, insurance, claims, legal, and similar types of services;

- o The administrative services to be provided by Utilities after full implementation of the Agreement may include information services, payroll, accounts payable, accounting and similar types of services;

- o Utilities and Holding Company will pay to each other the actual cost of the services each receives;

- o Utilities and Holding Company will bill each other for the services each provides on a monthly basis and maintain separate accountability;

- o All services provided by Utilities will be on an "as available" basis to assure that Utilities' provision of such services will not interfere with its obligation to provide gas and electric service to the public.

- o The duties, obligations and liabilities of Utilities and Holding Company are several and not joint or collective, assuring that Utilities will not be responsible for any obligation or liability of Holding Company.

I have enclosed a duplicate copy of this letter and ask that it be stamped as received by your office and returned to me in the enclosed self-addressed stamped envelope. If any additional information is required, please call.

Very truly yours,

Thomas M. Jackal
Counsel

TMJ/klb

Enclosures

The Honorable John G. Alford, Secretary
April 30, 1992
page 4

bcc: J. C. Barney
A. S. Becker
A. C. Bullman
R. L. Bunn
M. J. Cuzzolina
R. R. Eynon
W. M. Graff
L. R. Greenberg
D. N. Knipel
C. L. Ladner
J. A. Lubas
S. R. Mauriello
J. A. Sutton
G. W. Westerman

ADMINISTRATIVE SERVICES AGREEMENT

THIS AGREEMENT made as of this 1st day of May, 1992, between UGI Corporation ("Holding Company"), a Pennsylvania corporation, and UGI Utilities, Inc. ("Utilities"), a Pennsylvania corporation.

WITNESSETH:

WHEREAS, Utilities is a public utility providing natural gas and electric service subject to regulation by the Pennsylvania Public Utility Commission ("Commission") and is a wholly owned subsidiary of Holding Company; and

WHEREAS, Holding Company, under its articles, has unlimited power to engage in any lawful act concerning any lawful business for which corporations may be incorporated under the Pennsylvania Business Corporation Law and was formed for the purpose of separating Utilities' regulated and former unregulated operations; and

WHEREAS, as a part of the transactions related to formation of the holding company organization, Utilities may transfer to Holding Company certain employees of Utilities' former corporate headquarters group for the purpose of providing administrative services to Utilities and unregulated subsidiaries; and

WHEREAS, the parties wish to provide and receive the administrative services under the terms and conditions set forth herein; and

WHEREAS, under the affiliated interest provisions of the Pennsylvania Public Utility Code ("Code") Holding Company is an affiliated interest of Utilities and any agreement between Holding Company and Utilities for the provision of administrative services must be filed with and approved by the Commission;

NOW THEREFORE, in consideration of the premises and of the mutual covenants of this Agreement and for other valuable consideration, received and acknowledged, and intending to be legally bound hereby, Holding Company and Utilities agree as follows:

1. Services.

(a) Holding Company agrees to provide such administrative services as may from time to time be requested by Utilities. These services may include but are not limited to executive management, finance, pension fund management, internal audit, legal, shareholder relations, human resources, insurance, claims, and similar types of services.

(b) Utilities agrees to provide such administrative services as may from time to time be requested by Holding Company or any of its subsidiaries on an "as available" basis. These services may include but not limited to information services, payroll, accounts payable, accounting and similar types of services.

2. Payment etc..

(a) Each party shall pay to the party providing the administrative services pursuant to Section 1, the actual cost of providing such services. In this regard, the party providing the services shall provide monthly to the party receiving the services an invoice and written documentation of the cost of providing the services pursuant to Section 1; the invoice shall be due and payable within 30 days after its receipt. When it is not reasonably possible or practical to determine actual costs, the parties may substitute allocation factors for actual costs.

(b) All such costs incurred by one party on behalf of the other (i) shall become the liability of the party receiving the services when incurred by the party providing the service, (ii) shall be determined in accordance with generally accepted accounting principles and (iii) shall include reasonable and appropriate indirect costs including overhead, as set forth on Attachment 1 to this Agreement.

(c) Holding Company may assume any liability of Utilities.

(d) Where Holding Company assumes any benefit, compensation, retirement or other similar plan of Utilities, Utilities may from time to time make payments to Holding Company in amounts not to exceed the payments Utilities would have been required to make at those times to beneficiaries under such plans had the plans not been assumed.

3. Agency.

(a) All services, materials, equipment and supplies purchased by Utilities at the request of Holding Company shall be purchased by Utilities on behalf of and as agent for

Holding Company. In that regard, Holding Company hereby appoints Utilities as its agent, and Utilities agrees as its agent to negotiate, execute and enforce contracts (including purchase order contracts) providing for the purchase of services, materials, equipment and supplies. Each such contract shall be made in the name of Holding Company and shall, among other things, provide that Utilities shall be agent for Holding Company concerning the administration of the contract and that performance of the contract shall be for the account of, title to all property acquired thereunder shall vest in, and charges therefor shall be paid by Holding Company.

(b) All services, materials, equipment and supplies purchased by Holding Company at the request of Utilities shall be purchased by Holding Company on behalf of and as agent for Utilities. To the extent permitted by law and without delegating any of its public service obligations, Utilities hereby appoints Holding Company as its agent, and Holding Company agrees as Utilities' agent to negotiate, execute and enforce contracts (including purchase order contracts) providing for the purchase of services, materials, equipment and supplies. Each such contract shall be made in the name of Utilities and shall, among other things, provide that Holding Company shall be agent for Utilities concerning the administration of the contract and that performance of the contract shall be for the account of, title to all property acquired thereunder shall vest in, and charges therefor shall be paid by Utilities.

4. Subsidiary Participation. Holding Company as used herein includes all subsidiary companies of UGI Corporation other than UGI Utilities, Inc.

5. Obligations Several. The duties, obligations and liabilities of Holding Company and Utilities under this Agreement are intended to be several and not joint or collective, and nothing in this Agreement shall ever be construed to create an association, joint venture, trust or partnership, or to impose a trust or partnership duty, obligation or liability on or with regard to any of the parties. Each party shall be individually responsible for its own obligations as herein provided. No party shall be under the control of or shall be deemed to control the other party solely by virtue of this Agreement. No party shall have a right or power to bind another party without its express written consent, except as expressly provided in this Agreement.

6. Termination. Any party shall have the right at any time to terminate this Agreement upon ninety (90) days written notice of its election to do so.

UGI Corporation Affiliated Interest Agreement G-00920296

7. Regulatory Approval. This Agreement is subject to the approval of the Commission, and shall be immediately effective upon receipt of such approval.

ATTEST:

David N. Knipel
DAVID N. KNIPEL, SECRETARY

UGI CORPORATION

By: George W. Westerman
George W. Westerman
Senior Vice President - Administration

ATTEST:

David N. Knipel
DAVID N. KNIPEL, SECRETARY

UGI UTILITIES, INC.

By: C. L. Ladner
Charles L. Ladner
Vice President

Attachment 1

Each party receiving the benefit of the administrative services shall pay the actual cost of the services provided. The cost of these administrative services will be allocated using a two-step process:

- Direct Charge - If charges can reasonably be determined to benefit only one particular party they will be charged directly to that organization.
- Allocation - If charges benefit more than one party, but a reasonable separation of the charges cannot be readily made, they will be allocated to applicable organizations based upon predetermined formulas.

PENNSYLVANIA
PUBLIC UTILTY COMMISSION
Harrisburg, PA 17105-3265

Public Meeting held November 9, 2016

Commissioners Present:

Gladys M. Brown, Chairman, Statement, Dissenting
Andrew G. Place, Vice Chairman
John F. Coleman, Jr.
Robert F. Powelson
David W. Sweet, Dissenting

Petition of UGI Utilities, Inc. – Electric	:	
Division For Approval of a Default Service	:	P-2016-2543523
Plan and Retail Market Enhancement	:	G-2016-2543527
Programs for the Period of June 1, 2017	:	
through May 31, 2021, and Associated	:	
Potential Affiliated Interest Transactions	:	

ORDER

BY THE COMMISSION:

We adopt as our action the Recommended Decision of Administrative Law Judges Angela T. Jones, dated October 3, 2016;

THEREFORE,

IT IS ORDERED:

1. That the Joint Petition for Settlement filed by UGI Utilities, Inc. – Electric Division, the Office of Consumer Advocate, and the Office of Small Business Advocate in the case captioned Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default

Service Plan and Retail Market Enhancement Programs for the Period of June 1, 2017, through May 31, 2021, and Associated Potential Affiliated Interest Transactions, Docket Nos. P-2016-2543523 and G-2016-2543527, is approved without modification.

2. That the default service program as set forth in UGI Utilities, Inc. – Electric Division's petition is approved as modified by the Joint Petition for Settlement.

3. That the request for affiliated interest approval for transactions with a UGI Utilities, Inc., affiliate(s) in the event such an affiliate(s) submits a winning bid under the default service program's proposed RFP processes and that bid is accepted by the Commission, is granted.

4. That the request that the Commission grant any waivers required to implement the default service program set forth in the petition, including a waiver of the Commission's regulation at 52 Pa.Code § 54.187 to allow UGI Utilities, Inc. – Electric Division to acquire default supplies for the GSR-1 and GSR-2 customer groups as described in the petition and modified by the Settlement Agreement is granted.

5. That UGI Utilities, Inc. – Electric Division is authorized to file tariff sheets substantially similar in the form of the pro forma tariff sheets included with the Settlement Agreement as Appendix "A" on or before May 2, 2017, to be effective June 1, 2017.

6. That UGI Utilities, Inc. – Electric Division is authorized to file tariff sheets no later than thirty days in advance of each quarter beginning June 1, 2017, specifying the applicable GSR-1 Group default service rates for the prospective quarter.

7. That UGI Utilities, Inc. – Electric Division's proposed retail choice market enhancement programs as modified by the Settlement are approved, including, to the extent required, any affiliated interest approvals necessary for UGI Utilities, Inc. – Electric Division affiliates to participate in such programs.

8. That UGI Utilities, Inc. – Electric Division's use of Pace Global Energy Services, LLC as its independent third party evaluator and monitor of AEPS credit for procurement and supply is approved.

9. That the request for admission of testimony and exhibits listed in Attachment A of the Recommended Decision is granted.

10. That the testimony and exhibits listed in Attachment A of the Recommended Decision are admitted.

BY THE COMMISSION

Rosemary Chiavetta
Secretary

(SEAL)

ORDER ADOPTED: November 9, 2016

ORDER ENTERED: November 9, 2016

AIA UGIU Insurance G-00930344

COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
P.O. BOX 3265, HARRISBURG, PA 17105-3265

June 10, 1993

IN REPLY PLEASE REFER TO OUR FILE

G-00930344

T.M.J. JUN 14 1993

THOMAS M JACKAL ESQUIRE
UGI UTILITIES INC
460 NORTH GULPH ROAD
PO BOX 858
VALLEY FORGE PA 19483-0858

Affiliated Interest Agreement between
UGI Utilities, Inc. and an as yet unformed
Affiliated Insurance Company, whose primary
purpose will be to provide insurance coverage
to all UGI Utilities

To Whom It May Concern:

This is to advise you that an Opinion and Order has been adopted by the Commission in Public Meeting on June 10, 1993 in the above entitled proceeding.

An Opinion and Order has been enclosed for your records.

Very truly yours,

John G. Alford

John G. Alford, Secretary

smk
Encls.
Cert.Mail

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA. 17105-3265

Public Meeting held June 10, 1993

Commissioners Present:

David W. Rolka, Chairman
Joseph Rhodes, Jr., Vice Chairman
John M. Quain
John Hanger

Affiliated Interest Agreement between UGI Utilities, Inc. and an as yet unformed Affiliated Insurance Company, whose primary purpose will be to provide insurance coverage to all UGI Utilities — G-00930344

OPINION AND ORDER

BY THE COMMISSION:

On May 17, 1993, UGI Utilities, Inc. filed a verified summary of an Agreement with an as yet unformed Affiliated Insurance Company, whose primary purpose will be to provide insurance coverage to all UGI Utilities. Upon review of the Agreement, staff found need for further information.

Section 2102 (b) of the Public Utility Code, 66 Pa. C.S. § 2102 (b), provides that the agreement shall be deemed approved if a written order is not entered at the end of thirty days after the filing of the agreement, unless the Commission extends the thirty day period. In order to adequately review the agreement, it is necessary that we extend the consideration period for an additional sixty days, or to August 15, 1993; **THEREFORE,**

IT IS ORDERED: That the period for consideration of the Affiliated Interest Agreement filed by UGI Utilities, Inc. on May 17, 1993, to become effective June 16, 1993, is hereby extended for an additional sixty days, or to August 15, 1993.

BY THE COMMISSION,

John G. Alford
Secretary

(SEAL)

ORDER ADOPTED: June 10, 1993

ORDER ENTERED: June 10, 1993

AIA UGIU Insurance G-00930344

UGI UTILITIES, INC.

UGI Utilities, Inc
460 North Gulph Road
King of Prussia, PA 19406

Post Office Box 858
Valley Forge, PA 19482-0858

(215) 337-1000 Telephone
(215) 992-3258 Fax

May 17, 1993

OVERNIGHT MAIL

The Honorable John G. Alford, Secretary
Pennsylvania Public Utility Commission
North Office Bldg., Room B-18
Commonwealth and North Streets
Harrisburg, PA 17105-3265

Re: Insurance Arrangement between UGI Utilities, Inc. and an Affiliated Insurer

Dear Secretary Alford:

Pursuant to Section 2102 of the Public Utility Code (the "Code"), 66 Pa. C.S. §2102, I submit for the Commission's approval the original and two (2) copies of this letter as a verified summary of an arrangement between UGI Utilities, Inc. ("UGI Utilities") and an as yet unformed affiliated insurance company. UGI Utilities, a wholly owned subsidiary of UGI Corporation, is a public utility as defined in Section 102 of the Code, 66 Pa. C.S. §102, and as such is subject to the Commission's jurisdiction. UGI Corporation expects to form and own a corporation ("Affiliated Insurer") whose primary purpose will be to provide insurance coverage to UGI Corporation, its affiliates and subsidiaries, including UGI Utilities. As a subsidiary of a common corporate parent, Affiliated Insurer will be an affiliated interest of UGI Utilities as defined in Section 2101(a)(3) of the Code, 66 Pa. C.S. §2101(a)(3). Section 2102 of the Code provides that no contract or arrangement between a public utility and an affiliated interest shall be valid or effective until it receives written approval of the Commission, and that a public utility may seek such approval by filing a verified copy or verified summary of the contract or arrangement. Accordingly, UGI Utilities requests approval of an unwritten arrangement whereby Affiliated Insurer may provide insurance coverage to UGI Utilities.

UGI Utilities currently receives insurance management services from its parent corporation, UGI Corporation, pursuant to the provisions of an administrative services agreement approved by the Commission on May 21, 1992, Docket No. G-00920296. As part of these services the Director of Insurance of UGI Corporation analyzes the insurance needs of UGI Utilities and obtains appropriate insurance coverage through policies negotiated annually with independent insurance companies. Currently UGI Utilities is self-insured for claims up to $500,000. For automobile, general liability and worker's compensation claims between $500,000 and $25,000,000, UGI Utilities has policies of insurance with Associated Electric & Gas Services Limited ("AEGIS"). UGI Utilities also has coverage through independent insurance companies for claims in excess of $25,000,000. Under the proposed arrangement, UGI Corporation will continue to manage UGI Utilities' insurance program, but insurance coverage may be provided by Affiliated Insurer.

UGI Corporation intends to incorporate Affiliated Insurer under the laws of the State of Vermont. Although Affiliated Insurer will be incorporated for all lawful purposes, its principal business is intended to be the provision of insurance coverage to UGI Corporation, its affiliates and subsidiaries. In its capacity as an insurance company, Affiliated Insurer will meet all capitalization and security requirements of Vermont law and will be subject to regulation by the Vermont Department of Banking, Insurance and Securities.

Subject to Commission approval, Affiliated Insurer would annually make available to UGI Utilities insurance coverage that may replace or supplement coverage now provided by independent insurance companies. To the extent possible Affiliated Insurer would write coverage on policy forms identical to the ones in effect between UGI Utilities and its independent insurance companies. UGI Utilities would then have the opportunity to choose between coverage offered by independent insurance companies and that offered by Affiliated Insurer. UGI Utilities would not be compelled to place insurance with Affiliated Insurer nor would it be compelled to renew coverage at the end of any policy year.

The following procedure will be used to assure that placing insurance with Affiliated Insurer will be in the best interests of UGI Utilities and its ratepayers. Each year, prior to the insurance renewal date of July 1, the Director of Insurance will define the level and scope of insurance coverage that can be offered by Affiliated Insurer. The Director of Insurance will then obtain quotes from independent insurance companies for this level of coverage. If the coverage can be provided by Affiliated Insurer at rates that are equal to or below the market rates, UGI Utilities would obtain policies of insurance from Affiliated Insurer. If independent insurance companies offer better rates or better coverage, UGI Utilities would choose policies from those companies. UGI Utilities will not be required to place its insurance with Affiliated Insurer but may choose independent insurance companies when costs or coverage are more advantageous.

By way of example, under the proposed arrangement UGI Utilities may choose to continue a $500,000 self-insured retention level, cover the risk of loss between $500,000 and $1,000,000 through Affiliated Insurer and continue excess insurance with AEGIS (or another carrier) for losses in excess of $1,000,000. In deciding whether to adopt this coverage UGI Utilities would obtain premium quotes from independent insurers both for coverage in excess of $500,000 (current coverage) and for coverage in excess of $1,000,000. The difference between these premiums would establish the maximum UGI Utilities would be required to pay Affiliated Insurer for coverage between $500,000 and $1,000,000 in claims. Put another way, if the sum of the premium for Affiliated Insurer's coverage plus the premium for coverage in excess of $1,000,000 is greater than the single premium for independent coverage in excess of $500,000, UGI Utilities would continue to cover losses in excess of $500,000 through independent insurers and would not place insurance with Affiliated Insurers.

AIA UGIU Insurance G-00930344

Placing insurance with an affiliated insurance company presents several advantages to UGI Utilities and its ratepayers. The first is decreased cost by improving UGI Utilities' access to insurance and reinsurance markets. For example, reinsurance (by which one insurance company assumes all or a part of the liability of an insurance company already covering the risk) is less costly than regular insurance and can only be purchased by a bona fide insurance company. This should enable Affiliated Insurer to offer lower than market rates to UGI Utilities. Doing business with an affiliate stabilizes insurance expenses by insulating UGI Utilities from insurance market cycles unrelated to the loss experience of UGI Utilities and its affiliates. Even if Affiliated Insurer's premiums rise on the basis of this loss experience, UGI Utilities' ratepayers will not be harmed because UGI Utilities retains the option of choosing market rates if they are lower. An affiliated insurance company may also provide potentially broader coverage, as the policies may be tailor-made to fit the particular needs of UGI Utilities. Coverage that may otherwise be unavailable or prohibitively expensive in the marketplace may be provided in a cost-effective way by an affiliate. Thus, placing insurance with an affiliate will reduce UGI Utilities' overall cost of insurance and may enable UGI Utilities to protect against losses that would otherwise be uninsurable.

I have enclosed an extra copy of this letter and ask that it be stamped as received by your office and returned to me in the enclosed self-addressed stamped envelope. If any additional information is required, please call.

Very truly yours,

Thomas M. Jackal

Thomas M. Jackal
Group Counsel - Utilities

TMJ/klb

Enclosures

cc: Robert Bennett (w/encl.)
Office of Special Assistants

TMJ\L-ALFORD.06

AIA UGIU Insurance G-00930344

The Honorable John G. Alford, Secretary
May 17, 1993
Page 4

bcc: (w/encl.)
J. C. Barney
T. J. Bonner
R. L. Bunn
M. M. Calabrese
M. J. Cuzzolina
J. A. Doan
W. M. Graff
L. R. Greenberg
S. R. Mauriello
G. W. Westerman

AIA UGIU Insurance G-00930344

COMMONWEALTH OF PENNSYLVANIA : SS
COUNTY OF ~~BERKS~~ Montgomery :

AFFIDAVIT

JOHN C. BARNEY, being duly sworn according to law deposes and says that he is Vice President - Finance and Accounting of UGI Utilities, Inc., a Pennsylvania corporation, that he is authorized to and does make this affidavit for it; that the arrangement summarized in the foregoing letter dated May 17, 1993, accurately reflects the proposed arrangement between UGI Utilities, Inc. and an affiliated insurance company for the purpose of providing insurance coverage to UGI Utilities, Inc.

John C. Barney
John C. Barney

Sworn to and subscribed before me this 17th day of May, 1993.

Rachel M. Reck
Notary Public

Notarial Seal
Rachel M. Reck, Notary Public
Upper Merion Twp., Montgomery County
My Commission Expires Nov. 18, 1996
Member, Pennsylvania Association of Notaries

II-D-9

Request:

Prepare a detailed schedule for the test year showing types of social and service organization memberships paid for, the cost thereof, the accounting treatment and whether included in claimed test year expenses.

Response:

UGI Electric does not include membership dues for social and service organizations in test year expenses.

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

II-D-10

Request:

Provide the following payroll and employe benefit data—regular and overtime—separately for the test year and for the 12-month period immediately prior to the test year:

a. The average and year-end number of employes and the unadjusted annual payroll expense and employe benefit expense associated with union personnel.

b. The average and year-end number of employes and the unadjusted annual payroll expense and employe benefit expense associated with nonunion personnel.

c. The average and year-end number of employes and the unadjusted annual payroll expense and employe benefit expense associated with management employes, if different than b.

d. A summary of the wage rate, salary and employe benefit changes granted or to be granted during the year.

e. The claimed test year payroll expense and employe benefit expense.

f. The percentage of payroll expense and employe benefit expense applicable to operation and maintenance expenses and the basis thereof.

Response:

a. Please see Attachment II-D-10.

b. Please see Attachment II-D-10.

c. Please see Attachment II-D-10.

d. Please see Schedule D-7, page 2 of 2 in UGI Electric Exhibit A (Fully Projected Future) and UGI Electric Exhibit A (Future).

e. Please see Attachment II-D-10.

f. Please see Attachment II-D-10.

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

UGI Utilities, Inc. - Electric Division
Payroll and Employee Benefit Data
($000)

			Years Ending September	
			2023	2024
a.	Union Personnel			
	Average Number of Employees		28	28
	Year-end Number of Employees		28	28
	Payroll Expenses			
	Normal		$ 1,096	$ 1,154
	Overtime		$ 168	$ 167
	Benefit Expenses		$ 249	$ 266
b.	Non-Union Personnel			
	Average Number of Employees		55	55
	Year-end Number of Employees		55	55
	Payroll Expenses			
	Normal	(A)	$ 4,266	$ 4,476
	Overtime	(A)	$ 400	$ 400
	Benefit Expenses	(A)	$ 1,023	$ 1,081
e.	Claimed for Test Year			
	Payroll to Expense		$ 5,929	$ 6,196
	Benefit to Expense		$ 1,272	$ 1,347
f.	Percent of Total Payroll + Benefit Applicable to O&M			
	Payroll		8.6%	8.9%
	Benefit		1.8%	1.9%

(A) Amounts presented include costs allocated for Utility Shared Service Personnel.

II-D-11

Request:

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

Response:

Please see Attachment II-D-11.

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

UGI UTILITIES, INC. - ELECTRIC DIVISION
COSTS RELATIVE TO LEASING EQUIPMENT, COMPUTER RENTAL AND OFFICE SPACE
TWELVE MONTHS ENDED SEPTEMBER 30, 2022
(THOUSANDS OF DOLLARS)

	ANNUAL COSTS	METHOD OF COMPUTING PAYMENTS	TERMS OF LEASE OR RENTAL AGREEMENT
BUILDING	38	MONTHLY PAYMENTS PER LEASE OR RENTAL AGREEMENTS. PERCENTAGE APPLIED FROM MODIFIED WISCONSIN FORMULA FOR LEASES OF SHARED PROPERTY.	THROUGH 2027
IS/ COMPUTER EQUIPMENT	37	MONTHLY PAYMENTS PER LEASE OR RENTAL AGREEMENTS. PERCENTAGE APPLIED FROM MODIFIED WISCONSIN FORMULA FOR LEASES OF SHARED PROPERTY.	THROUGH 2026
MOTOR VEHICLE	32	MONTHLY PAYMENTS FOR LEASES OR RENTAL AGREEMENTS.	THROUGH 2023
TOTAL	107		

II-D-12

Request:

Submit a statement of past and anticipated changes, since the previous rate case, in major accounting procedures, explain any differences between the basis or procedure used in allocations of revenues, expenses, depreciation and taxes in the current rate case and that used in the prior rate cases, and list all internal and independent audit reports for the most recent 2 year period.

Response:

Except as indicated below, the Company will maintain its existing accounting policies, including those resulting from previous PUC approvals.

New Accounting Standard Adopted in Fiscal 2022

Income Taxes. Effective October 1, 2021, the Company adopted ASU 2019-12, "Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes" prospectively and retrospectively where deemed applicable. This ASU simplifies the accounting for income taxes by eliminating certain exceptions within the existing guidance for recognizing deferred taxes for equity method investments, performing intra-period allocations and calculating income taxes in interim periods. Further, this ASU clarifies existing guidance related to, among other things, recognizing deferred taxes for goodwill and allocated taxes to members of a consolidated group. The adoption of the new guidance did not have a material impact on our consolidated financial statements.

New Accounting Standard Adopted in Fiscal 2021

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

II-D-12 (Continued)

Accounting Standard to be Adopted in Fiscal Year 2023

Debt and Derivatives and Hedging. Effective October 1, 2022, the Company adopted ASU 2020-06, "Debt - Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging – Contracts in Entity's Own Equity (Subtopic 815-40)," using the modified retrospective approach. The amendments in this ASU affect entities that issue convertible instruments and/or contracts indexed to and potentially settled in an entity's own equity. This ASU reduces the number of accounting models for convertible debt instruments and convertible preferred stock, expands disclosure requirements for convertible instruments, and simplifies the related earnings per share guidance. The adoption of the new guidance did not have a material impact on our consolidated financial statements.

Please see Attachment II-D-12 for a list of all internal and independent audit reports for the past two years.

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

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

Entity	Audit Report Name	Auditor	Audit year	Date Issued
UGI Utilities, Inc.	Audited Financial Statements for UGI Utilities,Inc.	Ernst & Young, LLP	FY 2022	12/21/2022
UGI Utilities, Inc.	Audited Financial Statements for UGI Utilities,Inc.	Ernst & Young, LLP	FY 2021	12/15/2021
UGI Utilities, Inc.	UGI Natural Gas - SAP Post Implementation Review	Internal Audit	FY 2021	9/3/2021
UGI Utilities, Inc.	UGI Natural Gas - Privileged Access Management	Internal Audit	FY 2021	7/17/2021
UGI Utilities, Inc.	UGI Utilities Safety Review Final Report	Internal Audit	FY 2021	6/24/2021
UGI Utilities, Inc.	UGI Utilities Journal Entry Audit Final Report	Internal Audit	FY 2021	4/23/2021
UGI Utilities, Inc.	UGI Utilities Payroll Overtime Audit Final Report	Internal Audit	FY 2021	4/12/2021
UGI Utilities, Inc.	UGI Utilities Fixed Asset Review Audit	Internal Audit	FY 2020	12/10/2020

II-D-13

Request:

Regardless of whether a claim for negative or positive net salvage is made, attach an exhibit showing gross salvage, cost of removal, third party reimbursements, if any, and net salvage for the test year and 4 previous years.

Response:

The information related to the historic test year is presented in Part IV of UGI Electric Exhibit C (Historic) in the section titled "Experienced Net Salvage."

The information related to the future test year is set forth in Part VIII of UGI Electric Exhibit C (Future) in the section titled "Experienced and Estimated Net Salvage."

The information related to the fully projected test year is set forth in Part IV of UGI Electric Exhibit C (Fully Projected Future) in the section titled "Experienced and Estimated Net Salvage."

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

II-D-14

Request:

State the amount of debt interest utilized for test year income tax calculations, including the amount so utilized which has been allocated from the debt interest of an affiliate, and provide details of debt interest and allocation computations.

Response:

See Schedule D-33 of UGI Electric Exhibit A (Historic), UGI Electric Exhibit A (Future), and UGI Electric Exhibit A (Fully Projected Future) for a calculation of the interest expense used in computing test year income tax expense. UGI Electric does not utilize any debt interest which has been allocated from the debt interest of an affiliate in the computation of taxable income.

Prepared by or under the supervision of: Darin T. Espigh

II-D-15

Request:

Provide a schedule for the test year of Federal and Pennsylvania taxes other than income taxes, per books, pro forma at present rates, and pro forma at proposed rates, including the following tax categories:

a. Social security.
b. Unemployment.
c. Capital stock.
d. Public utility.
e. P.U.C. assessment.
f. Other property taxes.
g. Any other appropriate categories.

Response:

See Schedule D-31 to UGI Electric Exhibit A (Historic), UGI Electric Exhibit A (Future), and UGI Electric Exhibit A (Fully Projected Future).

Prepared by or under the supervision of: Darin T. Espigh

II-D-16

Request:

Submit a schedule showing the adjustments from taxable net income per books to taxable net income pro forma under existing rates and pro forma under proposed rates, together with an explanation of all normalizing adjustments. Submit detailed calculations supporting taxable income before State and Federal income taxes where the income tax is subject to allocation due to operations in another state or due to operation of other taxable utility or non-utility business, or by operating divisions or areas.

Response:

See Schedules D-33 and D-34, UGI Electric Exhibit A (Historic), UGI Electric Exhibit A (Future), and UGI Electric Exhibit A (Fully Projected Future).

Prepared by or under the supervision of: Darin T. Espigh

II-D-17

Request:

Submit a schedule showing for the last 5 years the income tax refunds, plus interest—net of taxes, received from the Federal government due to prior years' claims.

Response:

None.

Prepared by or under the supervision of: Darin T. Espigh

II-D-18

Request:

Furnish a breakdown of major items comprising prepaid and deferred income tax charges and other deferred income tax credits, reserves and associated reversals on liberalized depreciation.

Response:

Please see UGI Electric Exhibit A, Schedule C-6 (Historic) for deferred taxes relative to liberalized depreciation.

The net value of deferred taxes on items other than plant in service at fiscal year ended 9/30/22 is $336,513 deferred tax asset.

Prepared by or under the supervision of: Darin T. Espigh

II-D-19

Request:

Explain how the Federal corporate graduated tax rates have been reflected for rate case purposes. If the Pennsylvania jurisdictional utility is part of a multi-corporate system, explain how the tax savings are allocated to each member of the system.

Response:

The Federal corporate graduated tax rates do not apply to the consolidated group because taxable income exceeds the graduated income limitations.

UGI Electric is included as part of a consolidated federal income tax return with UGI Corporation. UGI Corporation allocates its consolidated income tax liability among its subsidiary members consistent with the separate return method such that each member is allocated federal income tax according to the taxable income, benefits, and burdens it contributed to the consolidated return.

Prepared by or under the supervision of: Darin T. Espigh

II-D-20

Request:

Explain the treatment given to costs of removal in the income tax calculation and the basis for such treatment.

Response:

Cost of removal is treated as a tax deductible item as costs are incurred and/or paid pursuant to IRC Section 1.167(a)-11(d)(3) and 1.263(a)-3(g)(2).

Prepared by or under the supervision of: Darin T. Espigh

II-D-21

Request:

Show income tax loss/gain carryovers from previous years. Show loss/gain carryovers by years of origin and amounts remaining by years at the beginning of the test year.

Response:

Not applicable.

Prepared by or under the supervision of: Darin T. Espigh

II-D-22

Request:

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

If response is affirmative:

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

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

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

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

Response:

The Company does not eliminate tax savings by the payment of interest on construction work in progress.

Prepared by or under the supervision of: Darin T. Espigh

II-D-23

Request:

Under section 1552 of the Internal Revenue Code (26 U.S.C.A. § 1552) and 26 CFR 1.1552-1 (1983), if applicable, a parent company, in filing a consolidated income tax return for the group, must choose one of four options by which it must allocate total income tax liability of the group to the participating members to determine each member's tax liability to the Federal government (if this interrogatory is not applicable, so state):

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

b. Provide, in summary form, the amount of tax liability that has been allocated to each of the participating members in the consolidated income tax return for the test year and the most recent 3 years for which data is available.

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

d. Provide the most recent annual income tax return for the group.

e. Provide details of the amount of the net operating losses of any member allocated to the income tax returns of each of the members of the consolidated group for the test year and the 3 most recent years for which data is available, together with a summary of the actual tax payments for those years.

f. Provide details of the amount of net negative income taxes, after all tax credits are accounted for, of any member allocated to the income tax return of each of the members of the consolidated group for the test year and the 3 most recent years for which data is available, together with a summary of the actual tax payments for those years.

II-D-23 (Continued)

Response:

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

   UGI Corporation also elected to reflect currently the investment adjustment in earnings and profits pursuant to Regulation 1.1502-33(c)(4)(iii).

b. Please see Attachment II-D-23.b. The federal income tax return for the historic test year, September 30, 2022, has not been prepared; therefore, information has been provided for the years ended September 30, 2019 through September 30, 2021.

c. UGI Corporation ("UGI Corp") is the parent company of the UGI consolidated group that includes UGI Electric as a division of UGI Utilities, Inc. UGI Corp makes all necessary income tax payments to the IRS for the net tax liability that is due for its consolidated group. Further, UGI Corp collects the allocated tax liability from members of its group with positive taxable income and reimburses members of its group with a negative federal income tax allocation. The amounts UGI Corp collects or pays to each member of its group are the amounts listed on Attachment II-D-23.b.

d. The response to this question contains confidential information and is marked as such. This information will be provided to parties upon execution of a Confidentiality Agreement, to be circulated by the Company, pursuant to the terms of that agreement.

e. Please see Attachment II-D-23.b.

f. Please see Attachment II-D-23.b.

Prepared by or under the supervision of: Darin T. Espigh

UGI Utilities, Inc. - Electric Division
Allocation of UGI Corporation Consolidated Federal Income Tax Liability
For the Year Ended September 30, 2021
In Thousands

	(a)	(b)	(c)	(d)	(e)
Name of Company	Federal Taxable Income	Federal Income Tax @ 21% / 35% Allocated	Foreign Tax Credit	General Business Credit	Col (b) - Col (c) - Col (d) = Net Federal Income Tax Liability
AmeriGas Inc	178	37			0
AmeriGas Propane Inc.	30,085	6,318			0
AmeriGas Propane Holdings, Inc.	(136,979)	(47,943)			0
Amerigas Technology Group Inc.		0			0
Ashtola Production Company	(1)	(0)			0
Eastfield International Holdings Inc		0			0
Energy Service Funding	4,656	978			0
EuroGas Holdings Inc.		0			0
Four Flags Drilling Company		0			0
Hellertown Pipeline		0			0
Homestead Holding	(76)	(27)			0
Mountaineer Energy Holding & Subs	(4,891)	(1,712)			0
Newberry Holding	120	25			0
UGI Asset Management		0			0
UGI Black Sea Enterprises		0			0
UGI China, Inc.		0			0
UGI Corporation	(100,191)	(14,662)			0
UGI Development Company	(4,031)	(1,411)			0
UGI Energy Ventures, Inc.		0			0
UGI Ethanol Development Company		0			0
UGI Enterprises, Inc.		0			0
UGI Europe, Inc.	42,637	8,954			0
UGI Hunlock Dev	(0)	(0)			0
UGI HVAC Enterprises	(1,556)	(544)			0
UGI International China. Inc		0			0
UGI International (Romania)		0			0
UGI LNG	(3,679)	(1,288)			0
UGI Penn HVAC Services	0	0			0
UGI Petroleum Products of DE	0	0			0
UGI Properties, Inc.	438	92			0
UGI Romania, Inc.		0			0
UGI Storage Company	4,997	1,049			0
UGI Utilities, Inc.	62,490	13,123			0
UGID Holding Company	(8)	(3)			0
United Valley Insurance	146	31			0
Eliminations		0			0
Adjustments		0			0
Total Taxable	**(105,667)**	**(36,983)**	**0**	**0**	**0**

Allocation of Tax Liability:
The CARES act provided for a 5-year carryback of tax losses for taxable years beginning in 2018, 2019 and 2020. Our tax loss for FYE21 (taxable year beginning 10/1/2020) was carried back to FYE16, a 35% Federal tax year. As explained in our responses to II-D-23c and II-D-19, UGI Electric as a division of UGI Utilities, Inc. is included in the consolidated federal tax return of UGI Corporation (UGI Corp). UGI Corp settles with each legal entity of the consolidated group based on the amount that entity contributed to the overall tax liability on a separate return basis. As such, legal entities with a tax loss in FYE21 were availed of a carryback of the loss to FYE16. Legal entities with taxable income paid their share of tax at the tax rate in effect for FYE21.

UGI Utilities, Inc. - Electric Division
Allocation of UGI Corporation Consolidated Federal Income Tax Liability
For the Year Ended September 30, 2020
In Thousands

	(a)	(b)	(c)	(d)	(e)
Name of Company	**Federal Taxable Income**	**Federal Income Tax @ 21% / 35% Allocated**	**Foreign Tax Credit**	**General Business Credit**	**Col (b) - Col (c) - Col (d) = Net Federal Income Tax Liability**
AmeriGas Inc	(23)	(8)			0
AmeriGas Propane Inc.	56,320	11,827			0
AmeriGas Propane Holdings, Inc.	(207,170)	(72,510)			0
Amerigas Technology Group Inc.	0	0			0
Ashtola Production Company	(1)	(0)			0
Eastfield International Holdings Inc	0	0			0
Energy Service Funding	3,479	731			0
EuroGas Holdings Inc.	0	0			0
Four Flags Drilling Company	0	0			0
Hellertown Pipeline	0	0			0
Homestead Holding	(607)	(213)			0
Newberry Holding	955	201			0
UGI Asset Management	0	0			0
UGI Black Sea Enterprises	0	0			0
UGI China, Inc.	0	0			0
UGI Corporation	(201,320)	(46,526)			0
UGI Development Company	(16,858)	(5,900)			0
UGI Energy Ventures, Inc.	0	0			0
UGI Ethanol Development Company	0	0			0
UGI Enterprises, Inc.	0	0			0
UGI Europe, Inc.	22,795	4,787			0
UGI Hunlock Dev	0	0			0
UGI HVAC Enterprises	4,824	1,013			0
UGI International China. Inc	0	0			0
UGI International (Romania)	0	0			0
UGI LNG	2,318	487			0
UGI Penn HVAC Services	0	0			0
UGI Petroleum Products of DE	0	0			0
UGI Properties, Inc.	349	73			0
UGI Romania, Inc.	0	0			0
UGI Storage Company	4,152	872			0
UGI Utilities, Inc.	73,276	15,388			0
UGID Holding Company	(8)	(3)			0
United Valley Insurance	323	68			0
Eliminations	0	0			0
Adjustments	2,180	458			0
Total Taxable	**(255,015)**	**(89,255)**	**0**	**0**	**0**

Allocation of Tax Liability:
The CARES act provided for a 5-year carryback of tax losses for taxable years beginning in 2018, 2019 and 2020. Our tax loss for FYE20 (taxable year beginning 10/1/2019) was carried back to FYE15, a 35% Federal tax year. As explained in our responses to II-D-23c and II-D-19, UGI Electric as a division of UGI Utilities, Inc. is included in the consolidated federal tax return of UGI Corporation (UGI Corp). UGI Corp settles with each legal entity of the consolidated group based on the amount that entity contributed to the overall tax liability on a separate return basis. As such, legal entities with a tax loss in FYE20 were availed of a carryback of the loss to FYE15. Legal entities with taxable income paid their share of tax at the tax rate in effect for FYE20.

UGI Utilities, Inc. - Electric Division
Allocation of UGI Corporation Consolidated Federal Income Tax Liability
For the Year Ended September 30, 2019
In Thousands

Name of Company	(a) Federal Taxable Income	(b) Federal Income Tax @ 21% Allocated	(c) Foreign Tax Credit	(d) General Business Credit	(e) Col (b) - Col (c) - Col (d) = Net Federal Income Tax Liability
AmeriGas Inc	(26)	(5)			(5)
AmeriGas Propane Inc.	93,880	19,715			19,715
AmeriGas Propane Holdings, Inc.	90	19			19
Amerigas Technology Group Inc.	0	0			0
Ashtola Production Company	(1)	0			0
Eastfield International Holdings Inc	0	0			0
Energy Service Funding	5,062	1,063			1,063
EuroGas Holdings Inc.	0	0			0
Four Flags Drilling Company	0	0			0
Hellertown Pipeline	0	0			0
Homestead Holding	(273)	(57)			(57)
Newberry Holding	3,253	683			683
Petrolane Incorporated	0	0			0
UGI Asset Management	0	0			0
UGI Black Sea Enterprises	0	0			0
UGI Central Penn Gas	0	0			0
UGI China Inc	0	0			0
UGI Corporation	37,610	7,898			7,898
UGI Development Company	(5,924)	(1,244)		158	(1,402)
UGI Energy Ventures, Inc.	0	0			0
UGI Ethanol Development Company	0	0			0
UGI Enterprises Inc	0	0			0
UGI Europe Inc	35,767	7,511	5,905		1,606
UGI Hunlock Dev	0	0			0
UGI HVAC Enterprises	(305)	(64)			(64)
UGI International China. Inc	0	0			0
UGI International (Romania)	0	0			0
UGI International Enterprises, Inc.	0	0			0
UGI LNG	5,530	1,161			1,161
UGI Penn HVAC Services	3	1			1
UGI Penn Natural Gas, Inc.	0	0			0
UGI Petroleum Products of DE	0	0			0
UGI Properties, Inc.	245	51			51
UGI Storage Company	4,465	938			938
UGI Utilities, Inc.	57,929	12,165			12,165
UGID Holding Company	(8)	(2)			(2)
United Valley Insurance	(751)	(158)			(158)
Adjustments	6,510	1,367			1,367
Total	**243,056**	**51,042**	**5,905**	**158**	**44,980**

II-D-24

Request:

Provide detailed computations by vintage year showing State and Federal deferred income taxes resulting from the use of accelerated tax depreciation associated with post-1969 public utility property, ADR rates, and accelerated tax depreciation associated with post-1980 public utility property under the Accelerated Cost Recovery System (ACRS).

a. Reconcile and explain any differences in the base used to calculate State and Federal deferred income taxes.

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

c. Reconcile differences between the deferred tax balance, as shown as a reduction to rate base, and the deferred tax balance as shown on the balance sheet.

Response:

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

a. Not applicable.

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

c. The accumulated deferred tax balance, as shown as a reduction to measures of value, represents the annualized balance based on the plant in service included in the measures of value. The balance sheet represents the budgeted balance.

Prepared by or under the supervision of: Darin T. Espigh

II-D-25

Request:

Submit a schedule showing a breakdown of accumulated and unamortized investment tax credits, by vintage year and percentage rate, together with calculations supporting the amortized amount claimed as a reduction to pro forma income taxes. Provide details of methods used to write-off the unamortized balances.

Response:

Not applicable.

Prepared by or under the supervision of: Darin T. Espigh

II-D-26

Request:

Explain in detail by statement or exhibit the appropriateness of claiming any additional items, not otherwise specifically explained and supported in the statement of operating income.

Response:

Please see Section D of UGI Electric Exhibit A (Historic), UGI Electric Exhibit A (Future), UGI Electric Exhibit A (Fully Projected Future), and the Direct Testimony of Tracy A. Hazenstab, UGI Electric Statement No. 2, for an explanation and detail of the Company's claim for additional operating income items.

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

II-D-27

Request:

If the utility's operations include non-jurisdictional activities, provide a schedule which demonstrates the manner in which rate base and operating income date have been adjusted to develop the jurisdictional test year claim.

Response:

This rate filing is presented on a PUC jurisdictional basis only. Total system rate base and components of operating income have been assigned and/or allocated between FERC and PUC jurisdictions and the proposed revenue increase has been determined on a PUC jurisdictional basis only. Please also see the Direct Testimony of Tracy A. Hazenstab, UGI Electric Statement No. 2, UGI Electric Exhibit TAH-2, and the Direct Testimony of John D. Taylor, UGI Electric Statement No. 6.

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

II-E-1

Request:

Supply a copy of any budget utilized as a basis for any test year claim, and explain the utility’s budgeting process.

Response:

Please refer to the Direct Testimony of Tracy A. Hazenstab, UGI Electric Statement No. 2, for an explanation of the Company's budgeting process, as well as UGI Electric Exhibit TAH-2, pages 1 through 3 which provide a summary of the operating budgets utilized as the basis for UGI Electric's Fully Projected Future Test Year, Future Test Year and Historic Test Year claims on a Pennsylvania jurisdictional basis.

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

II-E-2

Request:

Supply summaries of the utility's projected operating and capital budgets for the 2 calendar years following the end of the test year.

Response:

UGI Electric does not prepare projected operating and capital budgets for the two calendar years following the end of the Fully Projected Future Test Year.

Prepared by or under the supervision of: Eric W. Sorber

III. RATE OF RETURN

III-A-1

Request:

Provide a schedule showing the major components of claimed capitalization, and the derivation of the weighted costs of capital for the rate case claim. This schedule shall include a descriptive statement concerning the major elements of changes in claimed capitalization, cost rates and overall return from comparable historical data.

Response:

Please refer to UGI Electric Exhibit B, Schedule 1 page 1, Schedule 5 page 1, and Schedule 6 pages 1, 2, 3 and 4, and the Direct Testimony of Paul R. Moul, UGI Electric Statement No. 9.

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

III-A-2

Request:

Provide a schedule in the same format as Schedule 1, except for the omission of the descriptive statement, for the most immediate comparable annual historical period prior to the test year and the two calendar years most immediately preceding the rate of return claim period. Irrespective of whether the capitalization claimed on Schedule 1 includes short-term debt, Schedule 2 should reflect capital ratios with and without short-term debt.

Response:

Please see Attachment III-A-2.

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

UGI UTILITIES, INC.
CAPITALIZATION SCHEDULE (Millions)
FOR THE HISTORIC YEARS ENDED SEPTEMBER 30, 2020 THROUGH 2022

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

	9/30/2020 Actual	9/30/2020 %	9/30/2021 Actual	9/30/2021 %	9/30/2022 Actual	9/30/2022 %
Common Equity	$ 1,314.0	52.5	$ 1,424.9	50.8	$ 1,654.8	52.1
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0
Short-Term Debt (Average less CWIP)	69.2	2.8	93.2	3.3	63.0	2.0
Long-Term Debt (excl. Capital Lease Obligations)	1,117.8	44.7	1,285.9	45.9	1,460.3	45.9
Total Capitalization	$ 2,500.9	100.0	$ 2,804.0	100.0	$ 3,178.1	100.0

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

	9/30/2020 Actual	9/30/2020 %	9/30/2021 Actual	9/30/2021 %	9/30/2022 Actual	9/30/2022 %
Common Equity	$ 1,314.0	54.0	$ 1,424.9	52.6	$ 1,654.8	53.1
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0
Long-Term Debt	1,117.8	46.0	1,285.9	47.4	1,460.3	46.9
Total Capitalization	$ 2,431.8	100.0	$ 2,710.8	100.0	$ 3,115.1	100.0

III-B-1

Request:

Provide a schedule showing the calculation of embedded cost of long-term debt by issue, supporting the related rate case claim. The schedule shall contain the following information:

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

Projected new issues, retirements and other major changes from the comparable historic data should be clearly noted.

Response:

Please refer to UGI Electric Exhibit B, Schedule 6, pages 1, 2, 3 and 4, and the Direct Testimony of Paul R. Moul, UGI Electric Statement No. 9.

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

III-B-2

Request:

In the event that a claim made for a true or economic cost of debt exceeds that shown in the preceding nominal cost schedule because of convertible features, sale with warrants or for any other reason, a full statement of the basis for such a claim should be provided.

Response:

No claim is made for a cost of debt that differs from the embedded cost noted in the response to III-B-1.

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

III-B-3

Request:

Provide the following information concerning bank notes payable for test year and for latest comparable annual historical period prior to the test year:

a. Line of credit at each bank.

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

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

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

e. Prospective future need for this type of financing.

Response:

a. As of September 30, 2022, UGI Utilities, Inc. had a five-year $350 million revolving credit facility ("RCF") with a consortium of banks. On December 13, 2022, the RCF was amended to increase its capacity by $75 million (to $425 million). The RCF matures in June 2024. Please see Attachment III-B-3 for the commitment from each bank (before and after the amendment).

b. The RCF is predominantly used to meet working capital needs and is more heavily utilized in the fall and winter months when inventory and receivable balances peak. The borrowings from each bank are pro rata as per their respective commitments. The average daily borrowing under the UGI Utilities, Inc. RCF was $163,389,041 for fiscal year 2022.

c. The interest rates for the majority of borrowings under the UGI Utilities, Inc. RCF are under the Term SOFR + Applicable Margin formula (this index rate was LIBOR, rather than Term SOFR, prior to the December 13, 2022 amendment). The Applicable Margin is based on public credit ratings as specified on Attachment III-B-3. UGI Utilities, Inc. has two public debt ratings (Moody's, Fitch). When there is a split rating, the highest rating applies unless such ratings differ by two or more levels. If ratings differ by two or more levels, the applicable

III-B-3 (Continued)

level will be deemed to be one level below the higher of such levels. Based on current ratings of UGI Utilities, Inc., the applicable margin is 1.00%.

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

e. The RCF provides adequate liquidity for working capital and CWIP needs and does not mature until June 2024.

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

UGI UTILITIES, INC. - ELECTRIC DIVISION
Line of Credit Bank Commitments and Applicable Margin

Lender Commitments of the UGI Utilities five year, $350 million (amended to $425 million) revolving credit facility:

Lender	Commitment at 9/30/22 (before amendment)	Commitment at 12/13/22 (after amendment)
PNC Bank, National Association	$75,000,000	$90,000,000
Citizens Bank, N.A.	$75,000,000	$90,000,000
Credit Suisse AG, Cayman Islands Branch	$40,000,000	$49,000,000
JPMorgan Chase Bank, N.A.	$40,000,000	$49,000,000
Wells Fargo Bank, National Association	$40,000,000	$49,000,000
Bank of America, N.A.	$40,000,000	$49,000,000
The Bank of New York Mellon	$40,000,000	$49,000,000
	$350,000,000	$425,000,000

Applicable Margin of the UGI Utilities five year, $350 million (amended to $425 million) revolving credit facility:

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

III-B-4

Request:

Provide detailed information concerning all other short-term debt outstanding.

Response:

The Company had no other short-term debt outstanding other than that identified in III-B-3.

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

III-B-5

Request:

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

a. Reacquisition by issue by year.
b. Total gain or loss on reacquisitions by issue by year.
c. Accounting for gain or loss for income tax and book purposes.
d. Proposed treatment of gain or loss on such reacquisition for ratemaking purposes.

Response:

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

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

III-C-1

Request:

Provide a schedule showing the calculation of the embedded cost of preferred stock equity by issue, supporting the related rate case claim. The schedule shall contain the following information:

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

Projected new issues, retirement and other major changes from the comparable historical data should be clearly noted.

Response:

The Company does not have preferred stock outstanding.

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

III-D-1

Request:

Provide complete support for claimed common equity rate of return.

Response:

Please refer to the Direct Testimony of Paul R. Moul, UGI Electric Statement No. 9.

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

III-D-2

Request:

Provide a summary statement of all stock dividends, splits or par value changes during the 2 calendar year period preceding the rate case filing.

Response:

The Company has not had any stock dividends, splits or par value changes during the past two calendar years preceding the rate case filing.

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

III-D-3

Request:

Provide a schedule of all issuances of common stock, whether or not underwriters are used, for the most immediately available annual historical period and the 2 calendar years most immediately preceding the test year.

Response:

There were no new issuances of common stock for the Company during the historical period or the two years preceding the test year.

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

III-D-4

Request:

Submit details on the utility and parent company stock offerings - past 5 years to present - as follows:

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

Response:

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

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

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

III-D-4 (Continued)

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

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

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

(iii) $35.325 in cash, without interest.

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

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

Based on the above transaction, please see below:

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

III-D-4 (Continued)

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

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

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

III-E-1

Request:

If a claim of the filing utility is based on utilization of the capital structure or capital costs of the parent company and system—consolidated—the reasons for this claim must be fully stated and supported.

Response:

The Company is claiming its own capital structure and capital cost rates in this case. No claim is being made for the parent company or system consolidated capital structure.

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

III-E-2

Request:

Regardless of the claim made, provide the capitalization data requested at Item III.A.2. for the parent company and for the system—consolidated.

Response:

Please see Attachment III-E-2 for the requested capitalization data.

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

UGI UTILITIES, INC. - ELECTRIC DIVISION
CAPITALIZATION SCHEDULE (Millions)
FOR THE HISTORIC YEARS ENDED SEPTEMBER 30, 2022
AND FOR THE FORECASTED YEARS ENDING SEPTEMBER 30, 2023 AND 2024

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

	9/30/2022 Actual	%	9/30/2023 Budget	%	9/30/2024 Budget	%
Common Equity	$ 1,654.8	52.1	$ 1,853.2	54.6	$ 2,011.3	54.6
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0
Short-Term Debt (Average less CWIP)	63.0	2.0	84.7	2.5	0.0	0.0
Long-Term Debt (excl. Capital Lease Obligations)	1,460.3	45.9	1,454.1	42.9	1,672.8	45.4
Total Capitalization	$ 3,178.1	100.0	$ 3,392.0	100.0	$ 3,684.1	100.0

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

	9/30/2022 Actual	%	9/30/2023 Budget	%	9/30/2024 Budget	%
Common Equity	$ 1,654.8	53.1	$ 1,853.2	56.0	$ 2,011.3	54.6
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0
Long-Term Debt	1,460.3	46.9	1,454.1	44.0	1,672.8	45.4
Total Capitalization	$ 3,115.1	100.0	$ 3,307.3	100.0	$ 3,684.1	100.0

III-E-3

Request:

Provide the latest available balance sheet and income statement for the parent company and system—consolidated.

Response:

Please see the response to III-F-1.

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

III-E-4

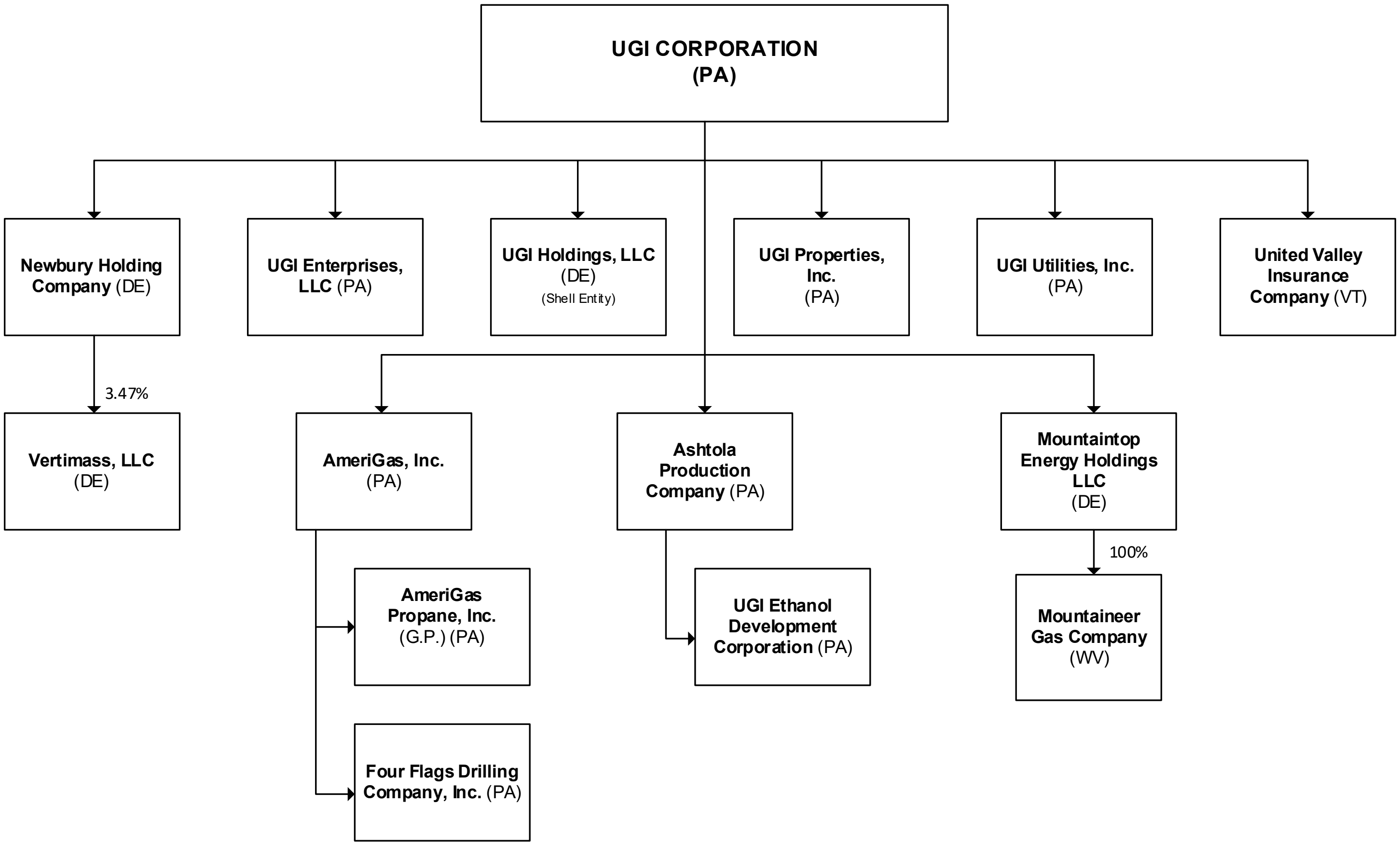
Request:

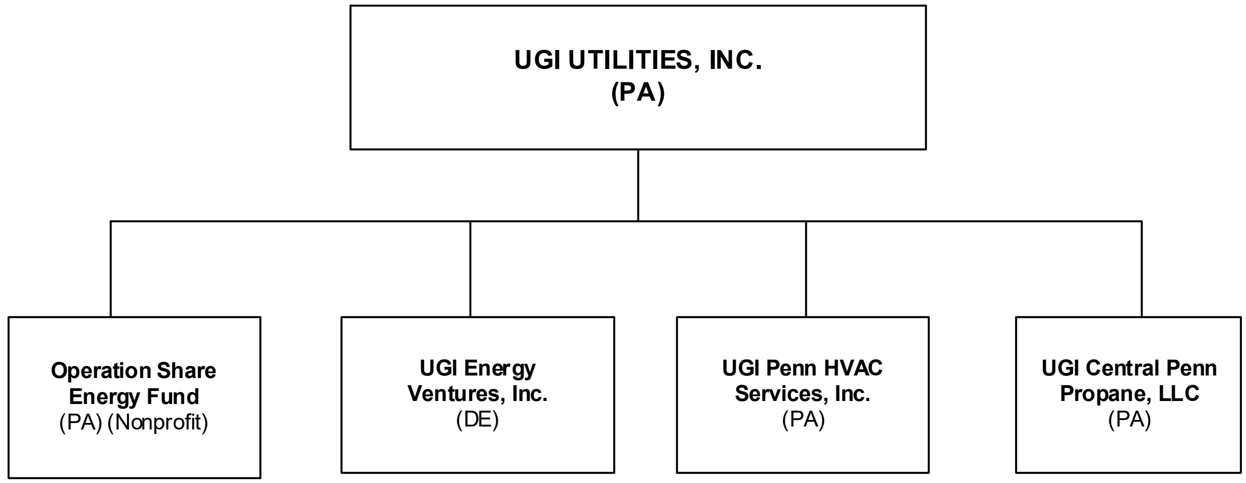
Provide an organizational chart explaining the filing utility's corporate relationship to its affiliates—system structure.

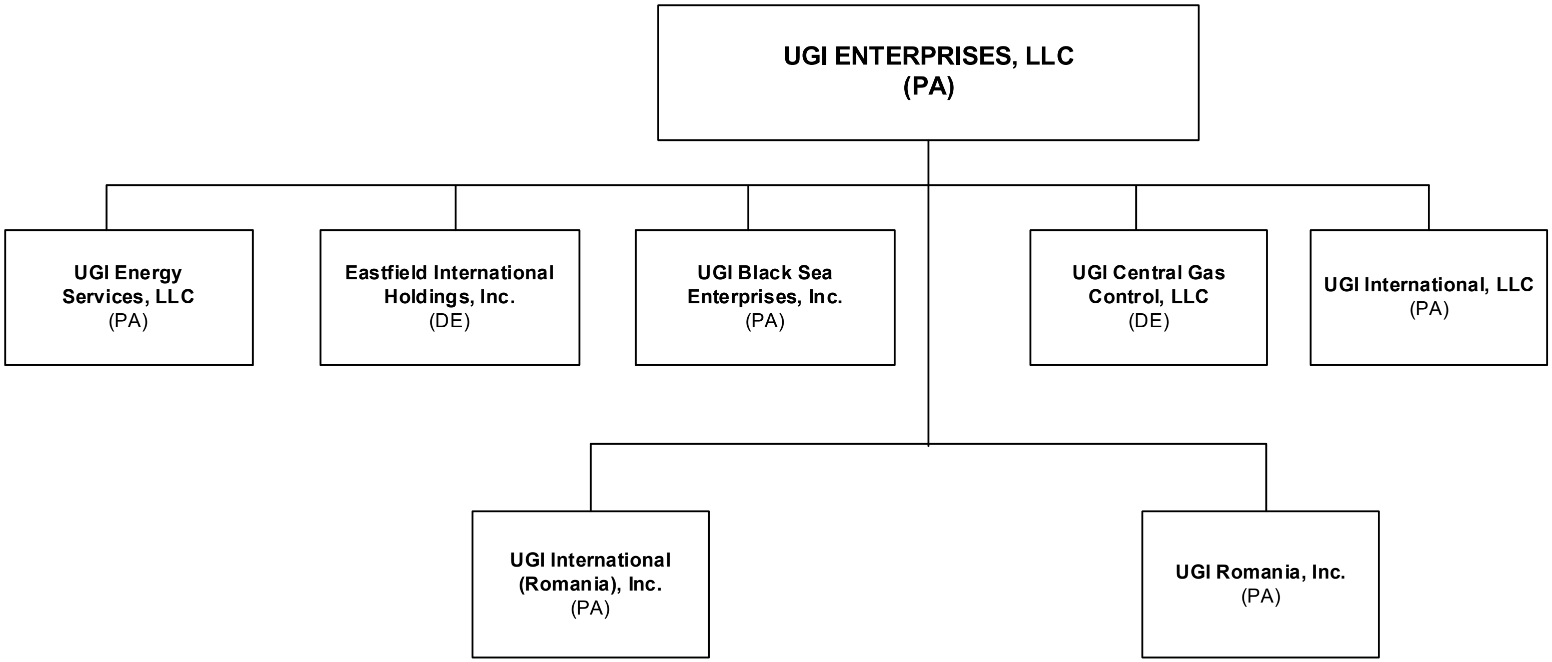
Response:

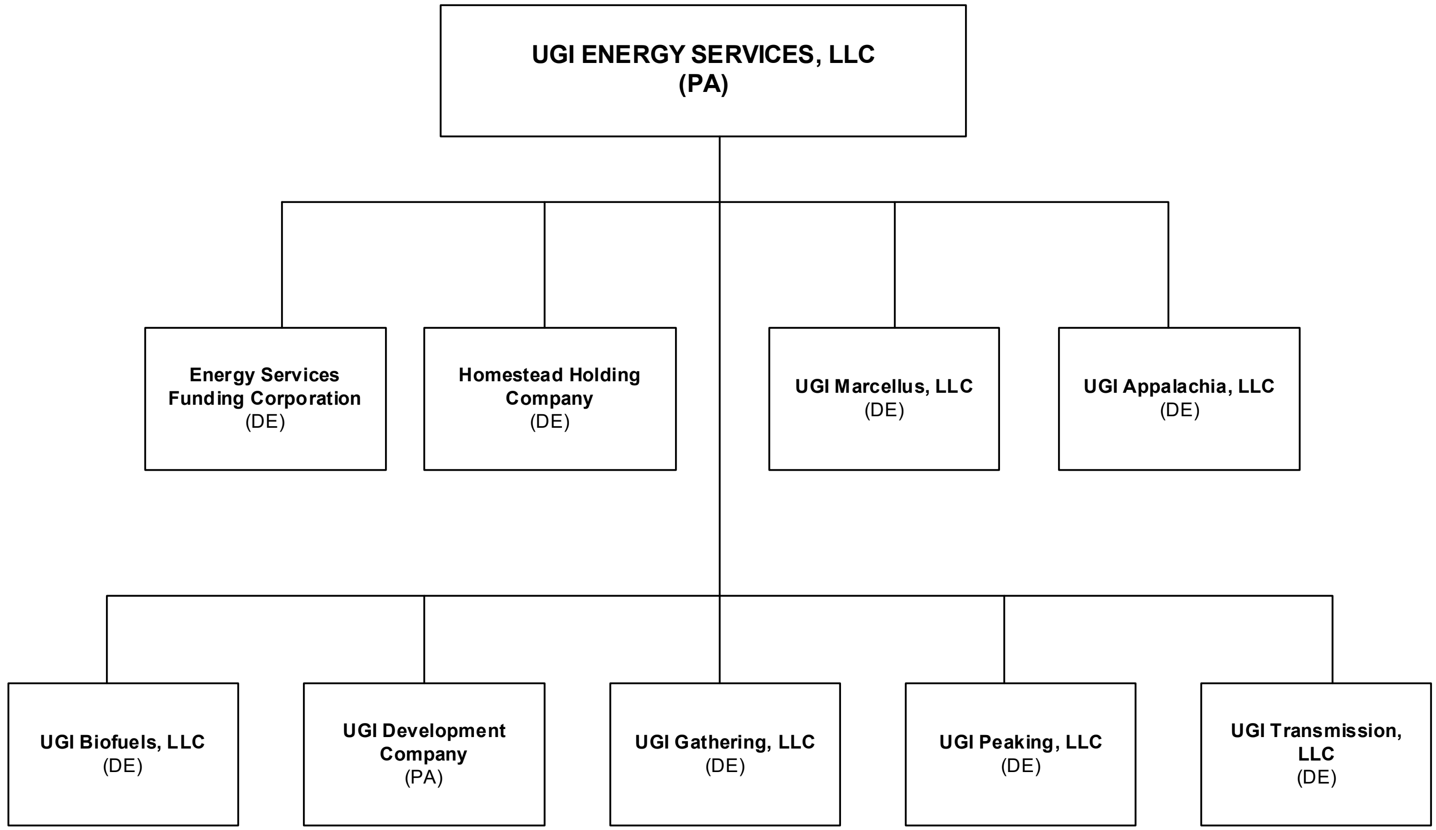
Please see Attachment III-E-4.

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


UGI CORPORATION (PA)
Newbury Holding Company (DE)
UGI Enterprises, LLC (PA)
UGI Holdings, LLC (DE) (Shell Entity)
UGI Properties, Inc. (PA)
UGI Utilities, Inc. (PA)
United Valley Insurance Company (VT)
3.47%
Vertimass, LLC (DE)
AmeriGas, Inc. (PA)
Ashtola Production Company (PA)
Mountaintop Energy Holdings LLC (DE)
100%
AmeriGas Propane, Inc. (G.P.) (PA)
UGI Ethanol Development Corporation (PA)
Mountaineer Gas Company (WV)
Four Flags Drilling Company, Inc. (PA)


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


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


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

III-F-1

Request:

The latest available quarterly operating and financial report, annual report to the stockholders and prospectus shall be supplied for the utility and for the utility's parent, if the relationship exists.

Response:

Please see the following links:

1. UGI Corporation latest quarterly financial report:
https://www.ugicorp.com/node/25156/html

2. UGI Utilities latest quarterly financial report:
https://www.ugicorp.com/static-files/addae737-6a22-4e58-befa-041dd254ef84

3. UGI Corporation latest annual report:
https://www.ugicorp.com/node/25286/html

4. UGI Utilities latest annual report:
https://www.ugicorp.com/static-files/6deda4a5-cb76-406e-8b14-1285efb15a43

5. UGI Corporation latest prospectus:
https://d18rn0p25nwr6d.cloudfront.net/CIK-0000884614/55fea8d6-6284-4055-80ed-7a89504926ad.pdf

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

III-F-2

Request:

Supply projected capital requirements and sources of the filing utility, its parent and system— consolidated—for the test year and each of 3 comparable future years.

Response:

The capital spend requirements for UGI Utilities, Inc. are as follows:

FY 2022 = $ 500,363,000
FY 2023 = $ 499,005,000
FY 2024 = $ 500,304,000

Projected information beyond the Fully Projected Future Test Year is not available.

The sources of funds will be from both internally generated funds and required external financing.

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

III-F-3

Request:

State what coverage requirements or capital structure ratios are required in the most restrictive of applicable indentures/charter tests and how these measures have been computed.

Response:

Certain of UGI Utilities Senior Notes contain the following restrictions:

1. Leverage Ratio - The Company will maintain a ratio of Consolidated Indebtedness to Consolidated Total Capital of not greater than 0.65 to 1.00.

2. Priority Debt Ratio -The Company will not at any time permit Consolidated Priority Debt to exceed 10% of Consolidated Total Assets.

Definitions:

Consolidated Indebtedness means at any time the Indebtedness (other than Non-Recourse Debt) of the Company and its Subsidiaries calculated on a consolidated basis as of such time.

Consolidated Priority Debt means at any time the sum of:

(a) Indebtedness of the Company or any Subsidiaries secured by Liens permitted by Section 10.5(m) of the agreement, plus (but without duplication);

(b) Indebtedness of Subsidiaries other than:

(i) Indebtedness of Subsidiaries existing as of the issuance date and described on Schedule 5.15 (and any renewals, extension, or replacement thereof without increase in the principal amount thereof);

(ii) Indebtedness of Subsidiaries owing to the Company or any Subsidiary;

III-F-3 (Continued)

(iii) Acquired Subsidiary Indebtedness (and any renewal, extension or replacement thereof without increase in the principal amount thereof), provided that immediately after such acquired Subsidiary becomes a Subsidiary, no Default or Event of Default shall exist;

(iv) Indebtedness arising under any derivatives transaction protecting against or benefiting from fluctuations in any rate or price entered into in the ordinary course of business and not for investment or speculative purposes;

(v) Indebtedness comprising a netting or set-off arrangement entered into by the Company or any Subsidiary in the ordinary course of its banking arrangements for the purpose of netting debit and credit balances;

(vi) Indebtedness of Subsidiary Guarantors;

(vii) Indebtedness of Subsidiaries secured by Liens permitted by Section 10.5(a) through (l), inclusive.

"Consolidated Total Assets" means the sum of the assets of the Company and its Subsidiaries determined on a consolidated basis in accordance with GAAP, as shown in the most recent consolidated financial statements published by the Company and its Subsidiaries.

"Consolidated Total Capital" means at any time with respect to the Company, the sum of (x) Consolidated Indebtedness plus (y) consolidated stockholders' equity of the Company and its consolidated Subsidiaries, in each case determined at such date; provided that any accumulated other comprehensive income and loss and, without duplication, any non-cash effects resulting from the application of Accounting Standards Codification 715 and any non-recurring non-cash charges and any non-recurring non-cash gains will be excluded.

Indebtedness with respect to any Person means, at any time, without duplication, (a) all indebtedness of such Person for borrowed money, (b) all obligations of such Person for the deferred purchase price of property or services (other than trade payables incurred in the ordinary course of such Person's business), (c) all obligations of such Person evidenced by notes, bonds, debentures or other similar instruments, (d) all obligations of such Person created or arising under any conditional sale or other title retention agreement with respect to property acquired by such Person (even though the rights and

III-F-3 (Continued)

remedies of the seller or lender under such agreement in the event of default are limited to repossession or sale of such property), (e) all obligations of such Person as lessee under leases that have been or should be, in accordance with GAAP, recorded as capital leases, (f) all non-contingent obligations of such Person in respect of acceptances, letters of credit or similar extensions of credit, (g) all Indebtedness of others referred to in clauses (a) through (f) above or clause (h) below (collectively, "Guaranteed Debt") guaranteed directly or indirectly in any manner by such Person, or in effect guaranteed directly or indirectly by such Person through an agreement (1) to pay or purchase such Guaranteed Debt or to advance or supply funds for the payment or purchase of such Guaranteed Debt, (2) to purchase, sell or lease (as lessee or lessor) property, or to purchase or sell services, primarily for the purpose of enabling the debtor to make payment of such Guaranteed Debt or to assure the holder of such Guaranteed Debt against loss, (3) to supply funds to or in any other manner invest in the debtor (including any agreement to pay for property or services irrespective of whether such property is received or such services are rendered) or (4) otherwise to assure a creditor against loss, and (h) all Indebtedness referred to in clauses (a) through (g) above (including Guaranteed Debt) secured by (or for which the holder of such Indebtedness has an existing right, contingent or otherwise, to be secured by) any Lien on property (including, without limitation, accounts and contract rights) owned by such Person, even though such Person has not assumed or become liable for the payment of such Indebtedness.

The Company’s revolving credit agreement and term loan also contain a covenant requiring the Company to maintain a ratio of Consolidated Debt to Consolidated Total Capital of not greater than 0.65 to 1.00 as of the end of any fiscal quarter.

“Consolidated Debt” means, with respect to the Borrower, at any date, the Debt (other than Non-recourse Debt) of the Borrower and its Consolidated Subsidiaries, determined on a consolidated basis as of such date.

“Consolidated Total Capital” means, with respect to the Borrower, at any date, the sum of (x) Consolidated Debt plus (y) consolidated stockholders’ equity of the Borrower and its Consolidated Subsidiaries, in each case determined at such date; provided that any accumulated other comprehensive income and loss and, without duplication, any non-cash effects resulting from the application of Accounting Standards Codification 715 will be excluded.

Please see Attachment III-F-3 for a copy of the covenant calculations for the period ended September 30, 2022.

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

UGI UTILITIES, INC.
NOTE PURCHASE AGREEMENT
Dated as of June 30, 2022
Computations pursuant to Section 10.6
as of September 30, 2022
(Dollar amounts in thousands)

Section
10.6(a):Leverage Ratio. The Company will maintain a ratio of Consolidated Indebtedness to Consolidated Total Capital of not greater than 0.65 to 1.00

Consolidated Debt		
Current maturities of long term debt	6,250	
Capital lease obligations	415	
Bank loans	151,000	
Long term debt	1,447,719	1,605,384
Consolidated Total Capital		
Consolidated debt	1,605,384	
Consolidated stockholder's equity	1,638,172	
Less: Accumulated other comprehensive income (loss)	(16,648)	3,260,204

Consolidated Debt / Consolidated Total Capital	49%
Maximum Allowable ratio of Consolidated Debt to Consolidated Total Capital	65%
Below Covenant Threshold	16%

Section
10.6(b):Priority Debt Ratio. The Company will not at any time permit Consolidated Priority Debt to exceed 10% of Consolidated Total Assets.

Consolidated Priority Debt	-
Consolidated Total Assets	4,471,000

Consolidated Priority Debt / Consolidated Total Assets	0%
Maximum Allowable ratio of Consolidated Debt to Consolidated Total Capital	10%
Below Covenant Threshold	10%

UGI UTILITIES, INC.
PNC BANK, N. A.
CREDIT AGREEMENT
Dated as of June 27, 2019
Computations pursuant to Section 5.03
as of September 30, 2022
(Dollar amounts in thousands)

Section
5.03 Financial Covenant. So long as any Advance shall remain unpaid, any Letter of Credit shall remain outstanding, any other amount shall remain unpaid hereunder or under any Note or any Lender shall have any Commitment hereunder, the Borrower will maintain a ratio of Consolidated Debt to the Consolidated Total Capital of not greater than 0.65:1.00 as of the end of any fiscal quarter.

Consolidated Debt		
Current maturities of long term debt	6,250	
Capital lease obligations	415	
Bank loans	151,000	
Long term debt	1,447,719	1,605,384
Consolidated Total Capital		
Consolidated debt	1,605,384	
Consolidated stockholder's equity	1,638,172	
Less: Accumulated other comprehensive income (loss)	(16,648)	3,260,204
Consolidated Debt / Consolidated Total Capital		49%
Maximum Allowable ratio of Consolidated Debt to Consolidated Total Capital		65%
Below Covenant Threshold		16%

III-F-4

Request:

A schedule of comparative financial data shall be supplied for the test year, the most immediately available annual historical period, prior to the test year, and the 2 calendar years most immediately preceding the test year. Changes in Moody's/S&P ratings, noted on this schedule, shall be accompanied by the Moody's/S&P writeup of such change, if available. The following financial data and ratios shall be supplied for the utility's parent, where applicable, if not available for the utility.

a. Times interest earned ratio—pre-tax and post-tax basis.
b. Preferred stock dividend coverage ratio—post-tax basis.
c. Times fixed charges earned ratio—pre-tax basis.
d. Earnings per share.
e. Dividend per share.
f. Average dividend yield (52-week high/low common stock price).
g. Average book value per share.
h. Average market price per share.
i. Market price-book value ratio.
j. Earnings-book value ratio (per share basis, average book value).
k. Dividend payout ratio.
l. AFUDC as a % of earnings available for common equity.
m. Construction work in progress as a % of net utility plant.
n. Effective income tax rate.
o. Internal cash generations as a % of total capital requirements.

Response:

Please see Attachment III-F-4.1 for financial data responses related to a-o above.

There were no changes in UGI Utilities Inc.'s ratings from credit rating agencies from 2020 – November 2022. In December 2022, Moody's changed the credit rating for UGI Utilities, Inc.'s senior unsecured debt from A2 to A3. See the writeup of this change at Attachment III-F-4.2.

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

UGI Utilities, Inc. - Electric Division
Select Financial Data for UGI Utilities, Inc. - Consolidated
For the Years Ended September 30,

	Description/Purpose		2020	2021		2022	2023	2024
a.	Times interest earned ratio - pre-tax		4.20	4.42		5.26	4.72	4.74
	Times interest earned ratio - post-tax		3.50	3.64		4.37	3.82	3.87
b.	Preferred stock dividend coverage ratio - post tax basis		N/A	N/A		N/A	N/A	N/A
c.	Times fixed charges earned ratio - pre-tax basis		4.17	4.38		5.21	4.68	4.69
d.	Earnings per share - diluted	(a)	2.54	6.92	(d)	4.97	(b)	(b)
e.	Dividend per share	(a)	1.310	1.350		1.410	(b)	(b)
f.	Average dividend yield (52 week high/low common stock price)	(a)	3.63%	5.61%		3.56%	(c)	(c)
g.	Average book value per share	(a)	20.37	22.91		27.12	(c)	(c)
h.	Average market price per share	(a)	36.83	41.09		40.72	(c)	(c)
i.	Market price-book value ratio	(a)	1.81	1.79		1.50	(c)	(c)
j.	Earnings -book value ratio (per share basis, average book value)	(a)	0.125	0.302	(d)	0.183	(c)	(c)
k.	Dividend payout ratio	(a)	51.6%	19.5%		28.4%	(b)	(b)
l.	AFUDC as a % of earnings available for common equity		0.9%	0.6%		1.1%	2.1%	1.9%
m.	Construction work in progress as a % of net utility plant		3.4%	2.5%		3.2%	3.6%	3.3%
n.	Effective income tax rate		22.1%	22.8%		21.0%	24.1%	23.1%
o.	Internal cash generations as a % of total capital requirements		80.2%	70.1%		57.6%	75.8%	77.6%

(a) Information presented for UGI Corporation, as it is not applicable to UGI Utilities.

(b) Requested data for 2023 and 2024 is confidential since it deals with the release of projected financial information. This information will be provided to the PUC upon the issuance of an appropriate protective order concerning the confidentiality of such information and will be provided to any party to the rate proceeding upon the execution of an agreement with UGI Utilities to hold such information in strict confidence and not disclose it to any person, whether or not a party to the proceeding, who has not executed a similar confidentiality agreement with UGI Utilities.

(c) Requested data for 2023 and 2024 is either unavailable or unpredictable.

(d) UGI Corporation's 2021 EPS included an unusual gain of $4.72 per share from commodity derivatives (unrelated to UGI Utilities, Inc.), which distorts the comparability of earnings per share and earnings-book value ratio from year to year. UGI Corporation's 10-K presents an "Adjusted EPS" amount which excludes these commodity gains / losses as well as other unusual adjustments. Adjusted earnings per share and the related adjusted earnings-book value ratio for 2020 - 2022 is shown below. See further details in the 10-K filing of UGI Corporation.

	2020	2021	2022
Adjusted earnings per share	2.67	2.96	2.90
Revised earnings-book value ratio (based on adjusted earnings per share)	0.131	0.129	0.107

MOODY'S

Rating Action: Moody's downgrades UGI Utilities to A3, outlook stable

13 Dec 2022

Approximately $140 million of debt securities affected

New York, December 13, 2022 -- Moody's Investors Service ("Moody's") downgraded UGI Utilities, Inc.'s ("UGI Utilities") senior unsecured rating to A3 from A2 and changed its outlook to stable from negative.

RATINGS RATIONALE

"The downgrade reflects Moody's expectation that UGI Utilities' financial metrics will be constrained by higher debt to fund elevated capital expenditures and considers higher UGI Corporation (UGI, not rated) family credit risk" stated Nana Hamilton, VP-Senior Analyst. "This additional credit risk emanates from its lower rated non-utility businesses and approximately $1 billion of parent debt incurred to support acquisitions in recent years," added Hamilton.

UGI Utilities' ratio of operating cash flow excluding changes in working capital (CFO pre-WC) to debt over the last three years has been at the very low end of the expectations Moody's has articulated for it to maintain its previous A2 rating. Averaging 20.4% from 2019 through 2021, the ratio was below that of most A2 rated LDC peers and significantly below the company's historical, pre-tax reform three-year average of 26.3%. Despite a strong financial performance in 2022, we see the utility's CFO pre-WC to debt ratio remaining around 20% in 2023 and beyond as debt increases to finance an elevated capital expenditure program. We expect capital expenditures to be around $500 million annually over the next three years, compared to an annual average of about $370 million from 2019 to 2021.

In addition, parent company UGI's propane retailing, energy services, and midstream and marketing businesses have a significantly higher risk profile than UGI Utilities and some have been facing recent headwinds. While financial challenges at UGI subsidiary UGI International, LLC's (Ba2 stable) European energy marketing business have thus far had no direct negative impact on the utility, they highlight the potential for contagion risk in the event of financial distress at UGI or one of its other subsidiaries.

Furthermore, parent UGI has introduced parent company debt into the organization's capital structure over the last few years. While it had no parent level debt prior to 2019, this has risen to about 15% of total consolidated company debt by the end of its fiscal 2022. This debt was incurred to finance acquisitions in both 2019 and 2021. With no ringfencing provisions in place to protect the utility should the parent change its financial policies, make additional acquisitions, or continue to add debt, the utility's credit quality could be adversely affected going forward. We note that over the last year, the overall credit quality of the UGI family has declined with the downgrades of AmeriGas Partners, L.P. (Ba3 stable) in January 2022 and UGI International on 12 December 2022.

The A3 rating and stable outlook of UGI Utilities are based on our expectation that management will continue to insulate the utility from UGI's other businesses, that there will be no further credit deterioration at these businesses and that no additional debt will be added at the parent company level. They also consider the attractive organic growth opportunities in the utility's service territory, which is in Pennsylvania's Marcellus shale region, and a credit supportive regulatory environment in Pennsylvania as demonstrated by UGI Utilities' recent rate case outcome.

On 15 September, the Pennsylvania Public Utility Commission (PAPUC) approved UGI Utilities' gas distribution rate case settlement to implement a $49.5 million, two-step rate increase, relative to the $82.7 million rate increase sought by the utility. The company was authorized to implement a $38 million rate increase, effective 29 October 2022, and an incremental $11.5 million increase to effective 1 October 2023. Positively, the settlement included a weather normalization adjustment rider under a 5-year pilot program, which should help to reduce revenue volatility.

Our credit rating on UGI Utilities continues to be predicated on the high degree of separation between it and its riskier affiliates, both in terms of legal organization, financing arrangements and by the additional layer of protection provided by PAPUC regulatory oversight. UGI Utilities has historically paid a conservative level of dividends to UGI and we expect the utility to continue to pay little to no dividends to UGI while it executes its significant capital program.

Outlook

UGI Utilities' stable outlook reflects our expectation that the company will maintain a CFO pre-WC to debt ratio above 19%. The outlook further assumes that the company will continue to maintain a constructive relationship with the PAPUC and benefit from credit supportive regulation, that a high degree of operational and financial separation will be maintained between the utility and its riskier affiliates, that the credit quality of UGI's other businesses will not deteriorate further and that UGI's growth and financing plans will not lead to higher holding company level debt.

FACTORS THAT COULD LEAD TO AN UPGRADE OR DOWNGRADE OF THE RATINGS

Factors that could lead to an upgrade

UGI Utilities' rating could be upgraded if the company produces stronger financial metrics, including CFO pre-WC to debt consistently above 22%, if there is a material reduction in debt at the UGI level and if the credit quality of UGI's other subsidiaries improves.

Factors that could lead to a downgrade

A downgrade could be considered if we expect the utility to maintain a ratio of CFO pre-WC to debt below 19%, if dividends from the utility to the parent increase materially, if UGI's growth and financing plans result in higher holding company debt or otherwise elevated credit risk, if the credit quality of UGI's non-utility subsidiaries deteriorate further or if the Pennsylvania regulatory environment becomes less credit supportive.

Downgrades:

..Issuer: UGI Utilities, Inc.

....Senior Unsecured Medium-Term Note Program, Downgraded to (P)A3 from (P)A2

....Senior Unsecured Regular Bond/Debenture, Downgraded to A3 from A2

Outlook Actions:

..Issuer: UGI Utilities, Inc.

....Outlook, Changed To Stable From Negative

UGI Utilities, Inc. is a rate regulated natural gas and electric utility serving over 678,000 gas customers throughout Pennsylvania (as well as several hundred customers in one county in Maryland) and about 62,600 electric customers in northeastern Pennsylvania. UGI Utilities' gas operations under UGI Gas account for substantially all the utility's operating income. UGI Utilities also has an electric utility (UGI Electric) which accounts for only about 3% of operating income.

The principal methodology used in these ratings was Regulated Electric and Gas Utilities published in June 2017 and available at https://ratings.moodys.com/api/rmc-documents/68547. Alternatively, please see the Rating Methodologies page on https://ratings.moodys.com for a copy of this methodology.

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IV. RATE STRUCTURE & COST ALLOCATION

IV-A-1

Request:

Provide a summary schedule of the individual rate effects. For each state jurisdictional rate, show the following information for the test period elected:

1. Rate schedule designation.

2. For existing rates:

    a. Customers served as of end of period.
    b. Annual Kwh sales.
    c. Base rate revenues adjusted for any changes in base rate application that may have occurred during the test period.
    d. Tax surcharge revenues.
    e. Energy Cost adjustment clause revenues.
    f. Revenues received from other clauses or riders separately accounted for.
    g. Total of all revenues.

3. For proposed rates:

    a. Estimated number of customers whose charges for electric service will be increased Or decreased as a result of this filing.
    b. Base rate revenues:
        1. Annual dollar amount of increase or decrease.
        2. Percentage change.
    c. Estimated tax surcharge revenues based on the assumption that the base rate changes proposed were in place.
    d. Estimated Energy cost adjustment clause revenues.
    e. Revenues received from other clauses or riders separately accounted for.
    f. Total of all revenues:
        1. Amount of total annual dollar change.
        2. Percentage change.

4. Supplement the revenue summary to obtain a complete revenue statement of the electric business, that is, show delayed payments, other electric revenues, FERC jurisdictional sales and revenues and all other appropriate revenue items and adjustments.

IV-A-1 (Continued)

5. Develop the grand total showing total sales and revenues as adjusted and the various increases and decreases and percent effects as described above.

Response:

Please see UGI Electric Exhibit E - Proof of Revenue and the Direct Testimony of Sherry A. Epler, UGI Electric Statement No. 10.

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

IV-B-1

Request:

Provide a description of changes proposed for the new tariff:

1. For each rate schedule proposed to be modified.

2. For each rate schedule proposed to be deleted.

3. For each new rate schedule proposed to be added.

Response:

Please see UGI Electric Exhibit F - Current Tariff, UGI Electric Exhibit F - Proposed Supplement No. 51 to UGI Electric Tariff - Pa P.U.C. No. 6 and Proposed Supplement No. 7 to UGI Electric Tariff - Pa P.U.C. No. 2S, as well as the Direct Testimony of Eric W. Sorber, UGI Electric Statement No. 4, the Direct Testimony of John D. Taylor, UGI Electric Statement No. 6, and the Direct Testimony of Sherry A. Epler, UGI Electric Statement No. 10.

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

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IV-C-1

Request:

The annual revenue effect of any proposed change to any rate must be supported by a billing analysis. This may consist of the use of bill frequency distributions or individual customer billing records for the most recent annual periods available. All billing determinants should be displayed. The blocking and corresponding prices of the existing rate and the proposed rate should be applied to the determinants to derive the base rate revenues under both present and proposed rates. The derived base rate revenues should form the basis for measuring the annual base rate effect of the rates in question for the test periods.

Response:

Please see Attachment IV-C-1 on USB flash drive for the calculation of the revenue effect of the rate change on the various rate classes.

Prepared by or under the supervision of: Sherry A. Epler

IV-D-1

Request:

The effects of the proposed rates on monthly billing conditions should be provided as follows:

1. Residential Bill Comparisons

For each rate applicable to residential service provide a chart or tabulation which shows the dollar and percentage effect of the proposed base rate on monthly bills ranging from the use of zero kWh to 5,000 kWh at appropriate intervals.

2. General Bill Comparisons

For each rate that requires both a billing demand (kW) and kWh's as the billing determinants, provide a tabulation or graphical comparison showing the percentage effect of the proposed base rate on monthly bills using several representative demand (kW) levels, the monthly kWh for each demand selected to be in load factor increments of 10% starting at 0% and ending at 100% (730H) or by hours' use increments that covers approximately 95% of the bills.

Response:

Please see Attachment IV-D-1.

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

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate R

kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
-	$ 9.98	$ 13.50	$ 3.52	35.3%
50	$ 19.11	$ 23.32	$ 4.21	22.0%
100	$ 28.25	$ 33.15	$ 4.89	17.3%
150	$ 37.39	$ 42.97	$ 5.58	14.9%
200	$ 46.53	$ 52.79	$ 6.26	13.5%
250	$ 55.67	$ 62.62	$ 6.95	12.5%
300	$ 64.80	$ 72.44	$ 7.64	11.8%
350	$ 73.94	$ 82.26	$ 8.32	11.3%
400	$ 83.08	$ 92.08	$ 9.01	10.8%
450	$ 92.22	$ 101.91	$ 9.69	10.5%
500	$ 101.35	$ 111.73	$ 10.38	10.2%
550	$ 110.49	$ 121.55	$ 11.06	10.0%
600	$ 119.63	$ 131.38	$ 11.75	9.8%
650	$ 128.77	$ 141.20	$ 12.43	9.7%
700	$ 137.91	$ 151.02	$ 13.12	9.5%
750	$ 147.04	$ 160.85	$ 13.80	9.4%
800	$ 156.18	$ 170.67	$ 14.49	9.3%
850	$ 165.32	$ 180.49	$ 15.17	9.2%
900	$ 174.46	$ 190.31	$ 15.86	9.1%
950	$ 183.59	$ 200.14	$ 16.54	9.0%
1,000	$ 192.73	$ 209.96	$ 17.23	8.9%
1,050	$ 201.87	$ 219.78	$ 17.91	8.9%
1,100	$ 211.01	$ 229.61	$ 18.60	8.8%
1,150	$ 220.15	$ 239.43	$ 19.28	8.8%
1,200	$ 229.28	$ 249.25	$ 19.97	8.7%
1,250	$ 238.42	$ 259.08	$ 20.65	8.7%
1,300	$ 247.56	$ 268.90	$ 21.34	8.6%
1,350	$ 256.70	$ 278.72	$ 22.02	8.6%
1,400	$ 265.83	$ 288.54	$ 22.71	8.5%
1,450	$ 274.97	$ 298.37	$ 23.39	8.5%
1,500	$ 284.11	$ 308.19	$ 24.08	8.5%
1,550	$ 293.25	$ 318.01	$ 24.76	8.4%
1,600	$ 302.39	$ 327.84	$ 25.45	8.4%
1,650	$ 311.52	$ 337.66	$ 26.14	8.4%
1,700	$ 320.66	$ 347.48	$ 26.82	8.4%
1,750	$ 329.80	$ 357.31	$ 27.51	8.3%
1,800	$ 338.94	$ 367.13	$ 28.19	8.3%
1,850	$ 348.08	$ 376.95	$ 28.88	8.3%
1,900	$ 357.21	$ 386.77	$ 29.56	8.3%
1,950	$ 366.35	$ 396.60	$ 30.25	8.3%
2,000	$ 375.49	$ 406.42	$ 30.93	8.2%

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate R

kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
2,050	$ 384.63	$ 416.24	$ 31.62	8.2%
2,100	$ 393.76	$ 426.07	$ 32.30	8.2%
2,150	$ 402.90	$ 435.89	$ 32.99	8.2%
2,200	$ 412.04	$ 445.71	$ 33.67	8.2%
2,250	$ 421.18	$ 455.54	$ 34.36	8.2%
2,300	$ 430.32	$ 465.36	$ 35.04	8.1%
2,350	$ 439.45	$ 475.18	$ 35.73	8.1%
2,400	$ 448.59	$ 485.00	$ 36.41	8.1%
2,450	$ 457.73	$ 494.83	$ 37.10	8.1%
2,500	$ 466.87	$ 504.65	$ 37.78	8.1%
2,550	$ 476.00	$ 514.47	$ 38.47	8.1%
2,600	$ 485.14	$ 524.30	$ 39.15	8.1%
2,650	$ 494.28	$ 534.12	$ 39.84	8.1%
2,700	$ 503.42	$ 543.94	$ 40.52	8.0%
2,750	$ 512.56	$ 553.77	$ 41.21	8.0%
2,800	$ 521.69	$ 563.59	$ 41.89	8.0%
2,850	$ 530.83	$ 573.41	$ 42.58	8.0%
2,900	$ 539.97	$ 583.23	$ 43.26	8.0%
2,950	$ 549.11	$ 593.06	$ 43.95	8.0%
3,000	$ 558.24	$ 602.88	$ 44.64	8.0%
3,050	$ 567.38	$ 612.70	$ 45.32	8.0%
3,100	$ 576.52	$ 622.53	$ 46.01	8.0%
3,150	$ 585.66	$ 632.35	$ 46.69	8.0%
3,200	$ 594.80	$ 642.17	$ 47.38	8.0%
3,250	$ 603.93	$ 652.00	$ 48.06	8.0%
3,300	$ 613.07	$ 661.82	$ 48.75	8.0%
3,350	$ 622.21	$ 671.64	$ 49.43	7.9%
3,400	$ 631.35	$ 681.46	$ 50.12	7.9%
3,450	$ 640.49	$ 691.29	$ 50.80	7.9%
3,500	$ 649.62	$ 701.11	$ 51.49	7.9%
3,550	$ 658.76	$ 710.93	$ 52.17	7.9%
3,600	$ 667.90	$ 720.76	$ 52.86	7.9%
3,650	$ 677.04	$ 730.58	$ 53.54	7.9%
3,700	$ 686.17	$ 740.40	$ 54.23	7.9%
3,750	$ 695.31	$ 750.23	$ 54.91	7.9%
3,800	$ 704.45	$ 760.05	$ 55.60	7.9%
3,850	$ 713.59	$ 769.87	$ 56.28	7.9%
3,900	$ 722.73	$ 779.69	$ 56.97	7.9%
3,950	$ 731.86	$ 789.52	$ 57.65	7.9%
4,000	$ 741.00	$ 799.34	$ 58.34	7.9%
4,050	$ 750.14	$ 809.16	$ 59.02	7.9%

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate R

kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
4,100	$ 759.28	$ 818.99	$ 59.71	7.9%
4,150	$ 768.41	$ 828.81	$ 60.39	7.9%
4,200	$ 777.55	$ 838.63	$ 61.08	7.9%
4,250	$ 786.69	$ 848.46	$ 61.76	7.9%
4,300	$ 795.83	$ 858.28	$ 62.45	7.8%
4,350	$ 804.97	$ 868.10	$ 63.14	7.8%
4,400	$ 814.10	$ 877.92	$ 63.82	7.8%
4,450	$ 823.24	$ 887.75	$ 64.51	7.8%
4,500	$ 832.38	$ 897.57	$ 65.19	7.8%
4,550	$ 841.52	$ 907.39	$ 65.88	7.8%
4,600	$ 850.65	$ 917.22	$ 66.56	7.8%
4,650	$ 859.79	$ 927.04	$ 67.25	7.8%
4,700	$ 868.93	$ 936.86	$ 67.93	7.8%
4,750	$ 878.07	$ 946.69	$ 68.62	7.8%
4,800	$ 887.21	$ 956.51	$ 69.30	7.8%
4,850	$ 896.34	$ 966.33	$ 69.99	7.8%
4,900	$ 905.48	$ 976.15	$ 70.67	7.8%
4,950	$ 914.62	$ 985.98	$ 71.36	7.8%
5,000	$ 923.76	$ 995.80	$ 72.04	7.8%

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate GS1

kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
-	$ 13.65	$ 14.00	$ 0.35	2.6%
50	$ 22.92	$ 24.32	$ 1.40	6.1%
100	$ 32.19	$ 34.65	$ 2.46	7.6%
150	$ 41.46	$ 44.97	$ 3.51	8.5%
200	$ 50.73	$ 55.30	$ 4.56	9.0%
250	$ 60.00	$ 65.62	$ 5.62	9.4%
300	$ 69.28	$ 75.95	$ 6.67	9.6%
350	$ 78.55	$ 86.27	$ 7.73	9.8%
400	$ 87.82	$ 96.60	$ 8.78	10.0%
450	$ 97.09	$ 106.92	$ 9.83	10.1%
500	$ 106.36	$ 117.25	$ 10.89	10.2%
550	$ 115.63	$ 127.57	$ 11.94	10.3%
600	$ 124.90	$ 137.89	$ 12.99	10.4%
650	$ 134.17	$ 148.22	$ 14.05	10.5%
700	$ 143.44	$ 158.54	$ 15.10	10.5%
750	$ 152.71	$ 168.87	$ 16.16	10.6%
800	$ 161.98	$ 179.19	$ 17.21	10.6%
850	$ 171.25	$ 189.52	$ 18.26	10.7%
900	$ 180.52	$ 199.84	$ 19.32	10.7%
950	$ 189.79	$ 210.17	$ 20.37	10.7%
1,000	$ 199.06	$ 220.49	$ 21.43	10.8%
1,050	$ 208.34	$ 230.81	$ 22.48	10.8%
1,100	$ 217.61	$ 241.14	$ 23.53	10.8%
1,150	$ 226.88	$ 251.46	$ 24.59	10.8%
1,200	$ 236.15	$ 261.79	$ 25.64	10.9%
1,250	$ 245.42	$ 272.11	$ 26.69	10.9%
1,300	$ 254.69	$ 282.44	$ 27.75	10.9%
1,350	$ 263.96	$ 292.76	$ 28.80	10.9%
1,400	$ 273.23	$ 303.09	$ 29.86	10.9%
1,450	$ 282.50	$ 313.41	$ 30.91	10.9%
1,500	$ 291.77	$ 323.74	$ 31.96	11.0%
1,550	$ 301.04	$ 334.06	$ 33.02	11.0%
1,600	$ 310.31	$ 344.38	$ 34.07	11.0%
1,650	$ 319.58	$ 354.71	$ 35.13	11.0%
1,700	$ 328.85	$ 365.03	$ 36.18	11.0%
1,750	$ 338.12	$ 375.36	$ 37.23	11.0%
1,800	$ 347.39	$ 385.68	$ 38.29	11.0%
1,850	$ 356.67	$ 396.01	$ 39.34	11.0%
1,900	$ 365.94	$ 406.33	$ 40.39	11.0%
1,950	$ 375.21	$ 416.66	$ 41.45	11.0%
2,000	$ 384.48	$ 426.98	$ 42.50	11.1%

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate GS1

kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
2,050	$ 393.75	$ 437.30	$ 43.56	11.1%
2,100	$ 403.02	$ 447.63	$ 44.61	11.1%
2,150	$ 412.29	$ 457.95	$ 45.66	11.1%
2,200	$ 421.56	$ 468.28	$ 46.72	11.1%
2,250	$ 430.83	$ 478.60	$ 47.77	11.1%
2,300	$ 440.10	$ 488.93	$ 48.83	11.1%
2,350	$ 449.37	$ 499.25	$ 49.88	11.1%
2,400	$ 458.64	$ 509.58	$ 50.93	11.1%
2,450	$ 467.91	$ 519.90	$ 51.99	11.1%
2,500	$ 477.18	$ 530.23	$ 53.04	11.1%
2,550	$ 486.45	$ 540.55	$ 54.09	11.1%
2,600	$ 495.73	$ 550.87	$ 55.15	11.1%
2,650	$ 505.00	$ 561.20	$ 56.20	11.1%
2,700	$ 514.27	$ 571.52	$ 57.26	11.1%
2,750	$ 523.54	$ 581.85	$ 58.31	11.1%
2,800	$ 532.81	$ 592.17	$ 59.36	11.1%
2,850	$ 542.08	$ 602.50	$ 60.42	11.1%
2,900	$ 551.35	$ 612.82	$ 61.47	11.1%
2,950	$ 560.62	$ 623.15	$ 62.53	11.2%
3,000	$ 569.89	$ 633.47	$ 63.58	11.2%
3,050	$ 579.16	$ 643.79	$ 64.63	11.2%
3,100	$ 588.43	$ 654.12	$ 65.69	11.2%
3,150	$ 597.70	$ 664.44	$ 66.74	11.2%
3,200	$ 606.97	$ 674.77	$ 67.79	11.2%
3,250	$ 616.24	$ 685.09	$ 68.85	11.2%
3,300	$ 625.51	$ 695.42	$ 69.90	11.2%
3,350	$ 634.79	$ 705.74	$ 70.96	11.2%
3,400	$ 644.06	$ 716.07	$ 72.01	11.2%
3,450	$ 653.33	$ 726.39	$ 73.06	11.2%
3,500	$ 662.60	$ 736.72	$ 74.12	11.2%
3,550	$ 671.87	$ 747.04	$ 75.17	11.2%
3,600	$ 681.14	$ 757.36	$ 76.23	11.2%
3,650	$ 690.41	$ 767.69	$ 77.28	11.2%
3,700	$ 699.68	$ 778.01	$ 78.33	11.2%
3,750	$ 708.95	$ 788.34	$ 79.39	11.2%
3,800	$ 718.22	$ 798.66	$ 80.44	11.2%
3,850	$ 727.49	$ 808.99	$ 81.49	11.2%
3,900	$ 736.76	$ 819.31	$ 82.55	11.2%
3,950	$ 746.03	$ 829.64	$ 83.60	11.2%
4,000	$ 755.30	$ 839.96	$ 84.66	11.2%
4,050	$ 764.57	$ 850.28	$ 85.71	11.2%

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate GS1

kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
4,100	$ 773.84	$ 860.61	$ 86.76	11.2%
4,150	$ 783.12	$ 870.93	$ 87.82	11.2%
4,200	$ 792.39	$ 881.26	$ 88.87	11.2%
4,250	$ 801.66	$ 891.58	$ 89.93	11.2%
4,300	$ 810.93	$ 901.91	$ 90.98	11.2%
4,350	$ 820.20	$ 912.23	$ 92.03	11.2%
4,400	$ 829.47	$ 922.56	$ 93.09	11.2%
4,450	$ 838.74	$ 932.88	$ 94.14	11.2%
4,500	$ 848.01	$ 943.21	$ 95.19	11.2%
4,550	$ 857.28	$ 953.53	$ 96.25	11.2%
4,600	$ 866.55	$ 963.85	$ 97.30	11.2%
4,650	$ 875.82	$ 974.18	$ 98.36	11.2%
4,700	$ 885.09	$ 984.50	$ 99.41	11.2%
4,750	$ 894.36	$ 994.83	$ 100.46	11.2%
4,800	$ 903.63	$ 1,005.15	$ 101.52	11.2%
4,850	$ 912.90	$ 1,015.48	$ 102.57	11.2%
4,900	$ 922.18	$ 1,025.80	$ 103.63	11.2%
4,950	$ 931.45	$ 1,036.13	$ 104.68	11.2%
5,000	$ 940.72	$ 1,046.45	$ 105.73	11.2%

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate GS5

kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
-	$ 9.98	$ 13.50	$ 3.52	35.3%
50	$ 18.51	$ 22.75	$ 4.24	22.9%
100	$ 27.04	$ 32.00	$ 4.95	18.3%
150	$ 35.58	$ 41.24	$ 5.67	15.9%
200	$ 44.11	$ 50.49	$ 6.38	14.5%
250	$ 52.65	$ 59.74	$ 7.09	13.5%
300	$ 61.18	$ 68.99	$ 7.81	12.8%
350	$ 69.71	$ 78.24	$ 8.52	12.2%
400	$ 78.25	$ 87.48	$ 9.24	11.8%
450	$ 86.78	$ 96.73	$ 9.95	11.5%
500	$ 95.32	$ 105.98	$ 10.66	11.2%
550	$ 103.85	$ 115.23	$ 11.38	11.0%
600	$ 112.38	$ 124.48	$ 12.09	10.8%
650	$ 120.92	$ 133.72	$ 12.81	10.6%
700	$ 129.45	$ 142.97	$ 13.52	10.4%
750	$ 137.99	$ 152.22	$ 14.23	10.3%
800	$ 146.52	$ 161.47	$ 14.95	10.2%
850	$ 155.05	$ 170.72	$ 15.66	10.1%
900	$ 163.59	$ 179.96	$ 16.38	10.0%
950	$ 172.12	$ 189.21	$ 17.09	9.9%
1,000	$ 180.66	$ 198.46	$ 17.80	9.9%
1,050	$ 189.19	$ 207.71	$ 18.52	9.8%
1,100	$ 197.72	$ 216.96	$ 19.23	9.7%
1,150	$ 206.26	$ 226.20	$ 19.95	9.7%
1,200	$ 214.79	$ 235.45	$ 20.66	9.6%
1,250	$ 223.33	$ 244.70	$ 21.37	9.6%
1,300	$ 231.86	$ 253.95	$ 22.09	9.5%
1,350	$ 240.39	$ 263.20	$ 22.80	9.5%
1,400	$ 248.93	$ 272.44	$ 23.52	9.4%
1,450	$ 257.46	$ 281.69	$ 24.23	9.4%
1,500	$ 266.00	$ 290.94	$ 24.94	9.4%
1,550	$ 274.53	$ 300.19	$ 25.66	9.3%
1,600	$ 283.06	$ 309.44	$ 26.37	9.3%
1,650	$ 291.60	$ 318.68	$ 27.09	9.3%
1,700	$ 300.13	$ 327.93	$ 27.80	9.3%
1,750	$ 308.67	$ 337.18	$ 28.51	9.2%
1,800	$ 317.20	$ 346.43	$ 29.23	9.2%
1,850	$ 325.73	$ 355.68	$ 29.94	9.2%
1,900	$ 334.27	$ 364.92	$ 30.66	9.2%
1,950	$ 342.80	$ 374.17	$ 31.37	9.2%
2,000	$ 351.34	$ 383.42	$ 32.08	9.1%

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate GS5

kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
2,050	$ 359.87	$ 392.67	$ 32.80	9.1%
2,100	$ 368.40	$ 401.92	$ 33.51	9.1%
2,150	$ 376.94	$ 411.16	$ 34.23	9.1%
2,200	$ 385.47	$ 420.41	$ 34.94	9.1%
2,250	$ 394.01	$ 429.66	$ 35.65	9.0%
2,300	$ 402.54	$ 438.91	$ 36.37	9.0%
2,350	$ 411.07	$ 448.16	$ 37.08	9.0%
2,400	$ 419.61	$ 457.40	$ 37.80	9.0%
2,450	$ 428.14	$ 466.65	$ 38.51	9.0%
2,500	$ 436.68	$ 475.90	$ 39.22	9.0%
2,550	$ 445.21	$ 485.15	$ 39.94	9.0%
2,600	$ 453.74	$ 494.40	$ 40.65	9.0%
2,650	$ 462.28	$ 503.64	$ 41.37	8.9%
2,700	$ 470.81	$ 512.89	$ 42.08	8.9%
2,750	$ 479.35	$ 522.14	$ 42.79	8.9%
2,800	$ 487.88	$ 531.39	$ 43.51	8.9%
2,850	$ 496.41	$ 540.64	$ 44.22	8.9%
2,900	$ 504.95	$ 549.88	$ 44.94	8.9%
2,950	$ 513.48	$ 559.13	$ 45.65	8.9%
3,000	$ 522.02	$ 568.38	$ 46.36	8.9%
3,050	$ 530.55	$ 577.63	$ 47.08	8.9%
3,100	$ 539.08	$ 586.88	$ 47.79	8.9%
3,150	$ 547.62	$ 596.12	$ 48.51	8.9%
3,200	$ 556.15	$ 605.37	$ 49.22	8.9%
3,250	$ 564.69	$ 614.62	$ 49.93	8.8%
3,300	$ 573.22	$ 623.87	$ 50.65	8.8%
3,350	$ 581.75	$ 633.12	$ 51.36	8.8%
3,400	$ 590.29	$ 642.36	$ 52.08	8.8%
3,450	$ 598.82	$ 651.61	$ 52.79	8.8%
3,500	$ 607.36	$ 660.86	$ 53.50	8.8%
3,550	$ 615.89	$ 670.11	$ 54.22	8.8%
3,600	$ 624.42	$ 679.36	$ 54.93	8.8%
3,650	$ 632.96	$ 688.60	$ 55.65	8.8%
3,700	$ 641.49	$ 697.85	$ 56.36	8.8%
3,750	$ 650.03	$ 707.10	$ 57.07	8.8%
3,800	$ 658.56	$ 716.35	$ 57.79	8.8%
3,850	$ 667.09	$ 725.60	$ 58.50	8.8%
3,900	$ 675.63	$ 734.84	$ 59.22	8.8%
3,950	$ 684.16	$ 744.09	$ 59.93	8.8%
4,000	$ 692.70	$ 753.34	$ 60.64	8.8%
4,050	$ 701.23	$ 762.59	$ 61.36	8.8%

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate GS5

kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
4,100	$ 709.76	$ 771.84	$ 62.07	8.7%
4,150	$ 718.30	$ 781.08	$ 62.79	8.7%
4,200	$ 726.83	$ 790.33	$ 63.50	8.7%
4,250	$ 735.37	$ 799.58	$ 64.21	8.7%
4,300	$ 743.90	$ 808.83	$ 64.93	8.7%
4,350	$ 752.43	$ 818.08	$ 65.64	8.7%
4,400	$ 760.97	$ 827.32	$ 66.36	8.7%
4,450	$ 769.50	$ 836.57	$ 67.07	8.7%
4,500	$ 778.04	$ 845.82	$ 67.78	8.7%
4,550	$ 786.57	$ 855.07	$ 68.50	8.7%
4,600	$ 795.10	$ 864.32	$ 69.21	8.7%
4,650	$ 803.64	$ 873.56	$ 69.93	8.7%
4,700	$ 812.17	$ 882.81	$ 70.64	8.7%
4,750	$ 820.71	$ 892.06	$ 71.35	8.7%
4,800	$ 829.24	$ 901.31	$ 72.07	8.7%
4,850	$ 837.77	$ 910.56	$ 72.78	8.7%
4,900	$ 846.31	$ 919.80	$ 73.50	8.7%
4,950	$ 854.84	$ 929.05	$ 74.21	8.7%
5,000	$ 863.38	$ 938.30	$ 74.92	8.7%

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate GS4

Average Demand of 5 kW

Hours Use	Load Factor	kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
-	0.0%	-	$ 34.60	$ 32.95	$ (1.65)	-4.8%
73	10.0%	365	$ 85.93	$ 84.62	$ (1.32)	-1.5%
146	20.0%	730	$ 137.27	$ 136.29	$ (0.98)	-0.7%
219	30.0%	1,095	$ 187.54	$ 186.86	$ (0.68)	-0.4%
292	40.0%	1,460	$ 234.79	$ 234.30	$ (0.49)	-0.2%
365	50.0%	1,825	$ 282.04	$ 281.74	$ (0.29)	-0.1%
438	60.0%	2,190	$ 329.28	$ 329.19	$ (0.10)	0.0%
511	70.0%	2,555	$ 376.36	$ 376.45	$ 0.09	0.0%
584	80.0%	2,920	$ 422.44	$ 422.69	$ 0.25	0.1%
657	90.0%	3,285	$ 468.53	$ 468.94	$ 0.41	0.1%
730	100.0%	3,650	$ 514.62	$ 515.19	$ 0.57	0.1%

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate GS4

Average Demand of 15 kW

Hours Use	Load Factor	kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
-	0.0%	-	$ 72.30	$ 68.85	$ (3.45)	-4.8%
73	10.0%	1,095	$ 226.30	$ 223.86	$ (2.44)	-1.1%
146	20.0%	2,190	$ 380.30	$ 378.87	$ (1.44)	-0.4%
219	30.0%	3,285	$ 531.12	$ 530.57	$ (0.54)	-0.1%
292	40.0%	4,380	$ 672.86	$ 672.90	$ 0.04	0.0%
365	50.0%	5,475	$ 814.60	$ 815.23	$ 0.63	0.1%
438	60.0%	6,570	$ 956.35	$ 957.56	$ 1.21	0.1%
511	70.0%	7,665	$ 1,097.57	$ 1,099.35	$ 1.78	0.2%
584	80.0%	8,760	$ 1,235.83	$ 1,238.08	$ 2.25	0.2%
657	90.0%	9,855	$ 1,374.09	$ 1,376.82	$ 2.73	0.2%
730	100.0%	10,950	$ 1,512.35	$ 1,515.56	$ 3.21	0.2%

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate GS4

Average Demand of 25 kW

Hours Use	Load Factor	kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
-	0.0%	-	$ 102.70	$ 97.80	$ (4.90)	-4.8%
73	10.0%	1,825	$ 359.37	$ 356.15	$ (3.22)	-0.9%
146	20.0%	3,650	$ 616.04	$ 614.49	$ (1.55)	-0.3%
219	30.0%	5,475	$ 867.39	$ 867.34	$ (0.05)	0.0%
292	40.0%	7,300	$ 1,103.63	$ 1,104.55	$ 0.92	0.1%
365	50.0%	9,125	$ 1,339.87	$ 1,341.77	$ 1.89	0.1%
438	60.0%	10,950	$ 1,576.11	$ 1,578.98	$ 2.87	0.2%
511	70.0%	12,775	$ 1,811.48	$ 1,815.29	$ 3.81	0.2%
584	80.0%	14,600	$ 2,041.91	$ 2,046.52	$ 4.61	0.2%
657	90.0%	16,425	$ 2,272.35	$ 2,277.75	$ 5.40	0.2%
730	100.0%	18,250	$ 2,502.78	$ 2,508.98	$ 6.19	0.2%

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate LP

Average Demand of 100 kW

Hours Use	Load Factor	kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
-	0.0%	-	$ 142.60	$ 135.80	$ (6.80)	-4.8%
73	10.0%	7,300	$ 795.73	$ 790.46	$ (5.27)	-0.7%
146	20.0%	14,600	$ 1,419.35	$ 1,415.23	$ (4.12)	-0.3%
219	30.0%	21,900	$ 2,025.64	$ 2,022.44	$ (3.20)	-0.2%
292	40.0%	29,200	$ 2,631.94	$ 2,629.66	$ (2.28)	-0.1%
365	50.0%	36,500	$ 3,229.01	$ 3,227.51	$ (1.50)	0.0%
438	60.0%	43,800	$ 3,824.96	$ 3,824.21	$ (0.75)	0.0%
511	70.0%	51,100	$ 4,419.89	$ 4,419.90	$ 0.02	0.0%
584	80.0%	58,400	$ 5,009.08	$ 5,009.89	$ 0.80	0.0%
657	90.0%	65,700	$ 5,598.28	$ 5,599.87	$ 1.59	0.0%
730	100.0%	73,000	$ 6,187.48	$ 6,189.86	$ 2.38	0.0%

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate LP

Average Demand of 250 kW

Hours Use	Load Factor	kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
-	0.0%	-	$ 290.67	$ 276.80	$ (13.87)	-4.8%
73	10.0%	18,250	$ 1,923.50	$ 1,913.46	$ (10.04)	-0.5%
146	20.0%	36,500	$ 3,482.54	$ 3,475.37	$ (7.17)	-0.2%
219	30.0%	54,750	$ 4,998.27	$ 4,993.41	$ (4.86)	-0.1%
292	40.0%	73,000	$ 6,514.00	$ 6,511.44	$ (2.56)	0.0%
365	50.0%	91,250	$ 8,006.70	$ 8,006.08	$ (0.62)	0.0%
438	60.0%	109,500	$ 9,496.56	$ 9,497.83	$ 1.27	0.0%
511	70.0%	127,750	$ 10,983.87	$ 10,987.06	$ 3.18	0.0%
584	80.0%	146,000	$ 12,456.87	$ 12,462.02	$ 5.15	0.0%
657	90.0%	164,250	$ 13,929.86	$ 13,936.99	$ 7.12	0.1%
730	100.0%	182,500	$ 15,402.86	$ 15,411.95	$ 9.09	0.1%

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate LP

Average Demand of 500 kW

Hours Use	Load Factor	kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
-	0.0%	-	$ 537.44	$ 511.80	$ (25.64)	-4.8%
73	10.0%	36,500	$ 3,803.10	$ 3,785.12	$ (17.98)	-0.5%
146	20.0%	73,000	$ 6,921.18	$ 6,908.94	$ (12.24)	-0.2%
219	30.0%	109,500	$ 9,952.64	$ 9,945.01	$ (7.63)	-0.1%
292	40.0%	146,000	$ 12,984.11	$ 12,981.08	$ (3.03)	0.0%
365	50.0%	182,500	$ 15,969.50	$ 15,970.35	$ 0.85	0.0%
438	60.0%	219,000	$ 18,949.22	$ 18,953.86	$ 4.64	0.0%
511	70.0%	255,500	$ 21,923.85	$ 21,932.31	$ 8.46	0.0%
584	80.0%	292,000	$ 24,869.84	$ 24,882.24	$ 12.40	0.0%
657	90.0%	328,500	$ 27,815.84	$ 27,832.17	$ 16.33	0.1%
730	100.0%	365,000	$ 30,761.83	$ 30,782.10	$ 20.27	0.1%

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate LP

Average Demand of 1,000 kW

Hours Use	Load Factor	kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
-	0.0%	-	$ 899.73	$ 856.80	$ (42.93)	-4.8%
73	10.0%	73,000	$ 7,431.04	$ 7,403.44	$ (27.60)	-0.4%
146	20.0%	146,000	$ 13,667.20	$ 13,651.08	$ (16.12)	-0.1%
219	30.0%	219,000	$ 19,730.13	$ 19,723.22	$ (6.91)	0.0%
292	40.0%	292,000	$ 25,793.06	$ 25,795.36	$ 2.30	0.0%
365	50.0%	365,000	$ 31,763.84	$ 31,773.90	$ 10.06	0.0%
438	60.0%	438,000	$ 37,723.28	$ 37,740.92	$ 17.64	0.0%
511	70.0%	511,000	$ 43,672.55	$ 43,697.82	$ 25.27	0.1%
584	80.0%	584,000	$ 49,564.53	$ 49,597.68	$ 33.15	0.1%
657	90.0%	657,000	$ 55,456.51	$ 55,497.54	$ 41.03	0.1%
730	100.0%	730,000	$ 61,348.49	$ 61,397.40	$ 48.91	0.1%

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate FCP

kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
-	$ 4.92	$ 6.31	$ 1.39	28.1%
350	$ 11.19	$ 14.17	$ 2.99	26.7%
700	$ 19.76	$ 25.00	$ 5.24	26.5%
1,050	$ 28.33	$ 35.83	$ 7.50	26.5%
1,400	$ 36.90	$ 46.65	$ 9.75	26.4%
1,750	$ 45.47	$ 57.48	$ 12.01	26.4%
2,100	$ 54.04	$ 68.30	$ 14.26	26.4%
2,450	$ 62.61	$ 79.13	$ 16.52	26.4%
2,800	$ 71.18	$ 89.95	$ 18.77	26.4%
3,150	$ 79.75	$ 100.78	$ 21.03	26.4%
3,500	$ 88.32	$ 111.60	$ 23.28	26.4%
3,850	$ 96.90	$ 122.43	$ 25.53	26.4%
4,200	$ 105.47	$ 133.26	$ 27.79	26.3%
4,550	$ 114.04	$ 144.08	$ 30.04	26.3%
4,900	$ 122.61	$ 154.91	$ 32.30	26.3%
5,250	$ 131.18	$ 165.73	$ 34.55	26.3%
5,600	$ 139.75	$ 176.56	$ 36.81	26.3%
5,950	$ 148.32	$ 187.38	$ 39.06	26.3%
6,300	$ 156.89	$ 198.21	$ 41.32	26.3%
6,650	$ 165.46	$ 209.03	$ 43.57	26.3%
7,000	$ 174.03	$ 219.86	$ 45.83	26.3%
7,350	$ 182.60	$ 230.68	$ 48.08	26.3%
7,700	$ 191.18	$ 241.51	$ 50.33	26.3%
8,050	$ 199.75	$ 252.34	$ 52.59	26.3%
8,400	$ 208.32	$ 263.16	$ 54.84	26.3%
8,750	$ 216.89	$ 273.99	$ 57.10	26.3%
9,100	$ 225.46	$ 284.81	$ 59.35	26.3%
9,450	$ 234.03	$ 295.64	$ 61.61	26.3%
9,800	$ 242.60	$ 306.46	$ 63.86	26.3%
10,150	$ 251.17	$ 317.29	$ 66.12	26.3%
10,500	$ 259.74	$ 328.11	$ 68.37	26.3%
10,850	$ 268.31	$ 338.94	$ 70.63	26.3%
11,200	$ 276.89	$ 349.77	$ 72.88	26.3%
11,550	$ 285.46	$ 360.59	$ 75.13	26.3%
11,900	$ 294.03	$ 371.42	$ 77.39	26.3%
12,250	$ 302.60	$ 382.24	$ 79.64	26.3%
12,600	$ 311.17	$ 393.07	$ 81.90	26.3%
12,950	$ 319.74	$ 403.89	$ 84.15	26.3%
13,300	$ 328.31	$ 414.72	$ 86.41	26.3%
13,650	$ 336.88	$ 425.54	$ 88.66	26.3%
14,000	$ 345.45	$ 436.37	$ 90.92	26.3%

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate FCP

kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
14,350	$ 354.02	$ 447.19	$ 93.17	26.3%
14,700	$ 362.59	$ 458.02	$ 95.43	26.3%
15,050	$ 371.17	$ 468.85	$ 97.68	26.3%
15,400	$ 379.74	$ 479.67	$ 99.93	26.3%
15,750	$ 388.31	$ 490.50	$ 102.19	26.3%
16,100	$ 396.88	$ 501.32	$ 104.44	26.3%
16,450	$ 405.45	$ 512.15	$ 106.70	26.3%
16,800	$ 414.02	$ 522.97	$ 108.95	26.3%
17,150	$ 422.59	$ 533.80	$ 111.21	26.3%
17,500	$ 431.16	$ 544.62	$ 113.46	26.3%
17,850	$ 439.73	$ 555.45	$ 115.72	26.3%
18,200	$ 448.30	$ 566.28	$ 117.97	26.3%
18,550	$ 456.88	$ 577.10	$ 120.23	26.3%
18,900	$ 465.45	$ 587.93	$ 122.48	26.3%
19,250	$ 474.02	$ 598.75	$ 124.73	26.3%
19,600	$ 482.59	$ 609.58	$ 126.99	26.3%
19,950	$ 491.16	$ 620.40	$ 129.24	26.3%
20,300	$ 499.73	$ 631.23	$ 131.50	26.3%
20,650	$ 508.30	$ 642.05	$ 133.75	26.3%
21,000	$ 516.87	$ 652.88	$ 136.01	26.3%
21,500	$ 529.12	$ 668.34	$ 139.23	26.3%
22,000	$ 541.36	$ 683.81	$ 142.45	26.3%
22,500	$ 553.60	$ 699.27	$ 145.67	26.3%
23,000	$ 565.85	$ 714.74	$ 148.89	26.3%
23,500	$ 578.09	$ 730.20	$ 152.11	26.3%
24,000	$ 590.34	$ 745.67	$ 155.33	26.3%
24,500	$ 602.58	$ 761.13	$ 158.55	26.3%
25,000	$ 614.83	$ 776.60	$ 161.77	26.3%
25,500	$ 627.07	$ 792.06	$ 164.99	26.3%
26,000	$ 639.31	$ 807.53	$ 168.21	26.3%
26,500	$ 651.56	$ 822.99	$ 171.44	26.3%
27,000	$ 663.80	$ 838.46	$ 174.66	26.3%
27,500	$ 676.05	$ 853.92	$ 177.88	26.3%
28,000	$ 688.29	$ 869.39	$ 181.10	26.3%
28,500	$ 700.54	$ 884.85	$ 184.32	26.3%
29,000	$ 712.78	$ 900.32	$ 187.54	26.3%
29,500	$ 725.02	$ 915.78	$ 190.76	26.3%
30,000	$ 737.27	$ 931.25	$ 193.98	26.3%
30,500	$ 749.51	$ 946.71	$ 197.20	26.3%
31,000	$ 761.76	$ 962.18	$ 200.42	26.3%
31,500	$ 774.00	$ 977.64	$ 203.64	26.3%

UGI Utilities, Inc. - Electric Division
Monthly Bill Comparison
Rate FCP

kWh	Current Rates Monthly Bill	Proposed Rates Monthly Bill	$ Change	% Change
32,000	$ 786.25	$ 993.11	$ 206.86	26.3%
32,500	$ 798.49	$ 1,008.57	$ 210.08	26.3%
33,000	$ 810.73	$ 1,024.04	$ 213.31	26.3%
33,500	$ 822.98	$ 1,039.50	$ 216.53	26.3%
34,000	$ 835.22	$ 1,054.97	$ 219.75	26.3%
34,500	$ 847.47	$ 1,070.43	$ 222.97	26.3%
35,000	$ 859.71	$ 1,085.90	$ 226.19	26.3%
35,500	$ 871.95	$ 1,101.36	$ 229.41	26.3%
36,000	$ 884.20	$ 1,116.83	$ 232.63	26.3%
36,500	$ 896.44	$ 1,132.29	$ 235.85	26.3%
37,000	$ 908.69	$ 1,147.76	$ 239.07	26.3%
37,500	$ 920.93	$ 1,163.22	$ 242.29	26.3%
38,000	$ 933.18	$ 1,178.69	$ 245.51	26.3%
38,500	$ 945.42	$ 1,194.15	$ 248.73	26.3%
39,000	$ 957.66	$ 1,209.62	$ 251.95	26.3%
39,500	$ 969.91	$ 1,225.08	$ 255.18	26.3%
40,000	$ 982.15	$ 1,240.55	$ 258.40	26.3%
40,500	$ 994.40	$ 1,256.01	$ 261.62	26.3%
41,000	$ 1,006.64	$ 1,271.48	$ 264.84	26.3%
41,500	$ 1,018.89	$ 1,286.94	$ 268.06	26.3%
42,000	$ 1,031.13	$ 1,302.41	$ 271.28	26.3%
42,500	$ 1,043.37	$ 1,317.87	$ 274.50	26.3%
43,000	$ 1,055.62	$ 1,333.34	$ 277.72	26.3%
43,500	$ 1,067.86	$ 1,348.80	$ 280.94	26.3%
44,000	$ 1,080.11	$ 1,364.27	$ 284.16	26.3%
44,500	$ 1,092.35	$ 1,379.73	$ 287.38	26.3%
45,000	$ 1,104.59	$ 1,395.20	$ 290.60	26.3%
45,500	$ 1,116.84	$ 1,410.66	$ 293.82	26.3%
46,000	$ 1,129.08	$ 1,426.13	$ 297.05	26.3%
46,500	$ 1,141.33	$ 1,441.59	$ 300.27	26.3%
47,000	$ 1,153.57	$ 1,457.06	$ 303.49	26.3%
47,500	$ 1,165.82	$ 1,472.52	$ 306.71	26.3%
48,000	$ 1,178.06	$ 1,487.99	$ 309.93	26.3%
48,500	$ 1,190.30	$ 1,503.45	$ 313.15	26.3%
49,000	$ 1,202.55	$ 1,518.92	$ 316.37	26.3%
49,500	$ 1,214.79	$ 1,534.38	$ 319.59	26.3%

IV-E-1

Request:

Provide a cost study which allocates the total cost of service to each proposed tariff rate schedule. Tariff rates schedules may be combined for this purpose provided that they are of a similar supply or end use nature. A statement describing which rates were combined and the reasons therefor should be submitted.

The rates of return for each tariff rate schedule as defined above should be determined at both the present and proposed rate levels. Base rate revenues should be used for this purpose unless there are good and sufficient reasons to include revenues derived from other sources. Should the latter be the case, an explanation of other revenue sources included and reasons therefor should accompany the cost allocation study.

The methods selected for use in allocating costs to rate classes should include cost analyses based on:

a. Peak responsibility.

b. Average and excess, on a non-coincident demand basis.

c. Company preferred method if different from the above-referenced methods, with rationale behind the selection.

This study should include a statement of the source and age of the load data used in the determination of demand responsibilities, a description of any special studies used to prepare the cost study, and the most recent overall system line loss study.
The cost data used in the allocation study may be based on the test year.

Response:

Please see UGI Electric Book VIII, Exhibit D – Cost of Service Study and the Direct Testimony of John D. Taylor, UGI Electric Statement No. 6. Also, for further clarification of rate classes, please see the Direct Testimony of Sherry A. Epler, UGI Electric Statement No. 10.

Prepared by or under the supervision of: John D. Taylor

IV-E-2

Request:

Provide comparisons in either graphical or tabular form showing cost, as defined in the cost of service study, and proposed base rate revenues and usage for all residential and demand/energy rate schedules. Demand shall be for representative loads for each demand/energy rate schedule.

Response:

Please see the Direct Testimony of John D. Taylor, UGI Electric Statement No. 6, for the requested information.

Prepared by or under the supervision of: John D. Taylor

V. PLANT & DEPRECIATION SUPPORTING DATA

UGI Utilities, Inc. - Electric Division
Docket No. R-2022-3037368
UGI Electric 2023 Base Rate Case
Responses to Section 53.53 - V-A - Adjusted Original Cost Plant with
Accum Book & Calc Deprn at Test Year-End
Delivered on January 27, 2023

V-A-1

Request:

Provide schedules supporting claimed amounts for Electric Plant in Service by function and by account if available.

Response:

Supporting schedules for Electric Plant in Service at September 30, 2022 are contained on pages II-3 through II-5 and pages III-15 through III-79 of UGI Electric Exhibit C (Historic).

Supporting schedules for Electric Plant in Service at September 30, 2023 are contained on pages V-4 through V-6 and pages VII-15 through VII-81 of UGI Electric Exhibit C (Future).

Supporting schedules for Electric Plant in Service at September 30, 2024 are contained on pages II-3 through II-5 and pages III-15 through III-82 of UGI Electric Exhibit C (Fully Projected).

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

V-A-2

Request:

Provide a comparison of calculated depreciation reserve versus book reserve at the end of the test year. Provide this comparison by functional group and by account if available.

Response:

The comparisons are set forth on the pages which follow. Attachment V-A-2 presents the comparison of calculated and book reserves as of the end of the respective test year-end periods.

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

UGI UTILITIES, INC. - ELECTRIC DIVISION

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

	ACCOUNT	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE
	(1)	(2)	(3)
ELECTRIC PLANT			
DISTRIBUTION PLANT			
361	STRUCTURES AND IMPROVEMENTS	56,051	36,400
362	STATION EQUIPMENT	1,080,019	796,511
364	POLES, TOWERS AND FIXTURES	15,288,380	15,594,836
365	OVERHEAD CONDUCTORS AND DEVICES	12,615,250	14,111,095
365.7	REG AFUDC	(26,694)	(83,047)
366	UNDERGROUND CONDUIT	2,012,591	2,409,512
367	UNDERGROUND CONDUCTORS AND DEVICES	4,186,700	4,071,859
368.1	TRANSFORMERS	6,808,537	8,046,476
368.2	TRANSFORMER INSTALLATIONS	4,971,712	6,195,958
369	SERVICES	6,109,134	7,527,834
370.1	METERS	1,743,238	2,073,283
370.2	METER INSTALLATIONS	708,270	778,252
370.3	ELECTRONIC METERS	3,530,112	4,010,096
371	INSTALLATIONS ON CUSTOMER PREMISES	1,020,840	873,689
371.5	INSTALLATIONS ON CUSTOMER PREMISES - DUSK TO DAWN LIGHTS	278,976	334,801
373	STREET LIGHTING AND SIGNAL SYSTEMS	1,085,263	980,610
TOTAL DISTRIBUTION PLANT		**61,468,379**	**67,758,165**
GENERAL PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	1,279,307	1,193,834
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	26,546	15,334
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	252,556	130,617
391.9	OFFICE FURNITURE AND EQUIPMENT - OUTAGE MANAGEMENT SOFTWARE	1,002,218	660,150
392.1	TRANSPORTATION EQUIPMENT - AUTOMOBILES	99,390	123,694
392.2	TRANSPORTATION EQUIPMENT - LIGHT TRUCKS	240,660	140,850
392.4	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	58,435	35,877
393	STORES EQUIPMENT	5,263	4,135
394	TOOLS, SHOP AND GARAGE EQUIPMENT	631,960	615,343
395	LABORATORY EQUIPMENT	73,685	83,568
396	POWER OPERATED EQUIPMENT	14,770	6,317
397	COMMUNICATION EQUIPMENT	362,460	152,259
398	MISCELLANEOUS EQUIPMENT	112,640	51,910
TOTAL GENERAL PLANT		**4,159,890**	**3,213,888**
TOTAL DEPRECIABLE PLANT		**65,628,269**	**70,972,053**
OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION*			
COMMON PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	3,182,800	3,018,983
390.2	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	0	10,628
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,166,301	1,011,569
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	596,708	272,031
392.1	TRANSPORTATION EQUIPMENT - AUTOMOBILES	66,459	71,637
TOTAL COMMON PLANT		**5,012,268**	**4,384,848**
INFORMATION SERVICES (IS)			
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	28,766	28,853
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	13,167,442	13,083,477
391.2	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	3,821,483	2,929,907
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	23,320,192	22,617,829
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	48,970,896	48,592,264
TOTAL INFORMATION SERVICES		**89,308,779**	**87,252,330**
EMPIRE YARD BUILDING			
390.1	STRUCTURES AND IMPROVEMENTS	7,941,904	8,535,610
TOTAL OTHER UTILITY PLANT		**102,262,951**	**100,172,788**
TOTAL ELECTRIC AND OTHER PLANT		**167,891,220**	**171,144,841**

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

UGI UTILITIES, INC. - ELECTRIC DIVISION

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

ACCOUNT		CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE
(1)		(2)	(3)
ELECTRIC PLANT			
DISTRIBUTION PLANT			
361	STRUCTURES AND IMPROVEMENTS	69,798	51,995
362	STATION EQUIPMENT	1,412,134	1,177,222
364	POLES, TOWERS AND FIXTURES	16,177,211	16,932,371
365	OVERHEAD CONDUCTORS AND DEVICES	13,392,029	13,966,110
365.7	REG AFUDC	(44,489)	(99,348)
366	UNDERGROUND CONDUIT	2,153,276	2,551,835
367	UNDERGROUND CONDUCTORS AND DEVICES	4,527,440	4,511,139
368.1	TRANSFORMERS	6,977,538	8,139,253
368.2	TRANSFORMER INSTALLATIONS	5,202,664	6,450,987
369	SERVICES	6,361,262	7,799,373
370.1	METERS	1,747,305	2,054,528
370.2	METER INSTALLATIONS	731,062	801,991
370.3	ELECTRONIC METERS	3,675,979	4,148,090
371	INSTALLATIONS ON CUSTOMER PREMISES	1,069,306	987,794
371.5	INSTALLATIONS ON CUSTOMER PREMISES - DUSK TO DAWN LIGHTS	284,177	336,331
373	STREET LIGHTING AND SIGNAL SYSTEMS	1,127,188	1,058,359
TOTAL DISTRIBUTION PLANT		**64,863,880**	**70,868,030**
GENERAL PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	1,457,016	1,275,204
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	29,849	20,137
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	326,400	285,540
391.92	OFFICE FURNITURE AND EQUIPMENT - OUTAGE MANAGEMENT SOFTWARE	1,025,925	697,801
392.1	TRANSPORTATION EQUIPMENT - AUTOMOBILES	145,372	167,889
392.2	TRANSPORTATION EQUIPMENT - LIGHT TRUCKS	391,790	307,336
392.4	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	95,993	75,520
393	STORES EQUIPMENT	6,724	5,885
394	TOOLS, SHOP AND GARAGE EQUIPMENT	632,785	622,707
395	LABORATORY EQUIPMENT	58,416	62,234
396	POWER OPERATED EQUIPMENT	51,000	45,151
397	COMMUNICATION EQUIPMENT	368,047	297,890
398	MISCELLANEOUS EQUIPMENT	162,731	126,923
TOTAL GENERAL PLANT		**4,752,048**	**3,990,217**
TOTAL DEPRECIABLE PLANT		**69,615,928**	**74,858,247**
OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION*			
COMMON PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	4,067,543	4,076,856
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,418,936	1,282,392
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	787,668	664,008
392.1	TRANSPORTATION EQUIPMENT - AUTOMOBILES	67,474	71,637
398	MISCELLANEOUS EQUIPMENT	9,789	3,864
TOTAL COMMON PLANT		**6,351,410**	**6,098,757**
INFORMATION SERVICES (IS)			
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	7,050	7,045
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	11,092,865	11,091,382
391.2	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	5,095,346	4,442,076
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	15,352,958	14,683,389
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	49,488,753	49,003,505
TOTAL INFORMATION SERVICES		**81,036,972**	**79,227,397**
EMPIRE YARD BUILDING			
390.1	STRUCTURES AND IMPROVEMENTS	8,213,654	8,781,870
TOTAL OTHER UTILITY PLANT		**95,602,036**	**94,108,024**
TOTAL ELECTRIC AND OTHER PLANT		**165,217,964**	**168,966,271**

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

UGI UTILITIES, INC. - ELECTRIC DIVISION

COMPARISON OF CALCULATED ACCRUED DEPRECIATION AND BOOK RESERVE AS OF SEPTEMBER 30, 2024

	ACCOUNT	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE
	(1)	(2)	(3)
ELECTRIC PLANT			
DISTRIBUTION PLANT			
361	STRUCTURES AND IMPROVEMENTS	83,359	67,339
362	STATION EQUIPMENT	1,749,259	1,555,321
364	POLES, TOWERS AND FIXTURES	17,060,768	18,154,021
365	OVERHEAD CONDUCTORS AND DEVICES	14,623,789	14,475,964
365.7	REG AFUDC	(62,285)	(115,649)
366	UNDERGROUND CONDUIT	2,290,748	2,692,439
367	UNDERGROUND CONDUCTORS AND DEVICES	4,866,345	4,927,497
368.1	TRANSFORMERS	7,192,304	8,266,630
368.2	TRANSFORMER INSTALLATIONS	5,426,933	6,688,323
369	SERVICES	6,618,654	8,069,605
370.1	METERS	1,587,761	1,938,784
370.2	METER INSTALLATIONS	753,778	825,222
370.3	ELECTRONIC METERS	3,811,434	4,274,497
371	INSTALLATIONS ON CUSTOMER PREMISES	1,114,892	1,087,883
371.5	INSTALLATIONS ON CUSTOMER PREMISES - DUSK TO DAWN LIGHTS	289,068	337,722
373	STREET LIGHTING AND SIGNAL SYSTEMS	1,173,782	1,138,619
TOTAL DISTRIBUTION PLANT		**68,580,589**	**74,384,217**
GENERAL PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	1,879,766	1,653,166
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	33,152	24,980
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	4,912	(613)
391.92	OFFICE FURNITURE AND EQUIPMENT - OUTAGE MANAGEMENT SOFTWARE	1,725,132	1,490,702
392.1	TRANSPORTATION EQUIPMENT - CARS	190,849	213,285
392.2	TRANSPORTATION EQUIPMENT - LIGHT TRUCKS	609,626	487,745
392.4	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	133,441	115,114
393	STORES EQUIPMENT	8,187	7,651
394	TOOLS, SHOP AND GARAGE EQUIPMENT	677,140	669,762
395	LABORATORY EQUIPMENT	27,771	28,138
396	POWER OPERATED EQUIPMENT	115,714	117,248
397	COMMUNICATION EQUIPMENT	405,150	368,166
398	MISCELLANEOUS EQUIPMENT	230,198	210,964
TOTAL GENERAL PLANT		**6,041,038**	**5,386,308**
TOTAL DEPRECIABLE PLANT		**74,621,627**	**79,770,525**
OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION*			
COMMON PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	4,926,372	5,076,206
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,668,883	1,549,592
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	753,469	727,143
392.1	TRANSPORTATION EQUIPMENT - AUTOMOBILES	68,346	71,637
398	MISCELLANEOUS EQUIPMENT	12,585	7,572
TOTAL COMMON PLANT		**7,429,655**	**7,432,150**
INFORMATION SERVICES (IS)			
390	STRUCTURES AND IMPROVEMENTS - NEW READING DATA CENTER	304,950	494,527
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,610	1,598
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	3,586,279	3,507,489
391.2	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	6,369,102	5,954,199
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	20,590,501	19,812,785
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	58,454,299	58,027,420
TOTAL INFORMATION SERVICES		**89,306,741**	**87,798,018**
EMPIRE YARD BUILDING			
390.1	STRUCTURES AND IMPROVEMENTS	8,415,240	8,845,824
TOTAL OTHER UTILITY PLANT		**105,151,636**	**104,075,992**
TOTAL ELECTRIC AND OTHER PLANT		**179,773,263**	**183,846,517**

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

V-A-3

Request:

Provide supporting schedules which indicate the procedures and calculations employed to develop the original cost plant and applicable reserves to the test year end as submitted in the current proceeding.

Response:

Supporting schedules developing original cost plant are listed on Table 3 of UGI Electric Exhibit C (Future) and UGI Electric Exhibit C (Fully Projected Future).

The development of book reserve is set forth on Table 2 of UGI Electric Exhibit C (Future) and Table 2 UGI Electric Exhibit C (Fully Projected Future).

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

V-A-4

Request:

Provide a schedule showing details of rate case adjustments.

Response:

Please see Section D of UGI Electric Exhibit A (Historic), UGI Electric Exhibit A (Future), UGI Electric Exhibit A (Fully Projected Future).

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

V-B-1

Request:

Provide a comparison of calculated depreciation accruals versus book accruals by function and by account if available.

Response:

The comparison of the calculated depreciation accruals versus book accruals by function and by account are presented on the following pages as Attachment V-B-1. Attachment V-B-1 presents the comparison of the calculated depreciation accruals versus book accruals by function and by account as of September 30, 2023 and September 30, 2024, respectively.

The book accruals for the future test year period were determined using the calculated annual accrual rates as of September 30, 2022 and the average annual plant balances for the future test year period. The calculated annual accrual rates as of September 30, 2023, and average monthly plant balances are the bases for book accruals during the period October 1, 2023 through September 30, 2024.

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

UGI UTILITIES, INC. - ELECTRIC DIVISION

COMPARISON OF CALCULATED AND BOOK DEPRECIATION ACCRUALS AS OF SEPTEMBER 30, 2023

	ACCOUNT	CALCULATED DEPRECIATION ACCRUALS	BOOK DEPRECIATION ACCRUALS
	(1)	(2)	(3)
ELECTRIC PLANT			
DISTRIBUTION PLANT			
361	STRUCTURES AND IMPROVEMENTS	15,093	15,374
362	STATION EQUIPMENT	366,341	369,258
364	POLES, TOWERS AND FIXTURES	1,018,082	1,036,683
365	OVERHEAD CONDUCTORS AND DEVICES	1,625,571	1,322,228
365.7	REG AFUDC	(16,333)	(16,301)
366	UNDERGROUND CONDUIT	137,656	138,723
367	UNDERGROUND CONDUCTORS AND DEVICES	428,554	444,047
368.1	TRANSFORMERS	379,659	347,494
368.2	TRANSFORMER INSTALLATIONS	213,344	221,917
369	SERVICES	271,960	268,618
370.1	METERS	55,146	51,868
370.2	METER INSTALLATIONS	24,969	24,902
370.3	ELECTRONIC METERS	126,120	137,534
371	INSTALLATIONS ON CUSTOMER PREMISES	82,731	95,866
371.5	INSTALLATIONS ON CUSTOMER PREMISES - DUSK TO DAWN LIGHTS	1,391	1,530
373	STREET LIGHTING AND SIGNAL SYSTEMS	106,847	105,892
TOTAL DISTRIBUTION PLANT		**4,837,131**	**4,565,633**
GENERAL PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	460,120	331,729
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	4,841	4,803
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	78,500	154,923
391.92	OFFICE FURNITURE AND EQUIPMENT - OUTAGE MANAGEMENT SOFTWARE	793,049	699,707
392.1	TRANSPORTATION EQUIPMENT - CARS	45,201	44,195
392.2	TRANSPORTATION EQUIPMENT - LIGHT TRUCKS	177,627	169,027
392.4	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	39,603	39,643
393	STORES EQUIPMENT	1,766	1,750
394	TOOLS, SHOP AND GARAGE EQUIPMENT	79,266	86,277
395	LABORATORY EQUIPMENT	2,910	2,525
396	POWER OPERATED EQUIPMENT	62,236	38,834
397	COMMUNICATION EQUIPMENT	115,248	237,758
398	MISCELLANEOUS EQUIPMENT	68,984	67,123
TOTAL GENERAL PLANT		**1,929,351**	**1,878,294**
TOTAL DEPRECIABLE PLANT		**6,766,482**	**6,443,927**
OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION*			
COMMON PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	999,640	1,047,245
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	278,239	278,006
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	315,961	480,595
392.1	TRANSPORTATION EQUIPMENT - AUTOMOBILES	0	0
398	MISCELLANEOUS EQUIPMENT	3,708	0
TOTAL COMMON PLANT		**1,597,548**	**1,805,846**
INFORMATION SERVICES (IS)			
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	263	877
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	2,002,004	3,592,336
391.2	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	1,511,599	1,512,169
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	5,345,423	4,747,149
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	9,020,360	8,891,579
TOTAL INFORMATION SERVICES		**17,879,649**	**18,744,110**
EMPIRE YARD BUILDING			
390.1	STRUCTURES AND IMPROVEMENTS	279,560	273,175
TOTAL OTHER UTILITY PLANT		**19,756,757**	**20,823,131**
TOTAL ELECTRIC AND OTHER PLANT		**26,523,239**	**27,267,058**

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

UGI UTILITIES, INC. - ELECTRIC DIVISION

COMPARISON OF CALCULATED AND BOOK DEPRECIATION ACCRUALS AS OF SEPTEMBER 30, 2024

ACCOUNT		CALCULATED DEPRECIATION ACCRUALS	BOOK DEPRECIATION ACCRUALS
(1)		(2)	(3)
ELECTRIC PLANT			
DISTRIBUTION PLANT			
361	STRUCTURES AND IMPROVEMENTS	14,856	15,123
362	STATION EQUIPMENT	370,323	371,828
364	POLES, TOWERS AND FIXTURES	1,029,131	1,024,283
365	OVERHEAD CONDUCTORS AND DEVICES	2,000,748	1,723,959
365.7	REG AFUDC	(16,334)	(16,301)
366	UNDERGROUND CONDUIT	136,759	137,845
367	UNDERGROUND CONDUCTORS AND DEVICES	432,991	434,336
368.1	TRANSFORMERS	427,778	381,335
368.2	TRANSFORMER INSTALLATIONS	206,924	213,291
369	SERVICES	279,667	275,473
370.1	METERS	65,979	55,618
370.2	METER INSTALLATIONS	25,015	24,990
370.3	ELECTRONIC METERS	114,671	125,947
371	INSTALLATIONS ON CUSTOMER PREMISES	73,861	83,883
371.5	INSTALLATIONS ON CUSTOMER PREMISES - DUSK TO DAWN LIGHTS	1,260	1,391
373	STREET LIGHTING AND SIGNAL SYSTEMS	110,861	108,934
TOTAL DISTRIBUTION PLANT		**5,274,490**	**4,961,935**
GENERAL PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	527,705	463,526
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	4,943	4,843
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	4,175	73,239
391.92	OFFICE FURNITURE AND EQUIPMENT - OUTAGE MANAGEMENT SOFTWARE	792,861	792,901
392.1	TRANSPORTATION EQUIPMENT - CARS	47,058	45,396
392.2	TRANSPORTATION EQUIPMENT - LIGHT TRUCKS	302,797	182,950
392.4	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	39,534	39,594
393	STORES EQUIPMENT	1,562	1,766
394	TOOLS, SHOP AND GARAGE EQUIPMENT	76,247	79,650
395	LABORATORY EQUIPMENT	3,126	2,136
396	POWER OPERATED EQUIPMENT	78,325	72,097
397	COMMUNICATION EQUIPMENT	100,692	123,609
398	MISCELLANEOUS EQUIPMENT	82,154	76,151
TOTAL GENERAL PLANT		**2,061,179**	**1,957,858**
TOTAL DEPRECIABLE PLANT		**7,335,669**	**6,919,793**
OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION*			
COMMON PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	964,749	999,350
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	275,805	279,096
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	232,828	340,331
392.1	TRANSPORTATION EQUIPMENT - AUTOMOBILES	0	0
398.0	MISCELLANEOUS EQUIPMENT	3,708	3,708
TOTAL COMMON PLANT		**1,477,090**	**1,622,485**
INFORMATION SERVICES (IS)			
390	STRUCTURES AND IMPROVEMENTS - NEW READING DATA CENTER	606,218	494,527
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	120	252
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	910,442	1,923,378
391.2	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	754,548	1,512,123
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	7,262,526	6,064,627
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	9,020,177	9,023,915
TOTAL INFORMATION SERVICES		**18,554,031**	**19,018,822**
EMPIRE YARD BUILDING			
390.1	STRUCTURES AND IMPROVEMENTS	385,936	281,419
TOTAL OTHER UTILITY PLANT		**20,417,057**	**20,922,727**
TOTAL ELECTRIC AND OTHER PLANT		**27,752,726**	**27,842,520**

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

V-B-2

Request:

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

a. For the purpose of this filing.

b. For the purpose of the most recent rate filing prior to the current proceeding.

c. Supply an explanation for any major change in annual accrual rate by account or by depreciable group.

d. Supply a comprehensive statement of major changes made in depreciation methods, procedures and techniques and the effect of the changes upon accumulated and annual depreciation, if any.

Response:

a. The survivor curves and associated accrual annual rates calculated as of September 30, 2024 are set forth on Table 1 of UGI Electric Exhibit C (Fully Projected Future). The survivor curves and associated annual accrual rates calculated as of September 30, 2023 are set forth on Table 1 of UGI Electric Exhibit C (Future). The survivor curves and associated annual accrual rates calculated as of September 30, 2022 are set forth on Table 1 of UGI Electric Exhibit C (Historic).

b. The survivor curves and associated annual accrual rates calculated as of September 30, 2022, the FPFTY in the prior filing, are presented on the following pages as Attachment V-B-2(b).

c. The Company prepares and submits service life studies to the Pennsylvania Public Utility Commission (Commission) every five years pursuant to the regulations set forth in 52 Pa. Code Chapter 73.5. The Company has submitted on May 31, 2022, a revised service life study to the Commission for their review and approval. The changes are identified and described in the prior service life study report. In general, the service lives for the major distribution plant accounts have trended longer since the prior electric rate filing. This is due to improvements in

V-B-2 (Continued)

materials used and improved maintenance practices. The service lives are longer, in part, due to capital budget constraints which requires some plant to remain in service longer. Also, the composite annual depreciation rate for distribution plant in the prior rate filing based on plant in service as of September 30, 2022 was 2.37 percent. The composite depreciation rate for distribution plant in the current filing based on plant in service as of September 30, 2024 is 2.21 percent. The lower composite depreciation rate for distribution plant is an indication that the service lives are trending longer, all else being equal.

d. The annual depreciation accrual rates used in the filing for most plant accounts are based on the straight line method using the average service life procedure for plant installed prior to 1982 and the equal life group procedure for 1982 and subsequent installations. These are the same methods and procedures as were used in the most recent filing.

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

UGI UTILITIES, INC. - ELECTRIC DIVISION

CURRENT SURVIVOR CURVES AND ANNUAL ACCRUAL RATES
AS OF SEPTEMBER 30, 2022

	ACCOUNT	SURVIVOR CURVE	ANNUAL ACCRUAL RATE
	(1)	(2)	(3)
ELECTRIC PLANT			
DISTRIBUTION PLANT			
361	STRUCTURES AND IMPROVEMENTS	50-R3	3.16
362	STATION EQUIPMENT	40-S1	3.31
364	POLES, TOWERS AND FIXTURES	56-R2.5	1.90
365	OVERHEAD CONDUCTORS AND DEVICES	55-R1	2.52
366	UNDERGROUND CONDUIT	65-R3	1.55
367	UNDERGROUND CONDUCTORS AND DEVICES	40-R2	3.04
368.1	TRANSFORMERS	43-S1	2.26
368.2	TRANSFORMER INSTALLATIONS	35-R2	2.58
369	SERVICES	50-R2	1.80
370.1	METERS	33-R1.5	1.95
370.2	METER INSTALLATIONS	70-R5	1.34
370.3	ELECTRONIC METERS	20-S3	3.38
371	INSTALLATIONS ON CUSTOMER PREMISES	30-O1	3.06
371.5	INSTALLATIONS ON CUSTOMER PREMISES - DUSK TO DAWN LIGHTS	20-R1.5	0.76
373	STREET LIGHTING AND SIGNAL SYSTEMS	34-L0	2.90
GENERAL PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	100-R1	4.52
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	20-SQ	5.53
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	5-SQ	21.69
391.92	OFFICE FURNITURE AND EQUIPMENT - OUTAGE MANAGEMENT SOFTWARE	5-SQ	20.00
392.1	TRANSPORTATION EQUIPMENT - AUTOMOBILES	7-L4	15.67
392.2	TRANSPORTATION EQUIPMENT - LIGHT TRUCKS	10-L2.5	11.82
392.4	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	14-S3	7.71
393	STORES EQUIPMENT	10-SQ	10.72
394	TOOLS, SHOP AND GARAGE EQUIPMENT	20-SQ	5.04
395	LABORATORY EQUIPMENT	10-SQ	11.16
396	POWER OPERATED EQUIPMENT	20-S0	7.44
397	COMMUNICATION EQUIPMENT	10-SQ	9.58
398	MISCELLANEOUS EQUIPMENT	10-SQ	10.13
OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION			
COMMON PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	70-R1	2.90
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	20-SQ	5.32
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	5-SQ	18.15
392.1	TRANSPORTATION EQUIPMENT - AUTOMOBILES	7-L2.5	0.17
INFORMATION SERVICES (IS)			
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	20-SQ	3.78
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	5-SQ	19.57
391.2	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	SQUARE	10.85
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	10-SQ	10.29
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	15-SQ	6.74

V-C-1

Request:

Where the retirement rate actuarial method of mortality analysis is utilized, set forth representative examples including charts depicting the observed and estimated survivor curves and a tabular presentation of the observed and estimated life tables plotted on the chart. Other analysis results shall be subject to request.

Response:

The charts and life tables for the accounts analyzed by the retirement rate method are set forth in Part VI of UGI Electric Exhibit C (Future).

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

V-D-1

Request:

Provide the surviving original cost plant at the appropriate test year date or dates by account or functional property group and include claimed depreciation reserves. Provide annual depreciation accruals where appropriate. These calculations should be provided for plant in service as well as other categories of plant, including but not limited to, contributions in aid of construction, customers' advances for construction, and anticipated retirements associated with construction work in progress claims, if applicable.

Response:

A summary of the original cost, depreciation reserve and annual depreciation accrual as of September 30, 2024, is presented on Table 1, pages II-3 through II-5 of UGI Electric Exhibit C (Fully Projected Future).

A summary of the original cost, depreciation reserve and annual depreciation accrual as of September 30, 2023, is presented on Table 1, pages V-4 through V-6 of UGI Electric Exhibit C (Future).

A summary of the original cost, depreciation reserve and annual depreciation accrual as of September 30, 2022, is presented on Table 1, pages II-3 through II-5 of UGI Electric Exhibit C (Historic).

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

V-D-2

Request:

Provide representative examples of detail calculations by vintage at account or at a more detailed level, as performed for these purposes. Other vintage detail calculations shall be subject to request.

Response:

The detailed calculations of depreciation by installation year as of September 30, 2024 are set forth in Part III of UGI Electric Exhibit C (Fully Projected Future).

The detailed calculations of depreciation by installation year as of September 30, 2023 are set forth in Part VII of UGI Electric Exhibit C (Future).

The detailed calculations of depreciation by installation year as of September 30, 2022 are set forth in Part III of UGI Electric Exhibit C (Historic).

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

V-E-1

Request:

Provide a description of the depreciation methods utilized in calculating annual depreciation amounts and depreciation reserves, together with a discussion of the significant factors which were considered in arriving at estimates of service life and forecast retirements by facilities, accounts or sub-accounts, as applicable.

Response:

A description of the depreciation methods used in the calculation of annual and accrued depreciation and the factors considered in the service life estimation are discussed in UGI Electric Exhibit C (Future) in Parts II and III under the sections titled "Part II. Estimation of Survivor Curves" and "Part III. Service Life Considerations".

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

VI. UNADJUSTED COMPARATIVE BALANCE SHEETS & OPERATING INCOME STATEMENTS

VI-A-1

Request:

Provide the following unadjusted detailed schedules by function and by FERC account for the claimed test year and for each of the 3 preceding comparable years:

A. Balance sheet, in the form available.

Response:

Please see Attachment VI-A-1.

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

UGI Utilities, Inc. - Electric Division
Unadjusted Comparative Balance Sheets
For the Years Ended September 30, 2021-2024
($ in Thousands)

	2021	2022	2023	2024
UTILITY PLANT (101 - 106, 108)				
Electric Utility Plant	$ 265,511	$ 314,688	$ 339,863	$ 367,052
Other Utility Plant	-	-	-	-
Total Plant In Service	$ 265,511	$ 314,688	$ 339,863	$ 367,052
Construction Work In Progress (107)	$ 11,054	$ 8,024	$ 8,000	$ 8,000
Total Utility Plant	$ 276,564	$ 322,712	$ 347,863	$ 375,052
Accumulated Provision for Depreciation - Electric (108)	$ (93,773)	$ (100,697)	$ (110,643)	$ (121,394)
Utility Acquisition Adjustment (114)	390	390	390	390
Accumulated Provision for Depreciation - Other (119)	-	-	-	-
Net Utility Plant	$ 183,181	$ 222,405	$ 237,610	$ 254,048
OTHER PROPERTY INVESTMENTS				
Non-utility Property (121)	$ 15	$ 15	$ 15	$ 15
Accumulated Depreciation on NUP (122)	-	-	-	-
Investment in Associated & Subsidiary Companies (123.1)	-	-	-	-
Other Investments (124)	-	-	-	-
Total Other Property and Investments	$ 15	$ 15	$ 15	$ 15
CURRENT AND ACCRUED ASSETS				
Cash & Other Temporary Investments(131-136)	$ 107	$ 2,265	$ 566	$ 566
Unbilled Revenues	-	-	-	-
Customer Accounts Receivable (142)	12,243	18,883	20,984	19,496
Other Accounts Receivable (143)	215	859	570	570
Accum Provision for Uncollectible (144)	(1,948)	(2,238)	(2,518)	(2,340)
Receivables from Associated Companies (145)	-	-	-	-
Accounts Receivable Assoc. Comp. (146)	369	477	404	404
Plant Materials & Operating Supplies (154)	1,472	2,627	2,621	3,100
Allowance Inventory (158.1)	487	345	682	682
Stores Expense - Undistributed (163)	106	127	181	183
Prepayments (165)	1,775	1,953	2,182	2,182
Accrued Utility Revenues (173)	3,223	4,326	3,500	4,000
Miscellaneous Current & Accrued Assets (174)	1,424	1,433	1,400	1,400
Derivative Instrument Assets (175)	-	-	-	-
Total Current and Accrued Assets	$ 19,473	$ 31,058	$ 30,572	$ 30,243
DEFERRED DEBITS				
Unamortized Debt Expense (181)	$ 23	$ 13	$ 20	$ 20
Other Regulatory Assets (182.3)	32,284	29,955	33,421	33,146
Other Preliminary Survey & Investigation Charges (183.2)	-	-	-	-
Clearing Accounts (184)	-	-	-	-
Miscellaneous Deferred Debits (186)	938	1,388	1,166	1,166
Deferred Loss from Disposition of Utility Plant (187)	-	-	-	-
Accumulated Deferred Income Taxes (190)	16,204	16,153	16,000	16,000
Total Deferred Debits	$ 49,449	$ 47,509	$ 50,606	$ 50,332
TOTAL ASSETS AND OTHER DEBITS	$ 252,118	$ 300,987	$ 318,803	$ 334,638

UGI Utilities, Inc. - Electric Division
Unadjusted Comparative Balance Sheets
For the Years Ended September 30, 2021-2024
($ in Thousands)

	2021	2022	2023	2024
PROPRIETARY CAPITAL				
Common Stock Issued (201)	$ 5,465	$ 6,026	$ 6,453	$ 6,453
Preferred Stock Issued (204)	-	-	-	-
Premium on Capital Stock (207)	42,949	50,858	50,720	50,720
Capital Stock Expense (214)	-	-	-	-
Retained Earnings (215, 215.2, 216)	33,807	71,682	76,516	82,897
Accum Other Comprehensive Income (219)	(1,268)	(814)	(1,586)	(1,235)
Total Proprietary Capital	$ 80,953	$ 127,752	$ 132,104	$ 138,836
LONG TERM DEBT				
Bonds (221)	$ -	$ -	$ -	$ -
Advances from Associated Companies (223)	-	-	-	-
Other Long-Term Debt (224)	72,302	70,788	78,906	90,828
Unamortized Premium on LTD (225)	-	-	-	-
Unamortized Discount on LTD (226)	-	-	-	-
Total Long-term Debt	$ 72,302	$ 70,788	$ 78,906	$ 90,828
OTHER NON-CURRENT LIABILITIES				
Obligations under Capital Leases (227)	$ -	$ -	$ -	$ -
Advances from Associated Companies (223)	-	-	-	-
Other Long-Term Debt (224)	-	-	-	-
Accum. Prov for Injuries & Damages (228.2)	-	-	-	-
Accum. Miscellaneous Operating Prov (228.4)	-	-	-	-
Accumulated Provision for Pension & Benefits (228.3)	8,802	8,593	8,592	8,592
Total Non-Current Liabilities	$ 8,802	$ 8,593	$ 8,592	$ 8,592
CURRENT & ACCRUED LIABILITIES				
Notes Payable (231)	$ 7,698	$ 7,690	$ 13,881	$ 11,062
Accounts Payable (232)	8,174	11,083	11,000	11,000
Notes Payable to Assoc. Companies (233)	-	-	-	-
Accounts Payable to Assoc. Cos (234)	1,131	978	1,000	1,000
Customer Deposits (235)	922	984	947	947
Taxes Accrued (236)	470	780	219	219
Interest Accrued (237)	594	599	705	705
Tax Collections Payable (241)	63	148	-	-
Misc Current & Accrued Liabilities (242)	2,244	2,606	2,600	2,600
Obligations under Capital Leases - Current (243)	29	-	-	-
Derivative Instrument Liabilities (244)	-	-	-	-
Total Current & Accrued Liabilities	$ 21,325	$ 24,867	$ 30,351	$ 27,532
OTHER DEFERRED CREDITS				
Customer Advances for Construction (252)	$ -	$ -	$ -	$ -
Other Deferred Credits (253)	485	422	450	450
Other Regulatory Liabilities (254)	25,631	28,084	28,000	28,000
Deferred ITC (255)	-	-	-	-
Accumulated Deferred Income Taxes (282)	42,620	40,481	40,400	40,400
Accumulated Deferred Income Taxes (283)	-	-	-	-
Total Other Deferred Credits	$ 68,736	$ 68,987	$ 68,850	$ 68,850
TOTAL LIABILITIES & OTHER CREDITS	$ 252,118	$ 300,987	$ 318,803	$ 334,638

VI-B-1

Request:

Provide the following unadjusted detailed schedules by function and by FERC account for the claimed test year and for each of the 3 preceding comparable years:

B. Statement of income.

Response:

Please see Attachment VI-B-1.

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

UGI UTILITIES, INC. - ELECTRIC DIVISION
INCOME STATEMENT SUPPORTING SCHEDULES
FOR THE YEARS ENDED SEPTEMBER 30, 2021 - 2024
(Thousands)

	2024	2023	2022	2021
OPERATING REVENUES	155,625	151,736	136,640	98,512
OPERATING EXPENSES				
401-402 Total Operation & Maintenance Expense	125,070	121,338	105,358	76,471
403-405 Depreciation Expense and Amortization	10,751	9,947	9,308	8,146
408.1 Taxes Other Than Income Taxes	9,523	9,255	8,469	6,455
Total operating Expenses Prior to Federal and State Income Taxes	145,343	140,540	123,135	91,072
Operating Income Prior to Federal and State Income Taxes	10,282	11,195	13,505	7,440
FEDERAL AND STATE INCOME TAXES				
409.1-411.4 Total Federal and State Income Taxes	1,312	2,019	2,920	761
Operating Income After Federal and State Income Taxes	8,970	9,176	10,585	6,679
OTHER INCOME AND DEDUCTIONS				
415.0 Revenues From Merchandising, Jobbing And Contract Work	-	-	-	-
418.0 Non-Utility Operating Income (Loss)	-	-	-	-
419.0 Interest and Dividend Income	20	20	(213)	11
419.1 Allowance for Other Funds Used During Construction	-	-	105	-
421.0 Other Misc Non-Operating Income	(112)	(111)	(184)	(161)
Total Other Income	(93)	(92)	(291)	(151)
Other Income Deductions				
421.2 Loss on Disposition of Property	-	-	-	-
426.0 Miscellaneous	-	-	-	-
Total Other Income Deductions	-	-	-	-
Taxes Applicable to Other Income Deductions				
408.2 Taxes Other than Income Taxes	-	-	-	-
409.2 Federal Income Tax	-	-	(502)	(417)
410.1 Deferred Federal Income Taxes - Net	-	-	-	-
411.2 Deferred State Income Taxes - Net	-	-	-	-
Total Taxes Applicable to Other Income Deduction	-	-	(502)	(417)
Income Before Interest Charges	8,878	9,084	10,795	6,945
INTEREST CHARGES				
427.0 Interest on Long-term Debt	3,400	3,059	3,032	2,881
428.0 Amortization of Debt Discount & Expense	44	41	42	31
431.0 Other Interest Expense	367	532	167	148
432.0 Allowance for Borrowed Funds Used During Construction	(196)	(208)	(247)	910
Net Interest Charges	3,615	3,424	2,994	3,970
Net Income	5,263	5,661	7,800	2,975

VI-C-1

Request:

Provide the following unadjusted detailed schedules by function and by FERC account for the claimed test year and for each of the 3 preceding comparable years:

C. Plant in service.

Response:

Please reference Attachment VI-C-1.

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

UGI UTILITIES, INC. - ELECTRIC DIVISION
UNADJUSTED PLANT IN SERVICE
FOR THE YEARS ENDED SEPTEMBER 30, 2021, 2022, 2023 AND 2024

	ACCOUNT	2021	2022	2023	2024
ELECTRIC PLANT					
DISTRIBUTION PLANT					
361	STRUCTURES AND IMPROVEMENTS	$ 507,004	$ 627,496	$ 627,496	$ 627,496
362	STATION EQUIPMENT	7,468,502	10,981,236	11,263,245	11,568,188
364	POLES, TOWERS AND FIXTURES	50,833,070	54,077,226	55,047,300	56,561,695
365	OVERHEAD CONDUCTORS AND DEVICES	49,407,548	54,595,611	69,557,228	83,518,448
365.7	REG AFUDC	(711,827)	(711,827)	(711,827)	(711,827)
366	UNDERGROUND CONDUIT	8,649,717	8,779,918	8,779,918	8,779,918
367	UNDERGROUND CONDUCTORS AND DEVICES	13,430,716	14,750,367	15,051,435	15,566,131
368.1	TRANSFORMERS	16,080,484	16,660,208	18,263,782	19,861,657
368.2	TRANSFORMER INSTALLATIONS	11,003,763	11,197,561	11,218,276	11,239,609
369	SERVICES	15,218,863	15,753,385	16,224,921	16,710,606
370.1	METERS	2,978,384	2,949,899	2,977,856	3,093,268
370.2	METER INSTALLATIONS	1,950,454	1,972,304	1,980,373	1,988,715
370.3	ELECTRONIC METERS	4,829,400	5,037,891	5,037,891	5,037,891
371	INSTALLATIONS ON CUSTOMER PREMISES	2,154,327	2,219,114	2,219,114	2,219,114
371.5	INSTALLATIONS ON CUSTOMER PREMISES - DUSK TO DAWN LIGHTS	347,706	347,706	347,706	347,706
373	STREET LIGHTING AND SIGNAL SYSTEMS	2,256,734	2,331,583	2,470,771	2,614,126
TOTAL DISTRIBUTION PLANT		**$ 186,404,845**	**$ 201,569,678**	**$ 220,355,485**	**$ 239,022,741**
GENERAL PLANT					
390.1	STRUCTURES AND IMPROVEMENTS				
	FORTY FORT	$ 1,263,625	$ 2,773,772	$ 4,192,673	$ 4,677,729
	PLYMOUTH	15,111	15,111	15,111	15,111
	IDETOWN	49,926	49,926	49,926	49,926
	NANTICOKE	76,179	76,179	76,179	76,179
	EMPIRE YARD	19,895	19,895	19,895	19,895
	SYSTEM CONTROL CENTER	1,879,416	1,891,888	1,891,888	1,891,888
	SUBTOTAL ACCOUNT 390.1	*$ 3,304,152*	*$ 4,826,771*	*$ 6,245,672*	*$ 6,730,728*
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	$ 68,648	$ 66,068	$ 66,068	$ 66,068
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	427,636	369,215	369,215	9,824
391.92	OFFICE FURNITURE AND EQUIPMENT - OUTAGE MANAGEMENT SOFTWARE	682,064	4,023,657	3,496,035	3,496,035
393	STORES EQUIPMENT	14,618	14,618	14,618	14,618
394	TOOLS, SHOP AND GARAGE EQUIPMENT	1,574,159	1,634,223	1,555,310	1,522,715
395	LABORATORY EQUIPMENT	182,141	97,830	73,971	37,739
397	COMMUNICATION EQUIPMENT	776,460	1,023,287	931,152	877,809
398	MISCELLANEOUS EQUIPMENT	225,085	410,294	591,542	757,799

UGI UTILITIES, INC. - ELECTRIC DIVISION
UNADJUSTED PLANT IN SERVICE
FOR THE YEARS ENDED SEPTEMBER 30, 2021, 2022, 2023 AND 2024

ACCOUNT		2021	2022	2023	2024
TOTAL GENERAL PLANT		**$ 7,254,963**	**$ 12,465,963**	**$ 13,343,583**	**$ 13,513,335**
SPECIAL DEPRECIABLE PLANT					
392.1	TRANSPORTATION EQUIPMENT - AUTOMOBILES	$ 375,979	$ 302,097	$ 336,097	$ 370,097
392.2	TRANSPORTATION EQUIPMENT - LIGHT TRUCKS	328,396	1,394,971	1,620,671	2,786,671
392.4	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	136,684	490,636	490,636	490,636
396	POWER OPERATED EQUIPMENT	95,952	176,632	804,018	1,071,351
TOTAL SPECIAL DEPRECIABLE PLANT		**$ 937,011**	**$ 2,364,336**	**$ 3,251,422**	**$ 4,718,755**
TOTAL DEPRECIABLE PLANT		**$ 194,596,819**	**$ 216,399,977**	**$ 236,950,490**	**$ 257,254,831**
NONDEPRECIABLE PLANT					
301.1	ORGANIZATION	$ 1,602	$ 1,602	$ 1,602	$ 1,602
302.1	FRANCHISES AND CONSENTS - PERPETUAL	6,436	6,436	6,436	6,436
360.1	LAND AND LAND RIGHTS - LAND	294,162	294,162	299,162	299,162
360.2	LAND AND LAND RIGHTS - LAND RIGHTS	14,336	14,336	14,336	14,336
389.1	LAND AND LAND RIGHTS - LAND	202,584	202,584	202,584	202,584
TOTAL NONDEPRECIABLE PLANT		**$ 519,120**	**$ 519,120**	**$ 524,120**	**$ 524,120**
LESS GENERAL PLANT ALLOCATED TO TRANSMISSION - 25.6247%		**$ (2,153,140)**	**$ (3,854,191)**	**$ (4,306,392)**	**$ (4,725,890)**
TOTAL ELECTRIC PLANT		**$ 192,962,799**	**$ 213,064,906**	**$ 233,168,218**	**$ 253,053,061**
SUMMARY					
DISTRIBUTION		186,404,845	201,569,678	220,355,485	239,022,741
GENERAL PLANT		6,557,954	11,495,228	12,812,733	14,030,320
TOTAL PLANT		**$ 192,962,799**	**$ 213,064,906**	**$ 233,168,218**	**$ 253,053,061**

Note: Common asset allocations are excluded from these plant in service amounts. Please refer to the UGI Electric Exibit A (Fully Projected), UGI Electric Exhibit A (Future) and UGI Electric Exhibit A (Historic) for the common asset allocations.

VI-D-1

Request:

Provide the following unadjusted detailed schedules by function and by FERC account for the claimed test year and for each of the 3 preceding comparable years:

D. Accumulated depreciation.

Response:

Please reference Attachment VI-D-1.

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

UGI UTILITIES, INC. - ELECTRIC DIVISION
UNADJUSTED ACCUMULATED DEPRECIATION EXPENSE
FOR THE YEARS ENDED SEPTEMBER 30, 2021, 2022, 2023 AND 2024

	ACCOUNT	2021	2022	2023	2024
ELECTRIC PLANT					
DISTRIBUTION PLANT					
361	STRUCTURES AND IMPROVEMENTS	$ 19,543	$ 36,400	$ 51,995	$ 67,339
362	STATION EQUIPMENT	516,513	796,511	1,177,222	1,555,321
364	POLES, TOWERS AND FIXTURES	14,856,683	15,594,836	16,932,371	18,154,021
365	OVERHEAD CONDUCTORS AND DEVICES	13,065,503	14,111,095	13,966,110	14,475,964
365.7	REG AFUDC	(68,810)	(83,047)	(99,348)	(115,649)
366	UNDERGROUND CONDUIT	2,269,301	2,409,512	2,551,835	2,692,439
367	UNDERGROUND CONDUCTORS AND DEVICES	3,669,796	4,071,859	4,511,139	4,927,497
368.1	TRANSFORMERS	8,249,294	8,046,476	8,139,253	8,266,630
368.2	TRANSFORMER INSTALLATIONS	5,979,297	6,195,958	6,450,987	6,688,323
369	SERVICES	7,208,602	7,527,834	7,799,373	8,069,605
370.1	METERS	1,985,392	2,073,283	2,054,528	1,938,784
370.2	METER INSTALLATIONS	753,939	778,252	801,991	825,222
370.3	ELECTRONIC METERS	3,890,307	4,010,096	4,148,090	4,274,497
371	INSTALLATIONS ON CUSTOMER PREMISES	850,251	873,689	987,794	1,087,883
371.5	INSTALLATIONS ON CUSTOMER PREMISES - DUSK TO DAWN LIGHTS	331,219	334,801	336,331	337,722
373	STREET LIGHTING AND SIGNAL SYSTEMS	986,733	980,610	1,058,359	1,138,619
TOTAL DISTRIBUTION PLANT		**$ 64,563,564**	**$ 67,758,165**	**$ 70,868,030**	**$ 74,384,217**
GENERAL PLANT					
390.1	STRUCTURES AND IMPROVEMENTS				
	FORTY FORT	$ 671,748	$ 745,320	$ 809,231	$ 1,141,047
	PLYMOUTH	15,111	15,111	15,111	15,111
	IDETOWN	10,390	11,035	11,815	13,389
	NANTICOKE	76,179	76,179	76,179	76,179
	EMPIRE YARD	19,895	19,895	19,895	19,895
	SYSTEM CONTROL CENTER	318,561	326,294	342,973	387,545
	SUBTOTAL ACCOUNT 390.1	*$ 1,111,884*	*$ 1,193,834*	*$ 1,275,204*	*$ 1,653,166*
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	12,354	15,334	20,137	24,980
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	38,869	130,617	285,540	(613)
391.92	OFFICE FURNITURE AND EQUIPMENT - OUTAGE MANAGEMENT SOFTWARE	635,694	660,150	697,801	1,490,702
393	STORES EQUIPMENT	2,568	4,135	5,885	7,651
394	TOOLS, SHOP AND GARAGE EQUIPMENT	533,742	615,343	622,707	669,762
395	LABORATORY EQUIPMENT	86,831	83,568	62,234	28,138
397	COMMUNICATION EQUIPMENT	261,885	152,259	297,890	368,166
398	MISCELLANEOUS EQUIPMENT	56,124	51,910	126,923	210,964
TOTAL GENERAL PLANT		**$ 2,739,951**	**$ 2,907,150**	**$ 3,394,321**	**$ 4,452,916**

UGI UTILITIES, INC. - ELECTRIC DIVISION
UNADJUSTED ACCUMULATED DEPRECIATION EXPENSE
FOR THE YEARS ENDED SEPTEMBER 30, 2021, 2022, 2023 AND 2024

ACCOUNT		2021	2022	2023	2024
SPECIAL DEPRECIABLE PLANT					
392.1	TRANSPORTATION EQUIPMENT - AUTOMOBILES	35,766	$ 123,694	$ 167,889	$ 213,285
392.2	TRANSPORTATION EQUIPMENT - LIGHT TRUCKS	65,443	140,850	307,336	487,745
392.4	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	17,854	35,877	75,520	115,114
396	POWER OPERATED EQUIPMENT	(2,384)	6,317	45,151	117,248
TOTAL SPECIAL DEPRECIABLE PLANT		**$ 116,679**	**$ 306,738**	**$ 595,896**	**$ 933,392**
TOTAL DEPRECIABLE PLANT		**$ 67,420,194**	**$ 70,972,053**	**$ 74,858,247**	**$ 79,770,525**
LESS GENERAL PLANT ALLOCATED TO TRANSMISSION - 25.6247%		**$ (732,003)**	**$ (823,549)**	**$ (1,022,481)**	**$ (1,380,225)**
TOTAL ELECTRIC PLANT		**$ 66,688,191**	**$ 70,148,504**	**$ 73,835,766**	**$ 78,390,300**
SUMMARY					
DISTRIBUTION		64,563,564	67,758,165	70,868,030	74,384,217
GENERAL PLANT		2,124,627	2,390,339	2,967,736	4,006,083
TOTAL PLANT		**$ 66,688,191**	**$ 70,148,504**	**$ 73,835,766**	**$ 78,390,300**

Note: Common asset allocations are excluded from these accumulated depreciation amounts. Please refer to the UGI Electric Exibit A (Fully Projected), UGI Electric Exhibit A (Future) and UGI Electric Exhibit A (Historic) for the common asset allocations.

INDEX OF CONTENTS ON USB FLASH DRIVE

UGI UTILITIES, INC. – ELECTRIC DIVISION
2023 BASE RATE CASE
DOCKET NO. R-2022-3037368

INDEX OF CONTENTS ON USB FLASH DRIVE

USB FLASH DRIVE

BOOK II

UGI UTILITIES, INC. – ELECTRIC DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI ELECTRIC STATEMENT NO. 1 – CHRISTOPHER R. BROWN
UGI ELECTRIC STATEMENT NO. 2 – TRACY A. HAZENSTAB
UGI ELECTRIC STATEMENT NO. 3 – VIVIAN K. RESSLER
UGI ELECTRIC STATEMENT NO. 4 – ERIC W. SORBER
UGI ELECTRIC STATEMENT NO. 5 – VICKY A. SCHAPPELL

UGI UTILITIES, INC. – ELECTRIC DIVISION
PA P.U.C. NO. 6, SUPPLEMENT NO. 51
PA P.U.C. NO. 2S, SUPPLEMENT NO. 7

DOCKET NO. R-2022-3037368

Issued: January 27, 2023 Effective: March 28, 2023

UGI ELECTRIC STATEMENT NO. 1

CHRISTOPHER R. BROWN

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368

UGI Utilities, Inc. – Electric Division

Statement No. 1

Direct Testimony of
Christopher R. Brown

Topics Addressed:	**Overview of Testimony and Witnesses**
	Need for Rate Relief
	UGI-1 Initiative and UNITE Systems Modernization
	Management Performance

Dated: January 27, 2023

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Christopher R. Brown. My business address is 1 UGI Drive, Denver, PA 17517.

Q. By whom and in what capacity are you employed?

A. I am employed by UGI Utilities, Inc. ("UGI") as its Vice President Finance and Chief Financial Officer. I have been in this role since January 2023. Prior to this very recent change, I was Vice President and General Manager Rates and Supply. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric" or the "Company") and the Gas Division ("UGI Gas"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. Please briefly describe your responsibilities in that capacity.

A. As Vice President Finance and Chief Financial Officer, I have responsibilities over the finance and accounting functions for the Company including managing cash flow, financial planning and analysis, and developing the overall business strategy for the Company. In this role, I report directly to the Chief Financial Officer of UGI Corp.

In my prior role as Vice President and General Manager of Rates and Supply, I was responsible for all rate, supply, and associated regulatory compliance activities for UGI Electric and UGI Gas. For the rates component, I oversaw the areas of sales and revenue forecasting, tariff administration and compliance, Choice administration and compliance, rate administration, Section 1307(f) purchased gas cost ("PGC") filings, electric provider of last resort ("POLR") filings, Section 1307(e) filings, base rate cases, and UGI's energy management information technology systems. My supply responsibilities included oversight of supply procurement and contracting, gas and power scheduling, and tracking of interstate pipeline and wholesale power market activities that affect UGI's gas and power procurement costs. My regulatory compliance responsibilities covered a broad range of oversight and compliance for the state and federal jurisdictional activities of UGI. Prior to my role as Vice President and General Manager of Rates and Supply, I was Senior Director of Operations for UGI's southern operating region.

Q. What is your educational and professional background?

A. Please see my resume, UGI Electric Exhibit CRB-1, which is attached to my testimony.

Q. Have you testified previously before this Commission?

A. Yes. UGI Electric Exhibit CRB-1 contains a list of those proceedings.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. In addition to UGI Electric Exhibit CRB-1, mentioned above, I am sponsoring certain responses to the Commission's filing requirements. Each filing requirement response identifies the witness sponsoring it. Specifically, I am sponsoring those schedules that were prepared by me or under my direction.

II. OVERVIEW OF TESTIMONY AND PRESENTATION OF WITNESSES

Q. Please describe the purpose of your testimony in this proceeding.

A. My testimony addresses several points. First, I present the Company's list of witnesses in this proceeding, including an outline of the subjects covered by each witness in their testimony. Second, I summarize the rate filing, including a brief explanation of the reasons for rate relief. Third, I will address the Company's UGI-1 Initiative and UGI Next Information Technology Enterprise ("UNITE") Systems Modernization. Lastly, I will summarize the evidence of UGI Electric's successful management performance.

Q. Please identify the other witnesses providing direct testimony on behalf of UGI Electric in this proceeding and the subject matter of their testimony.

A. In addition to my testimony, the following witnesses are providing testimony in support of the Company's rate request:

Tracy A. Hazenstab (UGI Electric St. No. 2) holds the position of Principal Analyst – Rates for UGI. Her testimony addresses UGI Electric's budgeting process; operating revenues and expenses; compliance with Section 1301.1 of the Public Utility Code; and the revenue requirement model supporting the Company's proposed rate increase (UGI Electric Exhibit A (Fully Projected)). Ms. Hazenstab also sponsors the revenue requirement models for the future and historic periods, UGI Electric Exhibit A (Future) and UGI Electric Exhibit A (Historic), respectively.

Vivian K. Ressler (UGI Electric St. No. 3) serves as Senior Manager, Finance for UGI and her duties include accounting services for UGI Electric. Ms. Ressler will explain UGI Electric's accounting processes. She will present UGI Electric's rate base claim in this proceeding and address the accounting for the projected plant additions and retirements, as well as for the cash working capital. Finally, Ms. Ressler will also address certain operating expense adjustments within the Company's expense claim.

Eric W. Sorber (UGI Electric St. No. 4) is Vice President and General Manager of UGI Electric. Mr. Sorber is responsible for developing and implementing business unit projects and long-term strategic infrastructure investment plans. Mr. Sorber provides an overview of UGI Electric's operations; reliability and safety commitment; and the impact of inflation and supply chain challenges on the Company's operations. Mr. Sorber also discusses certain tariff modifications proposed in this proceeding and provides an update on items from the Company's prior base rate case in 2021 at Docket No. R-2021-3023618.

Vicky A. Schappell (UGI Electric St. No. 5) holds the position of Principal Analyst – Capital Planning for UGI. Ms. Schappell addresses the Company's capital expenditures, capital planning process, and UGI Electric's history of performing on its budget.

John D. Taylor (UGI Electric St. No. 6) is a Managing Partner of Atrium Economics LLC. Mr. Taylor prepared and sponsors the Company's fully-allocated cost of service study used in this case to develop the allocated class costs of service ("ACOSS"), which is found in UGI Electric Exhibit D. The ACOSS allocates the Company's cost of service associated with Commission jurisdictional operations to the Company's retail customer classes. Mr. Taylor also supports the apportionment of the class revenue increase and the Company's rate design proposals.

John F. Wiedmayer (UGI Electric St. No. 7) is Senior Project Manager at Gannett Fleming Valuation & Rate Consultants, LLC. Mr. Wiedmayer developed and supports UGI Electric's claim for annual depreciation expense and the accumulated depreciation reserve. His studies are presented in UGI Electric Exhibit C (Fully Projected), UGI Electric Exhibit C (Future), and UGI Electric Exhibit C (Historic).

Darin T. Espigh (UGI Electric St. No. 8) is Senior Manager Natural Gas Tax Accounting, Finance for UGI Corp. and oversees the preparation of state and federal tax data, returns, and tax-related regulatory filings for UGI Electric. Mr. Espigh addresses various tax issues, including the Company's claim for federal and state income taxes, taxes other than income taxes, the calculation of the accumulated deferred income taxes ("ADIT") offset to rate base, the repairs allowance, and the calculation of a hypothetical consolidated tax savings adjustment as required by Section 1301.1 of the Public Utility Code, 66 Pa. C.S. § 1301.1.

Paul R. Moul (UGI Electric St. No. 9) is Managing Consultant of P. Moul & Associates, Inc. Mr. Moul presents expert testimony supporting the Company's claimed capital structure, cost of debt, cost of common equity, and overall fair rate of return. Schedules and workpapers supporting Mr. Moul's findings are set forth in UGI Electric Exhibit B.

Sherry A. Epler (UGI Electric St. No. 10) serves as Sr. Manager – Tariff and Supplier Administration at UGI. Ms. Epler addresses and sponsors the Company's proof of revenues as presented in UGI Electric Exhibit E - Proof of Revenue. Ms. Epler's testimony also presents and supports the sales and revenue adjustments. Ms. Epler is sponsoring UGI Electric Exhibit F, which is Supplement 51 to UGI Electric Pa. P.U.C. No. 6 ("Tariff No. 6"). Ms. Epler provides a summary of the proposed changes to the tariff rules, regulations, and rate schedules included in UGI Electric's Tariff No. 6, and the Choice Supplier Tariff, which is incorporated into Tariff No. 7 as Tariff No. 2S.

III. NEED FOR RATE RELIEF

Q. Please discuss the Company's proposed rate relief request.

A. UGI Electric is requesting an increase in its annual base rate operating revenues of $11.425 million, or 7.5 percent on a total revenue basis, with a proposed effective date of March 28, 2023. The base rate increase requested in this filing is based on the use of a Fully Projected Future Test Year ("FPFTY") ending September 30, 2024.

Q. Why is UGI Electric seeking a rate increase at this time?

A. The primary need for UGI Electric's proposed rate increase is the Company's continued extensive efforts to repair, replace, improve and modernize the aging portions of its distribution system. Since 2018, the Company has spent almost $50 million on these efforts. The Company anticipates that it will continue its accelerated capital programs over the coming years, as reflected in its recently approved Second Long-Term Infrastructure

Improvement Plan ("Second LTIIP"). The extensive capital work being undertaken by UGI Electric is described by Mr. Sorber in UGI Electric Statement No. 4.

Q. Are there any other reasons that UGI Electric is seeking a rate increase at this time?

A. Yes. Since its last base rate case, significant shifts in the economy occurred, including high inflation and low unemployment. These market dynamics impacted the Company, and in this case, UGI Electric reflected the impact of price increases on its operations. UGI Electric adopted annual wage and salary adjustments in this case and will continue to do so, where reasonable. The growth in operating and capital costs, along with relatively stagnant customer usage and growth trends, are the primary reasons why UGI Electric will not earn a fair rate of return on its investments at present rate levels.

Q. Has the Company evaluated the impact of its proposed rate increase on average customer bills generally?

A. Yes. As shown on Table 1, below, the Company has evaluated the effect of its proposed rate increase on the average monthly bill of residential, small commercial, and industrial customers.

Table 1. Average Monthly Bill Impact

Average Electric Customer Bill Impact

		Total Monthly Bill Impact			
	Average Usage	Current	Proposed	Increase	Total
Residential	1,000 kWh	$192.73	$209.96	$17.23	8.9%
Small Commercial	1,000 kWh	$199.06	$220.49	$21.43	10.8%
Industrial	50,000 kWh	$6,455.07	$6,475.18	$20.11	0.3%

The proposed rate increases shown in Table 1 are required to support important investments in the repair and replacement of aged and aging infrastructure and to recover reasonable and necessary increases in operating expenses. Even with such increases, UGI Electric will continue to have distribution rates that are comparable to other Pennsylvania EDCs.

Q. Why is the Company's proposed rate increase justified?

A. The Company's current rates do not provide it with a reasonable opportunity to earn a fair rate of return on its investments made to serve the public in the provision of safe and reliable electric distribution service. Specifically, as reflected in UGI Electric Exhibit A (Fully Projected), Schedule A-1, the Company's operations are projected to produce an overall return on rate base of just 3.768%, which equates to a return on common equity of only 3.28%, for the twelve months ending September 30, 2024. As explained by Company witness Paul R. Moul (UGI Electric St. No. 9), these returns are not adequate based on applicable financial data and the risks confronted by UGI Electric. Unless UGI Electric receives the requested rate relief, those returns will continue declining, deny the Company an opportunity to earn a fair and reasonable rate of return, and jeopardize the Company's ability to attract the capital needed to make the system investments necessary to support and ensure continued system reliability, safety, and customer service performance.

IV. UGI-1 INITIATIVE AND UNITE SYSTEMS MODERNIZATION

Q. What is UGI-1?

A. UGI-1 is a Company-wide improvement initiative focusing on people, tools, and processes. The centerpiece of UGI-1 is UNITE a business and technology transformation initiative driving standardization and improvement of business processes through the implementation of new technology solutions.

Q. What is the history of UNITE?

A. UNITE was established to position UGI to realize its UGI-1 strategic vision and was planned for implementation across multiple phases. Applying sound project management, UNITE has a consistent track record of delivering project phases on time and within budget. Phase I of UNITE replaced UGI Electric's Customer Information Systems ("CIS") in September 2017, enhancing the overall customer experience and improving back office support. Phase II of UNITE replaced the Company's Enterprise Resource Planning ("ERP") system and implemented SAP's Fieldglass solution for contractor billing in 2021. The Enterprise Performance Management ("EPM") project went live in October 2020. It implemented the PowerPlan Capital Budgeting and Forecasting solution, which is integrated with the Company's ERP and PowerPlan Fixed Asset and Tax systems. PowerPlan provides imbedded lifecycle governance for approving and monitoring Capital projects; improved visibility to Capital expenditure requests and authorized Capital projects; detailed forecasting for more accurate tracking of ongoing Capital projects; and improved data analytics for making timely and optimal Capital decisions. Powerplan is a critical resource for accurately tracking record Capital improvements at UGI Electric since implementation.

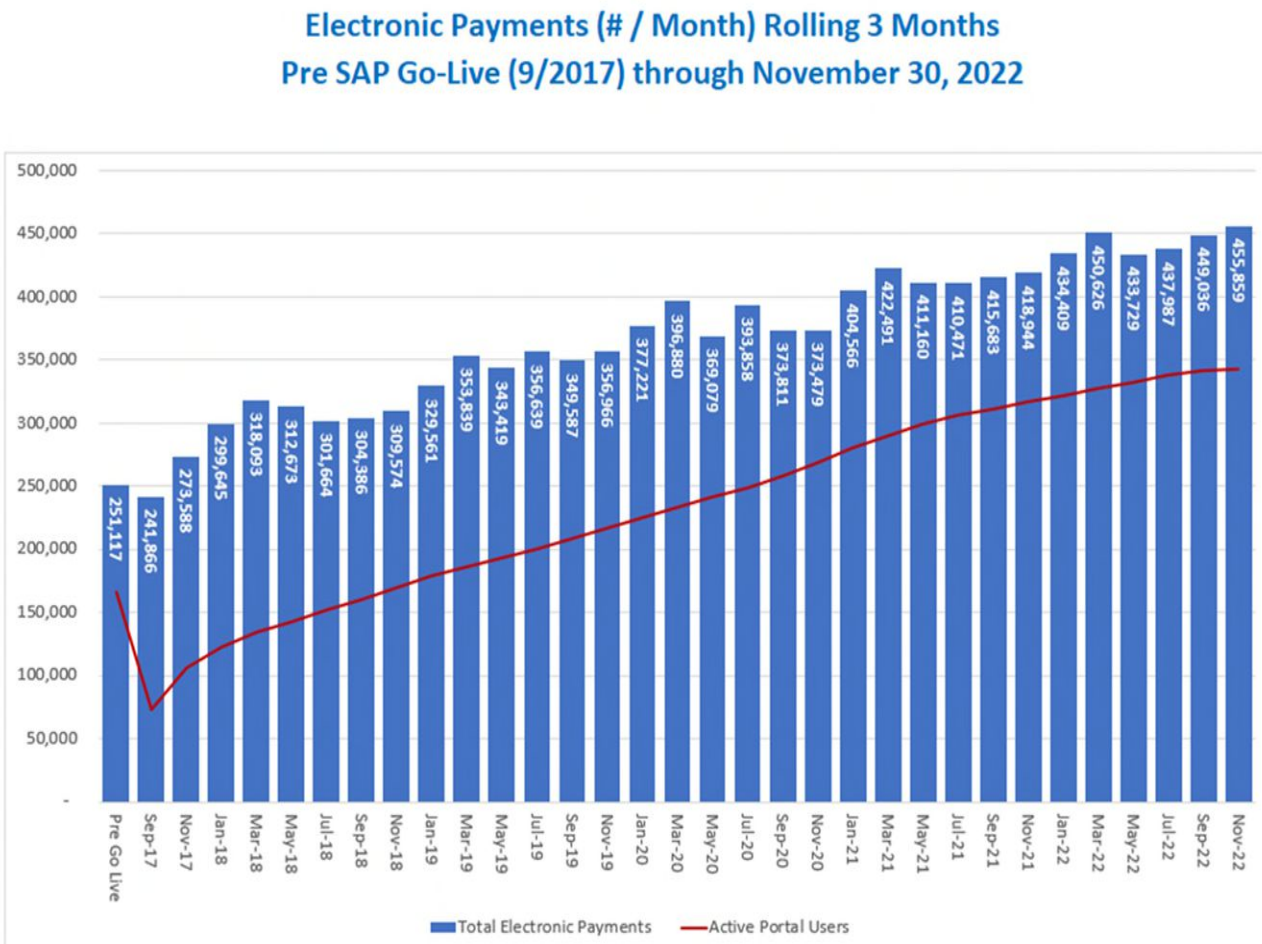
Q. Has UGI Electric implemented any additional UNITE projects since its last base rate case?

A. Yes. In September 2022, the Asset Data Collection ("ADC") project, the first part of a larger Enterprise Asset Management ("EAM") initiative, was implemented successfully at UGI Electric. Utilizing automated, digital smart forms, ADC enhanced the field collection of Operations facility asset data. Included with the ADC implementation was the ability to utilize high accuracy Global Positioning System ("GPS") technology. The ADC project has now created a robust digitized inventory of field assets that is available to support efficiency gains in record access for both field and analysis work across the Company.

Q. What improvements from UNITE has UGI Electric experienced?

A. Since the beginning of UNITE, electronic payments for UGI's gas and electric customers increased by approximately 81% and customer portal profiles increased by approximately 106%. These statistics demonstrate an improved customer experience, i.e., a simplified process for customers to access information and other services. The upward trend in electronic payment adoption can be seen in the following Figure 2.

Figure 2. Gas & Electric Electronic Payments Rolling 3 Months Pre CIS Go-Live (Sept. 2017) through Nov. 2022



In addition, through EPM and the implementation of PowerPlan, UGI experienced significant benefits that impact its ability to plan for and manage capital projects and to report on those projects. Specifically, PowerPlan allows for project managers and engineers to enter the actual in-service date in the system, which interfaces to UGI's accounting system and automatically calculates depreciation. Project Managers can enter the actual in-service date in PowerPlan as soon as a project is completed, and by doing so reduce the delay that the Company previously experienced in the post-implementation accounting process. PowerPlan also automatically generates the depreciation budget and forecast directly from the construction budget and estimated in-service dates, which eliminates the time-consuming manual process previously used by UGI. Finally, PowerPlan allows the Company to: (1) forecast projects and review projects at a more granular level of detail based on charge type; and (2) move from a spending budget to a placed in service budget more fluidly and without the manual tracking of project status historically used by UGI.

Q. What additional UNITE initiatives has UGI identified at this time?

A. As described previously, the first phase of EAM was implemented. While no costs are included in this rate case, planning is actively underway for the next UNITE project within EAM, with an anticipated go live date in FY2025. EAM is currently scoped to achieve, among other things, improved data quality; better facility tracking and traceability; tools for ensuring ongoing regulatory compliance; a standard dispatching and mobility solution for field work; enhanced work management capabilities; and improved risk management capabilities for guiding future betterment decisions.

V. MANAGEMENT PERFORMANCE AND RECOGNITION

Q. Please summarize the Company's initiatives and activities related to management performance.

A. UGI Electric focuses on a number of areas to enhance and improve the quality and effectiveness of UGI Electric's management performance. These management efforts include:

- High Standards for Electric Reliability: Historically, UGI Electric has strong reliability performance as measured by the Commission-established Benchmark levels for service reliability. The Company has met or performed better than the PUC Benchmark levels in two of the three categories in 2021 and 2022, with System Average Interruption Frequency Index ("SAIFI") being the outlier. For the rolling 12 months ending in the fourth quarter of calendar year 2022, UGI Electric achieved Customer Average Interruption Duration Index ("CAIDI"), and System Average Interruption Duration Index ("SAIDI") index levels that were 7.7% and 3.6% better than Benchmark levels, respectively. During that time, SAIFI was 4.8% above the Benchmark but remained better than the Commission-established Standard level of 1.12 by 22.3%. As noted by the Commission, reliability performance that is better than the Benchmark is considered to be "excellent" performance.[1]
- Consistent Performance on Long-Term Infrastructure Improvement Targets: UGI Electric consistently met or exceeded its targeted replacement of aged or aging facilities since it began its accelerated replacement program in 2018. On August 25, 2022, the Commission approved UGI Electric's Second LTIIP, which covers the period October 1, 2022 through September 30, 2027. Through the Second LTIIP, UGI Electric expects to expend significant capital, approximately $50.6 million and complete numerous projects that will enhance distribution system safety and reliability. The Company's progress on critical infrastructure replacement programs that enhance safety and reliability are further explained in Mr. Sorber's testimony.

1 *See, e.g., Electric Service Reliability in Pennsylvania 2021* "2021 Electric Reliability Report", page 4 (August 2022) ("Performance is considered excellent since [the metric] is below both benchmark and standard").

- Energy Efficiency and Conservation Plan: Though UGI Electric is exempt from the large EDC requirement to have an energy efficiency and conservation plan ("EE&C Plan") under Act 129, the Company has voluntarily operated an EE&C Plan since 2012. UGI Electric's EE&C Plan provides education and incentives to the Company's customers to help reduce their electric consumption and demand. On March 14, 2019, the Commission entered an Order approving the Company's five-year Phase III EE&C Plan, which began on June 1, 2019. In UGI Electric's most recent EE&C program year, June 1, 2021 – May 31, 2022, the Company issued $377,870 in rebates to residential and commercial customers and achieved savings of 3,935,000 kWh, resulting in material cost savings for customers and the equivalent greenhouse gas benefit of avoiding the release of 2,964 metric tons of CO2.[2] In addition, through its EE&C program, UGI Electric supports the School Education Program, which provides educational presentations and energy saving kits to more than 1,000 elementary and high school students in the UGI Electric service territory.
- Enhanced Customer-Service Offerings and Continued Information Technology System Replacements: As discussed previously in my testimony, the Company's investments in IT through the UNITE initiative promoted customer self-service through the Company's web portal, increased electronic payments, and improved the customer experience. UNITE also improved the Company's accounting processes, management of its capital programs, and ability to deploy and account for resources more accurately and precisely. In addition, UGI Electric has continued its efforts to support customers

[2] This figure was derived from the EPA Greenhouse Gas Equivalencies calculator: https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator

in need. Specifically, for program year 2022, UGI Electric provided 1,396 Low Income Home Energy Assistance Program ("LIHEAP") grants totaling more than $1 million, and 287 Operation Share grants for more than $85,000. In 2022, UGI Electric also supported customers in accessing $220,400 in weatherization assistance via UGI's Low Income Usage Reduction Program ("LIURP").

- Safety Focus: Safety is a fundamental imperative at UGI Electric. The Company continues to foster a robust safety culture that ensures the safety of employees, customers, and the communities we operate in. As just one example of the ways in which UGI Electric makes its community safer, the Company engages with local first responders to provide electric safety awareness training so that those first on the scene in an emergency will know how to safely identify and avoid electric hazards. UGI Electric also provides electrical safety tips as well as safety and conservation education through many mediums to the public. The Company's commitment to safety is described by UGI Electric witness Mr. Sorber (UGI Electric St. No. 4).
- Community Support: UGI Electric supports a variety of projects that benefit communities throughout its service territory. These include American Red Cross blood drives, 'Sound the Alarm' fire preparedness awareness events, the Commission on Economic Opportunity Thanksgiving food drive, Reading is Fundamental book distributions, Touch-a-Truck community events, S.P.A.R.K.S. foundation science explorer school events, and United Way of Wyoming Valley book drive and Day of Caring events, among many others. UGI invests more than $1.5 million annually to support education improvement programs, including approximately $270,000 in the overlapping UGI Electric and UGI Gas service territories. These programs support

pre-K, childhood literacy and enhanced “STEM” (science, technology, engineering and math) curriculum in elementary schools, fund technical training programs for high school students, and provide support and mentoring for women and minority engineering school students.

The above-described initiatives, as well as the operating factors addressed by other Company witnesses, demonstrate the role of exceptional management performance in UGI Electric’s commitment to, and focus on, providing safe, reliable, and quality distribution service to its customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC

EXHIBIT CRB-1

CHRISTOPHER R. BROWN

VICE PRESIDENT – FINANCE AND CHIEF FINANCIAL OFFICER

UGI Utilities, Inc.

Vice President – Finance and Chief Financial Officer	January 2023 - Present
Vice President and General Manager, Rates and Supply (Denver, Pa.)	May 2019 – January 2023
Sr. Director- Operations South Region (Reading, Pa.)	July 2015- May 2019
Manager - Operations (Reading, Pa.)	July 2013 – July 2015
Director- Central Services (Reading, Pa.)	October 2010 – July 2013
Manager – Strategy Processes and Implementation (Reading, Pa.)	February 2010 – October 2010
Manager – Customer Accounting Services (Reading, Pa.)	May 2009 – February 2010
Marketing Manager – East Region (Allentown, Pa.)	April 2008 – May 2009

Amerigas Propane, Inc.

Market Manager (Stroudsburg, Pa.)	June 2005 to April 2008

UGI Utilities, Inc.

Supervisor – Gas Supply and Transportation (Reading, Pa.)	September 2003 – June 2005
Distribution Superintendent (Harrisburg, Pa.)	September 2001 – September 2003
Staff Engineer – Commercial Marketing (Reading, Pa.)	September 1999 – September 2001
New Business Engineer (Allentown, Pa.)	June 1997 – September 1999

Education

MBA, Lebanon Valley College, Annville, Pa.
BS, Civil Engineering, Lehigh University, Bethlehem, Pa.

Previous testimony provided before the Pennsylvania Public Utility Commission:

Docket No. R-00050539	UGI Utilities Inc. - Annual 1307(f) Filing
Docket No. C-2015-2516051	Centre Park Historic District v. UGI Utilities, Inc.
Docket No. C-2016-2530475	City of Reading v. UGI Utilities, Inc.
Docket No. R-2019-3015162	UGI Utilities, Inc. Gas Division - Base Rate Case Proceeding
Docket No. R-2021-3023618	UGI Utilities, Inc. Electric Division - Base Rate Case Proceeding
Docket No. R-2021-3030218	UGI Utilities, Inc. Gas Division – Base Rate Case Proceeding

UGI ELECTRIC STATEMENT NO. 2

TRACY A. HAZENSTAB

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368

UGI Utilities, Inc. – Electric Division

Statement No. 2

Direct Testimony of
Tracy A. Hazenstab

Topics Addressed:	**Budget Process** **Revenue Requirements** **Operating Revenues and Expenses** **Compliance with PA Act 40 of 2016**

Dated: January 27, 2023

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Tracy A. Hazenstab. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed by UGI Utilities, Inc. ("UGI") as Principal Analyst, Rates. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric" or the "Company") and the Gas Division ("UGI Gas"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your responsibilities as Principal Analyst, Rates?

A. I am primarily responsible for various tariff filings and related computations for UGI Gas and UGI Electric rate and regulatory filings before federal and state regulatory commissions. As part of these responsibilities, I am responsible for budgeting/financial planning for UGI, which is a joint effort with the Rates Department (verifying the revenue and margin budgets) and the Financial Planning and Analysis Department (preparing the operating and capital budgets). I report directly to the Director, Rates and Regulatory Planning of UGI.

Q. What is your educational background?

A. I received an undergraduate degree in International Politics from Pennsylvania State University.

Q. Please describe your professional experience.

A. Please see my resume, UGI Electric Exhibit TAH-1, which is attached to my testimony.

Q. Have you testified previously before this Commission?

A. Yes. Attached to my direct testimony is UGI Electric Exhibit TAH-1, which contains a list of the Commission's proceedings in which I previously testified. Additional exhibits that I am sponsoring are described below.

II. PURPOSE OF TESTIMONY

Q. Please describe the purpose of your testimony in this proceeding.

A. I am providing testimony on behalf of UGI Electric in support of the Company's proposed revenue requirement. First, I will explain UGI Electric's budgeting processes (Part III). Next, I will present UGI Electric's ratemaking presentations for the historic test year ended September 30, 2022 ("HTY"), future test year ending September 30, 2023 ("FTY") and the fully projected future test year ending September 30, 2024 ("FPFTY"), including its principal accounting exhibits, operating expenses claims, and certain *pro forma* adjustments (Part IV). The Company's rate proposal in this case is predicated on its FPFTY exhibit, which demonstrates the need for a revenue increase of $11.425 million. I will also address the Company's compliance with Act 40 of 2016 (Part V).

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. In addition to UGI Electric Exhibit TAH-1 mentioned above, I am sponsoring UGI Electric Exhibit TAH-2, which provides the summary statements of Operating Income before Income Taxes of the Company on a FERC and PUC jurisdictional basis for the HTY, FTY and FPFTY. I am also sponsoring the principal accounting exhibits UGI Electric Exhibit A (Fully Projected), Exhibit A (Future) and Exhibit A (Historic). Other Company witnesses present testimony in support of various portions of these exhibits, including rate base (Vivian R. Ressler, UGI Electric Statement No. 3), fair rate of return (Paul R. Moul, UGI Electric Statement No. 9), depreciation expense (John F. Wiedmayer, UGI Electric Statement No. 7), operating revenue (Sherry A. Epler, UGI Electric Statement No. 10), and taxes (Darin T. Espigh, UGI Electric Statement No. 8). I am further sponsoring the Company's responses to the Commission's filing requirements and standard data requests where my name is indicated as the sponsoring witness.

III. <u>OVERVIEW OF PRINCIPAL ACCOUNTING EXHIBITS</u>

Q. Please describe the principal accounting exhibits used to support UGI Electric's claims in this proceeding.

A. UGI Electric Exhibit A (Fully Projected) provides the calculation of the revenue requirement for the FPFTY including principal accounting exhibits, rate base claims, operating expenses claims, and certain *pro forma* adjustments. The FPFTY information is derived from UGI Electric's operating and capital budgets for the 12 months ending September 30, 2024. UGI Electric Exhibit A (Future) is the principal accounting exhibit for the FTY ending September 30, 2023, including certain *pro forma* adjustments. The FTY information is derived from UGI Electric's operating and capital budgets for the 12-

month period ending September 30, 2023. UGI Electric Exhibit A (Historic) is the principal accounting exhibit for the HTY ended September 30, 2022, with appropriate ratemaking adjustments. The HTY information is derived from the book accounting data for the 12-months ended September 30, 2022. The FTY and HTY schedules are provided as a comparative benchmark with the FPFTY claim, which as explained above is the basis for UGI Electric's proposed revenue increase of $11.425 million.

The Company's principal accounting exhibits and cost of service study include the revenues and expenses associated with default generation supply service, but these revenues and expenses are equal as shown in UGI Electric Exhibit D, Section II – Summary of Results, and have no impact on the Company's requested distribution revenue requirement.

Q. Please provide an overview of UGI Electric's principal accounting exhibits.

A. UGI Electric's claims in this case are based on UGI Electric Exhibit A (Fully Projected), which is comprised of four sections:

- <u>Section A</u> summarizes UGI Electric's requested *pro forma* rate base, revenues, and expenses at present rates and the calculation of its requested revenue increase.
- <u>Section B</u> includes basic accounting data extracted from UGI Electric's financial, accounting, operating and capital budgets, and other records. This data includes a balance sheet, a statement of net operating income and test year revenues, a schedule of expense items by cost element, and a tax expense calculation. Also included are schedules showing UGI Electric's embedded cost of debt, year-end capital structure and overall claimed rate of return.

- Section C provides the elements of UGI Electric's rate base claim and how each element of that claim is derived. UGI Electric's rate base includes utility plant in service, cash working capital, materials and supplies inventory, and offsets for accumulated depreciation, accumulated deferred income taxes, and customer deposits.
- Section D presents UGI Electric's revenues and expenses on a *pro forma* ratemaking basis. Necessary adjustments to budgeted levels of expense items and revenues are summarized in Schedules D-1 through D-2 and detailed in the remaining schedules. The resulting FPFTY expense and revenue levels are shown on Schedule D-3 and were used to establish UGI Electric's *pro forma* income at present and proposed rates as set forth in Schedule A-1.

Q. What information is included in UGI Electric Exhibits A (Future) and A (Historic)?

A. UGI Electric Exhibits A (Historic) and A (Future) follow the format of UGI Electric Exhibit A (Fully Projected), but reflect data for the fiscal year ended September 30, 2022, and the fiscal year ending September 30, 2023, respectively. This information is provided to comply with the Commission's filing requirements and provides a basis for comparing our FPFTY claims with actual and projected results from the HTY and FTY.

Q. What are the data sources for the UGI Electric Exhibit A (Future) and UGI Electric Exhibit A (Historic)?

A. This data is derived from UGI Electric's books and records, and capital and operating budgets. UGI Electric Exhibit A (Future) is based on adjusted budgeted data for the fiscal year ending September 30, 2023. UGI Electric Exhibit A (Historic) is based on adjusted experienced data for the fiscal year ended September 30, 2022.

IV. BUDGETING PROCESS

Q. Please explain UGI Electric's budgetary preparation and approval process.

A. UGI Electric's fiscal year begins on October 1 and ends on September 30 of the following year. Preparation of the UGI Electric Operating Budget for the subsequent fiscal year begins during the spring, *i.e.*, the budget process for the October 1, 2022 through September 30, 2023 fiscal year begins in the spring of 2022, with information being requested and incorporated from all departments. Internal reviews and revisions occur throughout the spring and summer before the final budget is approved by the UGI Board of Directors in September – immediately prior to implementing the budget.

The revenue portion of the budget is developed by the Financial Planning and Analysis ("FP&A") Department. It determines customer counts, develops normalized usage per customer for core customer classes, and annualizes sales and total revenues. This process is further explained in the direct testimony of UGI Electric witness Ms. Epler (UGI Electric Statement No. 10). The number of customers by customer class is determined using the average customer count for fiscal year 2022. Usage per customer is developed by reviewing the long-term usage trends and current and anticipated levels of operation. The budgeted number of customers and usage per customer are combined to produce monthly budgeted sales. The revenue budget is calculated by applying tariff rates for each customer class to budgeted sales, plus an adjustment for unbilled revenue. The sales and revenue budget is then reviewed with, and approved by, senior management.

Concurrently, the expense portion of the Operating Budget is prepared. Operating and maintenance expenses are developed by each functional manager based upon review of trends, monthly expenditure patterns, and new or changed programs. Employee levels are reviewed, and appropriate staffing levels are set for the upcoming fiscal year. The direct expense portion of the Operating Budget is submitted for review and approval by senior management. UGI Electric's direct expenses are then consolidated with allocated expenses from shared administrative and general functions within UGI and from other affiliated companies providing shared services to UGI Electric to develop the budgeted Statement of Operations. Allocated expenses in the Statement of Operations include functions such as accounting, rates, electric supply, human resources, information systems, payroll, and remittance processing, which are performed in accordance with PUC-approved methods of allocation and affiliated interest arrangements or agreements.

The final Operating Budget is then submitted to UGI's President and Board of Directors for their review and approval. Each element of the UGI Electric Operating Budget is formulated by personnel with responsibilities specific to each aspect of the operation. The first and primary use of the Operating Budget is as a working tool for the management and planning of the business.

Operating personnel in each functional area prepare a detailed list of capital projects. Each project is identified, described and justified along with a breakdown of the costs associated with it. These projects are presented to senior management, which reviews them in terms of priority, capital availability, and strategic alignment with the operating budget. After due consideration, the Capital Budget is set and presented to senior management in a series of review meetings. The final Capital Budget is approved by the

UGI Board of Directors in September immediately prior to implementing the budget. Additional information concerning the factors considered in establishing the UGI Electric Capital Budget is provided in the direct testimony of Vicky A. Schappell (UGI Electric Statement No. 5).

The UGI Electric Capital Budget is prepared in conjunction with the Operating Budget. With the passage of Act 11 of 2012, UGI Electric has also instituted a process for establishing an Operating Budget and Capital Budget for an additional fiscal year in the future, *i.e.*, the FPFTY. This process is the same as outlined above; however, the starting point for the additional year is the FTY budget. The FPFTY revenue budget is based on normalized weather conditions, per customer usage trends, and projections concerning growth in numbers of customers. Similarly, FPFTY budget expense amounts are adjusted for salary and personnel increases, known program changes and expense needs. For the capital budget, projects are included based on the process described above, which is further described in Ms. Schappell's testimony (UGI Electric Statement No. 5).

Q. Please explain how expenses from affiliated companies are allocated to develop the budgeted Statement of Operations.

A. UGI Electric incurs costs for services provided by UGI Corp., and other affiliated companies, in accordance with affiliated interest arrangements authorized by the Commission. UGI also allocates or assigns costs between UGI Electric and UGI Gas. All costs which can be identified as pertaining exclusively to an operating unit are billed directly to that unit. Those costs which cannot be directly associated with the operation of an individual operating unit are allocated to the various companies benefiting from the service. Allocations are done by a methodology applicable to the cost (*e.g.*, budgeted time allocations, number of employees, etc.) or, if no one methodology is specific to the cost, by a formula referred to as the Modified Wisconsin Formula ("MWF") or another reasonable allocation methodology. The MWF or other allocation methodology achieves an equitable distribution of common expenses based on the relative activity and size of each operating unit to the total of all operating units, which benefit from the respective activities. Activity is measured by total revenues and total operating expenses and size is measured by tangible net assets employed (excluding acquisition goodwill).

Q. How is this budget information used to support UGI Electric's requested revenue increase?

A. This budget information is the starting point for UGI Electric's claims and is adjusted as appropriate to reflect new information gained since the completion of the budgeting process and through application of other appropriate ratemaking principles. Total UGI Electric system rate base and components of operating income are assigned and/or allocated between the FERC and PUC jurisdictions, and the proposed revenue increase is determined on a PUC jurisdictional basis. Revenue in the amount of $10.323 million related to transmission revenue was excluded from this filing. In addition, expenses related to the transmission operations were also adjusted and excluded from this filing. Please see UGI Electric Exhibit TAH-2, pages 1 through 3, for the summary statements of Pennsylvania Jurisdictional Operating Income before Federal and State Income Taxes, which will tie to Schedule D-2, Column 2, for the test periods presented.

V. <u>REVENUE REQUIREMENTS FOR THE FULLY PROJECTED FUTURE TEST YEAR</u>

Q. How is your discussion of UGI Electric's FPFTY revenue requirement presentation organized?

A. In Section V.A, I present a summary of UGI Electric's FPFTY revenue requirement. In Section V.B, I discuss UGI Electric's proposed rate base. In Section V.C, I explain the determination of UGI Electric's revenues and operating expenses, depreciation, and income taxes.

A. FULLY PROJECTED FUTURE TEST YEAR REVENUE REQUIREMENT

Q. How were the *pro forma* revenue increase and revenues at proposed rates established?

A. This calculation is shown at a summary level on Schedule A-1, column 3 of UGI Electric Exhibit A (Fully Projected) beginning with Present Rates. Lines 1-8 summarize the *pro forma* measure of value (rate base). Lines 9-18 show *pro forma* revenues at present rates, *pro forma* expenses, taxes at present rates, *pro forma* net operating income at present rates, and the calculated rate of return at present rates. Lines 19-22 show the increase in net operating income required to permit UGI Electric to earn its required overall rate of return of 8.15%. Application of the Gross Revenue Conversion Factor ("GRCF") on line 23 establishes the revenue increase shown on line 24 needed to generate that net operating income. Column 4 of Schedule A-1 shows the level of the revenue increase and the increase in expenses associated with the revenue increase. Column 5 of Schedule A-1 shows the revenue, expenses, and rate base at proposed rates, as well as the resulting overall rate of return of 8.15%.

Q. What is the overall requested increase in revenue?

A. The overall requested increase in revenue is $11.425 million. This represents the difference between the *pro forma* FPFTY revenue requirement of $164.116 million and the annual level of operating revenues of $152.691 million under existing rates. These figures are shown on line 12 of Schedule A-1 of UGI Electric Exhibit A (Fully Projected).

B. RATE BASE

Q. With reference to UGI Electric Exhibit A (Fully Projected), please discuss how the Company's specific rate base items are determined.

A. UGI Electric's rate base presentation is shown in UGI Electric Exhibit A (Fully Projected), Schedule C-1. Schedule C-1 summarizes the UGI Electric rate base values for the FPFTY. Column 1 indicates the schedule upon which the calculation of each of the rate base elements is found. Columns 3 and 5 show the amounts at present and proposed rates, respectively. UGI Electric's total FPFTY rate base claim is $172.242 million. Please see the direct testimony of Vivian K. Ressler (UGI Electric Statement No. 3) for a discussion of the rate base components.

C. REVENUES AND EXPENSES

Q. How were revenues at present rates determined?

A. Revenues at present rates were determined by adjusting the budgeted revenues to reflect the anticipated change in the number of customers, the projected change in existing customer usage, and other *pro forma* normalizing adjustments. The net effect of these adjustments is shown in UGI Electric Exhibit A (Fully Projected), Schedule D-5, and is discussed in the direct testimony of Sherry A. Epler (UGI Electric Statement No. 10).

Q. Please provide an overview of UGI Electric's principal accounting exhibits relative to operating expense claims.

A. UGI Electric's principal accounting exhibit is UGI Electric Exhibit A (Fully Projected), which includes a presentation for the FPFTY ending September 30, 2024. Section D of UGI Electric Exhibit A (Fully Projected) presents UGI Electric's claims and necessary adjustments to budgeted levels of expense items and revenues. The *pro forma* adjustments related to expense are summarized in Schedules D-3 and D-6 through D-34. These expense adjustments are used, in part, to derive UGI Electric's *pro forma* income at present and proposed rates as set forth in Schedule D-1.

UGI Electric Exhibits A (Historic) and A (Future) follow the format of UGI Electric Exhibit A (Fully Projected) but reflect data for the appropriate test years ending September 30, 2022 and 2023, respectively. This information is provided in an effort to comply with the Commission's filing requirements and provides a basis for comparing our FPFTY claims with prior results.

1. Summary

Q. Please describe Schedule D-1 of UGI Electric Exhibit A (Fully Projected).

A. Schedule D-1 presents a summary income statement that includes UGI Electric's claimed electric revenues, expenses, and taxes at present and proposed rate levels. The direct testimony of Sherry A. Epler (UGI Electric Statement No. 10) addresses the presentation of *pro forma* revenues, adjustments thereto, and the supporting schedules. Schedule D-1 also shows the proposed revenue increase of $11.425 million on line 5 in column 2.

Q. What is the level of net income at proposed rates?

A. As shown on column 3, line 20, this amount is $14.038 million. This represents a $7.548 million increase from the level under current rates (i.e., $6.490 million), as shown on line 20 in column 1 of Schedule D-1.

Q. Please describe Schedule D-2.

A. Schedule D-2 shows the development of the various line items found on Schedule D-1. Column 2 contains the Company's budgeted level of revenues and expenses for the 12-month period ending September 30, 2024. Column 3 shows adjustments to the Column 2 figures, where applicable, to reflect various annualization and/or normalization adjustments. Column 4 is the sum of Columns 2-3. The amount of the revenue increase and related expenses are shown in Column 5 with the resulting revenues and expenses at proposed rates shown in Column 6.

Q. Are there schedules showing the derivation of the adjustments shown in Schedule D-2, Column 3?

A. Yes. The derivation of the various Column 3 revenue adjustments in Schedule D-2 is included in UGI Electric Exhibit A (Fully Projected) in summary fashion on Schedule D-3, page 1, lines 1-14, and then listed by individual adjustment on Schedule D-5. Customer charge and distribution rate revenue adjustments for each customer class are shown on Schedule D-5, lines 1-6. Electric Cost revenue adjustments for each customer class are shown on lines 7-12 and details of other revenue adjustments are shown on lines 14-17. Details for each revenue adjustment are shown in Schedules D-5 (including supporting

Schedule D-5A) and D-6, which are discussed in the direct testimony of UGI Electric witness Ms. Epler (UGI Electric Statement No. 10). Regarding *pro forma* expenses, the derivation of the various adjustments are summarized individually on pages 1 and 2 of Schedule D-3, lines 17-26 and lines 45-55. The details for these adjustments are found in Schedules D-5 through D-31.

2. Operating Expense

Q. How were the claimed operating expenses for the FPFTY determined?

A. *Pro forma* FPFTY expenses are based on the PUC jurisdictional budgeted level of expenses as a starting point. The budgeted data, by FERC account, was then adjusted in accordance with Commission precedent and generally accepted ratemaking principles to reflect a normal, ongoing level of operations. Schedules supporting those adjustments are found in UGI Electric Exhibit A (Fully Projected), Section D.

Q. Does UGI Electric budget its operating expenses by FERC account?

A. Yes, it does. UGI Electric budgets its operating expenses both by FERC account and by cost element, such as payroll, employee benefits, rent, etc. UGI Electric uses historic data as a basis for the distribution of expenses to each FERC account. This is shown in Schedule B-4 and is the starting point to determine the FPFTY adjusted operating expenses shown on Schedule D-3.

Q. Were each of the *pro forma* adjustments reflected on Schedule D also charged to an appropriate FERC account?

A. Yes. Each *pro forma* adjustment was calculated based on the appropriate cost element and then distributed to FERC accounts directly or by using the ratio used to distribute the budgeted cost for that element.

Q. Does Schedule D-3 depict the *pro forma* expense adjustments using FERC accounts?

A. Yes. These *pro forma* expense adjustments are presented by major FERC account category. These adjustments are also shown in the Section D summary schedules.

3. Salary and Wages Adjustments

Q. Please discuss the Salaries and Wages ("S&W") adjustment shown on Schedule D-7.

A. Schedule D-7 shows a $33,000 increase to budgeted salaries and wages to reflect end of FPFTY operating conditions. This adjustment annualizes payroll expense and is distributed among the various cost accounts. Page 2 shows the development of this adjustment.

Q. Please describe the annualization adjustment.

A. This adjustment annualizes the effect of wage increases for unionized, and non-exempt employees that will take place during the FPFTY. Schedule D-7, page 2, line 2, reflects the increased percentages for each classification of employee. Lines 3 through 5 indicate the percentage of the year for which the salaries and wages increases are not reflected in the budget. Wage increases for exempt employees begin at the start of the fiscal year, therefore, no annualization adjustment is required for this employee classification.

Q. How did you determine the split of the budgeted salaries among the various employee classifications shown on Schedule D-7?

A. The split of the budgeted salaries among the various classifications shown on Schedule D-7, page 1, was determined using the allocations of labor and headcount for Operating and Maintenance expense in the budget. These employee groupings are the same groupings utilized in developing the labor budget. These categories were used in UGI Electric's budgeting process for the operating expense portion of salaries and wages.

4. Rate Case Expense Adjustment

Q. Please discuss Schedule D-10, which shows an adjustment to Rate Case Expense.

A. Lines 1 through 3 show the rate case expense UGI Electric expects to incur in this case, in the amount of $769,000.[1] That amount is then normalized over a two-year period in the amount of $385,000 per year, reflecting the expected period between this case and a future base rate case filing. The rate case expense is incurred in the FTY, however, the FTY does not include any rate case expense related to this proceeding. The FPFTY budget includes a rate case expense in the amount of $444,000, representing one-year of normalized expense. This results in an increase in the level of rate case expense for the FPFTY from the budgeted amount of $444,000 as shown on line 5. Therefore, rate case expense was decreased by $59,000 to reflect a normal annual level of rate case expense. We believe that UGI Electric will make regular rate case filings going forward, given the significant capital investments it has undertaken in accordance with its PUC-approved Long-Term Infrastructure Improvement Plan.

[1] By way of comparison, the actual rate case expense in UGI Electric's last base rate case totaled $717,886.

5. Uncollectible Accounts Expense Adjustments

Q. What is the nature of the two adjustments shown in Schedule D-11 for Uncollectible Accounts Expense?

A. The first adjustment in Schedule D-11, \$557,000, adjusts the budgeted uncollectible accounts expense to reflect a longer-term average charge-off ratio. Lines 1 through 4 of Schedule D-11 develop this adjustment by showing a ratio that represents the three-year average rate of uncollectible accounts expense for the fiscal years 2020 to 2022. The baseline amount for 2022 is \$2.133 million. This ratio is used to adjust the amount of uncollectible expense in the budget to conform to the three-year average for the charge-offs. The resulting 1.838 percent ratio shown on line 4 in column 5 is applied on line 7 to the *pro forma* revenues at present rates to calculate the *pro forma* uncollectible accounts expense of \$2.796 million shown in column 4 on line 7. This results in an increase in the level of uncollectible accounts expenses for the FPFTY from the budgeted amount of \$2.239 million as shown on line 5. The 1.838 percent figure is then applied to determine the level of uncollectible accounts expense at *pro forma* proposed rates through the gross revenue conversion factor, as shown in column 3, line 10 of Schedule D-35.

The second adjustment in Schedule D-11 represents the amortization of the regulatory asset balance \$1.013 million over a three-year amortization period. The amortization period was approved in the settlement to the 2021 UGI Electric Rate Case at Docket No. R-2021-3023618. The amortization amount of \$338,000 was included in the FPFTY, therefore as shown on Line 14, no pro forma adjustment was included.

The third adjustment in Schedule D-11 represents the amortization of the regulatory asset balance of \$315,000 for uncollectible expense related to COVID-19 that was recorded after the filing of the 2021 UGI Electric Rate Case. The Company is proposing to amortize this amount over three years and is recording an adjustment to its budgeted bad debt expense in the amount of $105,000 as shown on Line 19. The total increase in the uncollectible account expense for the FPFTY is $662,000 as shown on line 20.

6. Benefits Expense Adjustment

Q. Please explain the adjustment shown on Schedule D-14.

A. The adjustment shown on Schedule D-14 in the amount of $427,000 is designed to reflect an update of estimated pension expense prepared after the budget was finalized. The updated estimate is based on a more recent calculation and reflects the cash to be contributed to the plan in the FPFTY. The amounts reflected in the calculation for the pension adjustment include those directly attributable to the UGI Electric pension in addition to the portion of the UGI Corp. and UGI pension expense that is included in the expenses allocated to UGI Electric. A portion of this adjustment has been allocated to Transmission Operations and is excluded from the revenue claim in this proceeding.

7. Customer Deposit Interest Adjustment

Q. The next adjustment on Schedule D-15 shows a $66,000 cost item for Interest on Customer Deposits at line 1. Please discuss.

A. Under the Company's tariff, the Company is required to pay interest on Customer Deposits it holds in accordance with other requirements of its tariff. As this is a typical business expense, the Company has added this amount to its expense claim that is otherwise not reflected in the Company's operations budget. It is calculated by using the 13-month average level of customer deposits anticipated for the FPFTY (*i.e.*, $949,000) times the required interest rate (*i.e.*, 7 percent) anticipated for the FPFTY, as published by the Pennsylvania Department of Revenue and required under the Company's tariff.

8. Universal Service Expense Adjustment

Q. Please discuss the *pro forma* adjustment on Schedule D-16 for Universal Service expense.

A. This adjustment in the amount of $96,000 normalizes the amount of Universal Services Program ("USP") expense recovered through the Company's USP Rider based on the level of the Universal Service Rider charge effective at the time of the Company's filing in this proceeding. The USP Rider recovers the Company's Customer Assistance Program ("CAP") Credits, Pre-Program Arrearages, third party administrator expense, Low Income Usage Reduction Program ("LIURP") expense, and administrative costs associated with its hardship program. The Company's claim represents the ongoing normalized level of costs based on anticipated levels of CAP program participation. This adjustment increases the Company's budgeted expense by $96,000 to align the Company's current USP Rider charge. As the USP Rider is a fully reconcilable rider, the USP adjustment assures that expenses related to the existing rider are aligned with revenues and no impact related to USP flows through to the revenue requirement calculation. Please see the direct testimony of Ms. Epler (UGI Electric Statement No. 10) for additional discussion of the Universal Service Rider.

9. Gross Receipts Tax Adjustment

Q. Please explain the adjustment on Schedule D-17.

A. This adjustment, in the amount of $310,000, is due to a Gross Receipts Tax adjustment and is based on total revenues for the *pro forma* test year at present rates plus other operating revenues reduced by the uncollectible expense. The Gross Receipts Tax rate applied to this amount is 5.9%.

10. Power Supply Expense Adjustment

Q. Please explain the adjustment on Schedule D-18.

A. This adjustment, in the amount of $5.225 million, is to adjust the Power Supply Expense for the normalized and annualized use per customer. This adjustment is designed to increase power supply expense (net of Gross Receipts Tax) in order to match power supply revenue at current December 1, 2022 Generation Supply Revenue ("GSR") levels and remove any potential distribution base rate impacts related to 1307(e) power cost recovery. Corresponding revenue adjustments are discussed in the direct testimony of Ms. Epler (UGI Electric Statement No. 10).

11. Energy Efficiency and Conservation Expense Adjustment

Q. Please discuss the *pro forma* adjustment on Schedule D-19 for Energy Efficiency and Conservation program expenses.

A. As with the USP Rider adjustment discussed above, this adjustment in the amount of ($89,000) aligns the amount of EE&C expense with the EE&C Rider charge (based on the level of the EE&C Rider charges effective at the time of the Company's filing in this matter). The EE&C Rider recovers the Labor and Administrative, Prescriptive Program, Retrofit Program, New Construction Program, Custom Program, Legal and Consulting, Combined Heat and Power, and other Costs associated with the Company's Energy Efficiency and Conservation Program. This adjustment decreases the Company's budgeted expense to align with the Company's current EE&C charge. As the EE&C Rider is a fully reconcilable rider, the EE&C adjustment assures that expenses related to the existing rider are aligned with revenues and that no impact related to EE&C flows through to the revenue requirement calculation. Please see the direct testimony of Ms. Epler (UGI Electric Statement No. 10) for additional discussion of the EE&C Rider. The Company's Phase III EE&C program received PUC approval at Docket No. M-2018-3004144.

12. Depreciation Expense Adjustment

Q. How was the level of depreciation expense for the FPFTY determined?

A. UGI Electric's depreciation study is set forth in UGI Electric Exhibit A (Fully Projected) and shows the determination of *pro forma* depreciation expense. This study uses the FPFTY ending September 30, 2024 plant in service and the applicable depreciation rates, service lives, and procedures. A summary of the budgeted depreciation expense and adjustments thereto is found in UGI Electric Exhibit A (Fully Projected), Schedule D-21, and is further explained in the direct testimony of John F. Wiedmayer (UGI Electric Statement No. 7).

Q. Please describe the depreciation expense adjustments shown on Schedule D-21.

A. UGI Electric witness John F. Wiedmayer (UGI Electric Statement No. 7.) presents the depreciation analysis that serves as the foundation of the depreciation adjustment. The adjustment for depreciation expense of $703,000 set forth on Schedule D-21, Column 3, line 53, is designed to annualize budgeted FPFTY depreciation expense to calculate an entire year's worth of depreciation on plant in service as of the end of the FPFTY. This schedule also shows an increase to the net negative salvage amortization of $75,000. The total annualized depreciation expense for the FPFTY, net of costs charged to clearing accounts and net salvage amortization, is ($522,000) as shown on Schedule D-3, page 2, Column 10, line 53.

13. Taxes other than Income Taxes Adjustment

Q. Please describe the taxes other than income adjustments shown on Schedule D-31.

A. Schedule D-31 contains the details for taxes other than income adjustments. The adjustment to the Public Utility Realty Tax ("PURTA") in the amount of $31,000 on line 1 provides for a pro forma tax expense of $76,000. The valuation is based on the Pennsylvania Department of Revenue's 2021 Revised Notice of Determination, dated August 1, 2022 for UGI. The total PURTA liability per this notice is $957,873 with 10.71% allocated to the Electric operations resulting in the amount of $102,588. An additional allocation of 25.6247% is made to transmission operations in the amount of $26,288, resulting in a pro forma expense of $76,300. Line 2 provides an adjustment to the Gross Receipts tax in the amount of $310,000 and this amount is supported by the calculation on Schedule D-17 as discussed above. The adjustments to the payroll tax expenses on lines 4-6 are calculated by multiplying the ratio of tax expense to payroll expense included in the FPFTY budget by the amount of the payroll adjustment derived in Schedule D-7 to produce an adjustment to the amount of social security, Federal Unemployment Tax ("FUTA") and State Unemployment Tax ("SUTA") expense in the amount of $3,000. The calculation of these adjustments is shown in more detail on Schedule D-32.

14. Gross Revenue Conversion Factor

Q. What is the purpose of Schedule D-35?

A. Schedule D-35 shows the calculation of the Gross Revenue Conversion Factor used on Schedule A-1 to calculate the level of revenues required to achieve the net operating income required to generate the rate of return supported by the direct testimony of Mr. Moul (UGI Electric Statement No. 9). These additional revenues are required to recognize that uncollectible accounts expense vary with the level of revenue, and to recognize the Gross Receipts Tax and additional state and federal income taxes attributable to the proposed rate increase.

VI. <u>PA ACT 40 REQUIREMENTS</u>

Q. Ms. Hazenstab, are you familiar with Section 1301.1 of the Pennsylvania Public Utility Code, which is otherwise known as PA Act 40 of 2016?

A. Yes, I am. The legislation, among other things, eliminated the use of consolidated tax savings adjustments for setting rates for public utilities in Pennsylvania. It requires a public utility to demonstrate that it shall use at least 50 percent of what otherwise would have been the revenue requirement associated with a consolidated tax savings adjustment to support reliability or infrastructure related to the rate-base eligible capital investment and the other 50 percent shall be used for general corporate purposes. My understanding is predicated in part on the advice of counsel.

Q. Has the Company calculated what would have been the ratemaking level of a consolidated tax savings adjustment for UGI Electric prior to the enactment of Section 1301.1 of the Public Utility Code?

A. Yes, Company witness Mr. Espigh includes such a calculation with his testimony (UGI Electric Statement No. 8), wherein he determines that the amount of consolidated tax savings applicable to UGI Electric would have been $70,000. Applying the gross revenue conversion factor to that amount of tax expense results in a revenue requirement of $105,951.

Q. Does the Company's rate case claim in this case support the conclusion that it is using at least 50 percent of that revenue requirement amount (associated with a consolidated tax savings adjustment) to support reliability or infrastructure related capital investments?

A. Yes, as included in Schedule C-2 and as discussed in the direct testimony of Ms. Schappell (UGI Electric Statement No. 5), UGI Electric's *pro forma* capital additions for reliability or infrastructure projects in the FTY is $13.762 million and for the FPFTY is $15.127 million. This expenditure level is greater than 50% of the amount of what would have been the consolidated tax savings adjustment under prior ratemaking principles.

Q. Does the Company's rate case claim in this case support the conclusion that it is using at least 50 percent of that revenue requirement amount to support general corporate purposes?

A. Yes. The Company's general corporate purpose expense will also exceed 50% of the tax benefit resulting from elimination of the consolidated tax adjustment. Indeed, the

Company anticipated an operating expense budget of more than $121 million in operating expenditures to be used to render electric distribution service; 50 percent of the consolidated tax adjustment revenue requirement would equate to only $35,000.

Q. How is UGI applying the $35,000 to support general corporate purposes?

A. As shown in UGI Gas Exhibit A – FPFTY, Schedule B-4, the Company's total budgeted O&M expense is $120,745,000. These expenses will be used to the benefit of ratepayers, including, but not limited to $217,000 in meter reading expense, $9,712,000 for maintenance of overhead lines, and $1,275,000 for various customer service expenses. Therefore, UGI spends over 50% of the hypothetical CTA on general expenditures that are specifically for the purpose of providing utility service to ratepayers.

Q. Is the Company's presentation in this filing consistent with the Commission's and the Commonwealth Court's treatment of PA Act 40 of 2016?

A. Yes. The Company's presentation in this filing is consistent with the Commission's determination on PA Act 40 in the UGI Electric 2018 Base Rate Proceeding at Docket No. R-2017-2640058, and the Commonwealth Court's order affirming the Commission's order on appeal.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC

EXHIBIT TAH-1

Tracy A. Hazenstab
Principal Analyst - Rates

Work Experience:

2008 - Current	Rates Analyst – II/Sr/Principal (Progressive Positions) UGI Utilities, Inc., Denver, PA
2004 - 2008	Business Analyst PPL Gas, Lewistown, PA
2001 - 2004	Contact Center Analyst PPL Gas, Lock Haven, PA

Previous Testimony:

2014 1307(f) Proceeding:	Docket No. R-2014-2543523
2015 1307(f) Proceedings:	Docket Nos. R-2015-2480937, R-2015-2480934
2016 1307(f) Proceedings:	Docket Nos. R-2016-2543311, R-2016-2543314
2018 1307(f) Proceedings:	Docket Nos. R-2018-3001631, R-2018-3001632
2019 1307(f) Proceeding:	Docket No. R-2019-3009647
2020 1307(f) Proceeding:	Docket No. R-2020-3019680
UGI Electric EEC Petition:	Docket No. R-2019-3004144
2021 UGI Gas Base Rate Proceeding:	Docket No. R-2021-3030218

Education:

B.A. in International Politics, Pennsylvania State University, 1996

UGI ELECTRIC

EXHIBIT TAH-2

UGI UTILITIES, INC. - ELECTRIC DIVISION
($000s)

	AS OF SEPTEMBER 30, 2022		
	TOTAL T&D OPERATIONS	LESS: FERC JURISDICTIONAL	PA PUC JURISDICTIONAL
Operating Revenues:			
Electric Revenues	$ 124,822	$ -	$ 124,822
Other Electric Revenues	11,818	10,532	1,286
Total Operating Revenues	136,640	10,532	126,108
Operating Expenses:			
Operation and Maintenance Expenses			
Power Production Expenses	71,566	-	71,566
Transmission Expenses	2,418	2,418	-
Distribution Expenses	10,779	-	10,779
Customer Accounts Expenses	5,571	-	5,571
Customer Service & Informational Expenses	6,163	-	6,163
Sales Expenses	(5)	-	(5)
Administrative and General Expenses	8,866	1,769	7,097
Total Operation and Maintenance Expenses	105,358	4,187	101,171
Depreciation and Amortization Expenses	9,308	1,541	7,767
Taxes Other Than Income Taxes	8,469	198	8,271
Total Operating expenses Prior To Federal & State Income Taxes	123,135	5,926	117,209
Operating Income Prior To Federal & State Income Taxes	$ 13,505	$ 4,606	$ 8,899

UGI UTILITIES, INC. - ELECTRIC DIVISION
($000s)

	AS OF SEPTEMBER 30, 2023		
	TOTAL T&D OPERATIONS	LESS: FERC JURISDICTIONAL	PA PUC JURISDICTIONAL
Operating Revenues:			
Electric Revenues	$ 140,116	$ -	$ 140,116
Other Electric Revenues	11,620	10,517	1,103
Total Operating Revenues	151,736	10,517	141,219
Operating Expenses:			
Operation and Maintenance Expenses			
Power Production Expenses	83,714		83,714
Transmission Expenses	2,164	2,164	-
Distribution Expenses	12,436	-	12,436
Customer Accounts Expenses	11,622	-	11,622
Customer Service & Informational Expenses	1,439	-	1,439
Sales Expenses	-	-	-
Administrative and General Expenses	9,962	1,987	7,975
Total Operation and Maintenance Expenses	121,337	4,151	117,186
Depreciation and Amortization Expenses	9,947	1,536	8,411
Taxes Other Than Income Taxes	9,255	143	9,112
Total Operating expenses Prior To Federal & State Income taxes	140,539	5,830	134,709
Operating Income Prior To Federal & State Income Taxes	$ 11,197	$ 4,687	$ 6,510

UGI UTILITIES, INC. - ELECTRIC DIVISION
($000s)

	AS OF SEPTEMBER 30, 2024		
	TOTAL T&D OPERATIONS	LESS: FERC JURISDICTIONAL	PA PUC JURISDICTIONAL
Operating Revenues:			
Electric Revenues	$ 144,200	$ -	$ 144,200
Other Electric Revenues	11,426	10,323	1,103
Total Operating Revenues	155,626	10,323	145,303
Operating Expenses:			
Operation and Maintenance Expenses			
Power Production Expenses	85,951		85,951
Transmission Expenses	2,276	2,276	-
Distribution Expenses	13,259	-	13,259
Customer Accounts Expenses	12,040	-	12,040
Customer Service & Informational Expenses	1,275	-	1,275
Sales Expenses	-	-	-
Administrative and General Expenses	10,269	2,049	8,220
Total Operation and Maintenance Expenses	125,070	4,325	120,745
Depreciation and Amortization Expenses	10,751	1,676	9,075
Taxes Other Than Income Taxes	9,523	148	9,375
Total Operating expenses Prior To Federal & State Income taxes	145,344	6,149	139,195
Operating Income Prior To Federal & State Income Taxes	$ 10,282	$ 4,174	$ 6,108

UGI ELECTRIC STATEMENT NO. 3

VIVIAN K. RESSLER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368

UGI Electric, Inc. – Electric Division

Statement No. 3

Direct Testimony of
Vivian K. Ressler

Topics Addressed:	**Accounting Process and Historic Costs** **Rate Base** **Operating Expense Adjustments**

Dated: January 27, 2023

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vivian K. Ressler. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed by UGI Utilities, Inc. ("UGI") as Senior Manager, Finance. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric" or the "Company") and the Gas Division ("UGI Gas"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your responsibilities as Senior Manager, Finance?

A. I have responsibility for financial analysis, budgeting and forecasting for UGI. I lead a team of three financial analysts and work with the Senior Director, Finance and the Chief Financial Officer to create financial budgets and to analyze the Company's financial performance. I transitioned to this role in January 2023, and continue to perform duties associated with my former role as Assistant Controller during a transition period. This testimony relates to matters under my responsibility as Assistant Controller.

Q. What were your responsibilities as Assistant Controller?

A. I had responsibility for the accounting functions for UGI. I led a team of accountants responsible for maintaining complete and accurate records in the areas of plant accounting, revenue and supply accounting, and general accounting. I was also responsible for the

Sarbanes-Oxley ("SOX") function and the coordination of these accounting and SOX functions with UGI Corp's Chief Accounting Officer and his staff of financial accounting and reporting personnel. I was also responsible for directing the preparation and submission of financial, accounting, and related regulatory filings with the PUC and the Federal Energy Regulatory Commission ("FERC").

Q. Please describe your educational background and work experience.

A. My full educational background and work experience are set forth in my resume attached as UGI Electric Exhibit VKR-1.

Q. Have you testified previously before this Commission?

A. Yes. I provided testimony for UGI Electric in the 2021 Electric Base Rate Case at Docket No. R-2021-3023618. I also provided testimony for UGI Gas in the 2020 Gas Base Rate Case proceeding at Docket No. R-2019-3015162 and in the 2022 Gas Base Rate Case proceeding at Docket No. R-2021-3030218.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Electric in support of the Company's rate case accounting methodology and test year methodology. First, I will explain UGI Electric's accounting processes, which were used to develop the actual book accounting results inputted into the Company's historic test year ended September 30, 2022 ("HTY") (Part

II).[1] Second, I will present the Company's claim for rate base in this proceeding using a FPFTY methodology (Part III). Finally, I will discuss certain operating expense adjustments (Part IV).

Q. Ms. Ressler, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring UGI Electric Exhibit VKR-1. In addition, I am sponsoring those portions of UGI Electric Exhibit A (Fully Projected), Exhibit A (Future) and Exhibit A (Historic), which address rate base and certain adjustments to rate base and operating expenses discussed later in my testimony. I am also sponsoring those responses to the Commission's standard filing requirements as stated on the master list accompanying this filing.

II. ACCOUNTING PROCESS AND HISTORIC COSTS

Q. How are the accounting records of UGI Electric maintained?

A. The accounting records of UGI Electric are kept in accordance with generally accepted accounting principles ("GAAP") and the FERC's Uniform System of Accounts as required under the provisions of 52 Pa. Code § 57.42. The Company also maintains a continuing property records system in accordance with the requirements of 52 Pa. Code § 57.46.

[1] The budgets for the future test year ending September 30, 2023 ("FTY") and the fully projected future test year ending September 30, 2024 ("FPFTY") are discussed in the direct testimony of Tracy A. Hazenstab (UGI Gas St. No. 2).

Q. Are the books and records of UGI Electric subject to audit?

A. Yes. The books and records of UGI Electric are audited by its internal auditors. In addition, UGI Electric's books and records are included in Company-wide audits of UGI Utilities, Inc., performed by its external auditor, Ernst & Young, LLP. The Company's books and records are further subject to audit by the PUC and the FERC.

Q. Do the continuing property records of UGI Electric reflect the original cost value of property?

A. Yes, they do. UGI Electric's plant in service, plant additions, retirements, and book adjustments have been recorded on an original cost basis in accordance with GAAP and the Uniform System of Accounts requirements.

Q. What process does UGI Electric follow to assure that property reflected in its plant accounts is in service?

A. UGI Electric's capital project managers create records that document the costs of projects and/or asset purchases. When a capital project or asset is placed into service, the project manager records the in-service date and the retirement detail for any related assets that are taken out of service. Then, the record is provided to accounting personnel. This information is transferred through accounting entries into the appropriate UGI Electric plant property accounts, subject to review by authorized individuals who approve the entries and further review by internal and external auditors.

Q. How was the Company's accounting process used in preparing the Company's filing?

A. The above-described accounting process was used to prepare the principal accounting exhibits that support UGI Electric's claim in this proceeding. As discussed in the direct testimony of Company witnesses Christopher R. Brown (UGI Electric Statement No. 1) and Tracy A. Hazenstab (UGI Electric Statement No. 2), the Company's claim is based on the FPFTY. The accounting data for the FPFTY was derived from UGI Electric's operating and capital budgets for the 12 months ending September 30, 2024, as shown in UGI Electric Exhibit A (Fully Projected). The accounting data for the FTY was derived from UGI Electric's operating and capital budgets for the 12 months ending September 30, 2023, as shown in UGI Electric Exhibit A (Future). The accounting data for the HTY was derived from UGI Electric's books and records for the 12 months ending September 30, 2022, as shown in UGI Electric Exhibit A (Historic).

III. <u>FULLY PROJECTED FUTURE TEST YEAR RATE BASE</u>

Q. With reference to UGI Electric Exhibit A (Fully Projected), please discuss how the Company's specific rate base items are determined.

A. UGI Electric's rate base presentation is shown in UGI Electric Exhibit A (Fully Projected), Schedule C-1. It summarizes the UGI Electric rate base values for the FPFTY. Column 1 provides the schedule upon which the calculation of each of the rate base elements is found. Columns 3 and 5 show the amounts at present and proposed rates, respectively. UGI Electric's total FPFTY rate base claim—net of deductions for accumulated depreciation, accumulated deferred income taxes and customer deposits—is $172.2 million. Except where otherwise noted, I will describe each of these rate base elements in greater detail below.

1. Utility Plant in Service

Q. Please explain how UGI Electric determined its FPFTY rate base value for plant in service.

A. UGI Electric's claim for utility plant in service represents the sum of the closing plant balances as of September 30, 2022, and budgeted plant additions for the years ending September 30, 2023 and September 30, 2024, less expected FTY and FPFTY plant retirements. The direct testimony of Company witness Vicky A. Schappell (UGI Electric Statement No. 5) discusses the capital addition planning process and the basis for the plant additions placed in service in the FTY and FPFTY.

Q. Please describe Schedule C-2 to UGI Electric Exhibit A (Fully Projected).

A. This schedule presents UGI Electric's FPFTY claim of $275.0 million for used and useful electric utility plant in service on page 1, column 2, line 48. Electric utility plant enables UGI Electric to provide safe and reliable electric service to its customers.

Q. How was the electric utility plant in service amount of $275.0 million shown on Schedule C-2, page 1, column 2, line 48 determined?

A. As noted above, this amount is based on the *pro forma* balance as of September 30, 2024. The amount includes: (1) utility plant in service as of September 30, 2022, and (2) budgeted capital expenditures expected to be placed in service for the 12-month periods ending September 30, 2023 and 2024, less expected plant retirements during the same periods. UGI Electric witness Vicky A. Schappell (UGI Electric Statement No. 5) also discusses the basis for the plant additions in the FTY and FPFTY.

Q. Please describe the information included on Schedule C-2, page 2.

A. This information provides a summary of UGI Electric's *pro forma* claim for utility plant in service by category. Column 2 shows the FPFTY ending balances based on the placed in-service budget; column 3 shows the net effect of the various plant adjustments, if any; and column 4 provides the adjusted FPFTY plant in service.

Q. What information is included on Schedule C-2, page 3?

A. Columns 2 and 3 on this page show the electric plant in service balances for 2023 and 2024 at the FERC account level, based on the placed in service budget. Column 5 provides the ending FPFTY plant balance at the FERC account level.

Q. Where are the HTY, FTY and FPFTY additions shown?

A. Page 4 of Schedule C-2 provides actual (for the HTY) and projected (for the FTY and FPFTY) plant in service additions. The Company categorizes plant additions by FERC account.

Q. Where are the HTY, FTY and FPFTY retirements shown?

A. Page 5 of Schedule C-2 provides actual (for the HTY) and projected (for the FTY and FPFTY) plant retirements. Retirements for most plant accounts were projected by plant account. The Company applied an average retirement ratio rate, as a percent of additions, for the fiscal years 2018 through 2022, to the FTY and FPFTY plant additions for most plant accounts. The average retirement ratios for a few plant accounts during the past five years were either atypical or indeterminate (e.g., no plant activity recorded during the period 2018 – 2022). In those instances, professional judgment was used to select an appropriate retirement ratio for a plant account based on industry experience. For certain plant accounts subject to amortization accounting, retirements are recorded when a vintage is fully amortized. For these accounts, all units are retired when the vintage is fully amortized.

2. Accumulated Depreciation

Q. Please explain how UGI Electric determined its rate base deduction for accumulated depreciation.

A. UGI Electric started with accumulated depreciation as of September 30, 2022, added the budgeted level of depreciation expense for the FTY and FPFTY, and calculated the impact of the FTY and FPFTY plant retirements and a provision for net salvage as shown on Schedule C-3. The depreciation rates and test year expense levels are discussed in the direct testimony of John F. Wiedmayer (UGI Electric Statement No. 7), with the underlying FPFTY depreciation analysis provided in UGI Electric Exhibit A (Fully Projected).

Q. Please describe UGI Electric's accumulated depreciation claim.

A. UGI Electric's accumulated depreciation claim is shown on Schedule C-3 of UGI Electric Exhibit A (Fully Projected). This schedule presents the accumulated provision for depreciation as of September 30, 2024, distributed among the various FERC accounts. The total amount for accumulated depreciation, $85.7 million, is summarized on page 1 of this schedule. That amount is reflected on line 2 of the measure of value summary on Schedule C-1.

Page 2 shows the *pro forma* FPFTY level of accumulated depreciation distributed to the various plant categories. Page 3 shows the details of the accumulated depreciation by FERC account for Fiscal Years 2023 (column 2) and 2024 (column 3) based on budget plus adjustments (column 4) to arrive at the FPFTY balance (column 5). Pages 4 and 5 show the cost of removal and negative net salvage amortization by FERC account, respectively. Page 6 includes the salvage amounts by FERC account. All of these amounts are included in the FPFTY accumulated depreciation calculations. The amortization of negative net salvage was calculated using a 5-year amortization schedule in accordance with Commission precedent.

3. Cash Working Capital

Q. Please explain how UGI Electric determined its rate base value for cash working capital ("CWC").

A. CWC is the capital requirement arising from the difference between (1) the lag in the receipt of revenue for rendering service and (2) the lag in the payment of cash expenses incurred to provide that service, as shown in Schedule C-1. A detailed analysis of UGI Electric's CWC requirements is provided in Schedule C-4.

Q. Where is the CWC rate base value summarized?

A. The CWC rate base value is summarized at Schedule C-4, page 1. The various components of the working capital claim are listed on this page, along with a reference to the page where the component is further detailed within Schedule C-4.

Q. What data is shown on page 2 of Schedule C-4?

A. Page 2 summarizes the derivation of UGI Electric's revenue collection lag and overall expense payment lag. The revenue lag days of 59.56 are shown on line 1. Expense lag days include three categories of annual operating expenses: (1) payroll; (2) purchased power costs; and (3) other expenses. The expense lag days are shown for each component on lines 3-5, which amount to 31.69 (on line 7). The net lag in the collection of revenue is 27.87 days as shown on line 8. This number is then multiplied by the average daily operating expense balance on line 9 to arrive at a base CWC amount for Operations and Maintenance ("O&M") expense of $9.4 million. The average daily expense balance of $339,000 shown on line 9 is determined by dividing the total *pro forma* annual operating expenses, excluding uncollectible accounts expense, of $123.9 million, as shown on line 6 of column 2, by the number of days in the year, or 365. I will describe the other components of the CWC claim when I discuss the related schedules.

Q. Please describe the revenue lag calculation shown on Schedule C-4, page 3.

A. The Company's calculation for the total revenue lag days of 59.56 (line 23) consists of several steps. First, the annual revenue (line 18, column 3) was divided by the average month-end accounts receivable balances for the thirteen months ended September 30, 2022 (line 17, column 2). This results in an accounts receivable turnover rate of 8.44 (line 19, column 4), which is equivalent to 43.25 lag days (line 20, column 5) (i.e., 365 divided by 8.44 accounts receivable turnover rate). As shown on lines 20-23, the payment portion of the revenue lag is added to (1) the 1.10 day lag between the meter reading day and the day bills are sent out and recorded as revenue and accounts receivable by the Company (appearing on line 21); and (2) the 15.21 day service lag (i.e., midpoint lag factor), which is the time from the mid-point of the service period until the meter reading date. This calculation results in a total revenue lag of 59.56 days.

Q. How was the mid-point of the service period calculated?

A. The mid-point of the service period is equal to the number of days in an average service month (365 days divided by 12, or 30.4 days) divided by two (i.e., 15.21 days).

Q. How are the payroll expense lag days for the CWC claim calculated?

A. This calculation is shown on page 4 of Schedule C-4, lines 1-6. The payroll amounts shown there reflect the payroll for the FPFTY, which is shown on Schedule D-7. The lag periods for union and non-union payroll are shown separately on page 4 of Schedule C-4, lines 1-2, with the same bi-weekly pay period. The lag days are calculated based on 14 days in the pay period divided by 2 (for an average) with a 5-day payroll processing time period added, resulting in a 12-day lag period.

Q. How were the lag days associated with the purchased power costs shown on Schedule C-4, page 4, line 8 calculated?

A. This calculation is shown on page 6 of Schedule C-4, and is based on a review of electric purchases during the 12-month period of October 2021 through September 2022. The total dollar amount of electricity purchased during this period was $62.613 million (on line 13, column 2). The average payment lag was calculated by dividing the total dollar days for purchased power costs (or $2,084.738 million) by the total dollar amount of electric supply purchased (or $62.613 million), which equals 33.30 days (on line 14). The payment lag was determined using the midpoint of the service period for each of the payments and the payment date for each, averaged over the 12-month study period. The 33.30-day lag for electric supply purchased is then brought forward to Schedule C-4, page 4, line 8 and Schedule C-4, page 2, column 3, line 4.

Q. What are dollar days, and how were they used in the CWC calculation?

A. Dollar days are the product of a payment amount multiplied by the number of days between the invoice date or service date and the date that the payment clears the Company's bank. The dollar days calculation is used to calculate a weighted average number of lag days for both electric supply purchases (Schedule C-4, page 6) and general disbursements (Schedule C-4, page 5).

Q. How were the Other O&M Expense lag days, shown on Schedule C-4, page 4, line 22, calculated?

A. The calculation is shown on page 5 of Schedule C-4. The average payment lag for all remaining expenses was derived from data over the HTY, as shown in more detail on page 5 of Schedule C-4. A summary list of all cash disbursements, including the invoice date, the amount of the disbursement, the date the payment was made, and the type of disbursement (for capital, commodity or expense), during each of these months was used. As shown on page 5, lines 1-24, columns 1 and 2, each month's listing contained numerous cash disbursements. Once the raw payment data was assembled, the dollar days for expense purchases were determined by multiplying the amount of the disbursement by either (i) the number of days from invoice date until bank clearance for wire and Automated

Clearing House ("ACH") payments, or (ii) the number of days from the invoice date until check date, plus seven days (representing mail lag) for payments made by check. For vendors where the invoice date did not represent the service date, an appropriate adjustment to the invoice date was made. Disbursements were eliminated if they were included in another calculation (e.g., electric supply purchases) or were paid for capital items. After these adjustments, the average of the expense lag days for each month shown on Schedule C-4, page 5, column 4, line 25, resulted in a payment lag for general disbursements of 30.76 days. The 30.76-day lag for Other Disbursements is then brought forward to Schedule C-4, page 4, line 22 and Schedule C-4, page 2, column 3, line 5.

Q. Please explain how the interest payment amount included on line 2 of Schedule C-4, page 1 was determined.

A. The calculation of this amount is shown on Schedule C-4, page 7. This calculation measures the lag associated with the payment of interest on outstanding debt. The *pro forma* annual interest expense shown on line 4 is divided by 365 to obtain the daily interest expense of $9,000 shown on page 7, line 5. That amount is then multiplied by the net payment lag, resulting in a reduction to the working capital allowance of $295,000 as shown on page 7, line 9 of Schedule C-4. This amount is then included on page 1, line 2 of Schedule C-4.

Q. How was the tax payment lag for the working capital requirement, shown on line 3 of Schedule C-4, page 1, determined?

A. This calculation is shown on page 8 of Schedule C-4. Separate tax payment lag calculations (for working capital) are made for federal income tax, state income tax, PA Property Tax and Public Utility Realty Tax Act ("PURTA") taxes. Each of these calculations is based on anticipated FPFTY tax payments and an April 1 mid-point of annual service. The result for each of these components is shown and summed in column 10 to derive the net working capital allowance for tax payments of $261,000.

Q. How was the working capital allowance for prepayments, shown on line 4 of Schedule C-4, page 1, derived?

A. That amount is calculated on page 9 of Schedule C-4 and represents the 13-month average of actual prepaid amounts for each month ended from September 2021 through September 2022. The 13-month average of total actual prepaid amounts during that period is $2.032 million.

Q. What is the total amount of the Company's CWC claim?

A. UGI Electric's claim for CWC is $11.447 million. This amount is shown on Schedule C-4, page 1, line 5; Schedule C-1, line 4; and on Schedule A-1, line 4.

4. Materials and Supplies Inventory

Q. What is the rate base claim for materials and supplies inventory?

A. UGI Electric maintains various materials and supplies in inventory for use in its operations. The Company's claim for those items is $2.152 million, as shown on Schedule C-1, line 7.

This amount is based on the average inventory for the 13-month period ending September 30, 2022, as shown on Schedule C-8. This value is also shown on Schedule A-1, line 7. The Company will update this average during the course of this proceeding.

5. Accumulated Deferred Income Taxes

Q. Does the Company include in its rate base calculation a reduction for the value of Accumulated Deferred Income Taxes ("ADIT"), including Excess Deferred Federal Income Taxes ("EDFIT")?

A. Yes. The Company's determination of its rate base value for ADIT, including EDFIT, is shown on Schedule C-6 and is discussed in the direct testimony of Darin T. Espigh (UGI Electric Statement No. 8).

6. Customer Deposits

Q. Please explain how the Company calculated the rate base value for customer deposits.

A. Customer deposits offset the need for UGI Electric to provide capital. UGI Electric's rate base reduction for customer deposits is based on the average customer deposit balance for the 13-month period ending September 30, 2022, as shown on Schedule C-7.

Q. What is the rate base offset for customer deposits?

A. The customer deposit offset is $0.949 million as shown on Schedule C-1, line 6 and on Schedule A-1, line 6.

IV. OPERATING EXPENSE ADJUSTMENTS

Q. Please describe how the Company's claimed operating expenses were determined.

A. As discussed in the direct testimony of Tracy A. Hazenstab (UGI Electric Statement No. 2), the *pro forma* FPFTY expenses were based on the budgeted level of expenses as a starting point. This budgeted level of expenses was then adjusted to comply with Commission precedent and generally accepted ratemaking principles to reflect a normal, ongoing level of operations. The supporting schedules for those adjustments are found in UGI Electric Exhibit A (Fully Projected), Section D. Below, I will discuss the specific operating adjustments that I am sponsoring, as contained in UGI Electric Exhibit A (Fully Projected), Section D.

1. Uncollectible Accounts Expense

Q. Please explain the three adjustments being shown on Schedule D-11 for Uncollectible Accounts Expense.

A. The first adjustment, $0.557 million, adjusts budgeted uncollectible accounts expense to reflect a three-year average rate of uncollectible accounts expense for Fiscal Years 2020, 2021 and 2022. The baseline amounts for Fiscal Years 2020 and 2021 include $1.013 million and $0.315 million, respectively, of amounts recorded as a regulatory asset (as further discussed under the second and third adjustments in Schedule D-11 below). This ratio is used to adjust the amount of uncollectible expense in the budget to conform to the three-year average uncollectible rate. The resulting 1.838 percent ratio shown on line 4, column 5, is applied on line 7 to the *pro forma* revenues at present rates to calculate the *pro forma* uncollectible accounts expense of $2.796 million shown on line 7, column 4. This results in an increase in the level of uncollectible accounts expense for the FPFTY from the budgeted amount of $2.239 million shown on line 5. The 1.838 percent uncollectible ratio is then applied to determine the level of uncollectible accounts expense at *pro forma* proposed rates through the gross revenue conversion factor, as shown in column 3, line 2 of Schedule D-35.

The second adjustment on Schedule D-11 represents the amortization of the regulatory asset balance for Fiscal Year 2020 of $1.013 million for COVID-19 Pandemic uncollectible costs over a three-year amortization period (in accordance with Ordering Paragraph 63 in the Commission's Order for settlement of the 2021 UGI Electric rate case, entered October 28, 2021 at Docket No. R-2021-3023618). According to Ordering Paragraph 63, "The Company's revenue increase provided in this Settlement is reflective of a three-year amortization of the Company's COVID-19 regulatory asset related to incremental uncollectible accounts expense, or $337,666 per year, which includes all incremental uncollectible expense through September 30, 2020." The Company included $0.338 million within its budget for Fiscal 2024 for amortization of this asset. Therefore, no adjustment is needed between budget and the Company's claim related to the Fiscal Year 2020 excess COVID-19 uncollectible amortization.

The third adjustment on Schedule D-11 represents the amortization of the regulatory asset balance for Fiscal Year 2021 of $0.315 million for COVID-19 Pandemic uncollectible costs over a three-year amortization period. These costs were deferred in accordance with Ordering Paragraph 29 in the Commission's Order entered October 8, 2020 at Docket No. R-2019-3015162. While the Fiscal Year 2020 COVID-19 Pandemic uncollectible costs were included in the UGI Electric 2020 rate case claim at Docket No. R-2021-3023618, the similar Fiscal Year 2021 COVID-19 Pandemic uncollectible costs (which were incurred between October 1, 2020 and the November 9, 2021 effective date of the new rates established as a result of the UGI Electric 2020 rate case) were not included in that rate case claim because the Company had not yet incurred such costs at that time. As the Company's Fiscal 2024 budget does not include any amortization for the Fiscal Year 2021 COVID-19 Pandemic uncollectible costs, this adjustment of $0.105 million represents annual amortization of these uncollectible costs.

2. Benefits Expense Adjustment

Q. Please describe the adjustment shown on Schedule D-14.

A. The adjustment shown on Schedule D-14 reflects an adjustment from budgeted pension expense to reflect cash to be contributed to the plan in the FPFTY. The Company's budget shown on line 1 reflects the service portion of the Company's budgeted pension expense, as the non-service portion of pension is excluded from the budget used to develop the revenue claim. This budget is based on an actuarial calculation utilizing various assumptions about future costs. However, consistent with prior ratemaking practices, the Company claims pension costs within its rates on a cash basis. The adjustment is calculated as the total cash contributions (per the Company's most recent actuarial report), reduced to reflect only the portion attributable to UGI Electric, and then further reduced to eliminate the portion of pension that is capitalizable. This cash pension expense of $0.827 million (line 5) is compared to the budgeted pension expense of $0.293 million (line 1), also calculated for UGI Electric only and net of the capitalizable portion, resulting in a total adjustment of $0.534 million (line 6). This total adjustment is then allocated to UGI Electric's distribution operations using the distribution allocation factor of 80.05 percent, resulting in a *pro forma* adjustment to the Company's claim of $0.427 million.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC

EXHIBIT VKR-1

Vivian K. Ressler

Senior Manager, Finance

Work Experience

UGI Utilities, Inc. – Denver, PA:

January 2023 – Current	Senior Manager, Finance
March 2022 – January 2023	Assistant Controller
December 2021 – March 2022	Sr. Manager – Plant & Regulatory Accounting
Feb. 2020 – December 2021	Sr. Manager – SOX, Plant Accounting & Accounts Payable
June 2018 – Feb. 2020	Manager – Technical Accounting & Controls

The Bon-Ton Stores, Inc. – York, PA

May 2014 – May 2018	Departmental Vice President – Corporate Accounting

Trout, Ebersole & Groff, LLP – Lancaster, PA

May 2012 – May 2014	Supervisor – Attest Services

BI-LO, LLC – Greenville, SC

Nov. 2007 – May 2012	Sr. Manager – Corporate Accounting & Tax

Deloitte & Touche, LLP – Greenville, SC

Sept. 1998 – Oct. 2007	Staff Accountant through Sr. Manager – Audit Services

Previous Testimony before the Pennsylvania Public Utility Commission

UGI Gas Base Rate Case	Docket No. R-2019-3015162
UGI Electric Base Rate Case	Docket No. R-2021-3023618
UGI Gas Base Rate Case	Docket No. R-2021-3030218

Education & Professional Certification

B. S. in Accounting – Bob Jones University, Greenville, SC

Certified Public Accountant – Commonwealth of Pennsylvania

UGI ELECTRIC STATEMENT NO. 4

ERIC W. SORBER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368

UGI Utilities, Inc. – Electric Division

Statement No. 4

Direct Testimony of
Eric W. Sorber

Topics Addressed:	**System Operations**
	System Reliability and Performance
	Safety Initiatives
	Inflation and Supply Chain Impacts
	Proposed Tariff Modifications
	Prior Case Compliance Items

Dated: January 27, 2023

I. <u>INTRODUCTION</u>

Q. Please state your name and business address.

A. My name is Eric W. Sorber. My business address is 1 UGI Center, Wilkes Barre, Pennsylvania 18711.

Q. By whom are you employed and in what capacity?

A. I am employed by UGI Utilities, Inc. ("UGI") as the Vice President and General Manager of UGI Electric. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric" or the "Company") and the Gas Division ("UGI Gas"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your responsibilities as Vice President and General Manager of UGI Electric?

A. As Vice President and General Manager of UGI Electric, I am responsible for developing and implementing business unit strategies, including monitoring and deploying emerging technologies. I also provide leadership for engineering, operations, and technical services functions for UGI Electric to improve overall system reliability and modernize the electric system. I report directly to the President of UGI and assist him with budgeting and capital planning for UGI Electric. I am also responsible for developing the long-term strategic infrastructure investment plans for UGI Electric. Under my direction is the UGI Electric engineering and operations staff, which is accountable for five major areas: (1) distribution engineering and construction; (2) transmission engineering and construction; (3) System Operations; (4) planning, standards, and compliance; and (5) safety.

Q. Please describe your educational background and work experience.

A. They are set forth in my resume attached as UGI Electric Exhibit EWS-1 to my testimony.

Q. Have you testified previously before this Commission?

A. Yes. UGI Electric Exhibit EWS-1 identifies the proceedings in which I provided testimony.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Electric. In my testimony, I will address the following topics related to UGI Electric: (1) system operations overview; (2) system reliability and performance; (3) safety initiatives; (4) inflation and supply chain impacts; (5) proposed tariff modifications; and (6) prior case compliance items.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring UGI Electric Exhibits EWS-1 and EWS-2 and certain portions of UGI Electric Exhibit F – Proposed Tariff. I am also sponsoring certain responses to the Commission's standard filing requirements as indicated on the master list accompanying this filing.

II. SYSTEM OPERATIONS

Q. Please provide an overview of UGI Electric's system.

A. UGI Electric provides electric service to approximately 62,000 customers in Luzerne and Wyoming Counties within a service territory encompassing approximately 410 square miles. The UGI Electric service territory is mainly rural, with urban areas located on the outskirts of the city of Wilkes Barre. UGI Electric owns, operates and maintains over 1,250 circuit miles of overhead and underground primary distribution lines; 13 distribution substations; and 54 distribution circuits. In addition to distribution facilities, UGI Electric owns and operates one Bulk Electric System substation, 16.5 miles of double circuit 230 kV transmission lines, and 126 miles of 66 kV transmission lines. UGI Electric is a member of the PJM Interconnection LLC ("PJM"), which is a regional transmission organization, and sits on the PJM Transmission Owners Agreement-Administrative Committee.

The costs associated with owning and operating UGI Electric's substation and transmission facilities at 66 kV and above are recovered through the Company's transmission formula rates set under the regulatory jurisdiction of the Federal Energy Regulatory Commission ("FERC"). The costs associated with those facilities are excluded from UGI Electric's claim in this proceeding.

Q. Please describe UGI Electric's operations?

A. UGI Electric's main office is located in Wilkes Barre and houses the bulk of the Company's electric employees, including operations management, engineering, clerical, and a number of field personnel. UGI Electric also maintains a combined warehouse and linemen service location in Forty Fort, as well as a substation service center in Hanover Township, Luzerne County. Further, UGI Electric operates two fully redundant (primary and backup) System Operations control centers located in Edwardsville, Pennsylvania.

Q. How does UGI Electric staff its operations?

A. UGI Electric uses a combination of dedicated electric division staff and staff that are shared with the Gas Division. The employees shared with the Gas Division provide various management and support services to both of the Company's Divisions (e.g., payroll, supply, rates, purchasing, fleet, marketing, administrative duties, customer service, and credit and collections). In addition, UGI Electric receives management and support services provided by its parent company UGI Corp. (e.g., insurance, human resources, legal, treasury operations, communications and corporate governance). The Company also relies on a contractor workforce for the majority of its line construction and maintenance activities.

III. SYSTEM RELIABILITY AND PERFORMANCE

Q. Please describe UGI Electric's reliability performance in recent years.

A. UGI Electric has historically demonstrated consistently strong system reliability based on its frequency of achieving or outperforming the Commission-established reliability indices, benchmarks and standards for UGI Electric (i.e., System Average Interruption Frequency Index ("SAIFI"), Customer Average Interruption Duration Index ("CAIDI"), and System Average Interruption Duration Index ("SAIDI")).

Q. Has the Company prepared an analysis showing its performance history?

A. Yes. UGI Electric Exhibit EWS-2 provides an historical view of UGI Electric's system reliability between Calendar Years 2004 and 2022. As shown in UGI Electric Exhibit EWS-2, over the last 19 years, UGI Electric has a general history of excellent reliability performance, exceeding Commission Benchmark metrics over the vast majority of the period.[1]

Q. How is UGI Electric positioning itself to continue the support of reliable service into the future?

A. UGI Electric continues its accelerated efforts in critical areas, including robust vegetation management practices on a shorter cycle, and reliability driven Long Term Infrastructure Improvement Plan ("LTIIP") initiatives such as relocation of off right-of-way lines and development of inter-substation tie-lines. Another significant threat to reliability is the presence of aging equipment and equipment that is not built to meet modern design standards. As discussed below, UGI Electric is entering its sixth year of targeted repair and replacement programs for key assets, such as wood poles and associated appurtenances, distribution substation equipment, and underground residential primary cable in order to address aging distribution assets and reduce the risk aging assets pose to reliability and safety.

Q. Please describe UGI Electric's LTIIP.

A. In 2017, UGI Electric filed its Initial LTIIP, which was approved by the Commission in December 2017.[2] The Company's Initial LTIIP provided a comprehensive and detailed plan for addressing the threat of aging and outdated infrastructure across the Company's service territory in a proactive manner that would protect customers from experiencing a

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[1] *See, e.g., Electric Service Reliability in Pennsylvania 2021* "2021 Electric Reliability Report", page 4 (August 2022) ("Performance is considered excellent since [the metric] is below both benchmark and standard").

[2] *Petition of UGI Utilities Inc. – Electric Division for Approval of its Long-Term Infrastructure Improvement Plan*, Docket No. P-2017-2619834 (Opinion and Order entered December 21, 2017) ("Initial LTIIP").

degradation in service. The Initial LTIIP reflected UGI Electric's effort to improve safety and reliability through accelerated replacement of aging distribution infrastructure and a buildout of reliability-based system improvement projects. The Company implemented its Initial LTIIP from 2018 to 2022.

Q. Please describe the progress that was made by the Company through its Initial LTIIP.

A. Significant progress was made by UGI Electric during the five years of its Initial LTIIP. UGI Electric identified, repaired, improved, and replaced its distribution infrastructure on an accelerated basis, consistent with its obligations and commitments as described in the LTIIP. Over the course of the initial plan, UGI Electric generally met or exceeded its planned replacement activities. These activities included: (1) the replacement of nearly 1,000 wood poles under its inspection and maintenance program and over 2,000 additional wood poles through various other system improvement programs; (2) the replacement of over 72,000 trench feet of underground cable; (3) the replacement of five substation power transformers; and (4) the continued replacement and conversion of non-standard lower voltage circuit elements. The continued accelerated replacement of aging infrastructure, over time, will result in a more modern and resilient distribution system. In the short term, through its Initial LTIIP efforts, the Company has already reduced the average age of power transformers on its system by 10 years (from 42 years to 32 years), and the average age of distribution circuit breakers on the system by eight years (from 26 years to 18 years).

Q. How has the Initial LTIIP impacted reliability?

A. Every individual replacement or upgrade contributes to the long-term reliability of the system. Small incremental improvements are accomplished by replacing individual units that are at or near the end of their useful life. Other LTIIP programs are components of an overall resiliency strategy that reduces the risk of outage. For example, the accelerated expansion of distribution automation ("DA") devices, the installation of new sectionalizing devices, and the creation of inter-substation tie-lines have an immediate impact on the frequency and duration of outages. Over the course of the Initial LTIIP, UGI Electric installed 56 remotely monitored and controlled reclosers under the DA program and completed several reliability/capacity based tie-lines between substations. These efforts are directly contributing to improved operational flexibility and reduced customer outage minutes by providing for remote switching and sectionalizing of faults that increase the ability to serve impacted customers by a secondary supply point. Before the deployment of these devices, such activities would normally be handled manually by crews responding to an emergency. This type of capability can save a significant amount of outage minutes when utilized.

Q. How much capital did the Company invest through its Initial LTIIP?

A. Total expenditures for the Initial LTIIP were nearly $49 million over the five-year term.

Q. Is the Company undertaking a Second LTIIP?

A. Yes. In April 2022, UGI Electric filed its Second LTIIP. In the Second LTIIP, UGI Electric is continuing many of the programs undertaken by the Company in its Initial

LTIIP. Additionally, the Company modified certain programs from the Initial LTIIP to improve reliability in a more efficient and effective manner.

Q. How does the Second LTIIP continue the Company's focus on improving reliability on UGI Electric's system?

A. Overall, the Second LTIIP continues the Company's focus on accelerated infrastructure improvement, repair and replacement, including several infrastructure and technology-based reliability programs that will target significant long-term reliability factors. The Second LTIIP continues to remove aging portions of the system and replaces them with newer equipment and materials that are designed and installed using modern construction specifications and standards. The Second LTIIP renews many of the core infrastructure programs adopted in the Initial LTIIP including several infrastructure and technology-based reliability programs (e.g., accelerated underground cable and wood pole replacements, enhanced feeder sectionalizing and porcelain cutout replacements). The Second LTIIP also combines several programs with a similar focus under consolidated categories that will allow UGI Electric to better deploy resources to meet its operational objectives.

Q. Can you provide examples of the consolidated programs?

A. One example is the new Circuit Improvement program, which is mainly associated with the replacement and improvement of typical distribution facilities that are at or near end of life. The program targets poles (outside of the poles identified via the inspection and maintenance program), wire, cross-arms, and transformers. This program also revises equipment clearances and implements necessary equipment upgrades (e.g., transformers). Another program consolidation, Reliability and Capacity Enhancements, includes projects related to inter-substation tie-lines and relocations of off right-of-way primary lines. In both cases, the consolidation provides for better prioritization of projects and associated dollars to address both planned and emergent reliability issues.

Q. How much does UGI Electric anticipate investing in its Second LTIIP?

A. During the five-year term of the second LTIIP, UGI Electric anticipates investing more than $50 million in proposed improvements that will modernize and continue to increase the overall resiliency of the system to guard against significant weather-related events as well as "blue-sky" day emergencies. These capital investments, and all other capital investments that UGI Electric anticipates placing in service during the Fully Projected Future Test Year, are discussed in detail in the testimony of Ms. Schappell (UGI Electric St. No. 5).

IV. <u>SAFETY INITIATIVES</u>

Q. Please describe UGI Electric's safety culture.

A. UGI Electric understands the importance of, and continually strives to foster, a positive safety culture within its day-to-day operations. The Company's safety culture is embodied by several key elements, each of which is essential to creating and sustaining a safe work environment for employees and the safe and reliable delivery of energy to our customers. These elements include Management Commitment, Employee Involvement, Open Communication, and Training. The result of a positive safety culture is that employees understand their role and responsibilities with respect to safety and consistently fulfill them. The UGI Electric safety culture is founded on the idea that the Company must continuously pursue the safety of its employees, its customers, and the public in general. Moreover, UGI Electric is committed to continuous forward progress in its efforts to protect the public and the Company's employees and its customers.

Q. What programs and initiatives does UGI Electric have to promote employee, customer, and system safety?

A. As discussed above, employee safety is a function of safety culture. To that end, the Company is working to enhance the elements that drive a positive safety culture. UGI Electric has a very active local safety committee with involvement from all work groups. It provides an open forum to identify, discuss, investigate and address employee safety concerns. It also acts as a mechanism to communicate and discuss utility wide safety metrics, incidents, and initiatives.

Additionally, UGI Electric has a new learning management system ("LMS") that provides Occupational Safety and Health Administration ("OSHA") based training curriculum. It also has the ability to add and track Company-developed safety content and training. Specific to content, a UGI Electric team of subject matter experts worked together to research and completely overhaul the Company's Clearance Holder procedure in July 2021. This procedure governs the process for de-energizing lines and issuing clearance for qualified employees to work on de-energized facilities. Training on this newly enhanced procedure is ongoing. Finally, the Company began using the IntelliShift Fleet Management System in late 2021. Central to this system is the ability to provide drivers with real-time in-cab coaching on a variety of parameters including distractions, distance, and speed. The system includes both inward and forward-facing cameras as well as Global Positioning System ("GPS") location tracking to assist with dispatch operations. Initial IntelliShift data since implementation indicates positive driver improvement across several metrics.

Q. What are some actions that UGI Electric takes to focus on public safety?

A. At the core of UGI Electric's focus, the LTIIP plans contain numerous repair, replacement, and improvement activities, which directly impact the delivery of safe and reliable electric service. Preventing would-be facility failures directly supports the creation and maintenance of safe conditions across the UGI Electric service territory where the public resides, works, and dwells. Well-defined and executed vegetation management programs work to likewise facilitate public safety (e.g., avoiding prolonged outages, surges, etc.) in addition to hardening reliability and resiliency.

In addition, UGI Electric personnel meet with local first responders (e.g., volunteer fire departments) to provide an electrical safety awareness training program. Non-utility first responders do not always have access to information on electric specific hazards or a general understanding of the electric system. This program provides an opportunity to share information and interact with these important volunteers that are often on-scene before utility personnel arrive.

UGI also distributes safety-related news releases that provide seasonal safety tips via traditional media outlets, through social media, and on UGI's website. UGI's website further includes tips on electrical safety. Finally, UGI provides both safety and conservation information to fourth grade students through a program of in-school presentations offered by certified teachers. Schools that participated in the UGI Electric program in the Fall 2022 included Lake Lehman, Pittston, Dallas, Wyoming Area, Wyoming Valley West, and Hanover School Districts.

V. INFLATION AND SUPPLY CHAIN IMPACTS

Q. How has inflation impacted UGI Electric?

A. UGI Electric has experienced significant cost increases particularly in key material and equipment categories. Pole and pad transformers have seen the largest surge in costs with current unit prices for most common size transformers increasing by over 300% since 2020. Other common items experiencing large cost increases since 2020 include wood poles (up 97%), cross arms (up 117%), and primary wire (up 164%). Moreover, substation power transformer prices have increased by 64% since 2020. The following Table 1 provides additional detail on material/equipment cost increases for select items.

Table 1: Price Changes from FY2020 to FY2023

Material/Equipment Item	FY2020 Unit Price	FY2023 Unit Price	Unit Price $ Increase	Unit Price % Increase
Poles: 45 Ft Wood Pole	$346.00	$682.00	$336.00	97%
Cross Arms: 8 FT Wood	$45.00	$97.56	$52.56	117%
Primary Wire: 397.5 ACSR	$1.68	$4.43	$2.75	164%
750 MCM AL Insulated wire	$6.73	$14.93	$8.20	122%
URD MV Cable - 2 AWG	$1.58	$4.23	$2.65	168%
25 KVA Pole Transformer	$776.00	$3,149.00	$2,373.00	306%
25 KVA Padmount Transformer	$1,408.00	$5,454.00	$4,046.00	287%
50 KVA Pole Transformer	$1,126.00	$4,804.00	$3,678.00	327%
50 KVA Padmount Transformer	$1,653.00	$8,091.00	$6,438.00	389%
100 KVA Pole Transformer	$1,953.00	$8,521.00	$6,568.00	336%
100 KVA Padmount Transformer	$2,205.00	$12,297.00	$10,092.00	458%
3-Phase Circuit Recloser	$25,238.00	$33,216.00	$7,978.00	32%
Insulators: Pin_13 KV Polymer	$4.90	$5.35	$0.45	9%
Substation Transformer	$325,033.00	$532,619.00	$207,586.00	64%
Circuit Breakers	$32,740.00	$37,197.00	$4,457.00	14%

Q. Has UGI Electric experienced any impacts from supply chain issues?

A. Yes. In addition to the price increase associated with substation power transformers, lead times for that equipment has nearly doubled. UGI Electric has also experienced supply chain issues with most other core utility products, resulting in delays or even non-availability of items from some vendors. Manufacturing and delivery lead times for equipment and general material items have all increased substantially. Substation power transformer lead times have increased to nearly a year. In addition, other transformer lead times are now as long as 72 weeks (typically 13); circuit reclosers are now 50 weeks (typically 8); primary wire is now 26 weeks (typically 12); and wood poles are 8 weeks (typically 1). Table 2 below provides additional detail on material/equipment supply chain issues reflective of increased lead times being experienced by the Company.

Table 2: Lead Time Changes from FY2020 to FY2023

Material/Equipment Item	FY2020 Lead Time	FY2023 Lead Time	Lead Time Increase	Lead Time % Increase
Poles: 45 Ft Wood Pole	1 Weeks	8 Weeks	7 Weeks	700%
Cross Arms: 8 FT Wood	10 Days	28 Days	18 Days	180%
Primary Wire: 397.5 ACSR	12 Weeks	26 Weeks	14 Weeks	117%
750 MCM AL Insulated wire	8 Weeks	40 Weeks	32 Weeks	400%
URD MV Cable - 2 AWG	8 Weeks	28 Weeks	20 Weeks	250%
25 KVA Pole Transformer	9 Weeks	60 Weeks	51 Weeks	567%
25 KVA Padmount Transformer	13 Weeks	72 Weeks	59 Weeks	454%
50 KVA Pole Transformer	9 Weeks	60 Weeks	51 Weeks	567%
50 KVA Padmount Transformer	13 Weeks	72 Weeks	59 Weeks	454%
100 KVA Pole Transformer	9 Weeks	60 Weeks	51 Weeks	567%
100 KVA Padmount Transformer	13 Weeks	72 Weeks	59 Weeks	454%
3-Phase Circuit Recloser	8 Weeks	50 Weeks	42 Weeks	525%
Insulators: Pin_13 KV Polymer	1 Weeks	3 Weeks	2 Weeks	200%
Substation Transformer	30 Weeks	47 Weeks	17 Weeks	57%
Circuit Breakers	24 Weeks	34 Weeks	10 Weeks	42%

Q. Have the supply chain challenges impacted UGI Electric's operations?

A. UGI Electric modified its operations, and specifically its work to implement its LTIIP, to address changing timelines for delivery of critical equipment. The Company worked proactively with its suppliers to understand upcoming or ongoing impacts, obtain necessary equipment for planned projects in a timely fashion, re-sequence projects as needed, and adjust its purchasing practices to avoid material impacts.

Q. What steps has UGI Electric taken to reduce the impact of inflation and supply chain issues on its operations?

A. UGI Electric continues to leverage the use of requests for proposals ("RFPs") in order to competitively bid key procurement activities and control contract pricing. Additionally, the Company actively pursues new vendors and supply sources in an effort to combat cost increases as well as potential supply chain issues. One way that UGI Electric introduced lower supply costs was by increasing the number of reconditioned transformers. During 2022, UGI Electric's procurement team worked with a vendor to increase the supply of reconditioned transformers to hedge against supply chain issues and cost increases. Reconditioned transformers were increased from a typical annual amount of approximately 200 per year to over 300. Reconditioned units are approximately 50% less costly than new units.

VI. PROPOSED TARIFF MODIFICATIONS

Q. Has UGI Electric proposed any tariff modifications as part of this proceeding?

A. Yes. UGI Electric proposed certain tariff updates as part of this proceeding in UGI Electric Exhibit F – Proposed Tariff. While many of these updates are minor, the Company's proposed modifications to Rule 1-c, certain outdoor lighting provisions, and Rate LP are further explained below.

Q. Please explain the change to Rule 1-c?

A. The change to Rule 1-c clarifies that combining usage for billing purposes from two or more services is only intended for customers that: (1) transition from secondary to primary service; or (2) have multiple existing primary services that could be combined for billing, utilizing primary metering equipment, where the customer has requested and the Company has approved combined billing. As the modification more clearly establishes, tariff rates are intended for application at a single point of delivery with its own metering and associated billing. In the case of customers that have multiple services with individual billing, and who request combined use billing, approvals by UGI Electric will follow a typical service design in which UGI Electric provides primary service to one customer at one delivery point into customer-owned equipment, including the transformer(s). This more effectively aligns with UGI Electric's tariff, particularly Rate LP, and fosters the determination of usage (energy and demand) for combined billing.

Q. Please explain the changes to the outdoor lighting services?

A. The Company is updating its outdoor lighting services to address changing technology (e.g., phasing out of older bulb types) and customer behavior (e.g., movement toward more energy efficient bulb types). Specifically, UGI Electric is proposing revisions to Rates Sodium Outdoor Lighting ("SOL"), Metal Halide Outdoor Lighting ("MHOL"), Street Lighting ("SL"), and Sodium Street Lighting ("SSL"). The existing tariff provisions do not adequately address bulbs and fixtures that are no longer available or that are being phased out. The proposed revisions provide that these bulb types will be replaced as long as the bulbs are readily available at a reasonable cost. However, if the Company cannot replace these bulbs when they fail, customers with such equipment must be transitioned to new options. In addition, the Company is adding a decorative lighting rate for residential and commercial customers, which has separate higher cost considerations, to address an emerging area of customer interest in optional aesthetic fixture and pole choices.

Q. Please describe the changes to Rate Large Power ("LP") Service.

A. The proposed tariff includes changes to Rate LP to clarify eligibility for Rate LP and the service to be provided. Specifically, the Company proposes to require a single monthly peak demand of 100KW or greater during the 12-month period in order to qualify for Rate LP. In addition, the language in the Character of Service has been modified to reflect the phase out by the end of the FPFTY of older primary three-phase service configurations below 13,800 volts. Finally, the Company clarifies that Rate LP is only available for primary service at 13,800 volts, or via one transformation to a lower available standard Company voltage.

VII. PRIOR RATE CASE COMPLIANCE ITEMS

A. BATTERY PROJECT STATUS

Q. Has UGI Electric provided the required report on its battery storage project pursuant to the 2021 Electric Rate Case at Docket No. R-2021-3023618 settlement?

A. Yes, the Company filed the required status report on December 30, 2022 with the Commission. In brief, the status report identified the challenges that the Company faced in implementing the battery storage project and why the project has not moved forward at this time.

Q. Please explain the background for UGI Electric's battery storage project?

A. In the 2021 Electric Rate Case at Docket No. R-2021-3023618, the Commission approved a settlement provision allowing UGI Electric to install a 1.25 MWh battery storage project as a targeted means to enhance resiliency and improve reliability to customers served off the Ruckle Hill Road circuit ("Ruckle Hill"). Ruckle Hill is a fairly long, rural single-phase circuit located in Wapwallopen, Pennsylvania. Reliability issues (specifically the number of customer outages experienced) on this circuit were exacerbated by an elevated number of outages impacting the circuit for Ruckle Hill, which is constructed in a tight corridor that features mountainous terrain with heavy vegetation, railroad tracks, and a river. These features limit the availability of more traditional options to address reliability threats, such as line relocation, undergrounding or development of a tie-line, and reduce the effectiveness of increased vegetation management. The battery project was intended to support service reliability for approximately 67 customers.

Q. What is the status of the battery storage project?

A. UGI Electric hired an engineering consultant to assess the battery project and propose specific, fully engineered project options. The intent of the overall project design was to utilize core battery system components that were commercially available to achieve the desired technical solution in a cost-effective manner. After a comprehensive review of the battery storage project options available, none of the options currently on the market were able to provide a cost-effective solution that met the intended design parameters necessary to move forward with project construction at this time. Specifically, there were no readily available single-phase power inverter options in a size that could cost-effectively support the customer load identified by UGI Electric for the Ruckle Hill single-phase circuit. The single-phase inverter solutions readily available would only support a smaller customer load and would be insufficient in size to support the Ruckle Hill project needs. To support the identified customer load, UGI Electric would need a custom-built project to be compatible with a single-phase inverter. A custom-built solution would be very costly and challenging to maintain over the life of the asset. UGI Electric also explored a three-phase battery storage solution, but the cost of installing the additional overhead circuits would have materially changed the economics of the project. The lower anticipated project cost of the battery storage project was a significant factor in the Company's justification for selecting it as the preferred reliability solution to enhance reliability to Ruckle Hill. Accordingly, UGI Electric is not continuing to pursue the battery storage project at this time as contemplated in settlement of the 2021 Electric Rate Case.

Q. Did UGI Electric redirect funds for the battery storage project to other reliability projects?

A. Yes, the Company redirected approximately $1.5 million of battery storage funding to other reliability projects. This redirect is embedded in the comparison of the overall totals of the Replacement and Betterment plant placed in service when compared to the planned levels of spend for plant in service, as discussed by Ms. Schappell in her testimony (UGI Electric St. No. 5).

B. FLOOD CONTROL POWER ("FCP") RATE

Q. What customers are served by UGI Electric on Rate FCP?

A. Rate FCP is related to service for emergency flood control pumping stations protecting communities along the Susquehanna River. The Company provides service under Rate FCP to two municipal authorities through seven billed accounts. Of these, one authority has responsibility for six of the seven accounts related to Rate FCP. The remaining account is associated with emergency pumping facilities for a municipal sanitary authority. In the 2021 Electric Rate Case, the Commission approved a settlement provision that required UGI Electric to include a proposal to eliminate, consolidate, or otherwise support Rate FCP as a separately identified rate class in the Company's next rate case.

Q. Has UGI Electric complied with the settlement provision described above?

A. Yes. UGI Electric undertook a cost of service assessment of the Rate FCP and has proposed modifications to that rate. The analysis and modifications are discussed by UGI Electric witness John D. Taylor in his testimony (UGI Electric St. No. 6).

VIII. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC

EXHIBIT EWS-1

Eric W. Sorber

UGI Utilities, Inc. – Electric Division
Vice President & General Manager

WORK EXPERIENCE

UGI Utilities, Inc. (Wilkes-Barre, PA)

Vice President & General Manager	October 2019 to Present
Director Engineering and Operations	November 2014 to October 2019
Manager – Planning and Operations	March 2008 to November 2014
Project Engineer – Maps and Records Dept.	March 2006 to March 2008
Staff Engineer – Maps and Records Dept.	December 2005 to March 2006
Staff Engineer – Distribution Engineering Dept.	November 2002 to December 2005
Staff Engineer – Rates & Regulatory Dept.	February 1999 to November 2002
Engineer I & II – Resource Planning Dept.	February 1992 to February 1999

EDUCATION

B.S. in Electrical Engineering	Pennsylvania State University, 1988

PRIOR TESTIMONY

UGI Electric Base Rate Case	Docket No. R-2017-2640058
UGI Electric Base Rate Case	Docket No. R-2021-3023618

UGI ELECTRIC

EXHIBIT EWS-2

Rolling 12 Month - Calendar Year																						
	Metrics	Benchmark	Standard	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
UGI	SAIDI	140	256	93	76	88	114	90	80	48	121	54	85	63	41	78	64	213	182	66	127	135
	SAIFI	0.83	1.12	0.65	0.64	0.79	0.68	0.67	0.76	0.48	0.95	0.44	0.77	0.44	0.40	0.63	0.49	1.19	0.96	0.40	0.95	0.87
	CAIDI	169	228	143	119	112	167	135	105	99	128	122	110	144	103	125	131	178	188	163	134	156
Reportable Storms				0	0	0	1	0	0	0	1	1	0	0	0	0	0	0	2	0	1	0

UGI ELECTRIC STATEMENT NO. 5

VICKY A. SCHAPPELL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368

UGI Utilities, Inc. – Electric Division

Statement No. 5

Direct Testimony of
Vicky A. Schappell

Topics Addressed: **Capital Planning**

Dated: January 27, 2023

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vicky A. Schappell. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed as Principal Analyst, Capital Planning by UGI Utilities, Inc. ("UGI"). UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric" or the "Company") and the Gas Division ("UGI Gas"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. Please describe your educational background and work experience.

A. They are set forth in my resume attached as UGI Electric Exhibit VAS-1 to my testimony.

Q. What are your responsibilities as Principal Analyst?

A. As Principal Analyst, I supervise a team of analysts responsible for the preparation of the annual capital budgets for UGI Gas and UGI Electric. I am responsible for obtaining budget inputs from various departments including Engineering, Operations, Information Technology ("IT"), and the Building and Grounds Departments. I collaborate with the Vice President and General Manager of UGI Electric, Senior Engineering Managers and the Senior Director Financial Planning and Analysis to monitor annual capital budget performance and develop strategies to limit variances in capital installations and spending. I also work closely with the President of UGI Utilities in developing the overall capital spend and in-service strategy. I have prepared schedules and discovery requests for past rate cases. Also, I am responsible for preparing UGI Electric's Annual Asset Optimization Plan. Additionally, I had an integral role in developing an expanded capital spending monitoring process made necessary by the Company's accelerated capital investment programs. This was done through the adoption of PowerPlan, which is an upgraded capital planning, forecasting and budgeting tool that was implemented in UNITE Phase III-Enterprise Performance Management and went live in October 2020.

Q. Have you previously presented testimony in proceedings before a regulatory agency?

A. Yes. I previously presented testimony in the 2020 UGI Gas base rate case at Docket No. R-2019-3015162. I also testified in the 2022 UGI Gas base rate case at Docket No. R-2021-3030218.

Q. What is the purpose of your testimony?

A. My testimony will address the capital planning process used by UGI Electric, and support the future test year ending September 30, 2023 ("FTY") and fully projected future test year ending September 30, 2024 ("FPFTY" or "FY2024") plant in service expenditures included in the proposed rates in this proceeding.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, in addition to UGI Electric Exhibit VAS-1, I am sponsoring UGI Electric Exhibit VAS-2.

II. CAPITAL PLANNING

Q. What is the total plant in service budget for UGI Electric for the FPFTY that is reflected in the proposed rates?

A. The total budgeted plant additions for UGI Electric for the FPFTY is $24,665,000.

Q. As an initial matter, are Transmission plant additions excluded from Pennsylvania distribution service rate base for UGI Electric?

A. Yes, they are. The Company identifies projects that only serve a Transmission plant function as part of its overall capital budgeting process. Projects that are identified as having solely a Transmission purpose are excluded from the distribution rate base presented in this proceeding. Some categories of projects support both the distribution and transmission functions. For these projects, UGI Electric uses an allocation factor to ensure an appropriate portion of the dollars associated with these General and Common plant additions are recovered through distribution rates, while the transmission portion is excluded.

Q. What are the specific project categories included in the capital budget for UGI Electric?

A. UGI Electric has four main categories that make up its capital budgets: (1) replacement and betterment of infrastructure, which includes transmission, substation and distribution assets; (2) new business, including expansion of the transmission and distribution system to support growth; (3) IT; and (4) Other capital spending. I will describe each of these categories and the projects associated with them, as well as the total dollars attributable to each category, below.

Q. What process does UGI Electric use to develop its capital budget?

A. UGI Electric's capital budget starts by identifying the four critical areas where the Company must make capital investments in order to maintain safe and reliable service to customers. For each of these budget areas, the Company then identifies all of the projects or categories of project that are planned to occur in each year of the two-year forecast. Once those projects are determined, the Company identifies the FERC accounting treatment for each project. In this case, the Company presents them as part of the budgeted plant additions in Exhibit A, Schedule C-2. The process used to develop Exhibit A is further described in the direct testimony of Tracy A. Hazenstab (UGI Electric Statement No. 2).

Q. How does Schedule C-2 show plant additions?

A. Schedule C-2 is an accounting presentation based on FERC accounts that does not separately identify the four budget categories that make up and drive UGI Electric's Budget. For purposes of developing Schedule C-2, budgeted dollars in each budget category are broken out by the FERC account numbers that drive the accounting for depreciation. Schedule C-2 is split between Distribution Plant and General and Common

Plant. The General and Common Plant includes only the distribution portion of the plant additions.

Q. Have you prepared an exhibit that shows how UGI Electric's plant additions are comprised of the budget project categories?

A. Yes, I have. UGI Electric Exhibit VAS-2 reflects the Company's plant additions broken out by the different project categories for the seven-year period from fiscal year 2018 through fiscal year 2024. The exhibit splits the four budget project categories between Distribution Plant and General and Common plant, consistent with the categories on Schedule C-2. In addition, UGI Electric Exhibit VAS-2 shows a historical comparison of the total budgeted plant placed in service versus actual plant placed in service additions for the five-year period from fiscal year 2018 through fiscal year 2022. I will describe the Company's performance history in greater detail later in my testimony.

Q. Please comment on the presentations shown in UGI Electric Exhibit VAS-2 and Schedule C-2.

A. While the total plant in service figures match, there is a difference in the presentation of how UGI Electric Exhibit VAS-2 and Schedule C-2 present plant additions, and it is important to understand how these budget presentations align. Specifically, UGI Electric Exhibit VAS-2 shows how the Company's four individual budget categories constitute the Company's total Plant Additions and how they map into the Distribution and General and Common Plant on Schedule C-2. Exhibit VAS-2 shows that three of the four budget categories that are critical to the Company's business function fall into both of the plant categories when describing the budget by FERC accounts. IT projects are the only budget category where projects fall exclusively into one FERC plant account – General and Common plant – when recorded for accounting purposes.

Q. Why is it important to understand the relationship between the Company's budgeting process and the reflection of the budget in Schedule C-2?

A. When the Company plans for future operations, the Company does not budget using the FERC accounts and does not have work streams divided in the manner shown in Schedule C-2. When the Company budgets and then executes on its budget, it first looks at the total for the budget category, and then examines its overall budgeted projects on a total additions basis, because its operations and work streams are divided in the same manner to achieve core utility objectives. Ultimately, the Company's operations manage to the total overall budget. As a result of this process, it is more reasonable to review the Distribution and General and Common plant success together when considering how the Company performed to its budget, rather than the accounting distinction set forth in Schedule C-2, which does not directly flow into the Company's operational objectives. To properly compare historical budgeted plant additions to actuals for ratemaking purposes, the Distribution and General and Common plant additions should be reviewed in total.

Q. Turning to the capital budget categories, what are replacement and betterment projects?

A. Replacement and betterment ("R&B") projects improve or replace existing infrastructure and make up the majority of projects captured in UGI Electric's Long Term Infrastructure

Improvement Plan ("LTIIP"). The Company's LTIIP performance is described in the direct testimony of Eric W. Sorber (UGI Electric Statement No. 4).

Q. Please describe how the prioritization process is used to evaluate R&B Projects.

A. Projects are prioritized for inclusion in the budget according to the condition of, and risks associated with, existing assets, including those factors affecting safety and reliability. In determining the condition of an existing asset, the Company considers various criteria including, but not limited to age, material, performance, inspection and test results, obsolescence, and maintenance costs.

Q. How does UGI Electric determine which R&B projects are included in the capital budget for a given year?

A. UGI Electric's LTIIP guides the formulation of the overall R&B capital budget. Within the various program categories of the LTIIP, R&B projects are selected and prioritized in the budget under two key designations: condition-based replacements and reliability enhancements. Condition-based replacements address "aging infrastructure," such as poles, transformers, underground primary cable, open wire secondary, and deteriorated or failed pole mounted equipment (e.g., switches, reclosers and capacitors). Reliability enhancement projects are targeted towards addressing known reliability issues or implementing system resiliency strategies. These projects are prioritized based on metrics such as worst performing feeder circuits and include creation of inter-substation tie-lines and deployment of distribution automation devices. Additionally, through its comprehensive inspection and maintenance program, UGI Electric assesses asset conditions, which are used to identify and prioritize maintenance issues or trends. The information collected is used to schedule projects in a manner that mitigates short-term and long-term system impacts. The total anticipated budgeted plant additions associated with R&B projects in the FPFTY is $15,127,000 and is included in Distribution plant additions.

Q. What are new business projects?

A. New business projects provide new or upgraded electric service to customers and may involve primary overhead and underground line extensions, new or upgraded transformer installations, and associated service enhancements.

Q. Please describe how the new business infrastructure projects are selected for inclusion in the capital budget.

A. The new business portion of the capital budget is developed using historical trends as well as projections that are informed by known large customers, forecasts of new business projects, counts of residential developments and associated customers, and general construction and development trends in the UGI Electric service territory. The final budget layers in the above components considering construction timing and the level of confidence in the customer's ability to meet project timelines. The total anticipated budgeted plant additions associated with new business projects in the FPFTY is $4,635,000 and is included in Distribution plant additions.

Q. What are IT projects?

A. IT projects enhance the Company's IT systems in a number of ways. These projects improve the Company's methods for managing capital projects in a safe and reliable manner, including computerized systems and hardware/software applications. Further, these projects facilitate the Company's ability to enter, store, retrieve, and send data and information related to such projects. In addition, IT projects can address a wide range of operational concerns or needs, such as cybersecurity, customer communications, and billing. IT projects reflected in the FPFTY include the purchase of new IT equipment and servers to be added to the Company's new Data Center as further described below. The total anticipated budgeted plant additions associated with IT projects in the FPFTY is $1,338,000 and these projects are included in General and Common plant additions.

Q. Please describe the prioritization process used to evaluate IT projects.

A. IT projects are prioritized for inclusion in the budget based on identified business needs. UGI relies on an IT Prioritization Committee to develop a prioritized budget based on overall business impact, availability of system support, and resource availability. Examples of IT projects include the Electric Outage Management System that was placed in service in September 2022. It improved outage response capabilities, provided rate enhancements to the customer billing system, and upgraded the capital budgeting and forecasting system. In addition, UGI Electric placed its UNITE Phase III Enterprise Asset Data Collection project in-service in September 2022. This project focused on the identification and standardization and capture of asset data information.

Q. What are Other capital projects?

A. Other capital projects include building-related projects, capital tool purchases, and fleet purchases. Building-related projects consist of building and land purchases, building improvements/renovations, and the purchase of furniture, including the construction of the new Data Center as described below. Capital tool projects encompass new tool purchases for field use during capital projects. These tools include pole saws, wire strippers and test equipment, safety tools, and lighting equipment. Fleet purchases are needed to maintain a reliable mode of transportation and related apparatus for field employees to perform their daily functions. These acquisitions include SUVs, pickup trucks, cargo vans, service body trucks, bucket trucks, and equipment trailers for poles. The total anticipated budgeted plant additions associated with other projects in the FPFTY is $3,565,000 of which $341,000 is included in Distribution plant additions and $3,224,000 is included in General and Common plant additions.

Q. Please describe the prioritization process used to evaluate Other capital projects.

A. The prioritization process for Other capital projects is specific to the need being addressed. Building-related projects, such as the new Data Center described below, are prioritized for inclusion in the budget based on safety, security, regulatory, or financial and strategic needs. Regulatory driven projects often originate from audit observations. Physical security audits may prompt the installation of fencing, gates and access controls. Capital tool projects are prioritized for inclusion in the budget according to the useful life of the existing assets. Fleet purchases are prioritized for inclusion in the budget based on age, condition, maintenance costs, and mileage of the existing asset.

Q. Please describe the Company's plans to construct a new Data Center.

A. The FPFTY includes costs related to a new Data Center that UGI is constructing at the existing UGI Learning Center property in Reading, Pennsylvania. The new Data Center will provide adequate IT infrastructure to support the Company's business functions in a modern, secure and NERC/CIP[1] -compliant facility. The new Data Center will replace the existing Data Center located in Reading, Pennsylvania. Due to the age of the existing facility and the expense associated with renovating the entire building, construction of a new Data Center on an existing UGI property will best support the above-described IT goals. The new facility will house the IT infrastructure and will allow the Company to modernize its IT equipment. In addition, the new facility will provide physical and security infrastructure enhancements needed to meet UGI Electric's regulatory requirements and best practices. The new Data Center was approved by the UGI Corporation Board in September 2022, a ground-breaking occurred in December 2022, and it has a planned in-service date of November 2023.

Q. What costs are included in the FPFTY for the new Data Center?

A. The Data Center's total construction costs to UGI Utilities, Inc. is approximately $20.3 million. UGI Electric's portion of these costs is approximately $1.4 million. The construction costs are included in the Other capital budget category as a building-related project. The construction costs are also categorized as General and Common Plant additions. The Data Center also involves a separate IT project to migrate the critical servers and applications from the existing location to the new facility. UGI Electric's portion of

[1] NERC stands for the "North American Electric Reliability Corporation" and CIP stands for "Critical Infrastructure Protection".

the migration costs is $631,573 ($119,032 in FY2023 and $512,541 million in FY2024). The migration costs are included in the IT projects budget category. They are also categorized as General and Common Plant additions.

Q. How do UGI Electric's actual plant additions compare to its budgeted plant additions historically?

A. As shown in UGI Electric Exhibit VAS-2, over the past five years, the Company's total budgeted plant additions were $81,962,000, while the total actual plant additions were $86,111,000. UGI Electric's plant in service performance surpassed its total budgeted plant additions by $4,149,000 over a five-year period.

Q. What data points does UGI Electric use to compare its budgeted plant additions to actuals?

A. Annually, during the Company's capital budget process, which occurs during the summer/fall, a two-year budget is prepared. The first year of the capital budget is the basis for the FTY. The second year is a preliminary budget and is the basis for the FPFTY. During the budget process, project managers estimate the total project costs and budgeted in-service dates at the project level based on the current data available. These estimated in-service dates are the basis for the budgeted plant additions as further discussed in the testimony of UGI Electric witness Vivian K. Ressler (UGI Electric Statement No. 3). As the Company transitions from one budget year to the next, and the preliminary budget year becomes the active budget year, the Company makes certain adjustments to its budget for known and measurable changes in the assumptions about operating conditions that supported the preliminary budget. For example, the Company adjusts its project lists on an annual basis based on operational demands, such as the need to reprioritize projects based on emerging service needs or unanticipated equipment condition changes. The Company may also need to adjust the anticipated in-service dates of projects based on factors outside its control, such as the impact of supply chain shortages or delayed manufacture of certain critical parts.

Q. Please explain why it is necessary to compare budgeted plant additions to actual plant additions when determining if the Company's revenue requirement is reasonable.

A. It is important to understand that budgets are not static, as noted above. The Company conducts ongoing reviews to ensure its budgets are effective to provide customers with safe and reliable service throughout the year. The Company manages its budgets in total and if any budget changes are made, the dollars get reallocated between the four main budget categories, described above, such that the total plant additions align as close as possible to the total plant addition actuals.

Q. Did you calculate the percentage of plant additions accomplished by the Company during the five-year period reflected in UGI Electric Exhibit VAS-2?

A. Yes, I did. Exhibit VAS-2 compares plant additions placed in service (i.e., actuals) to the budgeted plant additions between 2018 and 2022. The exhibit provides these figures by the four above-described budget categories. It also separates them by distribution plant and general and common plant. Taken together, the distribution and general and common plant categories calculate total Plant Additions. Finally, the exhibit calculates plant in service as a percent of budget for each year and over the five-year period by dividing actuals by budgets.

Specifically, during this five-year period, the Company's plant additions were 105.1% of its budget. The percentage of plant additions is calculated by dividing the actual plant additions by the budgeted plant additions (Actual / Forecast). Thus, the Company has demonstrated that over a five-year period that accounts for both normal operating conditions and the years impacted by the COVID-19 pandemic, it has a documented history of meeting its budgeted plant additions. This close correlation between budgeted and actual plant placed in service over the past five years shows that UGI Electric's budget process is very effective at identifying its required plant additions, and supports the Company's claimed level of plant in service in this case.

III. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC

EXHIBIT VAS-1

Vicky A. Schappell

Principal Analyst – Capital Planning

WORK EXPERIENCE

UGI Utilities, Inc. (Reading, PA)

Principal Analyst - Capital Planning	January 2020-Present
Senior Analyst - Capital Planning	April 2018-January 2020
Senior Supervisor Plant Accounting	December 2014-April 2018
Senior Analyst - General Ledger	September 2011-December 2014
Analyst II – General Ledger	September 2008-September 2011

Teleflex Medical (Reading, PA)

Accounting Supervisor	December 2007-September 2008
Senior Accountant – Financial Reporting	March 2003-December 2007
Staff Accountant – Financial Reporting	October 1999-March 2003

Heffler, Radetich & Saitta, LLP (Philadelphia, PA)

Auditor	May 1997-October 1999

Education

B.S. in Accounting, Shippensburg University,
1997

Previous Testimony

UGI Gas Base Rate Case	Docket No. R-2019-3015162
UGI Gas Base Rate Case	Docket No. R-2021-3030218

UGI ELECTRIC

EXHIBIT VAS-2

UGI UTILITIES, INC. - ELECTRIC DISTRIBUTION DIVISION
Plant Additions Placed in Service Compared to Budget
$ amounts in '000s

Historical Performance

Description	Budget 2022	Actual 2022	Budget 2021	Actual 2021	Budget 2020	Actual 2020	Budget 2019	Actual 2019	Budget 2018	Actual 2018	5 Year Total Budget	5 Year Total Actual
Distribution												
Replacement and Betterment	12,815	13,134	9,026	10,702	10,570	9,538	14,556	16,496	10,950	7,060	57,917	56,929
Growth	2,943	3,576	3,356	2,926	1,534	2,489	2,045	1,793	1,399	1,456	11,277	12,240
Other	411	(172)	-	369	-	7	-	15	-	7	411	225
Subtotal Distribution	16,169	16,537	12,382	13,997	12,104	12,035	16,601	18,304	12,349	8,522	69,605	69,394
General and Common Plant												
Replacement and Betterment	-	286	-	186	-	30	-	2	-	178	-	682
Growth	-	-	-	0	-	86	-	12	-	247	-	345
Other	1,731	2,314	2,730	990	1,040	891	1,050	2,265	954	28	7,505	6,488
IT	929	3,480	997	1,473	1,466	-	1,460	4,249	-	-	4,852	9,202
Subtotal General and Common Plant	2,660	6,080	3,726	2,649	2,507	1,007	2,510	6,528	954	453	12,357	16,717
Total Plant Additions	18,829	22,617	16,108	16,646	14,611	13,042	19,111	24,832	13,303	8,975	81,963	86,111
	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)
Plant in Service as % of Budget	(2) / (1)	120.1%	(2) / (1)	103.3%	(2) / (1)	89.3%	(2) / (1)	129.9%	(2) / (1)	67.5%	(2) / (1)	105.1%

Forecasted Performance

Description	FPFTY Budget 2024	FTY Budget 2023
Distribution		
Replacement and Betterment	15,127	13,762
Growth	4,635	6,190
Other	341	71
Subtotal Distribution	20,103	20,023
General and Common Plant		
Replacement and Betterment	-	-
Growth	-	-
Other	3,224	2,088
IT	1,338	1,110
Subtotal General and Common Plant	4,562	3,198
Total Forecasted Plant Additions	24,665	23,221

BOOK III

UGI UTILITIES, INC. – ELECTRIC DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI ELECTRIC STATEMENT NO. 6 – JOHN D. TAYLOR
UGI ELECTRIC STATEMENT NO. 7 – JOHN F. WIEDMAYER
UGI ELECTRIC STATEMENT NO. 8 – DARIN T. ESPIGH
UGI ELECTRIC STATEMENT NO. 9 – PAUL R. MOUL
UGI ELECTRIC STATEMENT NO. 10 – SHERRY A. EPLER

UGI UTILITIES, INC. – ELECTRIC DIVISION
PA P.U.C. NO. 6, SUPPLEMENT NO. 51
PA P.U.C. NO. 2S, SUPPLEMENT NO. 7

DOCKET NO. R-2022-3037368

Issued: January 27, 2023 Effective: March 28, 2023

UGI ELECTRIC STATEMENT NO. 6

JOHN D. TAYLOR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368

UGI Utilities, Inc. – Electric Division

Statement No. 6

Direct Testimony

of

John D. Taylor, Managing Partner
Atrium Economics, LLC

Topics Addressed:	**Cost of Service**
	Revenue Allocation
	Rate Design

Dated: January 27, 2023

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name, affiliation, and business address.

A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

Q. Please describe your professional background and education.

A. As a utility pricing and policy expert, I am involved in various energy and utility-related projects regarding economics, finance, and public policy. Part of my role within these projects is to conduct various analyses considering accounting and financial factors and the particular operational configuration of a company's assets. I have presented expert testimony in state public utility regulatory proceedings in Indiana, Maine, Minnesota, Illinois, Delaware, Pennsylvania, Washington, West Virginia, British Columbia, and the Federal Energy Regulatory Commission ("FERC"). I began my education studying electrical and mechanical engineering and worked for an industrial inspection company, which provided me with hands-on experience with electric utility assets and equipment. I received an undergraduate degree in Environmental Economics, with an emphasis in econometrics and regulatory policy. I also earned a Master's in Economics from American University in Washington, DC. A copy of my resume is provided as UGI Electric Exhibit JDT-1.

Q. What is the purpose of your testimony in this proceeding?

A. I prepared and am sponsoring UGI Utilities, Inc. – Electric Division's ("UGI Electric" or the "Company") fully allocated cost of service study used in this case to develop the allocated costs of service study ("ACOSS" or "COSS"), which is found in UGI Electric Exhibit D. The ACOSS allocates the Company's cost of service associated with Pennsylvania Public Utility Commission ("Commission") jurisdictional operations to the Company's retail customer classes. I also support the allocation, or apportionment, of the class revenue increase and the Company's rate design proposal.

Q. Please summarize the content of your testimony.

First, I provide an overview of the ACOSS, including various principles and factors that influence the cost allocation framework, and general methods and approaches used to allocate costs to customer classes. Second, I discuss the underlying methodology and basis used in the ACOSS studies I conducted and am sponsoring for UGI Electric. I describe the studies of relative costs and other analyses employed to apportion the various categories of plant and operation and maintenance ("O&M") expenses to the respective customer classes. I present the class-by-class rate of return results and corresponding revenue surpluses or deficiencies from the ACOSS. Finally, I discuss the apportionment of the rate increase to the various rate classes and the customer-related costs and support for customer charges.

Q. Mr. Taylor, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Book IX, labeled as UGI Electric Exhibit D – Allocated Cost of Service Study (Fully Projected) ("Exhibit D"). Exhibit D contains three sections for which an index is provided on page 2 of Exhibit D. I also am sponsoring portions of Book II, Section 53.51 et seq. of the Commission's Regulations, Part IV-Rate Structure and Cost Allocation.

Q. Would you briefly describe the contents of Exhibit D?

A. Exhibit D provides the information required under 52 Pa. Code § 53.53(a)(3) and, in particular, Exhibit C - Electric utilities, Part IV (Rate Structure and Cost Allocation), Section E (1), by providing a cost of service study that fully distributes the Pennsylvania jurisdictional costs of providing retail distribution service to the various rate classes at both present and proposed rates. See 52 Pa. Code § 53.53(a)(3), Exhibit C. IV. E(1). The studies contained in UGI Electric Exhibit D are based on costs and operating conditions for the fully projected future test year ("FPFTY") ending September 30, 2024.

Exhibit D consists of three sections detailing the process of developing the COSS. *Section I – Introduction* includes an introduction, the general purpose and process of the cost of service study, as well as an overview of the excel-based fully functional COSS model presented in this proceeding. *Section II – UGI's Cost of Service Procedures* presents the COSS development process specific to the Company, including the Functionalization, Classification, and Allocation of costs. The Allocation section (Section

II.4) describes all internal and external allocation factors and the allocation processes used in the COSS. The last section, *Section III – UGI's Cost of Service Results* depicts the results of the cost of service studies, including revenue requirement apportionment, comparison of cost of service with revenues under present and proposed rates, and development of rate of return by customer class under present and proposed rates.

Q. Please describe the schedules included in Exhibit D.

A. The following is the list of Schedules included in Exhibit D:

- Schedule 1 - Account Balances and Allocation Methods
- Schedule 2 - Functional Split & Minimum System Study
- Schedule 3 - External Allocation Factors
- Schedule 4 - Internal Allocation Factors
- Schedule 5 - Comparison of Cost of Service with Revenues Under Present and Proposed Rates
- Schedule 6 – Summary of Cost of Service and Rate of Return Under Present and Proposed Rates
- Schedule 7 - Cost of Service Allocation Study Detail by Account
- Schedule 8 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

II. OVERVIEW OF ALLOCATED COST OF SERVICE STUDY

Q. What are the general purposes and use of the ACOSS in this base rate proceeding?

The purpose of the ACOSS is to allocate UGI Electric's Commission-jurisdictional overall adjusted FPFTY revenues and costs to the various classes of service in a manner that reflects the relative costs of providing service to each class. This is accomplished by analyzing costs and assigning each rate class its proportionate share of the utility's total revenues and costs within the FPFTY. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility. The requirement to develop a COSS results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more rate classes or the cost of providing multiple products to the same rate class, using the same facilities, and the use by one rate class precludes the use by another rate class. In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of electric demand, while variable costs change directly with changes in demand. Most non-fuel-related utility costs are fixed in the short run and do not vary as customer loads change. This includes the cost of poles and towers, distribution conductors, transformers, service lines, and meters. While these costs increase due to inflationary pressures, this equipment is purchased, installed, and used to serve customers based on their requirements; and once placed into service, the costs of this equipment do not vary as a result of changes in customer loads. Finally, the COSS contributes to developing economically efficient rates and the cost responsibility by rate class. The results of these studies can be utilized to determine the relative cost of service for each rate class to help determine the individual class revenue responsibility and provide guidance with rate design. Using the cost information per unit of demand, customer, and energy developed in the COSS to understand and quantify the allocated costs in each rate class is a useful step in the rate design process to guide the development of rates.

Q. Is the preparation of a cost allocation study an exact science?

A. No, it is not. The fundamental purpose of a cost allocation study is to aid in the design of rates to be charged by identifying all of the capital and operating costs incurred by a utility to provide service to all of its customers and then assigning or allocating those costs to individual rate classes based on how those rate classes cause the costs to be incurred. This process inherently requires a substantial level of judgment. The allocation of costs using a COSS is a practical requirement of utility regulation since rates are based on the cost of service for the utility under a cost-based regulatory model. In general, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing revenues that equate to the level of the revenue requirement.

Q. What is the guiding principle that should be followed when performing an ACOSS?

A. The ACOSS analysis intends to establish cost responsibility among the utility's various customer classes. The analysis should result in an appropriate allocation of the utility's total revenue requirement among the various customer classes. The most important theoretical principle underlying an ACOSS is that cost incurrence should follow cost causation. In other words, the costs assigned or allocated to particular customers should be those costs that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service.

Q. How do you establish the cost and utility service relationships?

A. An important element in the selection and development of a reasonable COSS allocation methodology is the establishment of relationships between customer requirements, load profiles, and usage characteristics on the one hand and the costs incurred by the Company in serving those requirements on the other hand. To accomplish this, I reviewed UGI Electric's expense and plant accounts, developed studies of the relative costs of providing facilities and services for each rate class, and analyzed the key factors that cause the costs to vary.

Q. What are the steps to performing an ACOSS?

A. A three-step analysis of the utility's total operating costs must be undertaken to establish each customer class's cost responsibility. The three steps that are the predicate for an ACOSS are (1) cost functionalization, (2) cost classification, and (3) cost allocation.

Q. Please describe cost functionalization.

A. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. UGI Electric's primary functional cost categories associated with electric distribution services include Primary Distribution, Secondary Distribution, and Customer Accounts and Services. In addition, various categories of costs within the distribution function are assigned to separate sub-functions to the extent their costs vary in response to different customer class characteristics. Indirect costs that support these functions, such as General Plant and Administrative and General Expenses, are allocated to functions using allocation factors related to plant and/or labor ratios.

Q. Please describe cost classification.

A. The second step, classification of costs, further separates the functionalized plant and expenses according to the primary factors determining the amount of costs incurred. These factors are: (1) the number of customers; (2) the need to meet the peak demand requirements that customers place on the system; and (3) the amount of electricity consumed by customers. These classification categories have been identified for purposes of the ACOSS as (1) Customer Costs, (2) Demand Costs, and (3) Energy Costs, respectively.

Q. Please describe the types of costs in the Customer, Demand, and Energy Costs categories.

A. ***Customer Costs*** are incurred to extend service to and attach a customer to the distribution system, meter electric usage, and maintain the customer's account. Customer Costs largely depend on the number of customers served and continue to be incurred whether or not the customer uses any electricity. They also include capital costs associated with minimum size distribution systems, services, meters, and customer billing and accounting expenses.

Demand Costs are capacity-related costs associated with plant that is designed, installed, and operated to meet maximum hourly or daily electric usage requirements, such as generating plants, transmission lines, transformers, substations, or more localized distribution facilities that are designed to satisfy individual customer maximum demands.

Energy Costs vary with the amount of kilowatt hours ("kWh") sold to customers. However, UGI Electric's distribution costs are fixed with respect to energy usage, and none of the remaining delivery service cost structure is energy-related.

Q. What is required to appropriately classify costs as Customer, Demand, and Energy?

A. Usually, a determination on the classification of costs can be made simply by knowing the type of activities or assets that reside in a particular FERC account. In these instances, the account as a whole can be classified. However, for some FERC account functions, it is beneficial to conduct classification studies to determine the portion of an account associated with each classification.

Q. Are there generally accepted methods for preparing classification studies?

A. The generally accepted methods are set forth in the National Association of Regulatory Utility Commissioners ("NARUC") Cost Allocation Manual ("NARUC Manual").[1] My ACOSS adheres to these cost allocation principles to classify the Company's distribution capital and operating costs. The NARUC Manual (pgs. 96-98) specifically states that an electric utility's distribution-related facilities are, from a design and operational basis, sized to meet the maximum kW load (demand) requirements of customers. Moreover, the NARUC Manual (pg. 89) also states that all distribution costs should be classified as either customer-related or demand-related or a combination of these two factors. To achieve this classification result, UGI Electric's distribution capital and operating costs are functionalized into their primary and secondary voltage level components. These primary and secondary voltage level capital and operating costs are then classified based on a "minimum size system" study, which identifies the portion of those costs required to serve a customer with minimum or no load, and that portion of the costs is allocated on a customer basis. The remaining portion of the costs is allocated on a demand basis, i.e., based on each rate class's average monthly contribution to the sum of the average monthly maximum demands for all classes. The average monthly demand is computed by

[1] National Association of Regulatory Utility Commissioners, "Electric Utility Cost Allocation Manual", 1992.

averaging a class's maximum non-coincident peak ("NCP") demand across all twelve months (i.e., the class's maximum energy demand during each month in a given hour; an hour of time that may not correspond to the system peak).

Q. Do all experts accept this classification approach?

A. No, they do not. Some experts take issue with the "minimum size system" study approach. They assert that the demand allocators produced by this type of study reflect certain equipment with some load-carrying capability; they suggest that the zero-intercept method may produce a better result. Others contend that some portion of the distribution system's fixed components (e.g., poles, conductors, services) should be classified on an energy basis. They also assert that the customer component is overstated and that the demand component is understated.

Q. Why do you support the use of the minimum size system approach?

A. The cost allocation methodology utilized in the minimum system studies is based on the specific design and operating characteristics of the Company's distribution system. It provides a more accurate and consistent measure of class cost responsibility than other approaches for providing distribution service to its customers. In other electric distribution cases where I developed and/or testified on an ACOSS, a similar method was employed to develop a minimum system study, notably in UGI Electric's recent base rate cases at Docket Nos. R-2017-2640058 and R-2021-3023618 and in PPL Electric Utilities

Corporation's ("PPL") base rate case at Docket No. R-2015-2469275. Further, the proposed "minimum size system" study, set forth in UGI Electric Exhibit D, is based on the same methodology and criteria that this Commission accepted in both of the fully-litigated proceedings at Docket Nos. R-2017-264008 and R-2015-2469275. As mentioned above, this method was explicitly approved and cited in the final orders by this Commission in those proceedings.

Q. Please describe the cost allocation process.

A. The final step, cost allocation, is the allocation of each functionalized and classified cost element to the rate class (or classes) that benefits from the cost. Customers are generally divided into customer classes based on the type and character of services they require. Costs are typically allocated to these customer classes based on the number of customers and the capacity required to serve the customer class. For example, much of the plant and equipment cost is related to the peak demand of the customers in each class, and these costs were accordingly allocated based on the average NCP demands of the rate class. Other portions of the cost depend upon the number of customers on the system, and these costs were allocated on a customer, or weighted-customer, basis.

Q. How does the cost analyst establish the fully-allocated costs related to various utility services?

A. To establish these relationships, the cost analyst must analyze a utility's electric system design, physical configuration and operations, accounting records, and system and customer load data. From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q. Please explain the considerations in determining the cost allocation methodologies used to perform an ACOSS.

A. As stated above, to allocate costs within any cost of service study, the factors that cause the costs to be incurred must be identified and understood. The availability of data for use in developing alternative cost allocation factors is also a consideration. In evaluating any cost allocation methodology, appropriate consideration should be given to whether it provides a sound rationale or theoretical basis, whether the results reflect cost causation and are representative of the costs of serving different types of customers, as well as the stability of the results over time.

III. UGI ELECTRIC'S ALLOCATED COST OF SERVICE STUDY

Q. What is the source of the cost data analyzed in UGI Electric's ACOSS?

A. All cost of service data was extracted from the Company's total cost of service (i.e., basic rate revenue requirement) contained in this general rate case filing for the FPFTY ending September 30, 2024. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company and information provided by Company personnel.

Q. How are UGI Electric's rate classes structured for the purposes of conducting its ACOSS?

A. For UGI Electric's ACOSS, I included six rate classes:

- Residential (Rate Schedule R)
- General Service (Rate Schedules GS-1 and GS-5)
- General Service-4 (Rate Schedule GS-4)
- Flood Control Power (Rate Schedule FCP)
- Large Power (Rate Schedule LP)
- Lighting (Rate Schedules OL, SL, SOL, SSL, MHOL, MHSL, and LED-OL)

In the past, UGI Electric's Flood Control Power ("FCP") Rate was included in the General Service-4. As part of the settlement agreement approved in UGI Electric's 2021 base rate case at Docket No. R-2021-3023618, UGI Electric was required to "either eliminate, consolidate, or otherwise support Rate FCP as a separately identified class in the cost of service presented in the Company's next rate case."[2] The FCP customers are served directly from the primary system and have paid for dedicated transformers and services, which results in FCP only being allocated costs upstream of the secondary system and the cost of meters. Given the nature of the cost to serve the FCP customers, the decision was made to keep the FCP class as a separate tariffed rate class. As such, the ACOSS presented in this filing contains a separately identified class for the FCP Rate.

[2] See *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket Nos. R-2021-3023618, et al., p. 13 (Opinion and Order entered Oct. 28, 2021) (quoting Paragraph 48 of the Joint Petition for Approval of Settlement of All Issues).

Q. Please explain how UGI Electric's Pennsylvania jurisdictional costs are derived.

A. This filing is based on the investment and expense incurred to provide distribution service to UGI Electric's Pennsylvania jurisdictional customers. Certain costs associated with UGI Electric's provision of transmission service under an open access transmission tariff administered by PJM Interconnection, LLC ("PJM") are recoverable from PJM through an annual formulary revenue requirement filing approved by the FERC. The costs subject to recovery through this FERC-jurisdictional rate mechanism were excluded to identify UGI Electric's Commission-jurisdictional distribution costs. Once UGI Electric completed this assignment, I utilized UGI Electric's cost of service specific to its Pennsylvania-jurisdictional retail customers.

Q. Please describe the Atrium Model used in conducting the ACOSS filed in this proceeding.

A. UGI Electric has selected the Atrium Excel-based model ("Atrium ACOSS Model") to conduct the ACOSS in this general base rate case. The Atrium ACOSS Model was developed by Atrium on a proprietary basis for its consulting engagements and has been used in multiple jurisdictions. This is the same Atrium ACOSS Model that UGI Electric presented and that I sponsored in UGI Electric's 2021 base rate case at Docket No. R-2021-3023618. Further, there are no material differences, in output and format, between the Atrium ACOSS Model used in this case and the past ACOSS model that UGI Electric presented and I sponsored in UGI Electric's 2018 base rate case at Docket No. R-2017-2640058.

Q. Does the methodology utilized in the current cost allocation study and supporting analyses match the methods used in UGI Electric's 2021 base rate case at Docket No. R-2021-3023618 and UGI Electric's 2018 base rate case at Docket No. R-2017-2640058?

A. Yes. The current ACOSS presented with this filing and proposed for use for decisions on the apportionment of the class revenue increases and rate design reflects the same methods utilized in UGI Electric's 2018 and 2021 base rate cases.

Q. Did the Commission opine on the appropriateness of these ACOSS methods?

A. Yes. In the UGI Electric 2018 base rate case (Docket No. R-2017-2640058), the Commission explicitly adopted UGI Electric's ACOSS and rejected the alternative proposed by the Office of Consumer Advocate ("OCA"), stating the following in the final order:

> Additionally, as UGI and the OSBA both highlighted, the Commission has affirmed the use of the "minimum system method" as the accepted approach to classify and allocate distribution system costs in several proceedings. See 2012 PPL Order, supra; see also, Pa. PUC v. PPL Electric Utilities Corp., Docket No. R-2010-2161694, (Order entered December 21, 2010) (2010 PPL Order). Further, we find that UGI's ACOSS is consistent with the NARUC Manual and more accurately reflects cost-causation principles than the ACOSS methodology proposed by the OCA.[3]

[3] *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket Nos. R-2017-2640058, *et al.*, p. 160 (Order entered Oct. 25, 2018).

Q. How did you functionalize and classify UGI Electric's Pennsylvania-jurisdictional distribution costs?

A. The process started with each of the Company's FERC accounts, which were assigned to a specific function. In some instances, the costs in an account were first split into separate functions or classifications if the costs in the account were incurred to perform more than one function or the costs in an account varied significantly with respect to more than one factor. For example, the accounts for distribution system poles, towers and fixtures, and conductors and conduits were separated into two functions: primary distribution and secondary distribution. In addition, these costs were further separated into demand and customer classifications. The functionalization and classification studies are provided in Section I of UGI Electric Exhibit D. It should be noted that the functionalization and classification of distribution plant investments and expenses are based on a detailed analysis of specific UGI Electric plant records and cost data.

Q. What cost assignment and allocation method was utilized in your studies?

A. I utilized the class average monthly maximum NCP demand to allocate demand-related distribution costs. Section II of UGI Electric Exhibit D presents the results of studies using other demand allocation methods, as required under the Commission's regulations. Further, the various customer-based allocation factors were developed utilizing Company records and data, including a meter investment allocation study and a services investment allocation study. Both are described in further detail and provided within Section II of UGI Electric Exhibit D.

Q. Please summarize the results of the Company's ACOSS.

A. Table 1 below presents a summary of the Company's ACOSS that can be reviewed in Schedule 1 of Book IX, UGI Electric Exhibit D. The ACOSS shows an overall revenue deficiency to the Company of $11.425 million.

Table 1 - Summary Results of the Company's ACOSS ($000)[4]

Customer Classes	Current Revenues	Cost to Serve	Class Revenue (Deficiency)/ Excess
Residential	$ 117,080	$ 131,771	$ (14,691)
General Service	6,647	7,386	(739)
General Service-4	14,321	13,161	1,160
Flood Control Power	19	24	(5)
Large Power	11,680	9,469	2,211
Lighting	1,843	1,203	639
Subtotal	**$ 151,589**	**$ 163,014**	**$ (11,425)**
Other Revenues	$ 1,102	$ 1,102	-
Total System	**$ 152,691**	**$ 164,116**	**$ (11,425)**

Table 1 presents the revenue deficiency/excess for each rate class and the class rate of return on the net rate base at present rates. Regarding rate class revenue levels, the ACOSS results show that the Residential, General Service, and Flood Control Power rate classes are being charged rates that recover less than their indicated costs of service, whereas rates for other rate classes provide for recovery of more than the indicated costs of serving these other rate classes. Next, I explain how these ACOSS results guided the Company's determination of the revenues by rate class and the proposed rate levels.

[4] See Exhibit D, Schedule 6 lines 18, line 58, and line 59. Other Revenues is the sum of lines 13 and 14 shown at line 57.

IV. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the rate design principles utilized in developing the Company's rate design proposals.

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures and rate levels within rate classes, relies upon principles that have broad acceptance in the recognized literature on utility ratemaking and regulatory policy, including:

1. Cost of Service;
2. Efficiency;
3. Value of Service;
4. Stability/Gradualism;
5. Non-Discrimination;
6. Administrative Simplicity; and
7. Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates.[5] Each of these principles plays an important role in analyzing the rate design proposals of UGI Electric. In addition, these principles are consistent with Pennsylvania practice and precedent, including the *Lloyd* decision,[6] where the Commonwealth Court indicated that cost of

[5] James Bonbright et al. Principles of Public Utility Rates, Public Utilities Reports, Inc. 2nd Edition, 1988.
[6] *Lloyd v. Pa. P.U.C.*, 904 A.2d 1010 (Pa. Cmwlth. 2006), *appeal denied*, 591 Pa. 676, 916 A.2d 1104 (2007).

service is the "polestar" of ratemaking but that other factors, including those listed above, can be considered as well.

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes. These principles can compete with each other, and this tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design recommendations must recognize the potential and actual tension between these principles. There are tensions between the cost and value of service principles as well as efficiency and simplicity. There are potential conflicts between simplicity and non-discrimination and between the value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. How are these principles translated into the design of rates?

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures within rate classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity, the rate design process must be, in part, influenced by judgmental evaluations.

V. ALLOCATION OF THE REVENUE INCREASE

Q. Please describe the approach generally followed in allocating UGI Electric's proposed revenue increase of $11.452 million to its various rate classes.

A. To reflect the results of the class cost-of-service study, the Company is proposing to move all rate classes closer to the overall system rate of return and, as a result, reduce the current subsidies occurring between classes. This movement of classes towards the overall system rate of return is consistent with regulatory practice and precedent, including the *Lloyd* decision and the Commission's Order on remand approving the settlement of that case.

Q. Please describe the proposed approach to apportion UGI Electric's proposed revenue increase to its rate classes.

A. As just described, the apportionment of revenues among rate classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. After discussions with the Company, the increase proposed in this case was allocated based on a desire to move toward full parity over time while addressing issues of gradualism. The decision was made to provide no rate decreases to classes when other classes are facing increases. As such, the rate increase was spread across three classes Residential, General Service, and Flood Control Power. While there are various yardsticks used to measure the degree of movement toward cost of service, the Company evaluated two metrics: (1) the percentage movement towards the system rate of return; and (2) the percentage change in the subsidies occurring between classes. With these considerations, the Company is proposing the revenue increases shown in Table 2 below.

In addition, Table 3 below provides the proposed revenue increase and the resulting percentage change in distribution operating revenues.

Table 2 – Proposed Class Revenue Apportionment ($000)[7]

Customer Classes	Current Revenues	Proposed Revenue	Proposed Revenue Change	Proposed Percentage Change
Residential	$ 117,080	$ 127,785	$ 10,705	9.1%
General Service	6,647	7,361	714	10.7%
General Service-4	14,321	14,321	-	0.0%
Flood Control Power	19	24	5	27.7%
Large Power	11,680	11,680	-	0.0%
Lighting	1,843	1,843	-	0.0%
Subtotal	**$ 151,589**	**$ 163,014**	**$ 11,425**	7.5%
Other Revenues	$ 1,102	$ 1,102	-	
Total System	**$ 152,691**	**$ 164,116**	**11,425**	7.5%

Table 3 – Proposed Change in Distribution Operating Revenue by Rate Class ($000)[8]

Customer Classes	Current Distribution Operating Revenue	Proposed Distribution Operating Revenue	Proposed Revenue Change	Proposed Percentage Change
Residential	$ 38,996	$ 49,701	$ 10,705	27.5%
General Service	2,718	3,433	$ 714	26.3%
General Service-4	5,084	5,084	$ -	0.0%
Flood Control Power	19	24	$ 5	27.7%
Large Power	6,617	6,617	$ -	0.0%
Lighting	1,262	1,262	$ -	0.0%
Subtotal	**$ 54,695**	**$ 66,120**	**$ 11,425**	20.9%
Other Revenues	$ 1,102	$ 1,102	-	0.0%
Total System	**$ 55,798**	**$ 67,223**	**11,425**	20.5%

[7] See Exhibit D, Schedule 6, line 18, line 65, line 60, line 67.
[8] See Exhibit D, Schedule 6, line 12, line 64, line 60, line 68.

Q. To what degree does the Company's proposed revenue apportionment move the classes toward their cost of service?

A. The Company's proposed revenue apportionment results in the reduction of the existing rate subsidies and excesses among the Company's rate classes and moves classes toward the overall system rate of return. From a class cost of service standpoint, this type of class movement, and reduction in class rate subsidies, is desirable such that class revenues and rates are closer to the indicated cost of service for each rate class.

Table 4 below compares the rate of return and relative rate of return under current and proposed class revenue levels. The percent change for the Residential, General Service, and Flood Control classes equals 74%.

Table 4 - Comparison of Relative Rate of Return by Rate Class[9]

Customer Classes	Current Rate of Return On Net Rate Base	Current Relative Rate of Return	Proposed Rate of Return on Net Rate Base	Proposed Relative Rate of Return	Percent Change
Residential	-0.18%	(0.05)	5.95%	0.73	74%
General Service	3.23%	0.86	7.85%	0.96	74%
General Service-4	17.29%	4.59	14.53%	1.78	78%
Flood Control Power	4.42%	1.17	8.51%	1.04	74%
Large Power	22.68%	6.02	19.07%	2.34	73%
Lighting	38.14%	10.12	31.87%	3.91	68%
Total Company	**3.77%**	**1.00**	**8.15%**	**1.00**	

[9] Exhibit D, Schedule 6, line 29, line 30, line 73, line 74. Percent Change = Proposed Relative Rate of Return/(1-Current Relative Rate of Return).

Q. To what degree does the Company's proposed revenue apportionment decrease the existing subsidies between rate classes?

A. Table 5 below summarizes the current and proposed subsidies and the reduction in all customer classes' subsidies resulting from the Company's proposed revenue apportionment.

Table 5 - Comparison of Present and Proposed Subsidies ($000) [10]

Customer Classes	Current Class Subsidy	Proposed Class Subsidy	Reduction in Subsidy
Residential	(6,237)	(3,986)	2,251
General Service	(59)	(25)	34
General Service-4	2,129	1,160	970
Flood Control Power	0.778	0.668	0.110
Large Power	3,352	2,211	1,140
Lighting	814	639	175

VI. UGI ELECTRIC'S RATE DESIGN PROPOSALS

Q. Please summarize the rate design changes UGI Electric has proposed in this rate proceeding.

A. In general, UGI Electric's rate design strategy is to make incremental movements toward reflecting the Company's relative cost of serving each rate class to provide electric distribution service to those customers. UGI Electric has proposed the following rate design changes to its current tariff schedules:

- Residential – Increase in the Monthly Customer Charge from $9.50 to $13.50, with the remaining proposed increase to be recovered in the Volumetric Charge.

[10] See Exhibit D, Schedule 6, line 40, line 66. Reduction in Subsidy = Absolute difference between Proposed Subsidy and Current Subsidy.

- General Service – Increase in the Monthly Customer Charge from $13.00 to $14.00, with the remaining proposed increase to be recovered in the Volumetric Charge.
- General Service-4 – No changes proposed.
- Flood Control Power – Recover the proposed increase in the volumetric charges.
- Large Power – No changes proposed.
- Lighting – No changes proposed.

Q. Has the Company prepared a detailed comparison of the Company's present and proposed rates and resulting revenues by rate class?

A. Yes. UGI Electric Exhibit E – Proof of Revenue, sponsored by Company witness Sherry A. Epler, presents a detailed comparison of present and proposed revenues for each of UGI Electric's rate classes.

Q. What insight does the ACOSS provide concerning the development of the Residential customer charge?

Atrium's ACOSS model allows for developing the total revenue requirement by functions and classifications. As such, we can see directly the revenue requirement associated with the customer classification and the respective functions that form this revenue requirement. Table 6 below provides this information for the Residential class at the proposed rate increase.

Table 6 - Components of Residential Customer-Related Revenue Requirement[11]

Customer Portion of Residential Revenue Requirement		
Function	**Amount**	**Includes**
Total Customer Related Costs	**$ 43,536,966**	
USP Rider Costs	**$ 6,656,204**	
Total Customer Related Costs Less USP	**$ 36,880,762**	Customer Portion of Distribution
Annual Bills (Customer Count * 12)	659,976	Facilities
Unit Costs	**$ 55.88**	PA PUC Direct Customer Costs
Function	**Amount**	**Includes**
Distribution Facilities - Customer Portion	**$ 22,050,615**	
Annual Bills (Customer Count * 12)	659,976	Distribution Primary
Unit Costs	**$ 33.41**	Distribution Secondary
Function	**Amount**	**Includes**
PA PUC Direct Customer Costs	**$ 21,486,351**	
USP Rider Costs	**$ 6,656,204**	Meters and Services
PA PUC Direct Customer Costs less USP	**$ 14,830,147**	Meter Reading
Annual Bills (Customer Count * 12)	659,976	Customer Service
Unit Costs	**$ 22.47**	Billing and Collections

As seen in the above table, the total customer-related costs of $36.9 million result in a monthly Residential customer cost of $55.88. These costs are fixed with respect to the number of customers and do not vary with the amount of energy used or the amount of demand. A total of $36.9 million of Residential customer-related costs are broken down between the customer portion of distribution facilities and customer service and billing costs.

[11] For Total Customer Related Costs See Exhibit D, Schedule 8, line 41, line 67 (annual bills) and Exhibit D, Schedule 7, line 139 (USP Rider Costs). For Distribution Facilities – Customer Portion see Exhibit D, Schedule 8, line 31. For PA PUC Direct Customer Costs see Exhibit D, Schedule 8, line 36.

Q. Can you please discuss the results in Table 6 above within the context of the Company's proposed Residential customer charge of $13.50 and past Commission precedent?

A. Yes, past Commission precedent defines customer-related costs for inclusion in a customer charge as costs associated with meters and services and related Operations and Maintenance ("O&M") expenses, meter reading and billing and collection expenses, meter data management systems, and related employee benefits, administrative and general expenses. The Company is proposing a customer charge of $13.50, which is below the $22.47 within Table 6 above and represents meter reading, customer service, and billing and collection expenses. These are all costs historically allowed by the Commission in a customer charge. Taking into consideration past precedent in Pennsylvania and given the results of the ACOSS as shown in Table 6 above, the Company is proposing to move the Rate R customer charge to $13.50.

Q. What criteria were utilized to determine that a $14.00 customer charge for the General Service rate class is appropriate?

A. The General Service rate class does not have a demand charge, so all distribution margin revenues are recovered through either the monthly customer or the volumetric charge. There were three options to recover the demand-related costs and the costs associated with the minimum distribution system: (1) introduce a demand charge; (2) put all of the increase in the volumetric charge; or (3) recover the demand and costs associated with the minimum distribution system within the monthly customer charge. Introducing a demand charge was not viable given current metering technology, and concerns relating to administrative billing complexity and recovering the demand costs and minimum distribution facilities fully through the customer charge or the volumetric charge did not balance the principles of rate design earlier discussed (e.g., fairness, stability, and consumer rationing/economic efficiency). After reviewing the current level of the customer charge for General Service-4 at $15.00 and the proposed level of Residential at $13.50, it was determined a reasonable middle ground would be to propose a $14.00 monthly customer charge for General Service-1. This allows some of these fixed demand and minimum distribution costs to be recovered through a fixed monthly customer charge rather than a volumetric charge, without introducing a demand charge for the General Service class. This proposed increase to the customer charge results in approximately 27% of the total non-default service revenue for General Service-1 being recovered through the customer charge, which is comparable to the 30% recovered from both the customer charge and the first block of the demand charge for General Service-4.

Q. Please describe why an increase to the customer charge is important.

A. This becomes particularly important when a customer considers different options for the generation portion of the customer's bill, the purchase of an Electric Vehicle, and investments in conservation and energy efficiency, as these decisions are fundamental functions of usage. These decisions can be distorted when non-usage-related fixed costs are collected on a usage basis. Further, without proper price signals, the economic markets that comprise materials, goods, and services that are inputs and outputs to energy products and services are distorted. As such, companies and people cannot make the proper decision to maximize their preferences on allocating their limited resources of time and money. It is economically inefficient when fixed distribution costs are recovered on a usage basis, and customers implement energy efficiency measures reducing their contribution to fixed costs with no corresponding reduction in the fixed costs of providing service.

VII. CONCLUSION

Q. Please summarize your conclusions and recommendations for UGI Electric's ACOSS, class revenues, and rate design.

A. My conclusions and recommendations are as follows:

- The Commission should accept the results of the Company's ACOSS as a realistic reflection of cost causation and the design and operating characteristics of the Company's distribution system.
- The Commission should accept the results from the Company's ACOSS as a guide to evaluate and set UGI Electric's class revenues and rate design in this proceeding. As noted above, the Commission previously approved the methods employed by UGI Electric's most recent base rate proceeding.
- The Commission should accept the Company's proposed apportionment of revenues to its rate classes because it reasonably balances the various criteria that the Company

considered in the revenue apportionment process and moves classes towards their cost to serve.

- The Commission should approve the rate design proposed by the Company because it reasonably balances key rate design objectives I presented earlier in my testimony, including: (1) achieving fair and equitable rate levels that are reflective of the cost to serve; (2) avoiding undue discrimination between and within rate classes; (3) developing rates that are stable and understandable; (4) creating economically efficient pricing for delivery service; (5) encouraging conservation and efficient use; and (6) recovering the revenue requirement in a manner that maintains revenue stability and minimizes year-to-year under- or over-collections.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC

EXHIBIT JDT-1

ATRIUM ECONOMICS
CENTERED ON ENERGY

John D. Taylor

Managing Partner

Mr. Taylor has experience with a wide range of costing, ratemaking, and regulatory activities for gas and electric utilities. He has testified numerous times on these and other issues for clients across North America. He has extensive experience with costing and pricing rates and services, regulatory planning and strategy development, revenue recovery and tracking mechanisms, merger and acquisitions analysis, new product and service development, affiliate transaction reviews, line extension policies, market assessments, litigation support, and organizational and operations reviews. He has testified on numerous occasions as an expert witness on costing and ratemaking related issues on behalf of utilities before federal, state, and provincial regulatory bodies and has extensive experience in evaluating and implementing innovative ratemaking approaches and rate design concepts.

He has also testified on return on equity, electric vehicle and battery storage programs, time-of-use rates, and the appropriate use of statistical analysis during audit testing. Mr. Taylor has led engagements relating to gas supply planning and the review of midstream transportation and storage capacity resources. He has worked as the market monitor for New England ISO's capacity market, supported the negotiation of PPAs, and supported feasibility and prudence studies of generation investments. He has also been involved in selling generating assets and distribution companies, supporting due diligence efforts, financial analyses, and regulatory approval processes.

Mr. Taylor received a master's degree in Economics from American University and holds a bachelor's degree in Environmental Economics from the University of North Carolina at Asheville.

His consulting career includes Managing Partner with Atrium Economics, LLC; Principal Consultant – Advisory & Planning with Black & Veatch Management Consulting, LLC; Senior Project Manager & Principal of Concentric Energy Advisors, Inc.; and CEO of Nova Data Testing, Inc. Mr. Taylor started his career working on Capitol Hill working with NGOs that were seeking Public Private Partnerships with the Federal Government, World Bank, and International Monetary Fund to pursue various projects in developing countries.

EDUCATION

M.A., Economics, American University

B.A., Environmental Economics, University of North Carolina at Asheville

YEARS EXPERIENCE

18

RELEVANT EXPERTISE

Utility Costing and Pricing, Expert Witness Testimony, Transaction Facilitation, Revenue Requirements, Statistics, Valuation, Market Studies, Rate Case Management, New Product and Service Development, Strategic Business Planning, Marketing and Sales

EXPERT WITNESS TESTIMONY PRESENTATION

United States

- California – Superior Court of California
- Delaware Public Service Commission
- Florida Public Service Commission
- Federal Energy Regulatory Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Maine Public Service Commission
- Massachusetts Department of Public Utilities
- Minnesota Public Utilities Commission
- New Hampshire Public Utilities Commission
- North Carolina Utilities Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission
- Public Service Commission of West Virginia

Canada

- Alberta Utilities Commission
- British Columbia Utilities Commission
- Ontario Energy Board

REPRESENTATIVE EXPERIENCE

Rate Design and Regulatory Proceedings

Mr. Taylor has worked on dozens of electric and gas rate cases including the development of revenue requirements, class cost of service studies, and projects related to utility rate design issues. Specifically, he has:

- Lead expert and witness for class costs of service studies across North America and worked on dozens of other class cost of service and rate design projects for other lead witnesses.
- Developed WNA mechanism for a gas utility including back casting results and supporting expert witness testimony and exhibits.
- Developed revenue requirement model to comply with a new performance-based formula ratemaking process for a Midwest electric utility.
- Supported the developed of time of use rates, demand rates, economic development rates, load retention rates, and line extension policies.
- Analyzed and summarized allocation methodology for a shared services company.
- Assessed the reasonableness of costs through various benchmarking efforts.
- Led the effort to collect and organize plant addition documentation for six Midwest utilities associated with the state commission's audit of rate base.
- Supported lead-lag analyses and testimonies.
- Analyzed customer usage profiles to support reclassification of rate classes for a gas utility.
- Helped conduct a marginal cost analysis to support rate design testimony.

Litigation Support and Expert Testimony

Mr. Taylor has testified in several cases on class cost of service studies and statistical audit methods. He has also supported numerous other expert testimonies. Specifically, he has:

- Filed testimony as an expert witness on allocated class cost of service studies for both electric and gas utilities.
- Filed testimony as an expert witness on the application of statistical analysis.
- Filed testimony before FERC on the rate of return for an Annual Transmission Revenue Requirement and participated in FERC settlement conferences.
- Part of two-person expert witness team that provided an expert report to the British Columbia Utilities Commission on the use of facilities for transportation balancing services for Fortis BC.
- Part of two-person expert witness team that provided an expert report on affiliate transactions and capitalized overhead allocations for Hydro One on three separate occasions.
- Sole expert for expert report on affiliate allocations for Alectra utilities, the second largest publicly owned electric utility in North America. This was conducted shortly after the merger of four distinct utilities.
- Sole expert for expert report on the allocation of overhead costs between transmission and distribution businesses for EPCOR.

Transaction Experience

Mr. Taylor has been involved with several generating asset transactions supporting both buy side and sell side analysis and due diligence. His work has included:

- Worked as buy side advisor for a large water utility in the mid-Atlantic region including supporting the review of revenue requirements, rates, and forecasts.
- Helped facilitate and manage processes for a nuclear plant auction by processing Q&A, collecting relevant documentation and managing the virtual data room for auction participants.
- Supported the auction process for steam and chilled water distribution and generation assets in the Midwest.
- Supported the development of a financial model to ascertain the net present value of several competing wholesale power purchase agreements and guided the client with a decision matrix for the qualitative aspects of the offers.
- Provided research on comparable transactions, previous mergers and acquisitions, and potential transaction opportunities for several clients.

Financial Analysis and Market Research

Other financial analysis and market research Mr. Taylor has conducted include:

- Estimated the rate impact and costs associated with moving California energy market to 100% renewable.
- Assessed the consequences of a divestiture on the cost of service model for a New England gas distribution company.
- Developed LNG market studies for two separate utilities and two separate competitive market participants.
- Modeling alternative mechanisms for the allocation of overhead costs to a nuclear plant.

UGI ELECTRIC STATEMENT NO. 7

JOHN F. WIEDMAYER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368

UGI Utilities, Inc. - Electric Division

Statement No. 7

Direct Testimony of
John F. Wiedmayer, C.D.P.

Topics Addressed: **Depreciation**

Date: January 27, 2023

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I. INTRODUCTION

Q. Please state your name and address.

A. My name is John F. Wiedmayer. My business address is 1010 Adams Avenue, Audubon, Pennsylvania 19403.

Q. Are you associated with any firm and in what capacity?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") as Project Manager, Depreciation and Valuation Studies.

Q. How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since I graduated from college in June 1986.

Q. What is your educational background?

A. I have an AB Engineering degree from Lafayette College and a Master of Business Administration from the Pennsylvania State University.

Q. Do you belong to any professional societies?

A. Yes. I am a member of the National and Pennsylvania Societies of Professional Engineers and the Society of Depreciation Professionals ("SDP"). In 2005, I served as President of the SDP and was a member of the SDP's Executive Board for the years 2003 through 2007.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The SDP has established national standards for depreciation professionals. The SDP administers an examination to become certified in this field. I passed the certification exam in September 1997 and have fulfilled the requirements necessary to remain a Certified Depreciation Professional.

Q. Please outline your experience in the field of depreciation.

A. I have over 36 years of depreciation experience, which includes expert testimony in numerous cases before 14 regulatory commissions, including the Pennsylvania Public Utility Commission ("PA PUC" or the "Commission").

In June 1986, I was employed by Gannett Fleming as a Depreciation Engineer. I held that position from June 1986 through December 1995. In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In August 2004, I was promoted to Project Manager of Depreciation Studies. In 2020, I was promoted to my present position as Senior Project Manager of Depreciation Studies. I am responsible for conducting depreciation and valuation studies, including the preparation of testimony, exhibits, and responses to data requests for submission to the appropriate regulatory bodies. My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

During the course of my employment with Gannett Fleming I have assisted in the preparation of numerous depreciation studies for utility companies in various industries such as electric, gas, water, steam, telephone and railroads.

In each of the studies I was involved with, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service lives and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies.

Q. Have you previously testified on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Kentucky Public Service Commission, the Newfoundland and Labrador Board of Commissioners of Public Utilities, the Nova Scotia Utility and Review Board, the Federal Energy Regulatory Commission, the Utah Public Service Commission, the Arizona Corporation Commission, the Missouri Public Service Commission, the Illinois Commerce Commission, the Maine Public Utilities Commission, the Maryland Public Service Commission, the New York Public Service Commission, the New Jersey Board of Public Utilities, Public Utilities Regulatory Authority (for Connecticut) and the PA PUC.

Q. Have you received any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation" and "Managing a Depreciation Study." In 1999, I became an instructor at the SDP's annual conference lecturing on "Salvage Concepts," "Depreciation Models," "Analyzing the Life of Real-World Utility Property – Actuarial Analysis," "Theoretical Reserve" and "Data Requirements for a Depreciation Study." I am a faculty member of the Society of Depreciation ("Society") and since 1999 have been responsible for preparing and presenting courses on depreciation matters each year at the Society's annual conference.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony is in support of the depreciation studies conducted under my direction and supervision for the electric plant of UGI Utilities, Inc. - Electric Division ("UGI Electric" or the "Company") in this proceeding. I have been retained by the Company as a depreciation consultant. UGI Electric retained me to determine the book depreciation reserve as of September 30, 2024, and to determine the annual depreciation expense to be included as an element of the cost of service, and to testify in support of those two determinations in this proceeding.

I am also a sponsoring witness for UGI Electric's depreciated original cost of electric plant in service included in rate base. My testimony will address my depreciation study, the appropriate depreciation reserve for ratemaking purposes, the original cost measure of value, and the appropriate annual depreciation expense to be included in the ratemaking cost of service as of September 30, 2024.

Q. Were you responsible for the preparation of any of the Company's responses to the Commission's filing regulations that were filed in support of the Company's general rate filing?

A. Yes. I am the responsible witness for the following items in UGI Electric Books I and II:

Item No.	Subject
II-D-13	Experienced and Estimated Net Salvage
V-A-1	Electric Plant in Service
V-A-2	Comparison of Calculated Reserve vs. Book Reserve
V-A-3	Projected Plant and Reserve Balances
V-B-1	Comparison of Calculated vs. Book Accruals
V-B-2	Survivor Curves and Surviving Original Cost Including Related Annual and Accrued Depreciation
V-C-1	Retirement Rate Actuarial Method of Life Analysis
V-D-1	Summary Depreciation Calculations by Account
V-D-2	Detailed Depreciation Calculations by Account and Vintage Year
V-E-1	Description of Depreciation Methods and Factors Considered in Arriving at Estimates of Service Life and Dispersion by Account

Q. Have you previously prepared comparable studies for UGI Electric?

A. Yes. I provided testimony on depreciation matters for the Company in the prior two UGI Electric base rate cases at Docket Nos. R-2017-2640058 and R-2021-3023618. Also, I provided testimony on depreciation matters for the Company in the prior two UGI Penn Natural Gas ("PNG") base rate cases at Docket Nos. R-2016-2580030 and R-2008-2079660, the prior two UGI Central Penn Gas ("CPG") base rate cases at Docket Nos. R-2010-2214415 and R-2008-2079675, and the prior four UGI Utilities, Inc. – Gas Division ("UGI Gas") base rate cases at Docket Nos. R-2021-303-0218, R-2019-3015162, R-2018-3006814 and R-2015-2518438. Prior to those rate filings, I prepared exhibits for the depreciation study in UGI Gas's previous base rate case filed in 1995 at Docket No. R-00953297 and UGI Electric's prior two base rate cases at Docket Nos. R-00973975 and R-00953534.

III. OUTLINE OF EXHIBITS C (FULLY PROJECTED FUTURE), C (FUTURE) AND C (HISTORIC)

Q. Will you be sponsoring any exhibits with your direct testimony?

A. Yes, I am attaching and sponsoring the following exhibits: UGI Electric Exhibit C (Fully Projected Future), UGI Electric Exhibit C (Future) and UGI Electric Exhibit C (Historic). UGI Electric Exhibit C (Fully Projected Future) presents the summarized depreciation calculations and supporting tables related to the fully projected future test year ending September 30, 2024 ("FPFTY"). UGI Electric Exhibit C (Future) presents summarized depreciation calculations and supporting charts and tables related to the depreciation study for the future test year ending September 30, 2023 ("FTY"). UGI Electric Exhibit C (Historic) presents the summarized depreciation calculations and supporting tables related to the historic test year ended September 30, 2022 ("HTY"). Each of the three exhibits is organized in a similar manner and each contains information and schedules supporting the amounts applicable to each test year period. UGI Electric Exhibit C (Future) contains additional information including the supporting charts and life tables related to the service life estimates.

Q. Does UGI Electric Exhibit C (Fully Projected Future) accurately portray the results of your depreciation study as of September 30, 2024?

A. Yes.

Q. In preparing the depreciation study (contained in Exhibit C (Future)), did you follow generally accepted practices in the field of depreciation?

A. Yes.

Q. Please describe the contents of the depreciation study reports, UGI Electric Exhibit C (Future) and UGI Electric Exhibit C (Fully Projected Future).

A. The depreciation study report in UGI Electric Exhibit C (Future) consists of eight parts, including charts and tables filed in the Company's most recent service life study report submitted to the PA PUC in May 2022 based on electric plant in service as of September 30, 2021. Part I, Introduction, includes statements related to the scope of and basis for the depreciation study. Part II, Estimation of Survivor Curves, presents detailed discussions of: (1) survivor curves; and (2) methods of life analysis including an example of the retirement rate method. Part III, Service Life Considerations, presents the relevant factors considered for estimating service lives. Part IV, Calculation of Annual and Accrued Depreciation, sets forth a description of: (1) the group depreciation procedures used for calculating annual and accrued depreciation; and (2) an explanation of the manner in which net salvage was incorporated in the calculations. Part V, Results of Study, includes a description of the results and summaries of the detailed depreciation calculations as of September 30, 2023. Part VI, Service Life Statistics, presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. Part VII, sets forth the detailed depreciation calculations related to surviving original cost as of September 30, 2023. The detailed depreciation calculations present the annual and accrued depreciation amounts by account and vintage year. The remaining life annual accrual rate is also set forth in the tables of Part VII. Part VIII, Experienced and Estimated Net Salvage, contains the net salvage amortization of experienced and estimated net salvage for the fiscal years 2019 through 2023.

UGI Electric Exhibit C (Fully Projected Future) includes: a description of the scope, basis and results of the studies; summaries of the depreciation calculations; and the detailed depreciation calculations as of September 30, 2024. The descriptions and explanations presented in UGI Electric Exhibit C (Future) are also applicable to the depreciation calculations presented in UGI Electric Exhibit C (Fully Projected Future). The graphs and tables related to service life presented in UGI Electric Exhibit C (Future) also support the service life estimates used in UGI Electric Exhibit C (Fully Projected Future) and UGI Electric Exhibit C (Historic), since the estimates are the same for all three test years.

The results of the study are set forth in Part II in UGI Electric Exhibit C (Fully Projected Future). Table 1, pages II-3 through II-5 of UGI Electric Exhibit C (Fully Projected Future), presents the estimated survivor curve, the original cost and depreciation reserve at September 30, 2024, and the calculated annual depreciation rate and amount for each account or subaccount of Electric Plant in Service. Table 2, pages II-6 through II-7 of UGI Electric Exhibit C (Fully Projected Future), presents the bring-forward to September 30, 2024, of the depreciation reserve as of September 30, 2023. Table 3, pages II-8 through II-10 of UGI Electric Exhibit C (Fully Projected Future), presents the calculation of the book depreciation amounts for the FPFTY. Table 4, pages II-11 and II-12 of UGI Electric Exhibit C (Fully Projected Future), presents the experienced and estimated net salvage for fiscal years 2020 through 2024. The amortization of net salvage is based on experienced and estimated net salvage during the period October 1, 2019 through September 30, 2024. The summary tables and detailed depreciation calculations set forth in UGI Electric Exhibit C (Fully Projected Future) as of September 30, 2024, are organized and presented in the same manner as those presented in UGI Electric Exhibit C (Future) as of September 30, 2023.

Q. Please outline the contents of Exhibit C (Historic).

A. UGI Electric Exhibit C (Historic) is organized like UGI Electric Exhibit C (Fully Projected Future). UGI Electric Exhibit C (Historic) includes: a description of the scope, basis and results of the studies; summaries of the depreciation calculations; and the detailed depreciation calculations as of September 30, 2022. The descriptions and explanations presented in UGI Electric Exhibit C (Future) are also applicable to the depreciation calculations presented in UGI Electric Exhibit C (Historic). The same depreciation methods and procedures used to calculate depreciation were used in all three test year periods. The summary tables and detailed depreciation calculations as of September 30, 2022, are organized and presented in the same manner as those as of September 30, 2024 with two exceptions. Tables 2 and 3 presented in UGI Electric Exhibit C (Fully Projected Future) are not necessary and, therefore, are not presented in UGI Electric Exhibit C (Historic).

IV. THE DEPRECIATION STUDY - OVERVIEW

Q. Please describe what you mean by the term "depreciation."

A. My use of the term "depreciation" is in accord with the definition set forth in the Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act (or, as referenced in Ms. Ressler's testimony, FERC Uniform System of Accounts). "Depreciation" refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation, against which the company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.

In the study that I performed, which is the basis for my testimony, I used the straight line remaining life method of depreciation, with the average service life and equal life group procedures. The annual depreciation is based on a system of depreciation accounting that aims to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of the unit, or group of assets, in a systematic and rational manner.

Q. Is the Company's claim for annual depreciation in the current proceeding based on the same methods of depreciation as were used in its most recent Annual Depreciation and Service Life Study Report filed in May 2022?

A. Yes, it is. For most plant accounts, the current claim for annual depreciation is based on the straight line remaining life method of depreciation, which has been used by the Company for many years. The depreciation methods and procedures are described further in Part II of UGI Electric Exhibit C (Future).

For General Plant Accounts 391, 393, 394, 395, 397 and 398, I used the straight line remaining life method of amortization. The annual amortization is based on amortization accounting, which distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account.

V. ORIGINAL COST MEASURE OF VALUE

Q. What is the original cost of electric plant to be included in rate base in this proceeding?

A. As of September 30, 2024, the original cost of electric plant in service is $275,001,657 as shown in column 4 of Table 1 on pages II-3 through II-5 of UGI Electric Exhibit C (Fully Projected Future). This amount includes $253,053,061 of Electric Plant and $21,948,596 of Other Utility Plant allocated to UGI Electric. Other Utility Plant is primarily comprised of plant assets included in Common Plant and Information Services ("IS"). The assets included in Common Plant and IS are assets that are shared and jointly used among the gas and electric divisions at UGI Corporation. The costs related to Common Plant and IS are allocated to UGI Electric using specific allocation factors.

Also, the Empire Office and Service Center in Wilkes Barre, PA is a facility jointly used by both UGI utility divisions; however, the cost of the facility is currently included in the gas division for book accounting purposes. For ratemaking purposes, a portion of the Empire facility has been allocated to the electric division.

Also, 25.6247 percent of the UGI Electric Division's Intangible, General and Common Plant were excluded from the Company's current proceeding based on the transmission factor from UGI Electric's most recent transmission rate filing before FERC. The amounts allocated to Transmission Plant and excluded from electric distribution operations are shown on Table 1 of Exhibit C (Fully Projected Future).

VI. THE ACCRUED DEPRECIATION CLAIM

Q. Have you determined UGI Electric's accrued depreciation for ratemaking purposes as of September 30, 2024?

A. Yes. I have determined the allocated book depreciation reserve as of September 30, 2024, to be $85,744,907.

Q. Is the Company's claim for accrued depreciation in the current proceeding made on the same basis as has been used for over thirty years?

A. Yes. The current claim for accrued depreciation is the book reserve brought forward from the book reserve approved by the Commission in the last proceeding.

Q. How did you determine UGI Electric's allocated book depreciation reserve as of September 30, 2023?

A. The book depreciation reserve allocated to UGI Electric as of September 30, 2023, is set forth in column 5 of Table 1 of UGI Electric Exhibit C (Future). Table 2 of UGI Electric Exhibit C (Future) presents an annual bring-forward of the book depreciation reserve as of September 30, 2022, using estimated accruals, retirements, salvage and cost of removal for the twelve months October 2022 through September 2023. The table sets forth, by plant account, the beginning book reserve balance as of September 30, 2022, the estimated reserve activity, and the ending reserve balance as of September 30, 2023. The estimated reserve activity consists of depreciation accruals (column 3), amortization of net salvage (column 4), projected retirements (column 5), projected salvage (column 6) and projected cost of removal (column 7). Table 3 of UGI Electric Exhibit C (Future) sets forth the calculation of the estimated depreciation accruals by plant account, which is carried forward to column 3 of Table 2. The book reserve as of September 30, 2022, by plant account, shown in column 2 of Table 2 was obtained from UGI Electric's books and records. The book depreciation reserve as of September 30, 2023 is the sum of the book reserve at the beginning of the fiscal year, September 30, 2022, and the projected 2023 reserve activity.

Q. Please explain the manner in which you projected the depreciation accruals for the twelve months ended September 30, 2023.

A. The depreciation accruals for the twelve months ended September 30, 2023, by plant account, were estimated by applying the annual depreciation accrual rates calculated as of September 30, 2022, to the projected average 2023 plant balance. The average balance for the twelve months ended September 30, 2023, is computed in columns 2 through 6 of Table 3 and is based on the projected additions and retirements in columns 3 and 4.

Q. With reference to Exhibit C (Future) Table 2, column 4, please explain what you mean by "the amortization of net salvage" and explain the manner in which you projected it.

A. The amortization of net salvage is the annual provision for recovering experienced negative net salvage. This process for recognizing net salvage in the cost of service is in accordance with Pennsylvania ratemaking practice. The amortization of net salvage is based on experienced net salvage during the preceding five-year period, October 1, 2018 through September 30, 2023.

Q. Please explain the manner in which you projected retirements, salvage and removal costs that are shown in columns 4, 5 and 6 of Table 2.

A. Retirements were projected, by plant account, by applying the average retirement ratio, expressed as a percent of additions, i.e., 2018 through 2022, to future test year (FTY) additions for most plant accounts. For certain General Plant accounts subject to amortization accounting, retirements are recorded when a vintage is fully amortized. All units are retired per books when the age of the vintage reaches the amortization period. Therefore, all vintages that reached or exceeded the amortization period were retired during the FTY for certain General Plant accounts subject to amortization accounting. Salvage and removal costs were projected by plant account by applying the average salvage and cost of removal ratios to the projected retirement amounts. The salvage and cost of removal ratios were determined as an average percent of the retirement amounts recorded for the five years 2018 through 2022.

Q. Was the book reserve at September 30, 2024, estimated using the same methodology?

A. Yes, essentially the same methodology was used with one minor exception. The book depreciation accruals for fiscal year 2024 were calculated by applying depreciation rates established as of September 30, 2023 to average monthly plant balances for purposes of calculating the book reserve as of September 30, 2024.

VII. THE ANNUAL DEPRECIATION EXPENSE CLAIM

Q. Have you determined UGI Electric's annual depreciation expense to be included as an element in the cost of service for purposes of this proceeding?

A. Yes, I have. The annual depreciation expense is $9.074,543 and consists of $8,217,505 of annual accruals to recover original cost and $857,038 of net salvage amortization. The $8,217,505 related to original cost recovery is comprised of two parts, $6,807,498 related to electric plant and $1,410,007 related to Other Utility Plant allocated to UGI Electric. These amounts are set forth in column 8 of Table 1 in UGI Electric Exhibit C (Fully Projected Future).

Q. How did you determine the annual accruals of $8,217,505?

A. The determination of annual depreciation accruals consists of two phases. In the first phase, survivor curves are estimated for each plant account or subaccount. In the second phase, the composite remaining lives and annual depreciation accruals are calculated based on the service life estimates determined in the first phase.

The determination of annual amortization amounts consists of the selection of amortization periods and the calculation of amortization amounts based on the remaining amortization period and the unrecovered cost for each vintage.

Q. Please describe the manner in which you estimated the service life characteristics for each depreciable group in the first phase of the study.

A. The service life study consisted of: compiling historical data from records related to UGI Electric's electric plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning UGI Electric's practices and plans as they relate to plant operations; and interpreting the above data to form judgments of average service life characteristics.

Q. What historical data did you analyze to estimate the service life characteristics of UGI Electric's electric plant?

A. The data consisted of the entries made by UGI Electric to record electric plant transactions during the period 1960 through 2021. The transactions included additions, retirements, transfers, acquisitions, and the related balances. I classified the data by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed.

Q. What method did you use to analyze these service life data?

A. I used the retirement rate method of life analysis. The retirement rate method is the most appropriate when aged retirement data are available because it develops the average rates of retirement actually experienced during the period of study. Other methods of life analysis infer the rates of retirement based on a selected type of survivor curve.

Q. Please describe the results of your use of the retirement rate method.

A. Each retirement rate analysis resulted in a life table, which, when plotted, formed an original survivor curve. Each original survivor curve, as plotted from the life table, represents the average survivor pattern experienced by the several vintage groups during the experience band studied. Inasmuch as this survivor pattern does not necessarily describe the life characteristics of the property group, interpretation of the original curves is required in order to use them as valid considerations in service life estimation. Iowa type survivor curves were used for the purposes of developing these analyses. The results of the retirement rate analyses are presented in Part VI of UGI Electric Exhibit C (Future).

Q. Please explain briefly what an "Iowa type survivor curve" is and how you used it in estimating service life characteristics for each depreciable group.

A. The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type survivor curves. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. Iowa curves are the accepted survivor curves for Pennsylvania, and the remaining 49 other states, and have been for many years.

Iowa type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the qualitative outlook for future retirements.

The estimated survivor curve designations for each depreciable group indicate the average service life, the family within the Iowa system and the relative height of the mode. For example, the Iowa 36-R2.5 curve indicates an average service life of thirty-six years; a Right-skewed, or R2.5, type curve (the mode occurs after average life for right modal curves); and a relatively medium height, 2.5, for the mode (possible modes for R type curves range from 0.5 to 5).

Q. Did you physically observe plant and equipment in the field?

A. Yes. Field trips are conducted periodically in order to be familiar with the operation of the Company and observe representative portions of the plant. Field trips are conducted each time a service life study is performed. Service life study reports are submitted to the PA PUC every five years, at minimum. UGI Electric's most recent service life study report was submitted in May 2022 based on electric plant in service as of September 30, 2021. Facilities visited during field trips, generally include representative substations, service centers, warehouses, and office buildings. The most recent field trip was conducted in December 2021. The specific dates and locations visited during recent field trips are listed in Exhibit C (Future) in Part III. A general understanding of the function of the plant and information with respect to the reasons for past retirements and expected causes of retirements are obtained during these field trips. This knowledge and information was incorporated in the interpretation and extrapolation of the statistical life analyses.

Q. Please describe the second phase of the process that you used to determine annual depreciation for ratemaking purposes.

A. After I estimated the service life characteristics for each depreciable group, I calculated annual depreciation accruals for each group in accordance with the straight line remaining life method, using remaining lives consistent with the average service life procedure for plant installed prior to 1982 and remaining lives consistent with the equal life group procedure for plant installed in 1982 and subsequent years. Summary tabulations of the survivor curve estimates and the annual accrual rates and amounts are set forth in Table 1 of UGI Electric Exhibit C (Historic), UGI Electric Exhibit C (Future) and UGI Electric Exhibit C (Fully Projected Future). The detailed tabulations of the depreciation calculations are presented in Part III of UGI Electric Exhibit C (Historic) and UGI Electric Exhibit C (Fully Projected Future) and Part VII of UGI Electric Exhibit C (Future).

Q. Please describe briefly the straight line remaining life method of depreciation that you used for depreciable property.

A. The straight line remaining life method of depreciation allocates the original cost less accumulated depreciation in equal amounts to each year of remaining service life for each vintage.

Q. Please describe briefly the average service life procedure that you used in conjunction with the straight line remaining life method for plant installed prior to 1982.

A. In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated survivor curve.

Q. Please describe briefly the equal life group procedure that you used in conjunction with the straight line remaining life method for plant installed in 1982 and in later years.

A. In the equal life group procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the composite remaining life for the surviving original cost of that vintage. The composite remaining life for the vintage is derived by weighting the individual equal life group remaining lives. In the equal life group procedure, the property group is subdivided according to service life. That is, each equal life group includes the portion of the property that experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve.

Q. Please describe briefly the amortization of certain General Plant accounts.

A. General Plant Accounts 391, 393, 394, 395, 397 and 398 include a very large number of units but represent a small percent of depreciable electric plant. Depreciation accounting is difficult for these assets, inasmuch as periodic inventories are required to properly reflect plant in service. Many utilities have changed to amortization accounting for general plant as a practical and reasonable solution that avoids significant accounting expenditures for such a small percent of plant.

In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, retirements are recorded when a vintage is fully amortized, rather than as the units are removed from service. That is, there is no dispersion of retirement for accounts being amortized. All units are retired per books when the age of the vintage reaches the amortization period. Amortization accounting was initiated for UGI Electric in Docket No. R-00932862.

VIII. ILLUSTRATION OF DEPRECIATION STUDY PROCEDURE

Q. Please illustrate the procedure followed in your depreciation study and the manner in which it is presented in UGI Electric Exhibit C (Future) using an account as an example.

A. I will use Account 368.1, Transformers, to illustrate the manner in which the study was conducted. Account 368.1 represents approximately 8.3 percent of the total depreciable distribution plant. As the initial step of the service life study phase, aged plant accounting data were compiled for the years 1960 through 2021. These data were coded in the course of UGI Electric's normal recordkeeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the electric plant was placed in service. The plant additions, retirements, and other plant transactions were analyzed by the retirement rate method of life analysis.

This account includes equipment used to reduce electric voltages, primarily pole-top or pad mounted line transformers. Retirements of line transformers are primarily caused by storm damage, deterioration, fire or third-party damage, capacity or loading issues, etc. Discussions with operating and management personnel indicated that the life characteristics of transformers will be similar in the future as they were in the past. Typical service lives for line transformers of other electric companies range from 35 to 45 years.

The life analysis was performed, and the Iowa 45-S1 survivor curve was judged most appropriate for this account and is the survivor curve used for this filing. The survivor curve estimate used in the previous service life study was the Iowa 43-S1 survivor curve. The Iowa 45-S1 survivor curve is a good fit for the original curve based on the Company's retirement experience for the period 1960-2021. The proposed 45-S1 survivor curve is within the range of estimates used by other electric companies and is consistent with the outlook of Company management. The original and smooth survivor curves are plotted in Part VI on page VI-21 of UGI Electric Exhibit C (Future). The original life table for the 1960-2021 experience band is set forth on pages VI-22 through VI-25.

The calculation of annual depreciation, the second phase, for the original cost of line transformers in service at September 30, 2023, is presented by vintage in Part VII on pages VII-16 through VII-17 of UGI Electric Exhibit C (Future) for Electric Plant in Service. The detailed depreciation calculations at September 30, 2024, are presented in Part III of Exhibit C (Fully Projected Future). The tabular presentations of the detailed depreciation calculations in Part VII of Exhibit C (Future) are similar in kind to those set forth in Part III of Exhibit C (Fully Projected Future). The expectancy and average life derived from the estimated survivor curve for each vintage were used to calculate the accrued depreciation by the average service life procedure for 1981 and prior vintages.

The accrued depreciation for vintages subsequent to 1981 was calculated by the equal life group procedure using the Iowa 45-S1 survivor curve. In the calculation, the surviving cost in each vintage was further subdivided, through the use of a computer program, into depreciable groups according to the expected service lives as defined by the Iowa 45-S1 survivor curve. The accrued depreciation was derived for each equal life group, based on its service life, and the totals shown for the vintages are the summations of the individually derived amounts.

The book reserve was allocated to vintages based on the calculated accrued depreciation. The remaining lives of the vintages were based on the Iowa 45-S1 survivor curve, the attained age, and the same group procedures as were used to calculate accrued depreciation. The future book accruals (original cost less allocated book reserve) were divided by the remaining lives to derive the annual depreciation accruals by vintage.

The total depreciation accrual on page VII-17 of UGI Electric Exhibit C (Future) was brought forward to column 8 of Table 1 on page V-4 of the exhibit and divided by the total original cost in column 4 to calculate the annual depreciation accrual rate in column 7. A similar process was used for the FPFTY.

Q. Is the procedure you described for Account 368.1 typical of that followed for most of the plant investment?

A. Yes, it is, since the straight-line method and the average service life and the equal life group procedures were used for most of the depreciable plant.

Q. Please illustrate the procedure followed for the amortization of certain General Plant accounts and the manner in which it is presented in UGI Electric Exhibit C (Future) using an account as an example.

A. I will use Account 394, Tools, Shop and Garage Equipment, to illustrate the amortization procedure. As the initial step of the amortization procedure, an amortization period of 20 years was selected based on the period during which such equipment renders most of its service, the amortization periods used by other utilities, and the service life estimate previously used for depreciation accounting.

The calculation of the annual amortization as of September 30, 2023, is presented by vintage in Part VII on page VII-44 of UGI Electric Exhibit C (Future). The calculated accrued amortization is based on the ratio of the vintage's age to the amortization period. The book reserve for vintages older than the amortization period was set equal to the original cost. The remaining book reserve was allocated to vintages based on the calculated accrued depreciation. The future book accruals or amortizations (original cost less assigned or allocated book reserve) were divided by the remaining amortization period to derive the annual amortizations by vintage.

The total amortization on page VII-44 of UGI Electric Exhibit C (Future) was brought forward to column 8 of Table 1 on page V-4 of UGI Electric Exhibit C (Future). A similar process was performed for UGI Electric Exhibit C (Fully Projected Future) and UGI Electric Exhibit C (Historic). That is, the calculation of the annual amortization related to the original cost of Tools, Shop and Garage Equipment in service at September 30, 2024, is presented by vintage on page III-46 of UGI Electric Exhibit C (Fully Projected Future) and summarized in Table 1 on page II-3.

Q. Briefly explain the methods used for the remaining portion of the depreciable plant.

A. The life span procedure was applied to major structures in Account 390. The life span procedure was used for groups such as buildings in which concurrent retirement of all property in the group is expected. The life span of both the original installation and subsequent additions is the number of years between installation and final retirement of the group. The complete details, by vintage, of the accrued depreciation and remaining life accrual calculations are set forth for each structure in Part III of UGI Electric Exhibit C (Historic) and UGI Electric Exhibit C (Fully Projected Future) and in Part VII of UGI Electric Exhibit C (Future).

IX. <u>THE NET SALVAGE AMORTIZATION CLAIM</u>

Q. Please briefly describe the accounting treatment regarding net salvage for public utilities operating in Pennsylvania.

A. In accordance with the Uniform System of Accounts and the rules for recovery of net salvage established by the Pennsylvania Superior Court in *Penn Sheraton Hotel v. Pa. P.U.C.*, 198 Pa. Super. 618, 184 A.2d 324 (1962) ("*Penn Sheraton*"), net salvage is charged to the depreciation reserve and is amortized over a five-year period beginning with the year after net salvage is actually incurred. These accounting procedures were affirmed by the Commission in PPL Gas Utilities Corporation's ("PPL Gas") most recent rate filing (Docket No. R-00061398). This procedure is consistent with how other Pennsylvania public utilities account for net salvage and is the method used in preparing the Company's Annual Depreciation Reports submitted each year to the Commission.

Q. Earlier in your testimony you indicated that UGI Electric's annual depreciation expense consists, in part, of $857,038 of net salvage amortization. How did you determine that amount?

A. The $857,038 is the result of determining the five-year average of net salvage experienced and estimated during the period of October 1, 2019 through September 30, 2024. Net salvage is defined in the Uniform System of Accounts as gross salvage less cost of removal. For most electric utilities, including UGI Electric, cost of removal exceeds gross salvage resulting in negative net salvage. Negative net salvage is recorded to the depreciation reserve as a debit, which reduces the depreciation reserve. Charges related to the negative net salvage amortization are recorded to the depreciation reserve as a credit in the five years subsequent to the initial recording of the negative net salvage amount. Therefore, the negative net salvage amount will have been fully amortized after five years and the net effect on the depreciation reserve is zero. Detailed data related to the experienced and estimated cost of removal and salvage are presented in Part VIII of UGI Electric Exhibit C (Future) and Part IV of UGI Electric Exhibit C (Fully Projected Future).

Q. Do you have any other comments on the other items which you are sponsoring in this proceeding?

A. Yes. The above testimony does not describe the responses to filing requirements set forth in Items V-A-2, V-B-1 and V-B-2. In general, these responses are self-explanatory. The response to V-A-2 is a comparison of the actual and projected book depreciation reserves with the calculated accrued depreciation as of the end of the test years. The response to V-B-1 is a comparison of the calculated depreciation accruals and the book depreciation accruals related to the future and fully projected future test years. The response to V-B-2 presents the survivor curves used in the most recent prior general rate proceeding and the annual accrual rates that resulted from the use of these curves.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC STATEMENT NO. 8

DARIN T. ESPIGH

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368

UGI Utilities, Inc. – Electric Division

Statement No. 8

Direct Testimony of
Darin T. Espigh

Topics Addressed: Taxes and Tax Adjustments

Dated: January 27, 2023

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Darin T. Espigh. My business address is One UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed by UGI Corporation ("UGI Corp.") as Senior Manager Natural Gas Tax Accounting. UGI Corp. is the parent company of UGI Utilities, Inc. ("UGI"). UGI has two operating divisions, the Electric Division ("UGI Electric" or the "Company") and the Gas Division ("UGI Gas"), each of which is public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your principal duties and responsibilities as Senior Manager Natural Gas Tax Accounting for UGI Corp.?

A. My primary duties as Senior Manager Natural Gas Tax Accounting include the preparation of tax data to be reported in UGI Corp.'s various United States Securities and Exchange Commission and regulatory filings, as well as its various federal and state income and non-income tax return related filings. Additionally, I maintain the current and deferred income tax accrual and expense accounts, perform tax research, and assist UGI with tax matters as they arise. I also manage the reporting of UGI's various tax filings with its local, state, and federal jurisdictions.

Q. Please describe your educational background and work experience.

A. They are set forth in my resume attached as UGI Electric Exhibit DTE-1.

Q. Please describe the purpose of your testimony.

A. I am providing testimony on behalf of UGI Electric. I will explain the Company's *pro forma* tax adjustments to its principal accounting exhibits for the fully projected future test year ending September 30, 2024 ("FPFTY"). I will also explain the tax adjustments made to the results of UGI Electric's historic test year ended September 30, 2022 ("HTY") and future test year ending September 30, 2023 ("FTY").

Q. Mr. Espigh, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring UGI Electric Exhibits DTE-1, DTE-2, and DTE-3. Together with other Company witnesses, I am sponsoring portions of UGI Electric Exhibit A (Fully Projected), UGI Electric Exhibit A (Future) and UGI Electric Exhibit A (Historic) that pertain to taxes. These exhibits comprise UGI Electric's principal accounting exhibits for the HTY, FTY, and FPFTY. I am also sponsoring certain responses to the Commission's filing requirements and standard data requests. Each response identifies the witness sponsoring it.

II. TAX ADJUSTMENTS

Q. Please provide an overview of UGI Electric's principal accounting exhibits relative to the proposed tax adjustments.

A. As explained in the direct testimony of Tracy A. Hazenstab (UGI Electric Statement No. 2), UGI Electric's principal accounting exhibit is UGI Electric Exhibit A (Fully Projected), which includes a presentation for the FPFTY. Section D of UGI Electric Exhibit A (Fully Projected) presents necessary adjustments to budgeted levels of expense items and revenues. The *pro forma* adjustments related to taxes are summarized in Schedules D-31 through D-34. These tax adjustments are used to derive UGI Electric's *pro forma* income at present and proposed rates as set forth in Schedule A-1 of the same exhibit.

UGI Electric Exhibit A (Future) and UGI Electric Exhibit A (Historic) follow the format of UGI Electric Exhibit A (Fully Projected), but reflect data for the HTY, and the FTY. This information is provided in accordance with the Commission's filing requirements and provides a basis for comparing UGI Electric's FPFTY claims with actual book results from the HTY and adjusted FTY results. Section D to UGI Electric Exhibit A (Historic), Schedule D-31, and UGI Electric Exhibit A (Future), Schedule D-31 include adjustments that share the same methodology as used in Schedule D-31 of UGI Electric Exhibit A (Fully Projected).

A. TAXES OTHER THAN INCOME TAXES

Q. How was the provision for taxes-other-than-income taxes ("TOTI") determined for the FPFTY?

A. TOTI consists of the Pennsylvania Utility Realty Tax ("PURTA"), the Pennsylvania Gross Receipts Tax, Pennsylvania and Local Use taxes, Social Security taxes, Federal Unemployment tax ("FUTA"), State Unemployment tax ("SUTA") and the Company's assessed contribution to the budgets of the Commission, the Pennsylvania Office of Consumer Advocate, and Pennsylvania Office of Small Business Advocate. TOTI amounts were based on the plan year budget, as adjusted for reasonably known and measurable changes to various payroll taxes as explained by the direct testimony of Ms. Hazenstab (UGI Electric Statement No. 2). The adjustments are shown on UGI Electric Exhibit A (Fully Projected), Schedule D-31. The net adjustment of $0.180 million is brought forward to Schedule D-3, page 2.

B. INCOME TAXES

Q. Please discuss the Company's claim for income taxes.

A. Income tax expense for the FPFTY at present and proposed rates is set forth in UGI Electric Exhibit A (Fully Projected), Schedule D-33. Income taxes are calculated using the procedures normally followed by the Commission, including the use of debt interest synchronization, the normalization method for accelerated depreciation used in the calculation of federal income taxes, and the flow-through of accelerated depreciation benefits for state tax purposes. UGI Electric is continuing its practice of normalizing the tax repairs expense deduction for federal tax purposes. For state tax purposes, UGI Electric continues to flow-through the repairs tax benefit over the tax lives of the asset that generated the benefit, which is generally 20 years. The fully adjusted claim for the FPFTY income tax expense is shown on UGI Electric Exhibit A (Fully Projected), Schedule D-1.

Q. Please describe the claim for income taxes shown on Schedule D-1, lines 18 and 19.

A. The calculation of federal and state income taxes can be found on Schedule D-33, lines 13 and 19. This schedule shows the calculation of *pro forma* income taxes for the FPFTY at present and proposed rates. Line 1 shows the revenue at present and proposed rates, while line 2 shows the operating expenses at present and proposed rates from Schedule D-1. Line 3 reflects operating income before debt interest is deducted, by netting line 1 from line 2. Debt interest expense is synchronized by multiplying the rate base claim from Schedule C-1 by the weighted cost of debt recommended in the direct testimony of Paul R. Moul (UGI Electric Statement No. 9) and shown on Schedule B-7. The resulting interest expense on line 6 is subtracted from net income before debt interest to calculate base taxable income on line 7.

In accordance with established Commission practice, lines 8 through 11 of Schedule D-33 reduce the base taxable income, for state tax purposes, by the total difference between accelerated tax depreciation shown on line 8 and the *pro forma* book depreciation shown on line 9. The statutory state corporate net income tax rate was then applied (as further described below in Section F of my testimony) to determine the *pro forma* state income tax expense shown on line 13. Lines 14 through 19 show the federal income tax expense calculation at current and proposed rates, while line 20 sums the state and federal tax expense amounts before application of Deferred Federal and State Income Taxes. At lines 21 through 28, Deferred Federal and State Income Taxes are used to increase the *pro forma* income tax expense at present and proposed rates with the total calculated amount for income taxes before the application of other adjustments shown on line 29. The amounts of accelerated depreciation, cost of removal, repairs tax deduction, tax basis adjustments to plant, straight line depreciation and book depreciation used in the determination of income taxes are summarized on Schedule D-34.

Q. What is the total FPFTY income tax expense for UGI Electric?

A. As shown on Schedule D-33 at line 31, the *pro forma* tax expense at present rates is $0.669 million and the *pro forma* tax expense at proposed rates for the FPFTY is $3.770 million. As explained below in Section E of my testimony, this figure is not reduced by a consolidated income tax adjustment.

Q. Did the Company reflect the amortization of Excess Deferred Federal Income Taxes ("EDFIT") resulting from the 2017 Tax Cuts and Jobs Act ("TCJA") in its income tax expense claim?

A. Yes, the Company calculated the amount of the EDFIT to be amortized and flowed back to ratepayers in its FPFTY. This amount is included in the overall federal deferred tax expense calculated on Line 25 of Schedule D-33. The total amortization was approximately $0.283 million, calculated using the Average Rate Assumption Method ("ARAM") as required by tax normalization rules.

C. ACCUMULATED DEFERRED INCOME TAXES

Q. How are Accumulated Deferred Income Taxes ("ADIT") calculated?

A. Schedule C-6 shows the FPFTY ending balance for federal ADIT at September 30, 2024. This amount is deducted from rate base. The total shown on line 8 reflects the difference in income tax expense for book and tax purposes attributable to the difference between the accelerated tax depreciation and straight-line book depreciation on test year plant balances, net of offsets associated with contributions in aid of construction. Rate base was reduced further by the state regulatory liability associated with UGI Electric's repairs tax method shown on line 6. As the state tax consequence of accelerated depreciation is flowed through, there is no associated state ADIT balance.

Q. What is the amount of the ADIT offset to rate base?

A. As shown on line 8 of Schedule C-6 and on line 5 of Schedule A-1, the ADIT offset is $29.665 million, which includes an amount related to the repairs tax method explained below in Section D of my testimony.

Q. Does the Company's reduction to rate base include an amount associated with EDFIT?

A. Yes, the Company reduced its rate base by the unamortized EDFIT, which is incorporated in the ADIT balance on Line 8 of Schedule C-6.

Q. Did the Company calculate its federal ADIT rate base deduction in compliance with the normalization requirements of the Internal Revenue Code?

A. Yes. The Company's calculation properly reflects the pro-rationing concept in accordance with Treasury Regulation 1.167(l)-1(h)(6)(ii) that it must follow for ratemaking purposes to comply with IRS normalization requirements. To qualify for normalization, the IRS requires utilities to pro-rate rate base deductions for ADIT to account for the fact that the Company accrues ADIT for plant additions throughout the year. See UGI Electric Exhibit DTE-2 for the calculation of the pro-rata adjustment.

D. REPAIRS TAX METHOD

Q. Please explain UGI Electric's accounting treatment of the Repairs Tax Method.

A. In its tax return for the year ended September 30, 2009, UGI Electric adopted a tax accounting method to expense as repairs certain items capitalized for book purposes in accordance with federal tax regulations. As it did in the Company's previous base rate case at Docket No. R-2021-3023618, UGI Electric chose to normalize its federal income tax expense claim, inclusive of the repairs tax deduction. This difference between accelerated tax depreciation versus book depreciation in the calculation of federal tax expense creates ADIT. For state income tax purposes, solely with respect to the repairs tax deduction, UGI Electric chose to flow-through the repairs tax benefit over the tax useful lives of the assets generating the tax deduction. The state ADIT balance associated with the repairs tax deduction is classified as a regulatory liability, as it represents the repairs tax benefit that ratepayers have not yet received. In both the federal and state instances, the ADIT balance amortizes or unwinds over the remaining life of the asset.

As noted previously, the Company reduces rate base by the sum of the federal ADIT balance and the state repair regulatory liability.

E. CONSOLIDATED TAX BENEFITS

Q. Does the Company's proposed revenue requirement reflect a consolidated tax expense adjustment?

A. No. The Company's revenue requirement is established based on its stand-alone federal income tax attributes. It is my understanding that Act 40 of 2016, which added 66 Pa. C.S § 1301.1 to the Public Utility Code, eliminates the need to show a consolidated tax adjustment for ratemaking purposes. However, Section 1301.1(b) requires a public utility to demonstrate that it shall use at least 50 percent of what would have been a consolidated tax expense adjustment under the law prior to Act 40 for reliability or infrastructure related capital investment and the other 50 percent shall be used for general corporate purposes.

A calculation of such an adjustment for that purpose, using the modified effective tax rate methodology traditionally used by the Commission prior to the enactment of Act 40, is included in the Company's filing as UGI Electric Exhibit DTE-3. Company witness Ms. Tracy A. Hazenstab (UGI Electric Statement No. 2) discusses how the Company has satisfied the requirements of Act 40.

F. PENNSYLVANIA TAX RATE CHANGE

Q. Are you familiar with the recently enacted Pennsylvania tax rate change?

A. Yes. On July 8, 2022, Governor Wolf signed into law Act 53, which will reduce the state corporate net income tax rate from the current 9.99% to 4.99% over a nine-year period. The initial reduction to 8.99% is effective for tax years beginning in calendar year 2023. Thus, the initial reduction applies to Fiscal Year End September 30, 2024, which is the Company's FPFTY.

Q. How has the Company accounted for the recently enacted Pennsylvania tax rate change?

The Company's claim for income taxes reflects the applicable state tax rate in effect for the HTY (i.e., 9.99%), FTY (i.e., 9.99%) and FPFTY (i.e., 8.99%). As explained above, the initial reduction applies to our FPFTY. The State Tax Adjustment Surcharge ("STAS") mechanism will adjust the Company's rates as applicable for future reductions to the state tax rate.

Q. How is the Company applying the Pennsylvania tax rate change to its Repairs Tax method?

A. Consistent with historic treatment as described in Section D of this testimony, UGI Electric's state regulatory liability associated with its repairs tax method will continue to represent the tax benefit, based on the rate in effect, that ratepayers have not yet received.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC

EXHIBIT DTE-1

DARIN ESPIGH, CPA

PROFESSIONAL EXPERIENCE

UGI UTILITIES, INC., Denver, PA ***March 2022 - Present***
Senior Manager of Natural Gas Tax Accounting

Manage the accounting for income taxes in accordance with ASC 740 for Natural Gas business segment. Provide technical accounting guidance and expertise on tax accounting, planning and compliance matters. Oversee and review the preparation of information supporting various regulatory filings. Oversee and review the preparation of various tax related filings. Supervise 2 direct reports.

JBS USA, Greeley, CO ***2014 – March 2022***
Senior Tax Manager, Tax Accounting and Global Reporting

Manage tax accounting and reporting under ASC 740 including effective rate development, perm development, valuation allowances, ABP 23 indefinite reinvestment assertions, financial statement footnotes, management of global deferred inventory and FIN48/FAS 5 analysis for international consolidated financial statements. Responsible for IFRS adjustments and reporting package to Brazilian parent company. Interface with internal and external auditors. Managed tax accounting aspects of a large global reorganization. Design and streamline provision reporting packages to meet increased demands of public reporting.

Managed both federal and state income tax compliance. Responsible for attribution memos related to the preparation of Form 5472, R&D Credits, Sec 163(j), Schedule G and Schedule O compliance for more than 10 separate federal tax returns. Supervised income tax audits. Managed documentation and notice requirements related to the Foreign Investment in Real Property Tax Act (FIRPTA) related to distributions of U.S. real property interests by foreign corporations. Managed, trained and developed staff in tax accounting and financial reporting and compliance.

UGI UTILITIES, INC., Reading, PA ***2007 to 2014***
Senior Tax Analyst

Responsible for quarterly and annual tax accounting and reporting under ASC 740 including effective rate development, maintenance and classification of deferred inventory balances and account reconciliations. Calculate annual provision to return adjustment for year-end provision. Interface with internal and external auditors on tax related matters. Provide budget and forecast amounts for all tax related items. Preparation of tax data to support external regulatory reporting including Base Rate Case filings.

Preparation of income tax return support submitted to corporate for inclusion in the consolidated income tax return. Responsible for indirect tax compliance.

BERTZ & COMPANY, CPA's, Lancaster, PA ***2000 to 2007***
Senior Associate

Responsible for preparation of individual, corporate, partnership, nonprofit and payroll tax returns. Charged with the preparation of financial statements including required disclosures for a wide range of industries including construction, hospitality and retail food establishments. Supervised, trained and developed staff on client engagements.

DARIN ESPIGH, CPA

Managed audit engagements of retirement plans and homeowner associations. Gained experience on a variety of other audits.

HATTER, HARRIS & BEITTEL, LLP, Lancaster, PA — ***1994 to 2000***
Senior Associate

Prepared individual, corporate, partnership, nonprofit and payroll tax returns. Managed review and compilation engagements. Managed nonprofit audit. Developed significant experience in audits of school districts, retail and manufacturing businesses. Gained strong working knowledge of financial statements and related disclosures for engagements of all levels. Trained and developed new staff.

EDUCATION & CREDENTIALS

Bachelor of Science in Accounting – Messiah College, Grantham, PA – May 1994

Certified Public Accountant

UGI ELECTRIC

EXHIBIT DTE-2

UGI - Electric Division
Calculation of Pro-Rata Accumulated Deferred Income Tax
(In Thousands)

	A	B	C = B/365	D = C*A	Per Treas. Reg.1.167(l)-1(h)(6)(ii)
Month	Increase to Deferred Taxes	# of Days	Pro-Rata %	Pro-Rata Incr to Deferred Taxes	Accumulated Deferred Income Tax Balance
9/30/2023					$ 29,114
10/31/2023	107	335	91.78%	98	29,212
11/30/2023	173	305	83.56%	144	29,356
12/31/2023	68	274	75.07%	51	29,407
1/31/2024	44	243	66.58%	29	29,436
2/28/2024	131	215	58.90%	77	29,513
3/31/2024	62	184	50.41%	31	29,544
4/30/2024	86	154	42.19%	36	29,581
5/31/2024	59	123	33.70%	20	29,600
6/30/2024	111	93	25.48%	28	29,629
7/31/2024	123	62	16.99%	21	29,650
8/31/2024	142	31	8.49%	12	29,662
9/30/2024	1,035	1	0.27%	3	**$ 29,665**

UGI ELECTRIC

EXHIBIT DTE-3

UGI Utilities, Inc. - Electric Division
Calculation of Consolidated Tax Adjustment
In Thousands (000)

		Taxable Income 2019	Taxable Income 2020	Taxable Income 2021	Average	% of Total
Tax Loss Entities						
AmeriGas Propane Holdings, Inc.		0	0		0	
Ashtola Production Company		(1)	(1)	(1)	(1)	
Hellertown Pipeline		0	0	0	0	
Homestead Holding		(273)	(607)	(76)	(319)	
Mountaineer Energy Holding & Subs	A/	0	0	0	0	
UGI Hunlock Dev		0	0	0	0	
UGI HVAC Enterprises		(305)	0	(1,556)	(620)	
UGI LNG		0	0	(3,679)	(1,226)	
UGID Holding Company		(8)	(8)	(8)	(8)	
United Valley Insurance		(751)	0	0	(250)	
UGI Corporation	A/	0	(11,911)		(3,970)	
AmeriGas Inc		(26)	(23)	0	(16)	
UGI China Inc		0	0	0	0	
UGI International China. Inc		0	0	0	0	
UGI Penn HVAC Services		0	0	0	0	
UGI Properties, Inc.		0	0	0	0	
UGI Development Company	A/	(5,924)	(4,961)	(4,031)	(4,972)	
UGI Enterprises Inc		0	0	0	0	
Subtotal Taxable Loss		**(7,286)**	**(17,511)**	**(9,351)**	**(11,383)**	
Tax Positive Entities						
AmeriGas Propane Inc.		93,880	56,320	30,085	60,095	25.4%
AmeriGas Propane Holdings, Inc.	A/	90	0	122,728	40,939	17.3%
AmeriGas Inc.		0	0	178	59	0.0%
Amerigas Technology Group Inc.		0	0	0	0	0.0%
Energy Service Funding		5,062	3,479	4,656	4,399	1.9%
Newberry Holding		3,253	955	120	1,443	0.6%
Petrolane Incorporated		0	0	0	0	0.0%
UGI China, Inc.		0	0	0	0	0.0%
UGI Corporation	A/	44,119	0	23,110	22,410	9.5%
UGI Development Company		0	0	0	0	0.0%
UGI Enterprises, Inc.		0	0	0	0	0.0%
UGI Europe, Inc.		35,767	22,795	42,637	33,733	14.2%
UGI HVAC Enterprises		0	4,824	0	1,608	0.7%
UGI LNG		5,530	2,318	0	2,616	1.1%
UGI Penn HVAC Services		3	0	0	1	0.0%
UGI Properties, Inc.		245	349	438	344	0.1%
UGI Storage Company		4,465	4,152	4,997	4,538	1.9%
UGI Utilities, Inc.		57,929	73,276	62,490	64,565	27.3%
UGI International Enterprises, Inc.		0	0	0	0	0.0%
United Valley Insurance		0	323	146	156	0.1%
Eliminations		0	0	0	0	0.0%
Subtotal Taxable Income		**250,343**	**168,792**	**291,584**	**236,906**	100.0%
Total Taxable Income		**243,056**	**151,281**	**282,233**	**225,523**	

Tax Savings Applicable to UGI Utilities, Inc.	(3,102)
MWF Allocation % for UGI Utilities - Electric Division	10.71%
Federal Tax Rate	21%
Total Consolidated Tax Adjustment	**(70)**

A/ Taxable income / loss is adjusted for unusual, non-recurring items and for expenses incurred related to the generation of income in other entities.

UGI ELECTRIC STATEMENT NO. 9

PAUL R. MOUL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368

UGI Utilities, Inc. – Electric Division

Statement No. 9

Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

Topics Addressed:	**Capital Structure**
	Cost of Equity
	Rate of Return

Dated: January 27, 2023

UGI Utilities, Inc. – Electric Division
Direct Testimony of Paul R. Moul
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Page No.

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CWIP	Construction Work in Progress
DCF	Discounted Cash Flow
FERC	Federal Energy Regulatory Commission
FOMC	Federal Open Market Committee
g	Growth rate
IGF	Internally Generated Funds
Lev	Leverage modification
LT	Long Term
P-E	Price-earnings
PUC	Pennsylvania Public Utility Commission
r	Represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Market risk premium
RP	Risk Premium
s	Represents the new common shares expected to be issued by a firm
s x v	Represents external growth
S&P	Standard & Poor's
UGIU	UGI Utilities, Inc.
UGI	UGI Corporation
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value

DIRECT TESTIMONY OF PAUL R. MOUL

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Q. Please state your name, occupation and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in UGI Electric Exhibit PRM-1, which follows my direct testimony.

Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate cost of common equity and overall rate of return that the Pennsylvania Public Utility Commission ("PUC" or the "Commission") should recognize in the determination of the revenues that UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company") should be authorized as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in UGI Exhibit B, which is a multi-page document divided into fourteen (14) schedules. All references to schedules in my testimony refer to portions of UGI Electric Exhibit B.

Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return for the Company?

A. My conclusion is that the Company should be afforded an opportunity to earn a cost of equity of 11.30%. The 11.30% rate of return on common equity includes 20 basis points in recognition of the strong performance of the Company's management. My 11.30% cost of equity recommendation is established using capital market and financial data relied upon by investors when assessing the relative risk, and hence cost of capital for the Company.

My overall rate of return recommendation is determined by using the weighted average cost of capital approach. This approach provides a means to apportion the return to each class of investor. The calculation of the weighted average cost of capital requires the selection of appropriate capital structure ratios and a determination of the cost rate for each capital component. The resulting overall cost of capital when applied to the Company's rate base will provide a level of return that will compensate investors for the use of their capital. My overall cost of capital recommendation is set forth below and is shown on page 1 of Schedule 1.

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-term Debt	45.41%	4.35%	1.98%
Common Equity	54.59%	11.30%	6.17%
Total	100.00%		8.15%

This overall rate of return is applicable to the September 30, 2024 fully projected future test year ("FPFTY") and the initial period that the Company's proposed rates will be effective. The direct testimony of Company witness Christopher R. Brown, VP and General Manager of Rates and Supply (UGI Electric Statement No. 1), explains that the Company has achieved a high level of management effectiveness and is entitled to recognition of this as a component of the rate of return on common equity. Therefore, an additional 0.20% is warranted in recognition of the strong performance by the Company in the area of management effectiveness.

Q. What noteworthy factors have influenced your cost of equity analysis?

A. My cost of equity analysis reflects the high levels of inflation which have not been seen for four decades. Indeed, the rate of inflation spiked upward to 9.1% in June 2022, and as of December 2022, it was 6.5%. High levels of inflation have an impact on the level of economic activity, the cost of capital – particularly the interest cost of debt – and the need for more cautious financial practices, such as a prudent level of borrowing. This is substantially higher than the target rate of 2%, which is the FOMC policy goal.

Contributing to "sky high" inflation is pandemic-related supply side issues, strong consumer demand, and tight labor markets. Supply disruptions have also significantly impacted the consumer sector of the economy, which developed during the Pandemic. Energy prices have increased as well. While short-term interest rates were at historically low levels during much of the Pandemic, longer term interest rates began to rise in February 2021 and have continued at high levels throughout 2022. Moreover, the first of several Fed Funds increases was announced on March 16, 2022, with an increase of 0.25%, and an additional 0.50% increase was announced on May 4, 2022. A 50 basis point increase in the Fed Funds rate has not occurred since 2000. Indeed, the Fed Funds rate was increased again with the announcement on June 15, 2022, when a 0.75% increase occurred. Additional 0.75% increases in the Fed Funds rate were announced on July 27, 2022, September 21, 2022, and November 2, 2022. This makes four consecutive three-quarter percentage point increases in the Fed Funds rate, which is unprecedented in recent history. Subsequently, at its December 14, 2022 meeting, the FOMC increased the Fed Funds rate by 0.50% to a level of 4-1/4 to 4-1/2 percent, a fifteen (15) year high. In total, the Fed Funds rate has been increased 425 basis points in 2022. The FOMC is projecting the Fed Funds rate will peak at a level between 5% and 5.5% in 2023. That level is expected to hold there until sometime in 2024. I will describe the forecasts of interest rates later in my testimony.

Q. What background information have you considered in reaching a conclusion concerning the Company's cost of capital?

A. UGI Utilities, Inc. ("UGIU") is a combination gas distribution and electric utility. UGIU is a wholly-owned subsidiary of UGI Corporation ("UGI"). UGIU provides electric distribution service to approximately 62,500 customers in portions of Luzerne and Wyoming Counties. UGIU also provides natural gas distribution services to approximately 672,000 customers in 46 eastern and central Pennsylvania counties.

The deliveries (i.e., direct sales and Provider of Last Resort ("POLR")) on UGIU's electric system in 2021 were approximately 58% to residential, 31% to commercial, 10% to industrial, and 1% to other customers. Of these percentages, 24% were direct sales and 76% were POLR. The Company obtains energy for its POLR and direct sales services primarily from the wholesale market and also delivers electricity that customers purchase directly from other suppliers.

Q. How have you determined the cost of equity in the case?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence, the cost of equity for an electric utility, such as the Company. In this regard, I have relied on four well recognized measures: the Discounted Cash Flow ("DCF") model, the Risk Premium analysis, the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings approach. By considering the results of a variety of approaches, I determined that 11.10% represents a reasonable cost of equity. To that equity cost rate, the Company is also entitled to a further 0.20% to recognize the strong performance of UGIU in the area of management effectiveness.

Q. In your opinion, what factors should the Commission consider when setting the Company's cost of capital in this proceeding?

A. The rate of return utilized by the Commission to set rates must be sufficient to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to raise capital on reasonable terms. The return that I propose fulfills these established standards of a fair rate of return set forth by the landmark Bluefield and Hope cases.[1] That is to say, my proposed rate of return is commensurate with returns available on investments having corresponding risks.

Q. What approach have you used in measuring the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed for my proxy group of ten (10) electric companies. The proxy group consists of electric companies that: (i) have publicly-traded common stock, (ii) are contained in The Value Line Investment Survey and are classified in the Electric Utility East group, (iii) are not currently the target of an announced merger or acquisition, and (iv) are not engaged in the construction of a nuclear generating plant. The companies in the proxy group are identified on page 2 of Schedule 3. I will refer to these companies as the "Electric Group" throughout my testimony.

Q. How have you performed your cost of equity analysis with the market data for the Electric Group?

A. I have applied the models/methods for estimating the cost of equity using the average data for the Electric Group. I have not measured separately the cost of equity for the individual companies within the Electric Group, because the determination of the cost of equity for an individual company has become increasingly problematic. If the models of the cost of equity were applied with individual company data, there is the possibility of anomalous results shown for selected companies, which would provide a misleading indication of the cost of equity. My approach of using average data for a portfolio of companies reduces the possibility that anomalous results might be shown by the models of the cost of equity. By employing group average data, rather than individual companies' analysis, I have helped to minimize the effect of extraneous influences on the market data for an individual company.

[1] Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, a single method can provide an incomplete measure of the cost of equity depending upon extraneous factors that may influence market sentiment. In an environment of high interest rates, the use of multiple methods is particularly compelling because the Risk Premium method and CAPM capture changes in interest rates much more expeditiously than does the DCF method. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches, as shown on page 2 of Schedule 1.

DCF	10.45%
Risk Premium	11.75%
CAPM	15.95%
Comparable Earnings	13.10%

From these measures, I recommend a cost of equity of 11.10%, prior to recognition for the Company's strong management performance. My determination of the cost of equity focuses on the DCF and Risk Premium approaches that provide a return of 11.10% (10.45% + 11.75% = 22.20% ÷ 2 = 11.10%). My 11.30% cost of equity recommendation includes 20 basis points or 0.20% recognition for the exemplary performance of the Company's management and falls within the range of 10.45% to 11.75% indicated above. Mr. Brown's testimony in UGI Electric Statement No. 1 demonstrates that the Company ranks high in customer service and management effectiveness.

To obtain new capital to support an expanded construction program and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements. In recognition of its performance, the Company should be granted an opportunity to earn an 11.30% cost of equity.

ELECTRIC UTILITY RISK FACTORS

Q. Please identify some of the factors that make the electric utility industry generally different today than it was in the past.

A. Electric utilities generally are faced with a variety of challenges that affect their operations, while retaining the obligation to serve under cost of service pricing that continues to dominate their business risk profile. On January 1, 1999, customer choice was fully available on UGI Electric's system. From that point forward, UGI Electric's responsibility became primarily the provision of delivery service at regulated prices, while it also retained the responsibility for POLR service.

UGI Electric is part of the PJM Interconnection, LLC. Aside from its traditional responsibility to maintain reliability and comply with the mandates of PJM, a different set of risks apply to the electric delivery business in Pennsylvania.

The risk of distributed generation is a concern, and could have an increasing influence on the business of electric delivery utilities. With technological advances in micro-turbines, potential commercialization of fuel cells, development of wind and solar power, and the creation of micro-grids, utilities face the potential for bypass and the resulting declines in transmission and distribution revenues.

The cost to replace aging infrastructure also adds to the risk of electric delivery utilities, such as UGI Electric, because these expenditures increase costs without any concomitant increase in revenues, except through regulatory approved rate increases, such as the Distribution System Improvement Charge ("DSIC"). The Company continues to make substantial investments to increase the resiliency and reliability of its system to reduce the number and duration of storm-related outages experienced by customers. However, the DSIC mechanism contains a variety of limitations that will not eliminate the need for periodic rate cases to cover the significant new investment that is being made by UGI Electric.

Q. What are the primary risk factors facing the electric delivery utilities industry?

A. A pricing structure restricted by regulation diminishes management's ability to adjust its business strategy quickly to changing market conditions to respond to broadening competition and the potential for bypass arising from self-generation or distributed-generation. The financial structure of the electric business is uncertain due to the adequacy of capital recovery, counter-party risk, potential for financial penalties associated with operational problems, and growth in the utilization of the transmission and distribution network by non-affiliated generators and marketers. Regulatory risks include the overall framework of rate-setting, cost allocation, and rate design issues, and the level of return that will be allowed.

Q. Please indicate how the Company’s risk profile is affected by its construction program.

A. Under its LTIIP, the Company is investing substantial capital to maintain and upgrade existing facilities in its service territory and to meet growth. Over the next five years, the Company’s total capital expenditures (transmission and distribution), as shown in the table below, are expected to be $131.588 million:

Year	Capital Expenditures
2023	$ 31,064,491
2024	$ 24,566,590
2025	$ 24,336,000
2026	$ 25,309,442
2027	$ 26,311,478
Total	$ 131,588,001

These expenditures represent approximately 72% ($131.588 million ÷ $182.952 million) of the Company's net electric utility plant at December 31, 2021. Indeed, in the situation where capital expenditures are high, a reasonable return is a key to a financial profile that will allow for the attraction of capital on reasonable terms to fund these expenditures. A reasonable opportunity to experience a fair rate of return represents the key to a financial profile that will provide the Company with the ability to raise capital in all market conditions to meet its needs, and to satisfy investor requirements in an evolving industry.

Q. How should the Commission respond to the evolving business environment facing the Company?

A. In the situation where substantial additional capital is being invested, as shown by the projected construction expenditures indicated above, the regulatory process must establish a return on equity that provides a reasonable opportunity for the Company to actually achieve its cost of capital. Where ongoing capital investment is required to meet the high quality of service that customers demand, supportive regulation is essential.

<u>FUNDAMENTAL RISK ANALYSIS</u>

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for the determination of the cost of equity?

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors which bear upon investors' assessment of overall risk. The qualitative factors that bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. For this purpose, I have compared UGIU, which represents the combined electric and gas divisions, to the S&P Public Utilities, an industry-wide proxy consisting of all types of public utility endeavors, and the Electric Group. In this analysis, I have used UGIU on a consolidated basis as it is the consolidated capital structure that is used to compute the weighted average cost of capital for this case.

Q. What are the components of the S&P Public Utilities?

A. The S&P Public Utilities is a widely recognized index comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4. I have used this group as a broad-based measure of all types of regulated public utility endeavors.

Q. What companies comprise your Electric Group?

A. My Electric Group obtained from the Value Line publication consists of the following companies: AVANGRID, Inc., Consolidated Edison, Dominion Energy, Duke Energy, Eversource Energy, Exelon Corp., FirstEnergy Corp., NextEra Energy, PPL Corp., and Public Service Enterprise Group.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is an important determinant in analyzing a company's cost of equity because the cost of each type of capital is directly related to the associated risk of the firm. So, while a company's credit quality risk is directly shown by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus a premium to recognize the higher risk of an equity investment compared to debt.

Q. How do the bond ratings compare for the Company, the Electric Group, and the S&P Public Utilities?

A. Presently, the Company's Long Term ("LT") issuer rating is A3 from Moody's, which resulted from a credit rating downgrade on December 13, 2022. In making the downgrade, Moody's stated that, among other factors, it was concerned with the Company's financial metrics that will be constrained by higher debt to fund elevated capital expenditures. As such, any inclination toward boosting the debt ratio in this case would be counter-productive and should be avoided so as to sustain its current credit quality rating. The LT issuer rating by Moody's focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. The Company's credit quality is the same as the average A3 credit rating of the Electric Group. For the S&P Public Utilities, the average composite credit rating is also A3 by Moody's and BBB+ by S&P. Many of the financial indicators which I will subsequently discuss are considered during the rating process. It is important to note that credit quality ratings provide a comprehensive summary of a company's risk from a creditor's perspective.

Q. How do the financial data compare for the Company, UGIU, the Electric Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedule 2, 3 and 4. The data cover the five-year period 2017-2021. For UGIU, its financial profile is represented by the combined electric and gas divisions, which are the results presented to investors. This is because UGIU raises all of its capital requirements for both of its divisions. The important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, UGIU is very much smaller than the average size of the Electric Group and the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity. This is the case for UGIU as compared to the Electric Group and the S&P Public Utilities.

Market Ratios. Historical market-based financial ratios, such as price-earnings multiples and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return for companies which exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[2]

Since UGIU's stock is not traded, there are no market ratios for the Company. The five-year average price-earnings multiple was fairly close for the Electric Group and the S&P Public Utilities. The five-year average dividend yield for the Electric Group was somewhat higher than the S&P Public Utilities. The average market-to-book ratios were somewhat lower for the Electric Group than the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a higher common equity ratio has lower financial risk, while a firm with a lower common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital based on book value, were 55.3% for UGIU, 45.2% for the Electric Group, and 41.0% for the S&P Public Utilities. The capital structure of the Company for the FPFTY in this case is within the range of the Electric Group both historically and prospectively based upon the Value Line forecasts. It is noteworthy that the ratios for the Electric Group are calculated based upon the consolidated common equity for these holding companies. For rate setting purposes, the ratios for their utility subsidiaries are typically employed which contains higher common equity than the holding company ratios.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relative levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficient

[2] For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

of variation, the greater degree of variability. During the five-year period, the coefficients of variation were 0.120 (1.4% ÷ 11.7%) for UGIU, 0.178 (1.6% ÷ 9.0%) for the Electric Group, and 0.051 (0.5% ÷ 9.9%) for the S&P Public Utilities. While less than the Electric Group, the Company's earnings variability was much higher when compared to the S&P Public Utilities. This signifies much higher risk for UGIU and the Electric Group.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation and taxes other than income).[3] The five-year average operating ratios were 77.5% for UGIU, 78.6% for the Electric Group, and 79.8% for the S&P Public Utilities. The operating ratio for UGIU was similar to the Electric Group, thus indicating similar risk.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average pre-tax interest coverage (excluding Allowance for Funds Used During Construction ("AFUDC")) was 4.89 times for UGIU, 3.00 times for the Electric Group, and 2.97 times for the S&P Public Utilities. The higher interest coverage for UGIU suggests lower credit risk, although its bond rating is similar to the other groups.

Quality of Earnings. Measures of earnings quality are usually revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds. Quality of earnings has not been a significant concern for UGIU and the Electric Group.

[3] The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to construction expenditures was 73.7% for UGIU, 68.3% for the Electric Group, and 66.0% for the S&P Public Utilities. This indicates a fairly comparable risk for the Company and the reference groups.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[4] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market.[5] A comparison of market risk is shown by the Value Line betas of .88 as the average for the Electric Group provided on page 2 of Schedule 3 and .90 as the average for the S&P Public Utilities provided on page 3 of Schedule 4. The systematic risk was similar for the Electric Group and the S&P Public Utilities.

Q. Please summarize your risk evaluation of UGIU and the Electric Group.

A. The investment risk of UGIU parallels that of the Electric Group in certain respects. In certain regards, UGIU has higher risk traits due to its relatively small size and the "negative" outlook on its credit quality. UGIU has lower risk as shown by its higher common equity and higher interest coverages. Operating ratios, quality earnings and

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[4] Beta is a relative measure of the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index. The ''Beta coefficient'' is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. The betas are adjusted for their long-term tendency to converge toward 1.00. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

[5] The procedure used to calculate the beta coefficient published by Value Line is described on page 3 of Schedule 14. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

IGF to construction indicate comparable risk to the Electric Group. On balance, the cost of equity for the Electric Group would fairly represent the Company's cost of equity for this case, albeit on the conservative side because of the small size of UGI Electric.

RECOMMENDED CAPITAL STRUCTURE RATIOS

Q. Please explain the selection of capital structure ratios for UGIU in this case.

A. In the situation where the operating public utility raises its own long-term debt directly in the capital markets, as is the case for UGIU, it is proper to employ the capital structure ratios and senior capital cost rates of the regulated public utility for rate of return purposes. In that case, the property and earnings of the operating public utility forms the basis of the capital employed and the capital cost rates are directly identifiable. The circumstances of UGIU indicate that its capital structure ratios should be used for rate of return purposes for each of its utility divisions, because the Company attracts all of its capital on a combined basis and investors make their capital commitments on that basis.

Q. Does Schedule 5 provide the capitalization and capital structure ratios you have considered?

A. Yes. Schedule 5 presents UGIU capitalization and related capital structure at September 30, 2022, the end of the historic test year ("HTY"). Also, shown on Schedule 5 is the UGIU capital structure estimated at September 30, 2023, the end of the future test year ("FTY"), and at September 30, 2024, the end of FPFTY. The changes in the Company's capital structure consist of: (i) sinking fund payments of $6.250 million in the FTY and FPFTY on the Senior Notes due in 2027, (ii) the issuance of $225 million of long-term debt in the FPFTY, and (iii) the Company's projection of retained earnings at the end of the FTY and FPFTY. The Company's planned issuance of long-term debt is part of the financial plan reflected in its budgeting process.

Q. Have you made adjustments to the Company's capitalization for rate-setting purposes?

A. Yes. I have removed the capitalized lease obligations from the Company's debt and removed the accumulated other comprehensive income ("OCI") from the Company's common equity account.

Q. Why have you removed capitalized lease obligations from the Company's capital structure?

A. I have made this elimination because for rate-setting purposes, the Company includes its total lease obligations as operating leases. That is to say, the total amount of lease payments, including both the principal and interest, is reflected in the Company's operating expenses. To avoid double-counting, capitalized leases must be removed from the capital structure for rate-setting purposes.

Q. Please explain the justification for removing the accumulated OCI.

A. The accumulated OCI must be eliminated from the capital structure for rate-setting purposes. OCI arises from a variety of sources, including: minimum pension liability ("MPL"), foreign currency hedges, unrealized gains and losses on securities available for sale, interest rate swaps, and other cash flow hedges. The accumulated OCI for the Company has its roots in the MPL and interest rate hedges associated with the variable-rate term-loan. An MPL entry must be recorded on the balance sheet when the present value of the pension benefit earned by employees exceeds the market value of trust fund assets. It should be noted that the Company records the change related to prior service cost and actuarial valuations as a regulatory asset for the portion of pension attributable to its retirees and employees that are part of its regulated utility operations. The amount in the accumulated OCI is just related to the portion attributable to employees of UGI Corporation and non-utility subsidiaries. That is to say, the accumulated OCI associated with MPL is not related to utility operations. The interest rate hedges, as they affect OCI, must also be removed because they have been reflected in the embedded cost of debt.

Q. Have you included short-term debt in the capital structure for UGIU?

A. No. In reaching this conclusion, I have analyzed the 12-month average balances of short-term debt for the historic test year, the FTY, and the FPFTY and compared those amounts to the Company's construction work in progress ("CWIP"). I have done this because the Company follows the FERC formula to calculate its AFUDC rate. That formula assigns short-term debt first to CWIP, with any excess balance of CWIP receiving the Company's overall rate of return. In order to avoid double-counting the amount of short-term debt that finances CWIP, those amounts must be removed from the average short-term debt amounts for rate case purposes. For the FPFTY, the CWIP balances approximately offsets the average amount of short-term debt. Therefore, the de minimis remaining amount of short-term debt is removed from the capital structure for the FPFTY.

Q. What capital structure ratios do you recommend be adopted for rate of return purposes in this proceeding?

A. Since ratemaking is prospective, the rate of return should reflect known conditions that will exist during the period of time the proposed rates are to be effective. I will adopt the Company's capital structure ratios at the end of the FPFTY of 45.41% long-term debt and 54.59% common equity. These ratios are within the ranges indicated for the Electric Group. I should note that due to the small size of UGIU and UGI Electric, less debt and more equity would be appropriate and an equity ratio in the upper end of the range would be warranted. These capital structure ratios are the best approximation of the mix of capital the Company will employ to finance its rate base during the period new rates are in effect.

EMBEDDED COST OF DEBT

Q. What cost rate have you assigned to the long-term debt portion of the capital structure?

A. Consistency requires that the embedded senior capital cost rates of UGIU must be used for developing a fair rate of return. It is essential that the cost rate of long-term debt is related to the same proportion of senior capital employed to arrive at the capital structure ratios. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is due to the fact that the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Schedule 6, I have computed the actual embedded cost rate of long-term debt at September 30, 2022. On page 2 of Schedule 6, I have shown the estimated embedded cost rate of long-term debt at September 30, 2023. And on page 3 of Schedule 6, the embedded cost of long-term debt is shown for the FPFTY. For the proposed issue of $225.000 million of new long-term debt to be issued in the FPFTY, the coupon rate is very conservatively estimated to be 4.551% and the effective cost rate is 4.60%. Indeed, due to the recent volatility of interest rates, the Company intends to update its cost of debt at the time of its rebuttal testimony. The development of the individual effective cost rates for each series of long-term debt, using the cost rate to maturity technique, is shown on page 4 of Schedule 6. The cost rate, or yield to maturity, is the rate of discount that equates the present value of all future interest and principal payments with the net proceeds of the bond.

I will adopt the 4.35% forecast embedded long-term debt cost rate at September 30, 2024, as shown on page 3 of Schedule 6. This rate is related to the amount of long-term debt shown on Schedule 5 which provides the basis for the 45.41% long-term debt ratio.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe how you determined the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among UGI Electric, the Electric Group, and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I identified above. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings also must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As I describe below, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Electric Group and arrived at a cost of equity of 11.30% for UGI Electric, which includes an increment for exemplary management performance.

DISCOUNTED CASH FLOW

Q. Please describe the DCF model.

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF-determined return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model, which assumes that future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: P = D/(k-g), where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: k= D/P + g. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model.[6] My DCF results are provided on Schedule 1, page 2, for the Electric Group. The DCF return is 10.45% with the leverage adjustment and 9.48% without the leverage adjustment for the Electric Group. The leverage adjustment is discussed more fully below.

Among the limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility. Other limitations of the DCF include the constant P-E multiple assertion that does not conform with actual stock market performance. And, indeed, the FERC has moved to using multiple methods for measuring the cost of equity due to the limitations of the DCF. Further, the DCF method is slow to reflect changes in interest rates. Hence, the DCF should always be used along with other methods that are more responsive to changes in interest rates.

Q. What is the dividend yield component of a DCF analysis?

A. The dividend yield reveals the portion of investors' cash flow that is generated by the return provided by the dividends an investor receives. It is measured by the dividends

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[6] Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950s, J.B. Williams exposited the DCF model in its present form nearly two decades earlier.

per share relative to the price per share. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended September 2022, the monthly dividend yields are shown on Schedule 7. The month-end prices were adjusted to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the twelve months ended October 2022, the average dividend yield was 3.37% for the Electric Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six-month and three-month periods were 3.37% and 3.53%, respectively. For applying the DCF model, I have used the six-month average dividend yield of 3.37% for the Electric Group. The use of this dividend yield will reflect current capital costs while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investors' anticipated cash flows. I have adjusted the six-month average dividend yield in three different but generally accepted manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Schedule 7.[7] This

[7] These adjustments are the 1/2 growth approach, the discrete approach, and the quarterly approach. Under the 1/2 approach, the procedure to adjust the average dividend yield for the expectation of a dividend increase during the initial investment period will be at a rate of one-half the growth component, which assumes that half of the dividend payments will be at the expected higher rate during the initial investment period. Under the discrete approach, the "*g*" in the DCF model reflects the discrete growth in the quarterly dividend, which is required for the periodic form of the DCF to properly recognize that dividends are expected to grow on a discrete basis. The quarterly approach takes into account that investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the periodic quarterly dividend payments (D_0) results in this third DCF formulation. This DCF equation provides no further recognition of growth in the quarterly dividend. A compounding of the quarterly dividend yield recognizes the necessity for an adjusted dividend yield.

adjustment adds eleven basis points to the six-month average historical yield, thus producing the 3.48% adjusted dividend yield for the Electric Group.

Q. What factors influence investors' growth expectations?

A. As noted previously, investors are interested principally in the dividend yield and future growth of their investment (i.e., the price per share of the stock). Future growth in earnings per share is the DCF model's primary focus because, under the model's assumption that the P-E multiple remains constant, the price per share of stock will grow at the same rate as earnings per share. A growth rate analysis considers a variety of variables to reach a consensus of prospective growth, including historical data and widely available analysts' forecasts of earnings, dividends, book value, and cash flow (all stated on a per-share basis). A fundamental growth rate analysis is frequently based upon internal growth, or b x r, where "r" is the expected rate of return on common equity and "b" is the retention rate (a fraction representing the proportion of earnings not paid out as dividends). To be complete, the internal growth rate should be modified to account for sales of new common stock (external growth), which is represented by the formula s x v, where "s" is the number of new common shares that the firm expects to issue and "v" is the value that accrues to existing shareholders from selling stock at a price above book value. Fundamental growth, which combines internal and external growth, encompasses the factors that cause book value per share to grow over time.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage during which a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage during which fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" stage, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilize at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps up and ramps down in cycles over time. For these reasons, there is no need to analyze growth rates individually for each cycle, but rather to rely upon analysts' growth forecasts that are used by investors when pricing common stocks.

Q. What factor should be considered in the determination of an appropriate growth rate?

A. The growth rate used in a DCF calculation should measure investor expectations. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. Investors are not influenced solely by a single set of company-specific variables weighted in a formulaic manner. Therefore, all relevant growth rate indicators should be evaluated using a variety of techniques when formulating a judgment of investor-expected growth.

Q. What data for the Electric Group have you considered in your growth rate analysis?

A. I considered the growth in the financial variables shown on Schedules 8 and 9, which reflect historical (Schedule 8) and projected (Schedule 9) rates of growth in earnings per share, dividends per share, book value per share, and cash flow per share for the Electric Group. While analysts will review all measures of growth, as I have done, earnings per share growth directly influences the expectations of investors for the future performance of utility stocks. Forecasts of earnings growth are required because the DCF model is forward-looking, and, with the constant P-E multiple and constant payout ratio that the DCF model assumes, all other measures of growth will mirror earnings growth. The historical growth rates, which were also reviewed to gain a perspective on the industry, were obtained from the Value Line publication that provides this data. While historical data cannot be ignored, they are much less significant when applying the DCF model than projections of future growth. Investors cannot purchase the past earnings of a utility. To the contrary, they are only entitled to future earnings, which are the focus of growth projections. Furthermore, if significant weight is assigned to historical performance, the historical data are double-counted because they are already factored into analysts' forecasts of earnings growth.

Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the traditional DCF model?

A. Yes, it is. Although the constant form of the DCF model assumes an infinite stream of cash flows, investors do not expect to hold an investment indefinitely. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investors' expected return. The growth in the price per share will equal the growth in earnings per share if, as the DCF model assumes, there is no change in the price-earnings ("P-E") multiple. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, conforms with the type of analysis that influences investors' expectations of their actual total return. Moreover, academic research also focuses on five-year growth rates specifically because market outcomes occurring over that investment horizon are what influence stock prices. Indeed, if investors required forecasts beyond five years in order to properly value common stocks, then it would be reasonable to expect that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of the marketplace. The absence of such a publication suggests that there is no market for this information because investors do not require forecasts for an infinite series of future data points in order to make informed decisions to purchase and sell stocks.

Q. What are the analysts' forecasts of future growth that you considered?

A. Schedule 9 provides projected earnings per share growth rates taken from analysts' five-year forecasts compiled by IBES/First Call, Zacks, and Value Line. These are all reliable authorities of projected growth that investors use to make buy, sell, and hold decisions. The IBES/First Call and Zacks estimates are obtained from the Internet and are widely available to investors. The growth rates reported by IBES/First Call and Zacks are consensus forecasts taken from a survey of analysts that make growth projections for these companies. Notably, First Call's earnings forecasts are frequently quoted in the financial press. The Value Line forecasts also are widely available to investors and can be obtained by subscription or free of charge at most public and collegiate libraries. The IBES/First Call and Zacks forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share for the Electric Group are also included on Schedule 9.

Q. What are the projected growth rates published by the sources you discussed?

A. Schedule 9 shows the prospective five-year earnings per share growth rates projected for the Electric Group by IBES/First Call (6.25%), Zacks (5.89%), and Value Line (4.83%).

Q. Are certain growth rate forecasts entitled to greater weight in developing a growth rate for use in the DCF model?

A. Yes. While a variety of factors should be examined to reach a reasonable conclusion on the DCF growth rate, growth in earnings per share should receive the greatest emphasis. Growth in earnings per share is the primary determinant of investors' expectations of the total returns they will obtain from stocks because the capital gains yield (i.e., price appreciation) will track earnings growth if the P-E multiple remains constant, as the DCF model assumes. Moreover, earnings per share (derived from net income) are the source of dividend payments and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In fact, Professor Gordon, the foremost proponent of the use of the DCF model in setting utility rates, concluded that the best measure of growth for use in the DCF model is a forecast of earnings per-share growth.[8] Consistent with Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, and Value Line, provide the best indication of investor expectations.

Q. What growth rate do you use in your DCF model?

A. The forecasts shown on Schedule 9 for the Electric Group exhibit a range of average earnings per share growth rates from 4.83% to 6.25%. DCF growth rates should not be established by mathematical formulation, and I have not done so. In my opinion, a growth rate of 6.00% is a reasonable estimate of investor-expected growth for the Electric Group. This value is within the array of analysts' forecasts of five-year earnings per share growth rates. The reasonableness of this growth rate is also supported by the expected continuation of electric utility infrastructure spending.

[8] Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

Q. Are the dividend yield and growth components of the DCF adequate to accurately depict the rate of return on common equity when it is used to calculate a utility's weighted average overall cost of capital?

A. The components of the DCF model are adequate for that purpose only if the capital structure ratios are measured by the market value of debt and equity. In the case of the Electric Group, average capital structure ratios are 40.58% long-term debt, 0.49% preferred stock, and 58.93% common equity, as shown on Schedule 10. If book values are used to compute the capital structure ratios, then a leverage adjustment is required.

Q. What is a leverage adjustment?

A. If a firm's capitalization, as measured by its stock price, diverges from its capitalization, measured at book value, the potential exists for a financial risk difference. Such a risk difference arises because a market-valued capitalization contains more equity and less debt than a book-value capitalization and, therefore, has less risk than the book-value capitalization. A leverage adjustment properly accounts for the risk differential between market-value and book-value capital structures.

Q. Why is a leverage adjustment necessary?

A. In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes), the market-derived cost rate must be adjusted to account for this difference in financial risk. The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different from the capital structure indicated by the market price (P). From the market perspective, the financial risk of the Electric Group is accurately measured by the capital structure ratios calculated from the market-valued capitalization of a firm. If the ratemaking process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the ratemaking process uses ratios calculated from a firm's book value capitalization, further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the firm's equity. This adjustment is developed through precise mathematical calculations, using well-recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. The calculations presented in the lower panel of data shown on Schedule 10, under the heading "M&M,"[9] provide a return of 8.10% when applicable to a capital structure with 100% common equity.

Q. Are there specific factors that influence market-to-book ratios that determine whether the leverage adjustment should be made?

A. No. The leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations concerning market prices relative to book value are not on point. The leverage adjustment deals with the issue of financial risk and does not transform the DCF result to a book value return through a market-to-book adjustment. Again, the leverage adjustment that I propose is based on the fundamental financial precept that the cost of equity is equal to the rate of return for an unleveraged firm (i.e., where the overall rate of return equates to the cost of

[9] Franco Modigliani and Merton H. Miller, "The Cost of Capital, Corporation Finance, and the Theory of Investments," American Economic Review, June 1958, at 261-97. Franco Modigliani and Merton H. Miller, "Taxes and the Cost of Capital: A Correction," American Economic Review, June 1963, at 433-43.

equity with a capital structure that contains 100% equity) plus the additional return required for introducing debt and/or preferred stock leverage into the capital structure.

Further, as noted previously, the relatively high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on the book value of equity that differs from their cost of equity determined from stock market prices. Stock prices above book value are common for utility stocks, and indeed the stock prices of non-regulated companies exceed book values by even greater margins. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of their cost of capital. Certainly, in our free-market economy, competition should contain such “excesses” if they actually exist.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true: when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

Q. Is the leverage adjustment that you propose designed to transform the market return into one that is designed to produce a particular market-to-book ratio?

A. No, it is not. What I label a “leverage adjustment” is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g) when the DCF return applies to a capital structure used for ratemaking that is computed with book-value weighting rather than market-value weighting. Although I specify a separate factor, which I call the leverage adjustment, there is no need to do so other than to identify this factor. If I were to express my return solely in the context of the book value weighting that we use to calculate the weighted average cost of capital and ignore the familiar D/P + g expression entirely, then a separate element in the DCF cost of equity determination would not be needed to reflect the differential in financial leverage between a market-value and book-value capitalization. As shown in the bottom panel of data on Schedule 10, the equity return applicable to the book value common equity ratio is equal to 8.10%, which is the return for the Electric Group appropriate for a capital structure with no debt (i.e., a 100% equity ratio) plus 2.31% to compensate investors for the risk of a 53.41% debt ratio and 0.04% for a 0.73% preferred stock ratio. These are the book-value ratios that differ markedly from the market-value based ratios I discussed previously. Under this approach, the parts add up to 10.45% (8.10% + 2.31% + 0.04%), and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I added the 3.48% dividend yield, the 6.00% growth rate, and 0.97% for the leverage adjustment in order to arrive at the same 10.46% (3.48% + 6.00% + 0.97%) return. I know of no means to mathematically solve for the 0.97% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.97% adjustment is merely a convenient way to compare the 10.45% return computed using the Modigliani & Miller formulas to the 9.48% return generated by the DCF model (i.e., D_1/P_0 + g, or the traditional form of the DCF shown on Schedule 1, page 2) based on a market-value capital structure. A 9.48% return assigned to anything other than the market value of equity cannot equate to a reasonable return on book value that has higher financial risk. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

Q. Please provide the DCF return based upon your preceding discussion of dividend yield, growth, and leverage.

A. As explained previously, I have utilized a six-month average dividend yield (D_1/P_0) adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate (g) previously developed. The DCF also includes the leverage modification (Lev.) required when the book value equity ratio is used in determining the weighted average cost of capital in the ratemaking process rather than the market value equity ratio related to the price of stock. The resulting DCF cost rate is 10.45%, computed as follows:

	D_1/P_0	+	g	+	$lev.$	=	k
Electric Group	3.48%	+	6.00%	+	0.97%	=	10.45%

The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant-growth assumption. I should reiterate, however, that the DCF-indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the P-E multiple. An assumption that there will be no change in the P-E multiple is not supported by the realities of the equity market because P-E multiples do not remain constant. This is one of the constraints of this model that makes it important to consider the results of other models when determining a company's cost of equity.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the Risk Premium approach to determine the cost of equity.

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on Schedule 1, page 2. That result is 11.75%.

Q. What long-term public utility debt cost rate did you use in your Risk Premium analysis?

A. In my opinion, and as I will explain in more detail further in my testimony, a 5.50% yield represents a reasonable estimate of the prospective yield on long-term, public utility bonds.

Q. What historical data are shown by the Moody's data?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on Schedule 11, page 1. For the twelve months ended October 2022, the average monthly yield on Moody's index of A-rated public utility bonds was 4.31%. For the six- and three-month periods ended October 2022, the yields were 5.05% and 5.31%, respectively. During the twelve months ended October 2022, the range of the yields on A-rated public utility bonds was 3.02% to 5.88%. Page 2 of Schedule 11 shows the long-run spread in yields between A-rated public utility bonds and long-term Treasury bonds. As shown on page 3 of Schedule 11, the yields on A-rated public utility bonds have exceeded those on Treasury bonds by 1.52% on a twelve-month average basis, 1.69% on a six-month average basis, and 1.73% on a three-month average basis. With these data, 1.50% represents a reasonable, albeit conservative, spread for the yield on A-rated public utility bonds over Treasury bonds.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe below. Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on November 1, 2022 and a yield spread of 1.50%, derived from historical data.

Q. How have you used these data to project the yield on A-rated public utility bonds for the purpose of your Risk Premium analyses?

A. Shown below is my calculation of the prospective yield on A-rated public utility bonds using the building blocks discussed above, i.e., the Blue Chip forecast of Treasury bond yields and the public utility bond yield spread. For comparative purposes, I also have shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2022	Fourth	5.3%	6.3%	4.0%	1.50%	5.30%
2023	First	5.5%	6.5%	4.1%	1.50%	5.40%
2023	Second	5.4%	6.5%	4.1%	1.50%	5.50%
2023	Third	5.4%	6.4%	4.0%	1.50%	5.40%
2023	Fourth	5.3%	6.3%	3.9%	1.50%	5.30%
2024	First	5.1%	3.2%	3.9%	1.50%	5.30%

Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its June 1, 2022 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2023-2027	4.9%	5.9%	3.8%
2028-2032	5.0%	5.9%	3.9%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. A 5.50% yield on A-rated public utility bonds represents a reasonable benchmark for measuring the cost of equity in this case. All the data I used to formulate my conclusion as to a prospective yield on A-rated public utility debt are available to investors, who regularly rely upon such data to make investment decisions. Recent FOMC pronouncements have moved the forecasts of interest rates to higher levels.

Q. What equity risk premium have you determined for public utilities?

A. To develop an appropriate equity risk premium, I analyzed the results from 2022 SBBI Yearbook, Stocks, Bonds, Bills and Inflation. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline, and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on Schedule 12, page 1.

Common Equity Risk Premiums	
Low Interest Rates	6.81%
Average Across All Interest Rates	5.93%
High Interest Rates	5.05%

Based on my analysis of the historical data, the equity risk premium was 6.81% when the marginal cost of long-term government bonds was low (i.e., 2.80%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.03% on average during periods of high interest rates), the spread narrowed to 5.05%. Over the entire spectrum of interest rates, the equity risk premium was 5.93% when the average government bond yield was 4.92%. From these data, I have utilized a 6.25% equity risk premium. The equity risk premium of 6.25% is between the premiums associated with low interest rates (i.e., 6.81%) and average for the entire historical period interest rates (i.e., 5.93%).

Q. What common equity cost rate did you determine based on your Risk Premium analysis?

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i") and the equity risk premium (i.e., "RP"). The Risk Premium approach provides a cost of equity of:

Electric Group	5.50%	+	6.25%	=	11.75%

CAPITAL ASSET PRICING MODEL

Q. How is the CAPM used to measure the cost of equity?

A. The CAPM uses the yield on a risk-free interest-bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Schedule 1, the result of the CAPM is 15.95% for the Electric Group with the leverage adjustment. Without the leverage adjustment, the CAPM result is 13.93% (15.95% - (0.20 x 10.12%)) through use of the Value Line beta excluding the leverage adjustment (i.e., 1.08 - 0.88 = 0.20). To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 2 of Schedule 3, the average beta is 0.88 for the Electric Group.

Q. Did you use the Value Line betas in the CAPM determined cost of equity?

A. I used the Value Line betas as a foundation for the leverage adjusted betas that I used in the CAPM. The Value Line betas are measured over a five-year period. The betas must be reflective of the financial risk associated with the ratemaking capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. Since we used book values in this case, the Value Line betas must be adjusted for the higher financial risk associated with the book value capital structure. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line (market value) betas have been unleveraged and re-leveraged for the book value common equity ratios using the Hamada formula,[10] as follows:

$$\beta l = \beta u\ [1 + (1 - t)\ D/E + P/E]$$

ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.60 for the Electric Group if it employed no leverage and was 100% equity financed. Those calculations are shown on Schedule 10 under the section labeled “Hamada,” who is credited with developing those formulas. With the unleveraged beta as a base, I calculated the leveraged beta of 1.08 for the book value capital structure of the Electric Group.

[10] Robert S. Hamada, “The Effects of the Firm’s Capital Structure on the Systematic Risk of Common Stocks;” The Journal of Finance, Vol. 27, No. 2; Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, Dec. 27-29, 1971. (May 1972), pp. 435-52.

Q. What risk-free rate have you used in the CAPM?

A. As shown on page 1 of Schedule 13, I provided the historical yields on Treasury notes and bonds. For the twelve months ended October 2022, the average yield on 30-year Treasury bonds was 2.79%. For the six- and three-months ended October 2022, the yields on 30-year Treasury bonds were 3.36% and 3.58%, respectively. During the twelve months ended October 2022, the range of the yields on 30-year Treasury bonds was 1.85% to 4.04%. The low yields that existed during 2020 can be traced to extraordinary events associated with the Pandemic that jolted the capital markets. I described these events in my pre-filed direct testimony previously. Much higher rates are currently in place. A forward-looking assessment of the capital markets is especially relevant now because the Company's rates will be based on financial conditions in 2024 and beyond. Higher inflation expectations are a contributing factor that points to higher interest rates. Indeed, higher inflation today is revealed by an 8.7% increase in 2023 Social Security payments announced on October 13, 2022, which is the largest one-year increase in four decades. This is symptomatic of high rates of inflation that are pushing upward the cost of capital.

This is revealed by the end of accommodative policy by the FOMC. Tighter monetary policy has promoted higher interest rates that have already occurred and will continue in the future. The Fed Funds rate is expected to continue to increase from very low levels that existed during the Pandemic. After the FOMC ended its bond-buying program (i.e., quantitative easing) in March 2022, it now plans to run off its $9 trillion asset portfolio, which will further boost interest rates, particularly those with 10 and 30-year maturities.

Higher interest rates clearly point to higher capital costs prospectively, as indicated by recent bond yield changes. The yield on 10-year Treasury bonds moved above the 3% level on May 2, 2022, the first time since late 2018. By October 2022, the yield on 30-year Treasury bonds moved to 4.04%, or an increase of 2.37% (or 142%) since December 2020.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on November 1, 2022, indicate that the yields on long-term Treasury bonds are expected to be in the range of 3.9% to 4.1% during the next six quarters. The forecasts show interest rates remaining at high levels through the second quarter of 2023, and then some moderation thereafter. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 3.8% from 2023 through 2027 and 3.9% from 2028 to 2032. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a 4.00% risk-free rate of return for CAPM purposes, which considers the Blue Chip forecasts, and is conservative.

Q. What market premium have you used in the CAPM?

A. As shown in the lower panel of data presented on Schedule 13, page 2, the market premium is derived from historical data and the forecast returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on Schedule 12, page 1. On that schedule, the market return was 12.21% on large stocks during periods between the low interest rate environment and the entire long-term average. During those periods, the yield on long-term government bonds was 3.86% (2.80% + 4.92% = 7.72% ÷ 2). Likewise, I carried over to Schedule 13, page 2, the average large common stock returns of 12.21% (12.09% + 12.33% = 24.42% ÷ 2) and the average yield on long-term government bonds of 3.86%. The resulting market premium is 8.35% (12.21% - 3.86%) based on historical data, as shown on Schedule 13, page 2. As also shown on Schedule 13, page 2, I calculated the forecast returns, which show a 15.89% total market return. With this forecast, I calculated a market premium of 11.89% (15.89% - 4.00%) using forecast data. The resulting market premium applicable to the CAPM derived from these sources equals 10.12% (11.89% + 8.35% = 20.24% ÷ 2).

Q. Are there adjustments to the CAPM that are necessary to fully reflect the rate of return on common equity?

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. As the size of a firm decreases, its risk and required return increases. Moreover, in his discussion of the cost of capital, Professor Eugene F. Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms. Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns;" The Journal of Finance, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," it was demonstrated that the CAPM could significantly understate the cost of equity according to a company's size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. To recognize this fact, I used the mid-cap adjustment of 1.02%, as shown on page 3 of Schedule 13, for the CAPM calculation. The adjustment here is related to the size of the Electric Group.

Q. What does your CAPM analysis show?

A. Using the 4.00% risk-free rate of return, the leverage adjusted beta of 1.08 for the Electric Group, the 10.12% market premium, and the 1.02% size adjustment, the following result is indicated.

	Rf	+	*(*	*β*	*x (*	*Rm-Rf*	*))*	+	*size*	=	*k*
Electric Group	4.00%	+	*(*	1.08	x (	10.12%	))	+	1.02%	=	15.95%

The CAPM results shown here should receive more weight in an environment of rising interest rates, because the DCF will provide an understated result. Indeed, the

Commission has used the results of the CAPM when the DCF is producing atypical results.

COMPARABLE EARNINGS APPROACH

Q. What is the Comparable Earnings approach?

A. The Comparable Earnings approach estimates a fair return on equity by comparing returns realized by non-regulated companies to returns that a public utility with similar risk characteristics would need to realize in order to compete for capital. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into investor expectations for public utility returns. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided.

There are two avenues available to implement the Comparable Earnings approach. One method involves the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms in order to avoid the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. The return should be reasonably sufficient to assure confidence in the financial

> soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works v. Public Service Commission, 262 U.S. 668 (1923).

It is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

Q. Did you compare the results of your DCF and CAPM analyses to the results indicated by a Comparable Earnings approach?

A. Yes. I selected companies from The Value Line Investment Survey for Windows that have six categories of comparability designed to reflect the risk of the Electric Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Electric Group. The items considered were Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The definition for these parameters is provided on Schedule 14, page 3. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on Schedule 14, page 1.

I relied upon Value Line data because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on Schedule 14, page 2, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities.

Q. What data did you consider in your Comparable Earnings analysis?

A. I used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 12.8% using only the returns that were less than 20%, as shown on Schedule 14, page 2. The average forecasted rate of return as published by Value Line is 13.4% also using values less than 20%, as provided on Schedule 14, page 2. Using the average of these data, my Comparable Earnings result is 13.10%, as shown on Schedule 1, page 2.

CONCLUSION ON COST OF EQUITY

Q. What is your conclusion regarding the Company's cost of common equity?

A. Based upon the application of a variety of methods and models described previously, it is my opinion that a reasonable rate of return on common equity is 11.30% for UGI Electric, which includes twenty basis points or 0.20% for recognition of the Company's strong management performance. My cost of equity recommendation is within the range of results and should be considered in the context of the Company's risk characteristics relative to the Electric Group companies. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method. In summary, the Company should be provided an opportunity to realize an 11.30% rate of return on common equity so that it can compete in the capital markets, attain reasonable credit quality, sustain its cash flow in the context of its high levels of capital expenditures, and receive recognition of the significant accomplishments that management has achieved.

Q. Does this complete your direct testimony?

A. Yes. However, I reserve the right to supplement my testimony, if necessary, and to respond to witnesses presented by other parties.

UGI ELECTRIC

EXHIBIT PRM-1

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past forty-two years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty-seven (37) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on Environmental Quality. My testimony has been offered in over 300 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509).

I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

UGI ELECTRIC STATEMENT NO. 10

SHERRY A. EPLER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368

UGI Utilities, Inc. – Electric Division

Statement No. 10

Direct Testimony of Sherry A. Epler

Topics Addressed:	**Sales and Revenues** **Tariff Changes**

Dated: January 27, 2023

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Sherry A. Epler. My business address is 1 UGI Drive, Denver, PA 17517.

Q. By whom are you employed and in what capacity?

A. I am employed by UGI Utilities, Inc. ("UGI") as Senior Manager, Tariff & Supplier Administration. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric" or the "Company") and the Gas Division ("UGI Gas"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your responsibilities as Senior Manager, Tariff & Supplier Administration with respect to UGI Electric?

A. My current responsibilities related to UGI Electric include: (1) all aspects of tariff and rate administration, including interactions with electric retail suppliers under the Company's electric supplier tariff; and (2) revenue analysis.

Q. Please provide your educational background and professional experience.

A. Please see my resume, UGI Electric Exhibit SAE-1, which is attached to my testimony.

Q. Have you testified previously before the Pennsylvania Public Utility Commission?

A. Yes. UGI Electric Exhibit SAE-1 contains a list of those proceedings.

Q. Please describe the purpose of your testimony.

A. I will address: (1) the development of sales and revenue for the historic test year ended September 30, 2022 ("HTY"), future test year ending September 30, 2023 ("FTY"), and fully projected future test year ending September 30, 2024 ("FPFTY"); and (2) and certain proposed tariff modifications.

Q. Are any other witnesses providing testimony on the areas you identified above?

A. Yes. Company witness John D. Taylor, Managing Partner of Atrium Economics, LLC (UGI Electric Statement No. 6) is sponsoring allocation of the revenue increase and rate design, in addition to his testimony supporting class cost of service, using the projected sales and revenue figures discussed in my testimony. Additionally, Company witness Eric W. Sorber (UGI Electric Statement No. 4) is sponsoring certain proposed tariff modifications.

Q. Are you sponsoring any exhibits or filing requirements in this proceeding?

A. Yes, I am sponsoring the following Exhibits: UGI Electric Exhibit SAE-1 (Resume), UGI Electric Exhibit SAE-2 (15 Year Normal Heating and Cooling Degree Days 2005-2019), UGI Electric Exhibit SAE-3 (UGI Electric Customer Counts), UGI Electric Exhibit SAE-4 (Fully Projected Future Test Year Sales and Revenue Adjustments), UGI Electric Exhibit SAE-5 (Future Test Year Sales and Revenue Adjustments), UGI Electric Exhibit SAE-6 (Historic Test Year Sales and Revenue Adjustments), UGI Electric Exhibit E (Proof of Revenue), and certain portions of UGI Electric Exhibit F (Proposed Tariff). I am also sponsoring certain responses to the Commission's standard filing requirements, as indicated on the matter list accompanying this filing, that were prepared by me or under my direction.

II. TEST YEARS' SALES AND REVENUES

A. Development of FPFTY Sales and Revenues

Q. Please explain how the Company's FPFTY sales and revenues were developed.

A. FPFTY sales and revenues were developed by annualizing and normalizing the Company's 2024 fiscal year planned sales and revenue budget. Annualized sales were determined by developing sales and revenue adjustments reflective of annual expected use per customer and projected customer counts as of the end of the FPFTY, or September 30, 2024. UGI Electric Exhibit SAE-2 provides the development of the Company's normal degree day values, which are based on the 15-year period 2005-2019. This data was used in normalizing use per customer for degree days. The Company's 15-year normal is updated every 5 years, with the most recent being the 15-year period of 2005-2019.

Q. Please explain the process for developing the Company's fiscal year ("FY") 2023 planned sales and revenue budget.

A. The planned sales and revenue budget for FY2023 or the FTY was developed by the Financial Planning and Analysis ("FP&A") group with input from various UGI Electric personnel. Historical data is used in developing a forecast of sales and revenue. Because of the static nature of the Company's customer base, the Company developed the budgeted number of customers for both the FTY and FPFTY by using the actual average customer count for FY2022. The Marketing group provided data for major customer additions for incorporation in the budgeted customer numbers.

UGI Electric Exhibit SAE-3 provides the actual historical customer count and illustrates the relatively static nature of the service territory. The budgeted sales-kilowatt hours ("kWh") were developed using a two-year average of the sales-kWh for each month for a two-year period ended April 2022. The revenue budget is then calculated by applying tariff rates for each customer class to budgeted sales. The sales and revenue budget is then reviewed and approved by senior management. The complete budget process is described in the direct testimony of Company witness Tracy A. Hazenstab (UGI Electric Statement No. 2).

Q. Please describe the adjustments made to FPFTY sales and revenues for the 12 months ending September 30, 2024.

A. A summary of all adjustments made to the 2024 planned budget in order to develop FPFTY sales is shown on UGI Electric Exhibit SAE-4(a). In total, these adjustments reflect an increase to sales of 35,942,000 kWh, or 3.52%, with a net upward adjustment to margin of $2,252,000, and a net increase to revenues of $7,388,000.

Q. Please explain the "Adjustment for Customer Changes" shown on UGI Electric Exhibit SAE-4(b).

A. The "Adjustment for Customer Changes" annualizes customer counts for certain rate classes to anticipated end-of-test-year levels. The Company projects customer growth forward from September 2022 actual levels based on a two-year average growth pattern from year end September 2020 to year end September 2021 and from year end September 2021 to year end September 2022, as shown in the presented customer rate categories.

Q. How is this adjustment quantified?

A. UGI Electric Exhibit SAE-4(b) provides the calculation of the associated sales and revenue adjustments related to customer count changes and reflects customer count increases for default service customers taking service under Rate R-General, Rate R-Heating, and Rate GS-1-Commercial General and a decrease for Rate GS-4-Commercial General. Adjustments were made to these four rate class categories as they comprise the majority of customer counts and the largest total margin dollars for the Company. In total, as reflected on UGI Electric Exhibit SAE-4(a), this adjustment increases sales by 5,393,000 kWh and increases projected revenues by $912,000. The impact to margin is an increase of $167,000.

Q. Please explain the adjustment for "Normalized Use/Customer."

A. As noted earlier, the sales-kWh values for the budget were developed using a two-year average of the sales-kWh for each month for a two-year period ending April 2022. As the associated average degree days for these periods differ from the Company's 15-year period used to define normal degree days for ratemaking purposes, or normal weather, an adjustment is necessary to normalize usage to the Company's stated 15-year normal weather. This adjustment utilizes the variance between the calculated average degree days for the periods utilized for budget development and the Company's 15-year normal degree days to calculate the normalizing adjustments. *See* UGI Electric Exhibit SAE-2 for related degree day data. UGI Electric Exhibit SAE-4(c) shows the calculation of the adjustment of the use per default service customer taking service under Rate R-General, Rate R-Heating, Rate GS-1-Commercial General, and Rate GS-4-Commercial General, respectively. As shown in this exhibit, this adjustment is calculated by applying the heating and cooling sensitivity per degree day to the difference between the calculated average degree days for the periods utilized for budget development and the Company's 15-year normal degree days. In total, as reflected on UGI Electric Exhibit SAE-4(a), this adjustment increases sales by 30,549,000 kWh and increases projected revenues by $5,513,000. The impact to margin is an increase of $1,179,000.

Q Please explain the adjustment on UGI Electric Exhibit SAE-4(d) "Adjustment for STAS."

A. The "Adjustment for STAS" is the calculated State Tax Adjustment Surcharge ("STAS") on all Revenue adjustments presented in UGI Electric Exhibits SAE-4(b), (c), and (e). This STAS adjustment increases projected revenues by $1,000 with no impact to margin.

Q. Please explain the "Adjustment for DSIC" on UGI Electric Exhibit SAE-4(e).

A. The "Adjustment for DSIC" annualizes the Distribution System Improvement Charge ("DSIC") rate to reflect end of FPFTY conditions. This DSIC adjustment increases projected revenues by $963,000 and increases projected margins by $906,000.

B. Development of Sales and Revenue for the FTY and HTY

Q. How were normalized and annualized sales and revenue determined for the FTY ending September 30, 2023?

A. Budgeted sales and revenues served as the starting point for the development of the normalized and annualized FTY sales and revenues summarized on UGI Electric Exhibit SAE-5(a). All of the adjustments that were made in the development of the FPFTY were also made in the development of the FTY with the exception of the "Adjustment for DSIC." These detailed adjustments are contained in UGI Electric Exhibits SAE-5(b)-(d).

Q. How were normalized and annualized sales and revenue determined for the HTY ended September 30, 2022?

A. Historic sales and revenues served as the starting point for the development of the normalized and annualized HTY sales and revenues shown in summary on UGI Electric Exhibit SAE-6(a). All of the adjustments that were made in the development of the FPFTY were also made in the development of the HTY, except for the "Adjustment for DSIC." Additional adjustments were made, which include: (1) "Adjustment for GSR-1" to annualize historic GSR-1 rates to the September 1, 2022 rate of $0.12902/kWh; (2) "Adjustment for USP" to annualize historic USP rates to the September 1, 2022 rate of $0.0115/kWh; and (3) "Adjustment for EEC" to annualize historic Energy Efficiency and Conservation ("EEC") rates to the September 1, 2022 rate of $0.00059/kWh for Class 1, $0.00132/kWh for Class 2, and $0.00203/kWh for Class 3 customers. These detailed adjustments are contained in UGI Electric Exhibits SAE-6(b)-(g).

III. TARIFF MODIFICATIONS

Q. What tariff changes are being proposed in this case?

A. The Company is revising references to the Supplement Number, Notice Language, Issue and Effective Dates, and page numbers as necessary; in accordance with 52 Pa. Code Chapter 53 standards. Apart from the proposed rate schedule changes (in accordance with this rate case filing), a complete list of tariff modifications are found in the List of Changes

Made by the Supplement section in UGI Gas Exhibit F – Proposed Supplement No. 51 to UGI Electric Tariff No. 6. More significant proposed changes to the tariff include:

- Rider A – The State Tax Adjustment Surcharge was rolled into rates and reset to 0.00%.
- Rider C – Universal Service Program was revised so the Customer Assistance Program ("CAP") credit bad debt offset will be associated with the participants in excess of the number of CAP enrollees as of September 30, 2023, in place of the existing September 30, 2021 date. This proposal is consistent with the establishment of the CAP enrollee figure in the last UGI Electric rate case at Docket No. R-2021-3023618.
- Rider G – DSIC was reset to 0.00% in accordance with 66 Pa. C.S. § 1358(b).

Q. Is the Company adding a definition for Contribution in Aid of Construction to its tariff?

A. Yes. The Company is adding a definition for Contribution in Aid of Construction to the "Definitions – General" part of its Electric tariff. There are various places in the current tariff where customers are required to pay UGI Electric for extending service, relocating facilities, or upgrading the system to accommodate customer needs (e.g., Rules 5, 17, 19 and various rate schedules). The definition clarifies the term's application in these situations as "a non-refundable cash contribution from an Applicant/Customer for those costs associated with a line extension, temporary service, or relocation of Company facilities, including all related activities." The term also replaces "aid in construction," which appears in different subparts of Rules 5, 17, and 19.

Q. What changes is UGI Electric proposing to Rule 16-b "Administration of Rates" in the tariff?

A. The Company is proposing a few revisions to Rule 16-b. First, UGI Electric is revising the title of Rule 16-b from "Billing Changes" to "Billing Corrections" to more adequately reflect the purpose of the rule. Second, the Company is clarifying that the subject of the billing reviews contemplated by the rule include customer usage in addition to billing demands. Third, the resulting billing/rate revisions now include changes to customer consumption to align with actual practice. The remaining changes to this section are minor housekeeping items.

Q. What changes is the Company proposing to Rule 16-c "Change in Rate" and Rule 16-d "Billing During Periods of Construction or Emergency" in the tariff?

A. The Company is revising Rules 16-c and 16-d to better align with the requirement in 66 Pa. C.S. § 1303 that utilities compute bills under the most advantageous rate to customers who qualify for more than one rate, after actual notice of service conditions.

Q. What tariff changes are being sponsored by Mr. Sorber?

A. Mr. Sorber is sponsoring tariff changes associated with Rule 1-c, certain outdoor lighting provisions, and Rate LP. These tariff sections are discussed in UGI Electric Statement No. 4.

Q. Are any other tariff changes being proposed by the Company?

A. The Company has proposed other, less substantive, changes to the tariff that are listed on page 2, List of Changes, of UGI Electric Exhibit F – Proposed Tariff. The Company also is making minor changes to the Electric Generation Supplier Coordination Tariff No. 2S.

Q. Does this conclude your testimony?

A. Yes.

UGI ELECTRIC

EXHIBIT SAE-1

Sherry Epler

Senior Manager, Tariff & Supplier Administration

Work Experience

UGI Utilities, Inc., Denver, PA

November 2019 – Present	Senior Manager, Tariff & Supplier Administration
2018 – November 2019	Manager, Revenue/Sales & Choice Administration

UGI Utilities, Inc., Reading, PA

2000 – 2018	Rates Analyst – I/II/Sr/Principal (Progressive Positions)
1997 – 2000	Data and Expense Analyst – Residential Marketing
1990 – 1997	Staff Accountant – Supply Accounting
1989 – 1990	Accounting Assistant, Supply – Accounting
1988 – 1989	Accounting Assistant, Rates & Budgets – Accounting
1986 - 1988	Accounting Assistant B – Accounting

Education

Bachelor of Science, Accounting, Albright College, 1995

Associate of Science, Business Administration, Pennsylvania State University, 1986

Previous testimony provided before the Pennsylvania Public Utility Commission:

Docket No. R-2021-3023618 UGI Electric Base Rate Case

Docket No. R-2021-3030218 UGI Gas Base Rate Case

UGI ELECTRIC

EXHIBIT SAE-2

UGI Utilities Inc. - Electric Division
15 Year Normal Heating Degree Days (2005-2019)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	15 Year Average
Jan	1,282	932	1,034	1,084	1,347	1,217	1,285	1,042	1,086	1,336	1,268	1,140	992	1,210	1,188	1,163
Feb	989	979	1,226	1,008	949	1,046	1,008	851	1,013	1,136	1,309	924	757	824	953	998
Mar	1,027	862	899	891	800	685	905	514	940	1,039	996	623	938	955	872	863
Apr	402	437	598	383	429	348	463	496	462	500	446	495	289	628	371	450
May	296	221	167	309	193	171	148	85	201	157	94	236	225	87	145	182
Jun	16	66	25	25	47	28	29	50	25	10	25	26	41	26	26	31
Jul	0	0	16	0	9	6	0	0	2	1	0	0	0	0	0	2
Aug	0	7	25	15	9	6	6	3	11	9	0	0	19	0	3	8
Sep	33	148	80	98	140	83	81	126	158	106	38	60	94	82	49	92
Oct	397	466	236	499	491	406	419	350	334	302	390	352	224	413	302	372
Nov	626	581	751	731	591	695	567	805	789	761	509	623	701	812	798	689
Dec	1,163	819	1,047	1,034	1,094	1,192	886	898	1,037	909	638	996	1,108	933	961	981
Totals	6,231	5,518	6,104	6,077	6,099	5,883	5,797	5,220	6,058	6,266	5,713	5,475	5,388	5,970	5,668	5,831

UGI Utilities Inc. - Electric Division
15 Year Normal Cooling Degree Days (2005-2019)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	15 Year Average
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Apr	6	0	4	5	41	15	14	7	4	6	0	1	15	4	7	9
May	10	32	54	9	19	80	61	72	56	30	143	69	35	77	32	52
Jun	230	92	129	154	60	183	116	127	133	152	153	151	161	117	113	138
Jul	312	264	177	224	97	305	304	308	311	214	244	326	244	261	320	261
Aug	306	175	205	86	157	209	133	194	147	139	210	290	140	262	196	190
Sep	119	8	94	71	9	91	71	61	60	71	134	117	102	119	79	80
Oct	6	0	41	0	0	0	0	2	14	9	0	9	37	28	14	11
Nov	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Totals	989	571	704	549	383	883	699	771	725	621	885	963	734	868	761	740

UGI ELECTRIC

EXHIBIT SAE-3

UGI Utilities Inc. - Electric Division
Customer Counts at Year End September

Rate	Sept 1995	Sept 2017	Sept 2018	Sept 2019	Sept 2020	Sept 2021	Sept 2022	Sept 2023	Sept 2024
Res-General	42,920	44,014	44,024	44,104	44,301	44,237	44,253	44,319	44,335
Res-Heating	10,389	10,341	10,372	10,347	10,415	10,448	10,532	10,586	10,661
Com-General	5,872	7,142	7,179	7,239	7,294	7,302	7,292	7,346	7,384
Com-Heating	585	336	338	337	331	327	329	331	331
Ind-General	136	118	118	115	117	121	120	121	121
Ind-Heating	45	35	35	35	35	35	35	35	35
Public St & Hwy Lighting	51	54	53	54	53	53	55	54	54
Other	5	7	7	7	7	7	7	7	7
Sales for Resale	2	3	3	3	3	3	3	3	3
Total	60,005	62,050	62,129	62,241	62,556	62,533	62,626	62,802	62,931

Note: Excludes unmetered Lighting

UGI ELECTRIC

EXHIBIT SAE-4(a) – SAE-4(e)

UGI Utilities, Inc.- Electric Division
Fully Projected Future Test Year 2024 Sales and Revenues
Summary of Adjustments

	Sales (000's) MWh	Revenues ($000's)	Margin ($000's)	Reference
Budget 2024	1,019,988	144,199	41,853	
Adjustment for Customer Changes	5,393	912	167	UGI Electric Exhibit SAE-4(b)
Adjustment for Normalized Use/Customer	30,549	5,513	1,179	UGI Electric Exhibit SAE-4(c)
Adjustment for STAS		1	0	UGI Electric Exhibit SAE-4(d)
Adjustment for DSIC		963	906	UGI Electric Exhibit SAE-4(e)
Fully Projected Future Test Year 2024	1,055,931	151,588	44,105	

UGI Utilities, Inc.- Electric Division
Fully Projected Future Period- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for Customer Changes
Rate R General, Rate R Heating, Rate GS-1 Com-Gen, Rate GS-4 Com-Gen
GSR subgroups only

Line #		[1] Rate R General	[2] Rate R Heating	[3] Rate GS-1 Com-Gen	[4] Rate GS-4 Com-Gen	[5] Total
1	Customers in Test Year 2024 (Unadjusted)	44,002	10,431	4,852	1,781	61,066
2	Future Test Year 2024 Customers (Fully Adjusted)	44,034	10,581	4,868	1,841	61,324
3	Change in Customers during Future Test Year 2024	32	150	16	60	258
4	Total UPC (Unadjusted)-kWh	8,981	17,374	4,879	40,358	71,592
5	Annualization Adjustment for Sales-MWh	287	2,606	78	2,421	5,393
6	Total Revenue unit rate (L7+L8+L9+L10+L11)	$ 0.1802	$ 0.1802	$ 0.1827	$ 0.1554	
7	USP unit rate	$ 0.0115	$ 0.0115	$ -	$ -	
8	EEC-Class 1 & Class 2 unit rate	$ 0.0006	$ 0.0006	$ 0.0013	$ 0.0013	
9	GSR-1 unit rate	$ 0.1290	$ 0.1290	$ 0.1290	$ 0.1290	
10	Distribution unit rate (margin plus GRT)	$ 0.0391	$ 0.0391	$ 0.0524	$ 0.0250	
11	Revenue Adjustment (L5 * L6)	$ 52	$ 470	$ 14	$ 376	$ 912
12	USP Adjustment (L5 * L7)	$ 3	$ 30	$ -	$ -	$ 33
13	EEC Adjustment (L5 * L8)	$ 0	$ 2	$ 0	$ 3	$ 5
14	GSR Adjustment (L5 * L9)	$ 37	$ 336	$ 10	$ 312	$ 696
15	Distribution Adjustment (L5 * L10)	$ 11	$ 102	$ 4	$ 61	$ 178
16	Margin Adjustment (L15 less GRT)	$ 11	$ 96	$ 4	$ 57	$ 167

UGI Utilities, Inc.- Electric Division
Fully Projected Future Period- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for Usage per Customer
Rate R General, Rate R Heating, Rate GS-1 Com-Gen, Rate GS-4 Com-Gen
GSR subgroups only

	[1] Rate R General	[2] Rate R Heating	[3] Rate GS-1 Com-Gen	[4] Rate GS-4 Com-Gen	[5] Total
Heating Sensitivity/HDD/cust (kWh/DD/cust)	1.7665	0.5411	3.0174	0.2109	
DD Variance (to 15 Year normal)	349	349	349	349	
kWh/customer adjustment (L1 * L2)	617	189	1,053	74	
Customers FY24 (fully adjusted)	44,034	10,581	4,868	1,841	
Normalizing Adj (MWh) (L3 * L4)/1000	27,153	1,999	5,127	136	34,414
Total Revenue unit rate (L7+L8+L9+L10+L11)	$ 0.18018	$ 0.18018	$ 0.18271	$ 0.15539	
USP unit rate	$ 0.01150	$ 0.01150	$ -	$ -	
EEC-Class 1 & Class 2 unit rate	$ 0.00059	$ 0.00059	$ 0.00132	$ 0.00132	
GSR-1 unit rate	$ 0.12902	$ 0.12902	$ 0.12902	$ 0.12902	
Distribution unit rate (margin plus GRT)	$ 0.03907	$ 0.03907	$ 0.05237	$ 0.02505	
Revenue Adjustment (L5 * L6)	$ 4,892	$ 360	$ 937	$ 21	$ 6,210
USP Adjustment (L5 * L7)	$ 312	$ 23	$ -	$ -	$ 335
EEC Adjustment (L5 * L8)	$ 16	$ 1	$ 7	$ 0	$ 24
GSR Adjustment (L5 * L9)	$ 3,503	$ 258	$ 662	$ 17	$ 4,440
Distribution Adjustment (L5 * L10)	$ 1,061	$ 78	$ 269	$ 3	$ 1,411
Margin Adjustment (L15 less GRT)	$ 998	$ 73	$ 253	$ 3	$ 1,328
Cooling Sensitivity/CDD/cust (kWh/DD/cust)	0.3442	0.3692	0.6874	0.0848	
DD Variance (to 15 Year normal)	(171)	(171)	(171)	(171)	
kWh/customer adjustment (L17 * L18)	(59)	(63)	(118)	(15)	
Customers FY24 (fully adjusted)	44,034	10,581	4,868	1,841	
Normalizing Adj (MWh) (L19 * L20)/1000	(2,596)	(669)	(573)	(27)	(3,865)
Total Revenue unit rate (L23+L24+L25+L26)	$ 0.18018	$ 0.18018	$ 0.18271	$ 0.15539	
USP unit rate	$ 0.01150	$ 0.01150	$ -	$ -	
EEC-Class 1 & Class 2 unit rate	$ 0.00059	$ 0.00059	$ 0.00132	$ 0.00132	
GSR-1 unit rate	$ 0.12902	$ 0.12902	$ 0.12902	$ 0.12902	
Distribution unit rate (margin plus GRT)	$ 0.03907	$ 0.03907	$ 0.05237	$ 0.02505	
Revenue Adjustment (L21 * L22)	$ (468)	$ (121)	$ (105)	$ (4)	$ (697)
USP Adjustment (L21 * L23)	$ (30)	$ (8)	$ -	$ -	$ (38)
EEC Adjustment (L21 * L24)	$ (2)	$ (0)	$ (1)	$ (0)	$ (3)
GSR Adjustment (L21 * L25)	$ (335)	$ (86)	$ (74)	$ (3)	$ (499)
Distribution Adjustment (L21 * L26)	$ (101)	$ (26)	$ (30)	$ (1)	$ (158)
Margin Adjustment (L31 less GRT)	$ (95)	$ (25)	$ (28)	$ (1)	$ (149)
Total Adjustment Summary-FY24					
Normalizing Adj (MWh) (L5+L21)	24,557	1,329	4,554	109	30,549
Total Revenue Adjustment (L11+L27)	$ 4,425	$ 240	$ 832	$ 17	$ 5,513
Total USP Adjustment (L12+L28)	$ 282	$ 15	$ -	$ -	$ 298
Total EEC Adjustment (L13+L29)	$ 14	$ 1	$ 6	$ 0	$ 21
Total GSR Adjustment(L14+L30)	$ 3,168	$ 172	$ 588	$ 14	$ 3,941
Total Distribution Adjustment(L15+L31)	$ 959	$ 52	$ 239	$ 3	$ 1,253
Total Margin Adjustment (L16+L32)	$ 903	$ 49	$ 224	$ 3	$ 1,179

UGI Utilities, Inc.- Electric Division
Fully Projected Future Period- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for STAS

	Unadjusted Budget Revenue Excluding STAS	Customer Adj	UPC Adj	DSIC Adj	Revised Revenue Excluding STAS	STAS Revenue @ Dec 1 Rate	STAS Revenue @ Budget Rate	STAS Adjustment
						0.01%	0.01%	
Residential	$ 111,365	$ 521	$ 4,664	$ 703	$ 117,254	$ 12	$ 11	$ 1
Commercial & Industrial	$ 32,037	$ 391	$ 849	$ 249	$ 33,526	$ 3	$ 3	$ 0
Public Streets & Highway Lighting	$ 748	$ -		$ 9	$ 758	$ 0	$ 0	$ 0
Other Sales to Public Authorities	$ 19	$ -		$ 0	$ 19	$ 0	$ 0	$ 0
Sales for Resale	$ 16	$ -		$ 0	$ 16	$ 0	$ 0	$ 0
Total	$ 144,185	$ 912	$ 5,513	$ 963	$151,572	$ 15	$ 14	$ 1

UGI Utilities, Inc.- Electric Division
Fully Projected Future Period- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for DSIC

	Unadjusted Budget DSIC Revenue @3.24%	Adjusted Budget DSIC Revenue @ 5%	DSIC Revenue Adjustment	GRT on DISC Adjustment	DSIC Margin Adjustment
Residential	$ 1,159	$ 1,862	$ 703	$ (42)	$ 662
Commercial & Industrial	$ 465	$ 714	$ 249	$ (15)	$ 235
Public Streets & Highway Lighting	$ 18	$ 27	$ 9	$ (1)	$ 9
Other Sales to Public Authorities	$ 1	$ 1	$ 0	$ (0)	$ 0
Sales for Resale	$ 0	$ 0	$ 0	$ (0)	$ 0
Total	$ 1,642	$ 2,605	$ 963	$ (57)	$ 906

UGI ELECTRIC

EXHIBIT SAE-5(a) – SAE-5(d)

UGI Utilities, Inc.- Electric Division
Future Test Year 2023 Sales and Revenues
Summary of Adjustments

	Sales (000's) MWh	Revenues ($000's)	Margin ($000's)	Reference
Budget 2023	1,001,278	140,115	40,243	
Adjustment for Customer Changes	2,692	455	84	UGI Electric Exhibit SAE-5(b)
Adjustment for Normalized Use/Customer	26,225	4,730	1,008	UGI Electric Exhibit SAE-5(c)
Adjustment for STAS		1	0	UGI Electric Exhibit SAE-5(d)
Future Test Year 2023	1,030,195	145,301	41,334	

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for Customer Changes
Rate R General, Rate R Heating, Rate GS-1 Com-Gen, Rate GS-4 Com-Gen
GSR subgroups only

Line #		[1] Rate R General	[2] Rate R Heating	[3] Rate GS-1 Com-Gen	[4] Rate GS-4 Com-Gen	[5] Total
1	Customers in Test Year 2023 (Unadjusted)	44,002	10,431	4,852	1,781	61,066
2	Future Test Year 2023 Customers (Fully Adjusted)	44,018	10,506	4,860	1,811	61,195
3	Change in Customers during Future Test Year 2023	16	75	8	30	129
4	Total UPC (Unadjusted)-kWh	8,976	17,356	4,876	40,273	71,481
5	Annualization Adjustment for Sales-MWh	144	1,302	39	1,208	2,692
6	Total Revenue unit rate (L7+L8+L9+L10+L11)	0.18018	0.18018	0.18271	0.15539	
7	USP unit rate	0.0115	0.0115	0.00000	0.00000	
8	EEC-Class 1 & Class 2 unit rate	0.00059	0.00059	0.00132	0.00132	
9	GSR-1 unit rate	0.12902	0.12902	0.12902	0.12902	
10	Distribution unit rate (margin plus GRT)	0.03907	0.03907	0.05237	0.02505	
11	Revenue Adjustment (L5 * L6)	$ 26	$ 235	$ 7	$ 188	$ 455
12	USP Adjustment (L5 * L7)	$ 2	$ 15	$ -	$ -	$ 17
13	EEC Adjustment (L5 * L8)	$ 0	$ 1	$ 0	$ 2	$ 2
14	GSR Adjustment (L5 * L9)	$ 19	$ 168	$ 5	$ 156	$ 347
15	Distribution Adjustment (L5 * L10)	$ 6	$ 51	$ 2	$ 30	$ 89
16	Margin Adjustment (L15 less GRT)	$ 5	$ 48	$ 2	$ 28	$ 84

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for Usage per Customer
Rate R General, Rate R Heating, Rate GS-1 Com-Gen, Rate GS-4 Com-Gen
GSR subgroups only

Line #		[1] Rate R General	[2] Rate R Heating	[3] Rate GS-1 Com-Gen	[4] Rate GS-4 Com-Gen	[5] Total
1	Heating Sensitivity/HDD/cust (kWh/DD/cust)	1.5866	0.5084	2.5523	0.3211	
2	DD Variance (to 15 Year normal)	349	349	349	349	
3	kWh/customer adjustment (L1 * L2)	554	177	891	112	
4	Customers FY23 (fully adjusted)	44,018	10,506	4,860	1,811	
5	Normalizing Adj (MWh) (L3 * L4)/1000	24,378	1,864	4,330	203	30,776
6	Total Revenue unit rate (L7+L8+L9+L10+L11)	0.18018	0.18018	0.18271	0.15539	
7	USP unit rate	0.0115	0.0115	0.00000	0.00000	
8	EEC-Class 1 & Class 2 unit rate	0.00059	0.00059	0.00132	0.00132	
9	GSR-1 unit rate	0.12902	0.12902	0.12902	0.12902	
10	Distribution unit rate (margin plus GRT)	0.03907	0.03907	0.05237	0.02505	
11	Revenue Adjustment (L5 * L6)	$ 4,393	$ 336	$ 791	$ 32	$ 5,551
12	USP Adjustment (L5 * L7)	$ 280	$ 21	$ -	$ -	$ 302
13	EEC Adjustment (L5 * L8)	$ 14	$ 1	$ 6	$ 0	$ 21
14	GSR Adjustment (L5 * L9)	$ 3,145	$ 241	$ 559	$ 26	$ 3,971
15	Distribution Adjustment (L5 * L10)	$ 952	$ 73	$ 227	$ 5	$ 1,257
16	Margin Adjustment (L15 less GRT)	$ 896	$ 69	$ 213	$ 5	$ 1,183
17	Cooling Sensitivity/CDD/cust (kWh/DD/cust)	0.4072	0.4394	0.7906	0.1057	
18	DD Variance (to 15 Year normal)	(171)	(171)	(171)	(171)	
19	kWh/customer adjustment (L17 * L18)	(70)	(75)	(135)	(18)	
20	Customers FY23 (fully adjusted)	44,018	10,506	4,860	1,811	
21	Normalizing Adj (MWh) (L19 * L20)/1000	(3,070)	(791)	(658)	(33)	(4,551)
22	Total Revenue unit rate (L23+L24+L25+L26)	0.18018	0.18018	0.18271	0.15539	
23	USP unit rate	0.0115	0.0115	0.00000	0.00000	
24	EEC-Class 1 & Class 2 unit rate	0.00059	0.00059	0.00132	0.00132	
25	GSR-1 unit rate	0.12902	0.12902	0.12902	0.12902	
26	Distribution unit rate (margin plus GRT)	0.03907	0.03907	0.05237	0.02505	
27	Revenue Adjustment (L21 * L22)	$ (553)	$ (142)	$ (120)	$ (5)	$ (821)
28	USP Adjustment (L21 * L23)	$ (35)	$ (9)	$ -	$ -	$ (44)
29	EEC Adjustment (L21 * L24)	$ (2)	$ (0)	$ (1)	$ (0)	$ (3)
30	GSR Adjustment (L21 * L25)	$ (396)	$ (102)	$ (85)	$ (4)	$ (587)
31	Distribution Adjustment (L21 * L26)	$ (120)	$ (31)	$ (34)	$ (1)	$ (186)
32	Margin Adjustment (L31 less GRT)	$ (113)	$ (29)	$ (32)	$ (1)	$ (175)
33	Total Adjustment Summary-FY23					
34	Normalizing Adj (MWh) (L5+L21)	21,309	1,074	3,672	170	26,225
35	Total Revenue Adjustment (L11+L27)	$ 3,839	$ 193	$ 671	$ 26	$ 4,730
36	Total USP Adjustment (L12+L28)	$ 245	$ 12	$ -	$ -	$ 257
37	Total EEC Adjustment (L13+L29)	$ 13	$ 1	$ 5	$ 0	$ 18
38	Total GSR Adjustment(L14+L30)	$ 2,749	$ 139	$ 474	$ 22	$ 3,383
39	Total Distribution Adjustment(L15+L31)	$ 833	$ 42	$ 192	$ 4	$ 1,071
40	Total Margin Adjustment (L16+L32)	$ 783	$ 39	$ 181	$ 4	$ 1,008

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for STAS

	Unadjusted Budget Revenue Excluding STAS	Customer Adj	UPC Adj	Revised Revenue Excluding STAS	STAS Revenue @ Dec 1 Rate	STAS Revenue @ Budget Rate	STAS Adjustment
					0.01%	0.01%	
Residential	$ 110,320	$ 260	$ 4,033	$ 114,613	$ 11	$ 11	$ 0
Commercial & Industrial	$ 29,015	$ 195	$ 697	$ 29,907	$ 3	$ 3	$ 0
Public Streets & Highway Lighting	$ 734	$ -		$ 734	$ 0	$ 0	$ 0
Other Sales to Public Authorities	$ 18	$ -		$ 18	$ 0	$ 0	$ -
Sales for Resale	$ 15	$ -		$ 15	$ 0	$ 0	$ (0)
Total	$ 140,101	$ 455	$ 4,730	$145,287	$ 15	$ 14	$ 1

UGI ELECTRIC

EXHIBIT SAE-6(a) – SAE-6(g)

UGI Utilities, Inc.- Electric Division
Historic Test Year 2022 Sales and Revenues
Summary of Adjustments

	Sales (000's) MWh	Revenues ($000's)	Margin ($000's)	Reference
Actual 2022	997,113	124,822	38,876	
Adjustment for Customer Changes	46	7	(1)	UGI Electric Exhibit SAE-6(b)
Adjustment for Normalized Use/Customer	17,961	3,243	699	UGI Electric Exhibit SAE-6(c)
Adjustment for GSR-1		22,191	0	UGI Electric Exhibit SAE-6(d)
Adjustment for USP		1,417	0	UGI Electric Exhibit SAE-6(e)
Adjustment for STAS		5	0	UGI Electric Exhibit SAE-6(f)
Adjustment for EEC		(60)		UGI Electric Exhibit SAE-6(g)
Adjusted Historic Test Year 2022	1,015,120	151,625	39,574	

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for Customer Changes
Rate R General, Rate R Heating, Rate GS-1 Com-Gen, Rate GS-4 Com-Gen
GSR subgroups only

Line #		[1] Rate R General	[2] Rate R Heating	[3] Rate GS-1 Com-Gen	[4] Rate GS-4 Com-Gen	[5] Total
1	Average Effective Customers in Historic Year	44,003	10,430	4,853	1,781	61,067
2	Number of Customers at End of Year	43,963	10,462	4,816	1,782	61,023
3	Change in Customers during Historic Year 2022	(40)	32	(37)	1	(44)
4	Total UPC (Unadjusted)-kWh	8,912	17,205	5,114	41,619	
5	Annualization Adjustment for Sales-MWh	(356)	551	(189)	42	46
6	Total Revenue unit rate (L7+L8+L9+L10+L11)	$ 0.18018	$ 0.18018	$ 0.18271	$ 0.15539	
7	USP unit rate	$ 0.01150	$ 0.01150	$ -	$ -	
8	EEC-Class 1 & Class 2 unit rate	$ 0.00059	$ 0.00059	$ 0.00132	$ 0.00132	
9	GSR-1 unit rate	$ 0.12902	$ 0.12902	$ 0.12902	$ 0.12902	
10	Distribution unit rate (margin plus GRT)	$ 0.03907	$ 0.03907	$ 0.05237	$ 0.02505	
11	Revenue Adjustment (L5 * L6)	$ (64)	$ 99	$ (35)	$ 6	$ 7
12	USP Adjustment (L5 * L7)	$ (4)	$ 6	$ -	$ -	$ 2
13	EEC Adjustment (L5 * L8)	$ (0)	$ 0	$ (0)	$ 0	$ (0)
14	GSR Adjustment (L5 * L9)	$ (46)	$ 71	$ (24)	$ 5	$ 6
15	Distribution Adjustment (L5 * L10)	$ (14)	$ 22	$ (10)	$ 1	$ (1)
16	Margin Adjustment (L15 less GRT)	$ (13)	$ 20	$ (9)	$ 1	$ (1)

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for Usage per Customer
Rate R General, Rate R Heating, Rate GS-1 Com-Gen, Rate GS-4 Com-Gen
GSR subgroups only

Line #		[1] Rate R General	[2] Rate R Heating	[3] Rate GS-1 Com-Gen	[4] Rate GS-4 Com-Gen	[5] Total
1	Heating Sensitivity/HDD/cust (kWh/DD/cust)	1.9331	0.5136	3.3826	0.2627	
2	DD Variance (to 15 Year normal)	247	247	247	247	
3	kWh/customer adjustment (L1 * L2)	478	127	836	65	
4	Customers FY22 (fully adjusted)	43,963	10,462	4,816	1,782	
5	Normalizing Adj (MWh) (L3 * L4)/1000	20,997	1,328	4,025	116	26,465
6	Total Revenue unit rate (L7+L8+L9+L10+L11)	$ 0.18018	$ 0.18018	$ 0.18271	$ 0.15539	
7	USP unit rate	$ 0.01150	$ 0.01150	$ -	$ -	
8	EEC-Class 1 & Class 2 unit rate	$ 0.00059	$ 0.00059	$ 0.00132	$ 0.00132	
9	GSR-1 unit rate	$ 0.12902	$ 0.12902	$ 0.12902	$ 0.12902	
10	Distribution unit rate (margin plus GRT)	$ 0.03907	$ 0.03907	$ 0.05237	$ 0.02505	
11	Revenue Adjustment (L5 * L6)	$ 3,783	$ 239	$ 735	$ 18	$ 4,776
12	USP Adjustment (L5 * L7)	$ 241	$ 15	$ -	$ -	$ 257
13	EEC Adjustment (L5 * L8)	$ 12	$ 1	$ 5	$ 0	$ 19
14	GSR Adjustment (L5 * L9)	$ 2,709	$ 171	$ 519	$ 15	$ 3,415
15	Distribution Adjustment (L5 * L10)	$ 820	$ 52	$ 211	$ 3	$ 1,086
16	Margin Adjustment (L15 less GRT)	$ 772	$ 49	$ 198	$ 3	$ 1,022
17	Cooling Sensitivity/CDD/cust (kWh/DD/cust)	0.9088	0.7596	1.189	0.2499	
18	DD Variance (to 15 Year normal)	(157)	(157)	(157)	(157)	
19	kWh/customer adjustment (L17 * L18)	(143)	(119)	(187)	(39)	
20	Customers FY22 (fully adjusted)	43,963	10,462	4,816	1,782	
21	Normalizing Adj (MWh) (L19 * L20)/1000	(6,283)	(1,250)	(901)	(70)	(8,504)
22	Total Revenue unit rate (L23+L24+L25+L26)	$ 0.18018	$ 0.18018	$ 0.18271	$ 0.15539	
23	USP unit rate	$ 0.01150	$ 0.01150	$ -	$ -	
24	EEC-Class 1 & Class 2 unit rate	$ 0.00059	$ 0.00059	$ 0.00132	$ 0.00132	
25	GSR-1 unit rate	$ 0.12902	$ 0.12902	$ 0.12902	$ 0.12902	
26	Distribution unit rate (margin plus GRT)	$ 0.03907	$ 0.03907	$ 0.05237	$ 0.02505	
27	Revenue Adjustment (L21 * L22)	$ (1,132)	$ (225)	$ (165)	$ (11)	$ (1,533)
28	USP Adjustment (L21 * L23)	$ (72)	$ (14)	$ -	$ -	$ (87)
29	EEC Adjustment (L21 * L24)	$ (4)	$ (1)	$ (1)	$ (0)	$ (6)
30	GSR Adjustment (L21 * L25)	$ (811)	$ (161)	$ (116)	$ (9)	$ (1,097)
31	Distribution Adjustment (L21 * L26)	$ (245)	$ (49)	$ (47)	$ (2)	$ (343)
32	Margin Adjustment (L31 less GRT)	$ (231)	$ (46)	$ (44)	$ (2)	$ (323)
33	Total Adjustment Summary-FY22					
34	Normalizing Adj (MWh) (L5+L21)	14,714	78	3,124	46	17,961
35	Total Revenue Adjustment (L11+L27)	$ 2,651	$ 14	$ 571	$ 7	$ 3,243
36	Total USP Adjustment (L12+L28)	$ 169	$ 1	$ -	$ -	$ 170
37	Total EEC Adjustment (L13+L29)	$ 9	$ 0	$ 4	$ 0	$ 13
38	Total GSR Adjustment(L14+L30)	$ 1,898	$ 10	$ 403	$ 6	$ 2,317
39	Total Distribution Adjustment(L15+L31)	$ 575	$ 3	$ 164	$ 1	$ 743
40	Total Margin Adjustment (L16+L32)	$ 541	$ 3	$ 154	$ 1	$ 699

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for GSR-1

	OCT 2021	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	TOTAL
Actual GSR-1 Rate FY 22	$0.06218	$0.06218	$0.09005	$0.09005	$0.09005	$0.08853	$0.08853	$0.08853	$0.12902	$0.12902	$0.12902	$0.12902	
HTY 2022 GSR-1 Sep 1 Rate	$0.12902	$0.12902	$0.12902	$0.12902	$0.12902	$0.12902	$0.12902	$0.12902	$0.12902	$0.12902	$0.12902	$0.12902	
GSR-1 Rate Variance	$0.06684	$0.06684	$0.03897	$0.03897	$0.03897	$0.04049	$0.04049	$0.04049	$0.00000	$0.00000	$0.00000	$0.00000	
Total GSR-1 Volumes-MWh	56,818	57,956	69,575	77,000	63,269	64,025	45,354	47,252	50,314	66,113	60,907	39,607	698,188
GSR-1 Revenue Adjustment	$3,798	$3,874	$2,711	$3,001	$2,466	$2,592	$1,836	$1,913	$0	$0	$0	$0	$22,191

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for USP

	OCT 2021	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	TOTAL
Historic Period FY22 USP Rate	$0.00565	$0.00565	$0.00865	$0.00865	$0.00865	$0.00762	$0.00762	$0.00762	$0.01150	$0.01150	$0.01150	$0.01150	
HTY 2022 USP Sep 1 Rate	$0.01150	$0.01150	$0.01150	$0.01150	$0.01150	$0.01150	$0.01150	$0.01150	$0.01150	$0.01150	$0.01150	$0.01150	
USP Rate Variance	$0.00585	$0.00585	$0.00285	$0.00285	$0.00285	$0.00388	$0.00388	$0.00388	$0.00000	$0.00000	$0.00000	$0.00000	
Total Rate R Volumes-MWh	38,033	48,873	60,227	66,679	54,098	53,971	37,576	38,892	41,203	54,811	49,633	32,051	576,049
Total Rate R excl CAP Volumes-MWh	35,218	45,257	55,771	61,745	50,095	49,977	34,795	36,014	38,154	50,755	45,961	29,680	533,421
USP Rate Revenue Variance	$206	$265	$159	$176	$143	$194	$135	$140	$0	$0	$0	$0	$1,417

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for STAS

	Actual Revenue Excluding STAS	Customer Adj	UPC Adj	GSR-1 Adj	USP Adj	EEC Adj	Revised Revenue Excluding STAS	STAS Revenue @ Sep 1 Rate	STAS Revenue @ FY 22	STAS Adjustment
								0.01%	0.01%	
Residential	$ 89,004	$ 24	$ 2,665	$ 18,015	$ 1,417	$ (120)	$ 111,006	$ 11	$ 7	$ 4
Commercial & Industrial	$ 34,805	$ (28)	$ 578	$ 4,110	$ -	$ 63	$ 39,527	$ 4	$ 3	$ 1
Public Streets & Highway Lighting	$ 982	$ -		$ 62	$ -	$ (3)	$ 1,042	$ 0	$ 0	$ 0
Other Sales to Public Authorities	$ 21	$ -		$ -	$ -	$ (1)	$ 20	$ 0	$ 0	$ 0
Sales for Resale	$ (0)	$ -		$ 4	$ -	$ (0)	$ 4	$ 0	$ 0	$ (0)
Total	$ 124,812	$ (4)	$ 3,243	$ 22,191	$1,417	($60)	$151,599	$ 15	$ 10	$ 5

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for EEC

	OCT 2021	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	TOTAL
Historic EEC-Class 1 Actual Rates FY 22	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00059	
Historic Year 2022 EEC-Class 1 Rate Effective Sept 1	$0.00059	$0.00059	$0.00059	$0.00059	$0.00059	$0.00059	$0.00059	$0.00059	$0.00059	$0.00059	$0.00059	$0.00059	
EEC-Class 1 Rate Variance	($0.00022)	($0.00022)	($0.00022)	($0.00022)	($0.00022)	($0.00022)	($0.00022)	($0.00022)	($0.00022)	($0.00022)	($0.00022)	$0.00000	
Total EEC-Class 1 Volumes	38,184	49,039	60,404	66,860	54,244	54,128	37,695	39,016	41,335	54,968	49,782	32,161	577,816
Total EEC-Class 1 Revenue Adjustment	($8)	($11)	($13)	($15)	($12)	($12)	($8)	($9)	($9)	($12)	($11)	$0	($120)
Historic EEC-Class 2 Actual Rates FY 22	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00132	
Historic Year 2022 EEC-Class 2 Rate Effective Sept 1	$0.00132	$0.00132	$0.00132	$0.00132	$0.00132	$0.00132	$0.00132	$0.00132	$0.00132	$0.00132	$0.00132	$0.00132	
EEC-Class 2 Rate Variance	($0.00071)	($0.00071)	($0.00071)	($0.00071)	($0.00071)	($0.00071)	($0.00071)	($0.00071)	($0.00071)	($0.00071)	($0.00071)	$0.00000	
Total EEC-Class 2 Volumes	11,279	12,369	12,706	13,963	12,147	13,559	10,615	11,036	12,104	14,837	14,368	9,931	148,913
Total EEC-Class 2 Revenue Adjustment	($8)	($9)	($9)	($10)	($9)	($10)	($8)	($8)	($9)	($11)	($10)	$0	($99)
Historic EEC-Class 3 Actual Rates FY 22	$0.00138	$0.00138	$0.00138	$0.00138	$0.00138	$0.00138	$0.00138	$0.00138	$0.00138	$0.00138	$0.00138	$0.00203	
Historic Year 2022 EEC-Class 3 Rate Effective Sept 1	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	
EEC-Class 3 Rate Variance	$0.00065	$0.00065	$0.00065	$0.00065	$0.00065	$0.00065	$0.00065	$0.00065	$0.00065	$0.00065	$0.00065	$0.00000	
Total EEC-Class 3 Volumes	20,429	20,707	17,062	27,690	23,818	17,622	24,036	21,318	22,658	22,854	25,455	26,735	270,384
Total EEC-Class 3 Revenue Adjustment	$13	$13	$11	$18	$15	$11	$16	$14	$15	$15	$17	$0	$158
Total EEC Revenue Adjustment	($3)	($6)	($11)	($7)	($5)	($10)	($0)	($3)	($3)	($8)	($5)	$0	($60)

BOOK IV

UGI UTILITIES, INC. – ELECTRIC DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI ELECTRIC EXHIBIT A – FULLY PROJECTED FUTURE
UGI ELECTRIC EXHIBIT A - FUTURE
UGI ELECTRIC EXHIBIT A – HISTORIC
UGI ELECTRIC EXHIBIT B – RATE OF RETURN
UGI ELECTRIC EXHIBIT E – PROOF OF REVENUE

UGI UTILITIES, INC. – ELECTRIC DIVISION
PA P.U.C. NO. 6, SUPPLEMENT NO. 51
PA P.U.C. NO. 2S, SUPPLEMENT NO. 7

DOCKET NO. R-2022-3037368

Issued: January 27, 2023 Effective: March 28, 2023

UGI ELECTRIC

EXHIBIT A

FULLY PROJECTED FUTURE

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission

Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)
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Fully Projected Future Period - 12 Months Ended September 30, 2024

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SECTION D

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Schedule A-1
Witness: T. A. Hazenstab
Page 1 of 1

Summary of Measure of Value and Revenue Increase

Line #	Description	[1] Function	[2] Reference Section	[3] Pro Forma Test Year Ended September 30, 2024 At Present Rates	[4] Increase	[5] Proposed Rates
RATE BASE						
1	Utility Plant		C-2	$ 275,001		$ 275,001
2	Accumulated Depreciation		C-3	(85,745)		(85,745)
3	Net Plant in service	L 1 + L 2		189,256	-	189,256
4	Working Capital		C-4	11,447		11,447
5	Accumulated Deferred Income Taxes		C-6	(29,665)		(29,665)
6	Customer Deposits		C-7	(949)		(949)
7	Materials & Supplies		C-8	2,152		2,152
8	TOTAL RATE BASE	Sum L 3 to L 7		$ 172,242	$ -	$ 172,242
	Operating Revenues					
9	Base Customer Charges		D-5	$ 44,106	$ 11,425	$ 55,531
10	Other Electric Revenue		D-5	107,482		107,482
11	Other Operating Revenues		D-5	1,103		1,103
12	Total Revenues	Sum L 9 to L 11		152,691	11,425	164,116
13	Operating Expenses		D-1	(145,378)	(926)	(146,304)
14	OIBIT	L 12 + L 13		7,313	10,499	17,812
15	Pro Forma Income Tax at Present Rates		D-33	(823)		
16	Pro Forma Income Tax on Revenue Increase		D-33		(2,951)	(3,774)
17	NET OPERATING INCOME	Sum L 14 to L 16		$ 6,490	$ 7,548	$ 14,038
18	RATE OF RETURN	L 17 / L 8		3.768%		8.150%
REVENUE INCREASE REQUIRED						
19	Rate of Return at Present Rates	L 18, Col 3		3.768%		
20	Rate of Return Required		B-7	8.150%		
21	Change in ROR	L 20 - L 19		4.382%		
22	Change in Operating Income	L 21 * L 8		$ 7,548		
23	Gross Revenue Conversion Factor		D-35	1.513583		
24	Change in Revenues	L 22 * L 23		$ 11,425		
25	Percent Increase -- Delivery Revenues	L 24 / L 9, C 3			25.90%	
26	Percent Increase -- Total Revenues	L 24 / L 12, C 3			7.48%	

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Balance Sheet

Line No	Description/(Account No)	[1] Budget TYE 9-30-24
	UTILITY PLANT (101 - 106, 108)	
1	Electric Utility Plant	$ 367,052
2	Other Utility Plant	
3	Total Plant In Service	367,052
4	Construction Work In Progress (107)	8,000
5	Total Utility Plant	375,052
6	Accumulated Provision for Depreciation - Electric (108)	(121,394)
7	Utility Acquisition Adjustment (114)	390
8	Accumulated Provision for Depreciation - Other (119)	-
9	Net Utility Plant	254,048
	OTHER PROPERTY INVESTMENTS	
10	Non-utility Property (121)	15
11	Accumulated Depreciation on NUP (122)	-
12	Investment in Associated & Subsidiary Companies (123.1)	-
13	Other Investments (124)	-
14	Total Other Property and Investments	15
	CURRENT AND ACCRUED ASSETS	
15	Cash & Other Temporary Investments(131-136)	566
16	Unbilled Revenues	-
17	Customer Accounts Receivable (142)	19,496
18	Other Accounts Receivable (143)	570
19	Accum Provision for Uncollectible (144)	(2,340)
20	Receivables from Associated Companies (145)	-
21	Accounts Receivable Assoc. Comp. (146)	404
22	Plant Materials & Operating Supplies (154)	3,100
23	Allowance Inventory (158.1)	682
24	Stores Expense - Undistributed (163)	183
25	Prepayments (165)	2,182
26	Accrued Utility Revenues (173)	4,000
27	Miscellaneous Current & Accrued Assets (174)	1,400
28	Derivative Instrument Assets (175)	-
29	Total Current and Accrued Assets	30,243
	DEFERRED DEBITS	
30	Unamortized Debt Expense (181)	20
31	Other Regulatory Assets (182.3)	33,146
32	Other Preliminary Survey & Investigation Charges (183.2)	-
33	Clearing Accounts (184)	-
34	Miscellaneous Deferred Debits (186)	1,166
35	Unamortized Loss on Reacquired Debt (189)	-
36	Accumulated Deferred Income Taxes (190)	16,000
37	Total Deferred Debits	50,332
38	TOTAL ASSETS AND OTHER DEBITS	$ 334,638

($ in Thousands)

Balance Sheet

Line No	Description/(Account No)	[1] Budget TYE 9-30-24
	PROPRIETARY CAPITAL	
39	Common Stock Issued (201)	$ 6,453
40	Preferred Stock Issued (204)	-
41	Premium on Capital Stock (207)	50,720
42	Capital Stock Expense (214)	-
43	Retained Earnings (215, 215.2, 216)	82,897
44	Accum Other Comprehensive Income (219)	(1,235)
45	Total Proprietary Capital	138,835
	LONG TERM DEBT	
46	Bonds (221)	-
47	Advances from Associated Companies (223)	-
48	Other Long-Term Debt (224)	90,828
49	Unamortized Premium on LTD (225)	-
50	Unamortized Discount on LTD (226)	-
51	Total Long-term Debt	90,828
	OTHER NON-CURRENT LIABILITIES	
52	Obligations under Capital Leases (227)	-
53	Advances from Associated Companies (223)	-
54	Other Long-Term Debt (224)	-
55	Unamortized Premium on LTD (225)	-
56	Unamortized Discount on LTD (226)	-
57	Accumulated Provision for Pension & Benefits (228.3)	8,592
58	Total Non-Current Liabilities	8,592
	CURRENT & ACCRUED LIABILITIES	
59	Notes Payable (231)	11,062
60	Accounts Payable (232)	11,000
61	Notes Payable to Assoc. Companies (233)	-
62	Accounts Payable to Assoc. Cos (234)	1,000
63	Customer Deposits (235)	947
64	Taxes Accrued (236)	219
65	Interest Accrued (237)	705
66	Tax Collections Payable (241)	-
67	Accrued Interest on Other Liabilities (237)	2,600
68	Tax Collections Payable (241)	-
69	Misc Current & Accrued Liabilities (242)	-
70	Total Current & Accrued Liabilities	27,533
	OTHER DEFERRED CREDITS	
71	Customer Advances for Construction (252)	-
72	Other Deferred Credits (253)	450
73	Other Regulatory Liabilities (254)	28,000
74	Deferred ITC (255)	-
75	Accumulated Deferred Income Taxes (282)	40,400
76	Accumulated Deferred Income Taxes (283)	-
77	Total Other Deferred Credits	68,850
78	TOTAL LIABILITIES & OTHER CREDITS	$ 334,638

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Statement of Net Utility Operating Income

		[1]	[2]
Line No	**Description**	**Budget TYE 9-30-24**	**Reference**
	Total Operating Revenues		
1	Total Sales Revenues	$ 144,200	B-3
2	Other Operating Revenues	1,103	B-3
3	Total Revenues	145,303	
	Total Operating Expenses		
4	Operation & Maintenance Expenses	120,745	B-4
5	Depreciation & Amortization Expense	9,075	D-3
6	Taxes Other Than Income Taxes	9,375	B-5
7	Total Operating Expenses	139,195	
8	Operating Income Before Income Taxes (OIBIT)	6,108	
	Income Taxes:		
9	State	173	B-5
10	Federal	650	B-5
11	Total Income Taxes	823	
12	**Net Utility Operating Income**	$ 5,285	

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Schedule B-3
Witness: T. A. Hazenstab
Page 1 of 1

Statement of Operating Revenues

Line No	Description	Account No		Budget TYE 9-30-24 [1]
	Electric Operating Revenues			
1	Residential	440	$	111,376
2	Commercial & Industrial	442		32,040
3	Public Streets & Highway Lighting	444		749
4	Other Sales to Public Authorities	445		19
5	Sales for Resale	447		16
6	Sub-Total Electric Operating Revenues			144,200
	Other Operating Revenues			
7	Forfeited Discounts	450	$	520
8	Miscellaneous Service Revenues	451		16
9	Rent from Electric Properties	454		567
10	Interest on Over/(Under) Collections	456.1		-
11	Sub-Total Other Operating Revenues			1,103
12	**Total Operating Revenues**		$	145,303

($ in Thousands)

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-24
	Other Power Supply Expenses		
1	Purchased Power	555.0	$ 79,973
2	Power Purchased for Storage Operations	555.1	-
3	System Control and Load Dispatching	556.0	-
4	Other Expenses	557.0	-
5	Load Dispatch - Reliability	561.1	-
6	Transmission of Electricty by Others	565.0	5,978
7	Gross Receipts Tax	408.1	-
8	Total Other Power Supply Expenses		85,951
	Transmission Expenses - Operation		
9	Operation Supervision and Engineering	560.0	-
10	Load Dispatch - Reliability	561.0	-
11	Load Dispatch - Monitor and Operate Trans. System	561.2	-
12	Load Dispatch - Transmission Service & Scheduling	561.3	-
13	Scheduling, System Control & Dispatch Service	561.4	-
14	Reliability Planning & Standards Development	561.5	-
15	Transmission Service Studies	561.6	-
16	Generation Interconnection Studies	561.7	-
17	Reliability Planning & Standards Development Services	561.8	-
18	Station Expenses	562.0	-
19	Operation of Energy Storage Equipment	562.1	-
20	Overhead Line Expense	563.0	-
21	Underground Line Expenses	564.0	-
22	Transmission of Electricty by Others	565.0	-
23	Miscellaneous Transmission Expenses	566.0	-
24	Rents	567.0	-
25	Operation Supplies and Expenses	567.1	-
26	Total Transmission Expenses - Operation		-
	Transmission Expenses - Maintenance		
27	Maintenance Supervision and Engineering	568.0	-
28	Maintenance of Structures	569.0	-
29	Maintenance of Computer Hadware	569.1	-
30	Maintenance of Computer Software	569.2	-
31	Maintenance of Communication Equipment	569.3	-
32	Maintenance of Miscellaneous Regional Trans Plant	569.4	-
33	Maintenance of Station equipment	570.0	-
34	Maintenance of Energy Storage Equipment	570.1	-
35	Maintenance of Overhead Lines	571.0	-
36	Maintenance of Underground Lines	572.0	-
37	Maintenance of Miscellaneous Transmission Plant	573.0	-
38	Maintenance of Transmission Plant	574.0	-
39	Total Transmission Expenses - Maintenance		-

($ in Thousands)

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-24
	Regional Market Expenses - Operation		
40	Operation Supervision	575.1	-
41	Day-Ahead and Real-Time Market Administration	575.2	-
42	Transmission Rights Market Administration	575.3	-
43	Capacity Market Administration	575.4	-
44	Ancillary Market Administration	575.5	-
45	Market Monitoring and Compliance	575.6	-
46	Market Facilitation, Monitoring and Compliance Serv	575.7	-
47	Rents	575.8	-
48	Total Region Market Expenses - Operation		-
	Regional Market Expenses - Maintenance		
49	Maintenance of Structures and Improvements	576.1	-
50	Maintenance of Computer Hardware	576.2	-
51	Maintenance of Computer Software	576.3	-
52	Maintenance of Communication Equipment	576.4	-
53	Maintenance of Misc Market Operation Plant	576.5	-
54	Total Region Market Expenses - Maintenance		-
	Distribution Expense - Operation		
55	Operation Supervision and Engineering	580.0	607
56	Load Dispatching	581.0	571
57	Line and Station Expenses	581.1	-
58	Station Expenses	582.0	96
59	Overhead Line Expenses	583.0	298
60	Underground Line Expenses	584.0	42
61	Operation of Energy Storage Equipment	584.1	-
62	Street Lighting and Signal System Expenses	585.0	31
63	Meter Expenses	586.0	782
64	Customer Installation Expenses	587.0	79
65	Miscellaneous Distribution Expenses	588.0	351
66	Rents	589.0	55
67	Total Distribution Expenses - Operation		2,912
	Distribution Expense - Maintenance		
68	Maintenance Supervision and Engineering	590.0	221
69	Maintenance of Structures	591.0	-
70	Maintenance of Station Equipment	592.0	208
71	Maintenance of Pipe Lines	592.1	-
72	Maintenance of Structures and Equipment	592.2	-
73	Maintenance of Overhead Lines	593.0	9,712
74	Maintenance of Underground Lines	594.0	61
75	Maintenance of Lines	594.1	-
76	Maintenance of Line Transformers	595.0	83
77	Maintenance of Street Lighting and Signal Systems	596.0	24
78	Maintenance of Meters	597.0	15
79	Maintenance of Miscellaneous Distribution Plant	598.0	23
80	Total Distribution Expenses - Maintenance		10,347
	Customer Accounts Expense - Operation		
81	Supervision	901.0	91
82	Meter Reading Expenses	902.0	217
83	Customer Records and Collection Expenses (USP)	903.0	9,082
84	Uncollectible Accounts	904.0	2,577
85	Miscellaneous Customer Accounts Expenses	905.0	73
86	Total Customer Accounts Expense - Operation		12,040

($ in Thousands)

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-24
	Customer Service & Information Expense		
87	Customer Service and Informational Expenses	906.0	-
88	Supervision	907.0	17
89	Customer Assistance Expenses	908.0	12
90	Information and Instructional Advertising Expenses	909.0	-
91	Miscellaneous Customer Service & Informational Exps (EEC)	910.0	1,246
92	Total Customer Service & Informational Exps - Operations		1,275
	Sales Expense - Operation		
93	Supervision	911.0	-
94	Demonstrating and Selling Expenses	912.0	5
95	Advertising Expenses	913.0	-
96	Miscellaneous Sales Expenses	916.0	(5)
97	Sales Expenses	917.0	-
98	Total Sales Expenses - Operation		-
	Administrative & General - Operations		
99	Administrative and General Salaries	920.0	2,749
100	Office Supplies and Expenses	921.0	1,787
101	Administrative Expenses Transferred - Credit	922.0	-
102	Outside Services Employed	923.0	1,887
103	Property Insurance	924.0	31
104	Injuries and Damages	925.0	251
105	Employee Pensions and Benefits	926.0	831
106	Franchise Requirements	927.0	-
107	Regulatory Commission Expenses	928.0	357
108	Duplicate Charges - Credit	929.0	(74)
109	General Advertising Expenses	930.1	74
110	Miscellaneous General Expenses	930.2	259
111	Rents	931.0	2
112	Transportation Expenses	933.0	-
113	Total Administrative and General Expenses - Operation		8,151
	Administrative & General - Maintenance		
114	Maintenance of General Plant	935.0	69
115	Total Administrative and General Expenses - Maintenance		69
116	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 120,745
117	Total Electric Operation Expenses		110,329
118	Total Electric Maintenance Expense		10,416
119	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 120,745

($ in Thousands)

Detail of Taxes

Line No	Description	Reference	[1] Budget TYE 9-30-24
	Taxes Other Than Income Taxes		
	Non-revenue related:		
1	Pennsylvania - PURTA	D-31	$ 45
2	Gross Receipts Tax	D-31	8,508
3	PA and Local Use taxes	D-31	22
4	PUC Assessment	D-31	297
5	Subtotal		8,871
6	Payroll Taxes		
7	Social Security	D-31	469
8	SUTA	D-31	3
9	FUTA	D-31	31
10	Other		-
11	Subtotal		504
12	Total Taxes Other Than Income Taxes		$ 9,375
	Income Taxes		
13	State	D-33	$ 173
14	Federal	D-33	650
15	Total Income Taxes		$ 823

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Composite Cost of Debt

		[1]	[2]	[3]	[4]	[5]	[6]
Line No	**Series**	**Issue Date**	**Maturity Date**	**Amount Outstanding**	**Percent to Total**	**Effective Interest Rate**	**Average Weighted Cost Rate**
							[4] * [5]
Medium Term Notes							
1	6.500%	8/14/2003	8/15/2033	$ 20,000	1.20%	6.56%	0.08%
2	6.133%	10/14/2004	10/15/2034	20,000	1.20%	6.19%	0.07%
Senior Unsecured Notes							
3	6.206%	9/15/2006	9/30/2036	100,000	5.98%	6.32%	0.38%
4	4.980%	3/26/2014	3/26/2044	175,000	10.46%	5.00%	0.52%
5	2.950%	6/30/2016	6/30/2026	100,000	5.98%	3.92%	0.23%
6	4.120%	9/30/2016	9/30/2046	200,000	11.96%	5.01%	0.60%
7	4.120%	10/31/2016	10/31/2046	100,000	5.98%	4.28%	0.26%
8	4.550%	2/1/2019	2/1/2049	150,000	8.97%	4.58%	0.41%
9	3.120%	3/19/2020	4/16/2050	150,000	8.97%	3.15%	0.28%
10	1.590%	6/15/2021	6/15/2026	100,000	5.98%	1.73%	0.10%
11	1.640%	9/15/2021	9/15/2026	75,000	4.48%	1.75%	0.08%
12	3.917%	7/12/2022	7/12/2027	82,813	4.95%	4.00%	0.20%
13	4.750%	7/15/2022	7/15/2032	90,000	5.38%	4.83%	0.26%
14	4.990%	9/15/2022	9/15/2052	85,000	5.08%	5.02%	0.26%
15	4.551%	10/31/2023	10/31/2053	225,000	13.45%	4.60%	0.62%
16	Total Long-Term Debt			$ 1,672,813	100.00%		4.35%
17	Total Long-Term Debt			$ 1,672,813	100.00%	4.35%	4.35%
18	Total Short-Term Debt			-	0.00%		0.00%
19	TOTAL			$ 1,672,813	100.00%		
20	Weighted Cost of Debt						4.35%

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Rate of Return

		[1]	[2]	[3]	[4]
Line No	**Description**	**Capitalization Ratio**	**Embedded Cost**	**Statement Reference**	**Return-%**
1	Long-Term Debt	45.41%	4.35%	B-6	1.98%
2	Short-Term Debt	0.00%	0.00%	B-6	0.00%
3	Common Equity	54.59%	11.30%		6.17%
4	Total	100.00%			8.15%

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Schedule C-1
Witness: V. K. Ressler

Measure of Value

		[1]	[2]	[3]	[4]	[5]
		Reference		Pro Forma Test Year Ended September 30, 2024 At		
Line #	Description	Fully Projected	# of Pages	Present Rates	Adjustments	Proposed Rates
	MEASURE OF VALUE					
1	Utility Plant	C-2	5	$ 275,001		$ 275,001
2	Accumulated Depreciation	C-3	6	(85,745)		(85,745)
3	Net Plant in service			189,256	-	189,256
4	Working Capital	C-4	9	11,447		11,447
5	Accumulated Deferred Income Taxes	C-6	1	(29,665)		(29,665)
6	Customer Deposits	C-7	1	(949)		(949)
7	Materials & Supplies	C-8	1	2,152		2,152
8	TOTAL MEASURE OF VALUE			$ 172,242	$ -	$ 172,242

($ in Thousands)

Pro Forma Electric Plant in Service

Line No	Description	[1] Account No	[2] Pro Forma 9/30/2024
	INTANGIBLE PLANT		
1	Organization	301	$ 11
2	Franchise & Consent	302	5
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		16
	TRANSMISSION PLANT		
5	Land & Land Rights	350	$ -
6	Structures & Improvements	352	-
7	Station Equipment	353	-
8	Station Equipment - SCADA	353.2	-
9	Towers and Fixtures	354	-
10	Poles and Fixtures	355	-
11	Overhead Conductors and Devices	356	-
12	Underground Conduit	357	-
13	Underground Conductors and Devices	358	-
14	Roads and Trails	359	-
15	TOTAL TRANSMISSION		-
	DISTRIBUTION PLANT		
16	Land & Land Rights	360	313
17	Structures & Improvements	361	627
18	Station Equipment	362	11,568
19	Storage Battery Equipment	363	-
20	Poles, Towers and Fixtures	364	56,561
21	Overhead Conductors and Devices	365	82,806
22	Underground Conduit	366	8,780
23	Underground Conductors and Devices	367	15,566
24	Transformers	368.1	19,861
25	Transformer Installations	368.2	11,241
26	Services	369	16,709
27	Meters	370.1	3,094
28	Meter Installations	370.2	1,989
29	Electronic Meters	370.3	5,038
30	Installations on Customers' Premises	371.0	2,219
31	Installations on Customers' Premises - EV Charging Stations	371.1	-
32	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	348
33	Leased Property on Customers' Premises	372	-
34	Street Lighting and Signal Systems	373	2,615
35	TOTAL DISTRIBUTION		239,335
	GENERAL & COMMON PLANT		
36	Land & Land Rights	389	659
37	Structures & Improvements	390	10,646
38	Office Furniture & Equipment	391	18,441
39	Transportation Equipment	392	2,718
40	Stores Equipment	393	11
41	Tools & Garage Equipment	394	1,132
42	Laboratory Equipment	395	28
43	Power Operated Equipment	396	797
44	Communication Equipment	397	652
45	Miscellaneous Equipment	398	566
46	Other Tangible Property	399	-
47	TOTAL GENERAL & COMMON PLANT		35,650
48	Total Plant		$ 275,001

($ in Thousands)

Pro Forma Plant Adjustment Summary

Line #	Description	[1] Factor Or Reference	[2] Test Year 9/30/24 Budget	[3] Adjustments	[4] Pro Forma Test Year [2] + [3]
1	Intangible Plant	Sch C-2, Page 3	$ 16	$ -	$ 16
2	Transmission Plant	Sch C-2, Page 3	-	-	-
3	Distribution Plant	Sch C-2, Page 3	239,335	-	239,335
4	General & Common Plant	Sch C-2, Page 3	35,650	-	35,650
5	Other Plant		-	-	-
6	Total Utility Plant		$ 275,001	$ -	$ 275,001

($ in Thousands)

Pro Forma Year End Plant Balances

		[1]	[2]	[3]	[4]	[5]
Line #	Description	Account Number	Year Ended September 30, 2023	2024	Pro Forma Adjustment	Balance
INTANGIBLE PLANT						
1	Organization	301	$ 11	$ 11		$ 11
2	Franchise & Consent	302	5	5		5
3	Miscellaneous Intangible Plant	303		-		-
4	TOTAL INTANGIBLE		16	16	-	16
TRANSMISSION PLANT						
5	Land & Land Rights	350		-		-
6	Structures & Improvements	352		-		-
7	Station Equipment	353		-		-
8	Station Equipment - SCADA	353.2		-		-
9	Towers and Fixtures	354		-		-
10	Poles and Fixtures	355		-		-
11	Overhead Conductors and Devices	356		-		-
12	Underground Conduit	357		-		-
13	Underground Conductors and Devices	358		-		-
14	Roads and Trails	359		-		-
15	TOTAL TRANSMISSION		-	-	-	-
DISTRIBUTION PLANT						
16	Land & Land Rights	360	313	313		313
17	Structures & Improvements	361	627	627		627
18	Station Equipment	362	11,263	11,568		11,568
19	Storage Battery Equipment	363	-	-		-
20	Poles, Towers and Fixtures	364	55,047	56,561		56,561
21	Overhead Conductors and Devices	365	68,846	82,806		82,806
22	Underground Conduit	366	8,780	8,780		8,780
23	Underground Conductors and Devices	367	15,051	15,566		15,566
24	Transformers	368.1	18,263	19,861		19,861
25	Transformer Installations	368.2	11,219	11,241		11,241
26	Services	369	16,224	16,709		16,709
27	Meters	370.1	2,978	3,094		3,094
28	Meter Installations	370.2	1,980	1,989		1,989
29	Electronic Meters	370.3	5,038	5,038		5,038
30	Installations on Customers' Premises	371	2,219	2,219		2,219
31	Installations on Customers' Premises - EV Charging Stations	371.1	-	-		-
32	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	348	348		348
33	Leased Property on Customers' Premises	372	-	-		-
34	Street Lighting and Signal Systems	373	2,471	2,615		2,615
35	TOTAL DISTRIBUTION		220,667	239,335	-	239,335
GENERAL & COMMON PLANT						
36	Land & Land Rights	389	659	659		659
37	Structures & Improvements	390	8,723	10,646		10,646
38	Office Furniture & Equipment	391	18,096	18,441		18,441
39	Transportation Equipment	392	1,826	2,718		2,718
40	Stores Equipment	393	11	11		11
41	Tools & Garage Equipment	394	1,156	1,132		1,132
42	Laboratory Equipment	395	55	28		28
43	Power Operated Equipment	396	598	797		797
44	Communication Equipment	397	692	652		652
45	Miscellaneous Equipment	398	442	566		566
46	Other Tangible Property	399		-		-
47	TOTAL GENERAL & COMMON PLANT		32,258	35,650	-	35,650
48	Total Plant		$ 252,941	$ 275,001	$ -	$ 275,001

($ in Thousands)

Additions to Plant

Line #	Description	[1] Account Number	[2] Year ended September 30, 2023	[3] Year ended September 30, 2024
	Plant Additions			
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	TRANSMISSION PLANT			
5	Land & Land Rights	350		
6	Structures & Improvements	352		
7	Station Equipment	353		
8	Station Equipment - SCADA	353.2		
9	Towers and Fixtures	354		
10	Poles and Fixtures	355		
11	Overhead Conductors and Devices	356		
12	Underground Conduit	357		
13	Underground Conductors and Devices	358		
14	Roads and Trails	359		
15	TOTAL TRANSMISSION		-	-
	DISTRIBUTION PLANT			
16	Land & Land Rights	360	5	-
17	Structures & Improvements	361	-	-
18	Station Equipment	362	285	308
19	Storage Battery Equipment	363	-	-
20	Poles, Towers and Fixtures	364	1,023	1,597
21	Overhead Conductors and Devices	365	15,749	14,695
22	Underground Conduit	366	-	-
23	Underground Conductors and Devices	367	316	540
24	Transformers	368.1	1,850	1,844
25	Transformer Installations	368.2	23	24
26	Services	369	496	511
27	Meters	370.1	96	398
28	Meter Installations	370.2	11	12
29	Electronic Meters	370.3	-	-
30	Installations on Customers' Premises	371	-	-
31	Installations on Customers' Premises - EV Charging Stations	371.1	-	-
32	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-	-
33	Leased Property on Customers' Premises	372	-	-
34	Street Lighting and Signal Systems	373	169	174
35	TOTAL DISTRIBUTION		20,023	20,103
	GENERAL & COMMON PLANT			
36	Land & Land Rights	389	-	-
37	Structures & Improvements	390	1,280	2,008
38	Office Furniture & Equipment	391	1,123	1,339
39	Transportation Equipment	392	193	892
40	Stores Equipment	393	-	-
41	Tools & Garage Equipment	394	-	-
42	Laboratory Equipment	395	-	-
43	Power Operated Equipment	396	467	199
44	Communication Equipment	397	-	-
45	Miscellaneous Equipment	398	135	124
46	Other Tangible Property	399	-	-
47	TOTAL GENERAL & COMMON PLANT		3,198	4,562
48	Total Additions		$ 23,221	$ 24,665

($ in Thousands)

Retirements

		[1]	[2]	[3]
Line #	Description	Account Number	Year Ended September 30, 2023	2024
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	TRANSMISSION PLANT			
5	Land & Land Rights	350		
6	Structures & Improvements	352		
7	Station Equipment	353		
8	Station Equipment - SCADA	353.2		
9	Towers and Fixtures	354		
10	Poles and Fixtures	355		
11	Overhead Conductors and Devices	356		
12	Underground Conduit	357		
13	Underground Conductors and Devices	358		
14	Roads and Trails	359		
15	TOTAL TRANSMISSION		-	-
	DISTRIBUTION PLANT			
16	Land & Land Rights	360	-	-
17	Structures & Improvements	361	-	-
18	Station Equipment	362	3	3
19	Storage Battery Equipment	363	-	-
20	Poles, Towers and Fixtures	364	53	83
21	Overhead Conductors and Devices	365	787	735
22	Underground Conduit	366	-	-
23	Underground Conductors and Devices	367	15	25
24	Transformers	368.1	247	246
25	Transformer Installations	368.2	2	2
26	Services	369	25	26
27	Meters	370.1	68	282
28	Meter Installations	370.2	3	3
29	Electronic Meters	370.3	-	-
30	Installations on Customers' Premises	371	-	-
31	Installations on Customers' Premises - EV Charging Stations	371.1	-	-
32	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-	-
33	Leased Property on Customers' Premises	372	-	-
34	Street Lighting and Signal Systems	373	30	30
35	TOTAL DISTRIBUTION		1,233	1,435
	GENERAL & COMMON PLANT			
36	Land & Land Rights	389	-	-
37	Structures & Improvements	390	189	85
38	Office Furniture & Equipment	391	2,306	994
39	Transportation Equipment	392	-	-
40	Stores Equipment	393	-	-
41	Tools & Garage Equipment	394	59	24
42	Laboratory Equipment	395	18	27
43	Power Operated Equipment	396	-	-
44	Communication Equipment	397	69	40
45	Miscellaneous Equipment	398	-	-
46	Other Tangible Property	399	-	-
47	TOTAL GENERAL & COMMON PLANT		2,641	1,170
48	Total Retirements		$ 3,874	$ 2,605

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Accumulated Provision for Depreciation

Line No	Description	[1] Account Number	[2] Pro Forma 9/30/2024
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	TRANSMISSION PLANT		
5	Land & Land Rights	350	-
6	Structures & Improvements	352	-
7	Station Equipment	353	-
8	Station Equipment - SCADA	353.2	-
9	Towers and Fixtures	354	-
10	Poles and Fixtures	355	-
11	Overhead Conductors and Devices	356	-
12	Underground Conduit	357	-
13	Underground Conductors and Devices	358	-
14	Roads and Trails	359	-
15	TOTAL TRANSMISSION		-
	DISTRIBUTION PLANT		
16	Land & Land Rights	360	-
17	Structures & Improvements	361	67
18	Station Equipment	362	1,555
19	Storage Battery Equipment	363	-
20	Poles, Towers and Fixtures	364	18,154
21	Overhead Conductors and Devices	365	14,476
22	Regulatory AFUDC	365.7	(116)
23	Underground Conduit	366	2,692
24	Underground Conductors and Devices	367	4,928
25	Transformers	368.1	8,267
26	Transformer Installations	368.2	6,688
27	Services	369	8,070
28	Meters	370.1	1,939
29	Meter Installations	370.2	825
30	Electronic Meters	370.3	4,275
31	Installations on Customers' Premises	371	1,088
32	Installations on Customers' Premises - EV Charging Stations	371.1	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	338
34	Leased Property on Customers' Premises	372	-
35	Street Lighting and Signal Systems	373	1,139
36	TOTAL DISTRIBUTION		74,384
	GENERAL & COMMON PLANT		
37	Land & Land Rights	389	11
38	Structures & Improvements	390	2,494
39	Office Furniture & Equipment	391	7,201
40	Transportation Equipment	392	612
41	Stores Equipment	393	6
42	Tools & Garage Equipment	394	498
43	Laboratory Equipment	395	21
44	Power Operated Equipment	396	87
45	Communication Equipment	397	274
46	Miscellaneous Equipment	398	157
47	Other Tangible Property	399	-
48	TOTAL GENERAL & COMMON PLANT		11,361
49	Total Accumulated Provision for Depreciation		$ 85,745

Summary of Accumulated Depreciation

		[1]	[2]	[3]	[4]
		Factor	Test Year Ended September 30, 2024		
Line #	Description	Or Reference	Amount	Pro Forma Adjustment	Balance
1	Intangible Plant	Sch C-3, Pg 3	$ -	$ -	$ -
2	Transmission Plant	Sch C-3, Pg 3	-	-	-
3	Distribution Plant	Sch C-3, Pg 3	74,384	-	74,384
4	General & Common Plant	Sch C-3, Pg 3	11,361	-	11,361
5	Other Plant		-	-	-
6	TOTAL ACC DEPR & AMORTIZATION		$ 85,745	$ -	$ 85,745

($ in Thousands)

Accumulated Depreciation by FERC Account

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2023	[3] Year Ended September 30, 2024	[4] Pro Forma Adjustment	[5] Balance
	INTANGIBLE PLANT					
1	Organization	301	$ -	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-	-
4	TOTAL INTANGIBLE		-	-	-	-
	TRANSMISSION PLANT					
5	Land & Land Rights	350	-	-	-	-
6	Structures & Improvements	352	-	-	-	-
7	Station Equipment	353	-	-	-	-
8	Station Equipment - SCADA	353.2	-	-	-	-
9	Towers and Fixtures	354	-	-	-	-
10	Poles and Fixtures	355	-	-	-	-
11	Overhead Conductors and Devices	356	-	-	-	-
12	Underground Conduit	357	-	-	-	-
13	Underground Conductors and Devices	358	-	-	-	-
14	Roads and Trails	359	-	-	-	-
15	TOTAL TRANSMISSION		-	-	-	-
	DISTRIBUTION PLANT					
16	Land & Land Rights	360	-	-	-	-
17	Structures & Improvements	361	52	67	-	67
18	Station Equipment	362	1,177	1,555	-	1,555
19	Storage Battery Equipment	363	-	-	-	-
20	Poles, Towers and Fixtures	364	16,932	18,154	-	18,154
21	Overhead Conductors and Devices	365	13,966	14,476	-	14,476
22	Regulatory AFUDC	365.7	(99)	(116)	-	(116)
23	Underground Conduit	366	2,552	2,692	-	2,692
24	Underground Conductors and Devices	367	4,511	4,928	-	4,928
25	Transformers	368.1	8,139	8,267	-	8,267
26	Transformer Installations	368.2	6,451	6,688	-	6,688
27	Services	369	7,799	8,070	-	8,070
28	Meters	370.1	2,055	1,939	-	1,939
29	Meter Installations	370.2	802	825	-	825
30	Electronic Meters	370.3	4,148	4,275	-	4,275
31	Installations on Customers' Premises	371	988	1,088	-	1,088
32	Installations on Customers' Premises - EV Charging Stations	371.1	-	-	-	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	336	338	-	338
34	Leased Property on Customers' Premises	372	-	-	-	-
35	Street Lighting and Signal Systems	373	1,058	1,139	-	1,139
36	TOTAL DISTRIBUTION		70,868	74,384	-	74,384
	GENERAL & COMMON PLANT					
37	Land & Land Rights	389	11	11	-	11
38	Structures & Improvements	390	2,100	2,494		2,494
39	Office Furniture & Equipment	391	6,239	7,201		7,201
40	Transportation Equipment	392	415	612		612
41	Stores Equipment	393	4	6	-	6
42	Tools & Garage Equipment	394	463	498	-	498
43	Laboratory Equipment	395	46	21	-	21
44	Power Operated Equipment	396	34	87	-	87
45	Communication Equipment	397	222	274	-	274
46	Miscellaneous Equipment	398	95	157	-	157
47	Other Tangible Property	399	-	-	-	-
48	TOTAL GENERAL & COMMON PLANT		9,628	11,361	-	11,361
49	Total Accumulated Provision for Depreciation		$ 80,496	$ 85,745	$ -	$ 85,745

($ in Thousands)

Cost of Removal

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2023	[3] Year Ended September 30, 2024
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	TRANSMISSION PLANT			
5	Land & Land Rights	350	-	-
6	Structures & Improvements	352	-	-
7	Station Equipment	353	-	-
8	Station Equipment - SCADA	353.2	-	-
9	Towers and Fixtures	354	-	-
10	Poles and Fixtures	355	-	-
11	Overhead Conductors and Devices	356	-	-
12	Underground Conduit	357	-	-
13	Underground Conductors and Devices	358	-	-
14	Roads and Trails	359	-	-
15	TOTAL TRANSMISSION		-	-
	DISTRIBUTION PLANT			
16	Land & Land Rights	360	-	-
17	Structures & Improvements	361	-	-
18	Station Equipment	362	0	0
19	Storage Battery Equipment	363	-	-
20	Poles, Towers and Fixtures	364	80	124
21	Overhead Conductors and Devices	365	787	735
22	Regulatory AFUDC	365.7	-	-
23	Underground Conduit	366	-	-
24	Underground Conductors and Devices	367	3	5
25	Transformers	368.1	14	14
26	Transformer Installations	368.2	1	1
27	Services	369	43	45
28	Meters	370.1	-	-
29	Meter Installations	370.2	2	2
30	Electronic Meters	370.3	-	-
31	Installations on Customers' Premises	371	-	-
32	Installations on Customers' Premises - EV Charging Stations	371.1	-	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-	-
34	Leased Property on Customers' Premises	372	-	-
35	Street Lighting and Signal Systems	373	15	15
36	TOTAL DISTRIBUTION		946	942
	GENERAL & COMMON PLANT			
37	Land & Land Rights	389	-	-
38	Structures & Improvements	390	-	-
39	Office Furniture & Equipment	391	-	-
40	Transportation Equipment	392	-	-
41	Stores Equipment	393	-	-
42	Tools & Garage Equipment	394	-	-
43	Laboratory Equipment	395	-	-
44	Power Operated Equipment	396	-	-
45	Communication Equipment	397	-	-
46	Miscellaneous Equipment	398	-	-
47	Other Tangible Property	399	-	-
48	TOTAL GENERAL & COMMON PLANT		-	-
49	Total Cost of Removal		$ 946	$ 942

($ in Thousands)

Negative Net Salvage Amortization

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2023	[3] 2024
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	TRANSMISSION PLANT			
5	Land & Land Rights	350	-	-
6	Structures & Improvements	352	-	-
7	Station Equipment	353	-	-
8	Station Equipment - SCADA	353.2	-	-
9	Towers and Fixtures	354	-	-
10	Poles and Fixtures	355	-	-
11	Overhead Conductors and Devices	356	-	-
12	Underground Conduit	357	-	-
13	Underground Conductors and Devices	358	-	-
14	Roads and Trails	359	-	-
15	TOTAL TRANSMISSION		-	-
	DISTRIBUTION PLANT			
16	Land & Land Rights	360	-	-
17	Structures & Improvements	361	0	0
18	Station Equipment	362	9	8
19	Storage Battery Equipment	363	-	-
20	Poles, Towers and Fixtures	364	405	394
21	Overhead Conductors and Devices	365	255	392
22	Regulatory AFUDC	365.7	-	-
23	Underground Conduit	366	3	2
24	Underground Conductors and Devices	367	12	12
25	Transformers	368.1	6	9
26	Transformer Installations	368.2	27	24
27	Services	369	65	56
28	Meters	370.1	(49)	(81)
29	Meter Installations	370.2	4	3
30	Electronic Meters	370.3	0	0
31	Installations on Customers' Premises	371	16	15
32	Installations on Customers' Premises - EV Charging Stations	371.1	-	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-	-
34	Leased Property on Customers' Premises	372	-	-
35	Street Lighting and Signal Systems	373	17	18
36	TOTAL DISTRIBUTION		772	853
	GENERAL & COMMON PLANT			
37	Land & Land Rights	389	-	-
38	Structures & Improvements	390	0	0
39	Office Furniture & Equipment	391	-	-
40	Transportation Equipment	392	(2)	(2)
41	Stores Equipment	393	-	-
42	Tools & Garage Equipment	394	-	-
43	Laboratory Equipment	395	-	-
44	Power Operated Equipment	396	-	-
45	Communication Equipment	397	0	0
46	Miscellaneous Equipment	398	6	6
47	Other Tangible Property	399	-	-
48	TOTAL GENERAL & COMMON PLANT		4	4
49	Total Negative Net Salvage Amortization		$ 776	$ 857

($ in Thousands)

Salvage

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2023	[3] 2024
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	TRANSMISSION PLANT			
5	Land & Land Rights	350	-	-
6	Structures & Improvements	352	-	-
7	Station Equipment	353	-	-
8	Station Equipment - SCADA	353.2	-	-
9	Towers and Fixtures	354	-	-
10	Poles and Fixtures	355	-	-
11	Overhead Conductors and Devices	356	-	-
12	Underground Conduit	357	-	-
13	Underground Conductors and Devices	358	-	-
14	Roads and Trails	359	-	-
15	TOTAL TRANSMISSION		-	-
	DISTRIBUTION PLANT			
16	Land & Land Rights	360	-	-
17	Structures & Improvements	361	-	-
18	Station Equipment	362	(0)	(0)
19	Storage Battery Equipment	363	-	-
20	Poles, Towers and Fixtures	364	-	-
21	Overhead Conductors and Devices	365	-	-
22	Regulatory AFUDC	365.7	-	-
23	Underground Conduit	366	-	-
24	Underground Conductors and Devices	367	-	-
25	Transformers	368.1	-	-
26	Transformer Installations	368.2	-	-
27	Services	369	-	-
28	Meters	370.1	(39)	(160)
29	Meter Installations	370.2	-	-
30	Electronic Meters	370.3	-	-
31	Installations on Customers' Premises	371	-	-
32	Installations on Customers' Premises - EV Charging Stations	371.1	-	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-	-
34	Leased Property on Customers' Premises	372	-	-
35	Street Lighting and Signal Systems	373	-	-
36	TOTAL DISTRIBUTION		(39)	(160)
	GENERAL & COMMON PLANT			
37	Land & Land Rights	389	-	-
38	Structures & Improvements	390	-	-
39	Office Furniture & Equipment	391	-	-
40	Transportation Equipment	392	-	-
41	Stores Equipment	393	-	-
42	Tools & Garage Equipment	394	-	-
43	Laboratory Equipment	395	-	-
44	Power Operated Equipment	396	-	-
45	Communication Equipment	397	-	-
46	Miscellaneous Equipment	398	-	-
47	Other Tangible Property	399	-	-
48	TOTAL GENERAL & COMMON PLANT		-	-
49	Total Salvage		$ (39)	$ (160)

Working Capital

Line No	Description	[1] Fully Projected Future 9/30/2024	[2] Reference
1	Working Capital for O & M Expense	$ 9,449	C-4, Page 2
2	Interest Payments	(295)	C-4, Page 7
3	Tax Payment Lag Calculations	261	C-4, Page 8
4	Prepaid Expenses	2,032	C-4, Page 9
5	Total Cash Working Capital Requirements	$ 11,447	

($ in Thousands)

Summary of Working Capital

Line #	Description	Reference	Test Year Expenses	Factor	Number of (Lead) / Lag Days	Totals
		[1]	[2]	[3]	[4]	[5]
					[2] * [3]	
WORKING CAPITAL REQUIREMENT						
1	REVENUE LAG DAYS	Page 3				59.56
2	EXPENSE LAG DAYS	Page 4				
3	Payroll	Sch D-7	$ 6,196	12.00	$ 74,352	
4	Purchased Power Costs	Sch D-6	91,176	33.30	3,035,752	
5	Other Expenses	L 19 - L 2 to L 4	26,496	30.76	815,004	
6	Total	Sum (L 3 to L 5)	$ 123,868		$ 3,925,108	
7	O & M Expense Lag Days	L6, C 4 / C 2				31.69
8	Net (Lead) Lag Days	L 1 - L 7				27.87
9	Operating Expenses Per Day	L 6, C 2 / 365				$ 339
10	Working Capital for O & M Expense	L 8 * L 9				$ 9,449
11	Interest Payments	Page 7				(295)
12	Tax Payment Lag Calculations	Page 8				261
13	Prepaid Expenses	Page 9				2,032
14	Total Working Capital Requirement	Sum (L 10 to L 13)				$ 11,447
15	Pro Forma O & M Expense		$ 127,107			
	Less:					
16	Uncollectible Expense		3,239			
17	Sub-Total		3,239			
18	Pro Forma Cash O&M Expense		$ 123,868			

($ in Thousands)

Revenue Lag

Line No.	Description	[1] Reference Or Factor	[2] Accounts Receivable Balance End of Month		[3] Total Monthly Sales		[4] A/R Turnover		[5] Days Lag
					Page 2		[3] / [2]		365 / [4]
1	Annual Number of Days								365
2	September, 2021		$ 11,849						
3	October		11,097		6,197				
4	November		9,723		7,951				
5	December, 2021		11,433		10,929				
6	January, 2022		14,407		12,474				
7	February		15,705		11,066				
8	March		16,494		10,190				
9	April		15,957		8,623				
10	May		14,986		8,280				
11	June		15,976		10,966				
12	July		17,542		14,900				
13	August		19,220		13,886				
14	September, 2022		18,672		9,911				
15	Total	Sum L 2 to L 14	$193,061						
16	Number of Months	13							
17	Average Acct Rec Balance	L 15 / L 16	$14,851						
18	Total Sales for Year	Sum L 3 to L 14			$ 125,373				
19	Acct Rec Turnover Ratio	L 18 / L 17					8.44		
20	Collection Lag Day Factor	L 1 / L 19							43.25
21	Meter Read Lag Factor								1.10
22	Midpoint Lag Factor		365	/	12	/	2	=	15.21
23	Total Revenue Lag Days	Sum L 20 to L 22							**59.56**

($ in Thousands)

Summary of Expense Lag Calculations

Line No.	Description	[1] Reference Or Factor	[2] Amount	[3] (Lead) / Lag Days	[4] Weighted Dollar Value [2] * [3]	[5] (Lead) / Lag Days [4] / [2]
PAYROLL						
1	Union Payrolls	Bi-Weekly	$ 1,321	12.00		
2	Exempt & Non-Exempt	Bi-Weekly	4,875	12.00		
3	Weighted for Union	L1, C2 * C3			$ 15,850	
4	Weighted for Other	L2, C2 * C3			58,501	
5	Payroll Lag	L 3 + L 4	$ 6,196		$ 74,351	
6	Payroll Lag Days	C 4 / C 2				12.00
PURCHASE POWER COSTS						
7	Payment Lag	Page 6	$ 62,613		$ 2,084,738	
8	Power Cost Lag Days	C 4 / C 2				33.30
OTHER O & M EXPENSES						
9	OCTOBER 2021	Page 5	$ 767		$ 15,119	
10	NOVEMBER 2021	Page 5	845		31,591	
11	DECEMBER 2021	Page 5	720		29,343	
12	JANUARY 2022	Page 5	1,005		31,292	
13	FEBRUARY 2022	Page 5	797		24,522	
14	MARCH 2022	Page 5	719		17,478	
15	APRIL 2022	Page 5	573		11,770	
16	MAY 2022	Page 5	613		16,801	
17	JUNE 2022	Page 5	1,218		27,473	
18	JULY 2022	Page 5	931		20,148	
19	AUGUST 2022	Page 5	1,314		46,926	
20	SEPTEMBER 2022	Page 5	2,031		82,279	
21	TOTAL		$ 11,532		$ 354,742	
22	Other O&M Expense Lag Days	C 4 / C 2				30.76

($ in Thousands)

General Disbursements Payment Lag Summary

Line #	Description	[1] Number of CDs	[2] Cash Disbursements	[3] Dollar-Days	[4] Expense Lag-Days [3] / [2]
OCTOBER 2021					
1	Total Disbursements for Month	913	$ 4,091		
2	Total Disbursements for Expenses	352	$ 767	$ 15,119	19.72
NOVEMBER 2021					
3	Total Disbursements for Month	672	$ 2,412		
4	Total Disbursements for Expenses	221	$ 845	$ 31,591	37.39
DECEMBER 2021					
5	Total Disbursements for Month	674	$ 2,824		
6	Total Disbursements for Expenses	209	$ 720	$ 29,343	40.76
JANUARY 2022					
7	Total Disbursements for Month	922	$ 3,219		
8	Total Disbursements for Expenses	325	$ 1,005	$ 31,292	31.15
FEBRUARY 2022					
9	Total Disbursements for Month	775	$ 2,732		
10	Total Disbursements for Expenses	229	$ 797	$ 24,522	30.78
MARCH 2022					
11	Total Disbursements for Month	983	$ 10,847		
12	Total Disbursements for Expenses	297	$ 719	$ 17,478	24.30
APRIL 2022					
13	Total Disbursements for Month	776	$ 2,479		
14	Total Disbursements for Expenses	231	$ 573	$ 11,770	20.54
MAY 2022					
15	Total Disbursements for Month	722	$ 2,621		
16	Total Disbursements for Expenses	209	$ 613	$ 16,801	27.43
JUNE 2022					
17	Total Disbursements for Month	996	$ 4,896		
18	Total Disbursements for Expenses	287	$ 1,218	$ 27,473	22.56
JULY 2022					
19	Total Disbursements for Month	830	$ 4,073		
20	Total Disbursements for Expenses	229	$ 931	$ 20,148	21.63
AUGUST 2022					
21	Total Disbursements for Month	1,127	$ 4,214		
22	Total Disbursements for Expenses	434	$ 1,314	$ 46,926	35.71
SEPTEMBER 2022					
23	Total Disbursements for Month	732	$ 4,129		
24	Total Disbursements for Expenses	202	$ 2,031	$ 82,279	40.50
TOTAL TWELVE TEST MONTHS					
25	Total Test Month Expense Disbursement	3,225	$ 11,532	$ 354,742	30.76

Purchase Power Cost Payment Lag Summary

Line #	Description	[1] Number of Invoices	[2] Amount of Invoice	[3] Dollar Days	[4] Total Payment Lag-Days
1	October 2021	5	$ 2,996	$ 106,020	35.39
2	November	5	3,317	108,740	32.78
3	December	7	5,193	181,364	34.93
4	January 2022	10	6,485	205,955	31.76
5	February	9	4,847	153,103	31.59
6	March	6	5,838	223,818	38.34
7	April	8	3,281	154,404	47.06
8	May	7	2,813	100,627	35.77
9	June	11	5,922	176,574	29.82
10	July	12	7,890	244,292	30.96
11	August	10	8,979	247,333	27.55
12	September 2022	6	5,052	182,509	36.13
13	Total		$ 62,613	$ 2,084,738	
14	Purchase Power Lag Days				33.30

Interest Payments

Line No.	Description	[1] Reference Or Factor	[2] # of Days	[3] # of Days	[4] Total
1	Measure of Value at September 30, 2024	Sch C-1			$ 172,242
2	Long-term Debt Ratio	Sch B-7			45.41%
3	Embedded Cost of Long-term Debt	Sch B-6			4.35%
4	Pro forma Interest Expense	L 1 * L 2 * L 3			$ 3,402
5	Daily Amount	L 4 / L 5 [2]	365		$ 9
6	Days to mid-point of interest payments			91.25	
7	Less: Revenue Lag Days	Page 3		59.56	
8	Interest Payment lag days	L 7 - L 6			(31.7)
9	Total Interest for Working Capital	L 5 * L 8			$ (295)

Tax Lag Day Calculations

Line #	Description	[1] Payment Dates	[2] Mid-Point of Service Period	[3] Lead (Lag) Payment Days	[4] Payment Amount	[5] Weighted Lead (Lag) Dollars	[6] Payment Lead (Lag) Days	[7] Revenue (Lag) Days	[8] Net Payment Lead (Lag) Days	[9] Total Dollar Days	[10] Working Capital Amount
		Fully Projected Future		[1] - [2]		[3] * [4]	[5] / [4]		[6] - [7]		365
1	**FEDERAL INCOME TAX**				$ 2,657						
2	First Payment	01/15/24	04/01/24	77.00	$ 664	51,147					
3	Second Payment	03/15/24	04/01/24	17.00	664	11,292					
4	Third Payment	06/15/24	04/01/24	(75.00)	664	(49,819)					
5	Fourth Payment	09/15/24	04/01/24	(167.00)	664	(110,930)					
6	Total				$ 2,657	$ (98,309)	(37.00)	(59.56)	22.56	$ 59,942	$ 164
7	**STATE INCOME TAX**				$ 1,117						
8	First Payment	12/15/23	04/01/24	108.00	$ 279	30,163					
9	Second Payment	03/15/24	04/01/24	17.00	279	4,748					
10	Third Payment	06/15/24	04/01/24	(75.00)	279	(20,946)					
11	Fourth Payment	09/15/24	04/01/24	(167.00)	279	(46,640)		c			
12	Total				$ 1,117	(32,676)	(29.25)	(59.56)	30.31	$ 33,860	$ 93
13	**PA PROPERTY TAX**				$ 22						
14	First Payment	04/30/24	04/01/24	(29.00)	$ 11	(313)					
15	Second Payment	08/31/24	04/01/24	(152.00)	11	(1,639)					
16	Total				$ 22	(1,952)	(90.50)	(59.56)	(30.94)	$ (667)	$ (2)
17	**PURTA**				$ 76						
18	Payment	05/01/24	04/01/24	(30.00)	$ 76	(2,269)	(30.00)	(59.56)	29.56	$ 2,235	$ 6
19	Total Working Capital For Other Taxes										$ 261

Prepaid Expenses

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Line #	Description		TOTAL	Insurance	PUC Assessment	Gross Receipts Tax	Subscriptions	Miscellaneous	Maintenance & Services
1	September, 2021		1,203	$ 449	$ 203	$ -	$ 30	$ 29	$ 492
2	October		1,244	426	203	-	46	24	545
3	November		1,241	412	178	-	102	21	530
4	December, 2021		1,131	348	152	-	61	12	559
5	January, 2022		1,226	290	127	-	61	50	699
6	February		1,090	231	101	-	55	30	673
7	March		4,791	173	76	3,798	49	27	668
8	April		4,117	121	51	3,238	44	21	643
9	May		3,515	66	25	2,783	39	27	575
10	June		2,305	12	-	1,635	33	21	604
11	July		1,964	620	-	772	12	12	548
12	August		1,193	577	-	-	22	41	553
13	September, 2022		1,399	522	223	-	1	35	618
14	TOTAL		$ 26,420	$ 4,246	$ 1,338	$ 12,225	$ 556	$ 351	$ 7,705
15	Percent to Electric			100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
16	Amount to Electric			$ 4,246	$ 1,338	$ 12,225	$ 556	$ 351	$ 7,705
17	Monthly Average	13		$ 327	$ 103	$ 940	$ 43	$ 27	$ 593
18	Rate Case Amount		$ 2,032						

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Accumulated Deferred Income Taxes

		[1]	[2]
Line #	Description	Amount Fully Projected	Total
	Accumulated Deferred Income Tax		
1	Electric Utility Plant - a/c # 282	(30,062)	
2	Sub-total		(30,062)
3	ADIT on CIAC	2,177	
4	Sub-total		2,177
5	Federal ADIT		(27,885)
6	State Repair Regulatory Liability	(3,367)	(3,367)
7	Pro-Rata Adjustment	1,588	1,588
8	Balance At September 30, 2024		$ (29,665)

($ in Thousands)

Customer Deposits

Line #	Description	[1] Balance at End Of Month
1	September, 2021	$ 922
2	October	$ 936
3	November	$ 950
4	December, 2021	$ 950
5	January, 2022	$ 956
6	February	$ 954
7	March	$ 958
8	April	$ 955
9	May	$ 949
10	June	$ 933
11	July	$ 941
12	August	$ 952
13	September, 2022	$ 984
14	Total	$ 12,338
15	Number of Months	13
16	Average Monthly Balance	$ 949

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Materials & Supplies

Line #	Month	[1] Materials and Supplies
1	September, 2021	$ 1,578
2	October	$ 1,571
3	November	$ 1,514
4	December, 2021	$ 1,763
5	January, 2022	$ 1,854
6	February	$ 2,014
7	March	$ 2,232
8	April	$ 2,266
9	May	$ 2,381
10	June	$ 2,713
11	July	$ 2,758
12	August	$ 2,705
13	September, 2022	$ 2,626
14	Total	$ 27,975
15	Number of Months	13
16	Average Monthly Balance	$ 2,152

($ in Thousands)

Summary of Revenue and Expenses
Pro Forma with Proposed Revenue Increase

Line #	Description	Factor Or Reference	[1] Pro Forma Test Year At Present Rates	[2] Rate Increase	[3] At Proposed Rates
	OPERATING REVENUES				
1	Customer & Distribution Revenue		$ 44,106	$ -	$ 44,106
2	Revenue - Cost of Purchased Power		107,483	-	107,483
3	Other Revenues		1,103	-	1,103
4	Revenue Increase			11,425	11,425
5	Total Operating Revenues		152,691	11,425	164,116
	OPERATING EXPENSES				
6	Other Power Supply Expenses		91,176		91,176
7	Transmission		-	-	-
8	Distribution		13,274	-	13,274
9	Customer Accounts		9,634	-	9,634
10	Uncollectible Expense	1.838%	3,239	210	3,449
11	Customer Information & Services		1,186	-	1,186
12	Sales		0	-	0
13	Administrative & General		8,598	-	8,598
14	Depreciation & Amortization		8,553	-	8,553
15	Taxes other than income taxes		9,718	716	10,435
16	Total Operating Expenses		145,378	926	146,304
17	Net Operating Income Before Income Tax		7,313	10,499	17,812
	Income Taxes				
18	Pro Forma Income Tax At Present Rates		823		823
19	Pro Forma Income Tax on Revenue Increase			2,951	2,951
20	Net Income (Loss)		$ 6,490	$ 7,548	$ 14,038

($ in Thousands)

Summary of Pro Forma Revenue and Expense Adjustments with Proposed Revenue Increase

Line #	Description	[1] Factor Or Reference	[2] Test Year At Present Rates: Budget For Year End 09/30/24	[3] Test Year At Present Rates: Adjustments Sch D-3 Increase (Decrease)	[4] Test Year At Present Rates: Pro Forma Adjusted For Test Year 9/30/24	[5] Proposed Increase	[6] Pro Forma Test Year With Proposed Increase
	OPERATING REVENUES			-	[2] + [3]		[4] + [5]
1	Residential	440	$ 111,376	$ 5,890	$ 117,266		$ 117,266
2	Commercial & Industrial	442	32,040	1,489	33,529		33,529
3	Public Streets & Highway Lighting	444	749	9	758		758
4	Other Sales to Public Authorities	445	19	0	19		19
5	Sales for Resale	447	16	0	16		16
6	Forfeited Discounts	450	520	-	520		520
7	Miscellaneous Service Revenues	451	16	-	16		16
8	Rent from Electric Properties	454	567	-	567		567
9	Interest on Undercollection - Refunded	456	-		-		-
10	Rate Increase		-	-	-	11,425	11,425
11	Total Operating Revenues		145,303	7,388	152,691	11,425	164,116
	OPERATING EXPENSES						
12	Other Power Supply Expenses		85,951	5,225	91,176	-	91,176
13	Transmission		-	-	-		-
14	Distribution		13,259	15	13,274		13,274
15	Customer Accounts		9,463	171	9,634		9,634
16	Uncollectible Expense	1.838%	2,577	662	3,239	210	3,449
17	Customer Information & Services		1,275	(89)	1,186		1,186
18	Sales		-	0	0		0
19	Administrative & General		8,220	377	8,598		8,598
20	Depreciation & Amortization		9,075	(522)	8,553		8,553
21	Taxes other than income taxes		9,375	344	9,718	716	10,435
22	Total Operating Expenses		139,195	6,183	145,378	926	146,304
23	Net Operating Income - BIT		$ 6,108	$ 1,205	$ 7,313	$ 10,499	$ 17,812

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Summary of Pro Forma Adjustments

Line #	Description		[1] As Budgeted And Allocated	[2] Not Used D-4	[3] Revenues D-5	[4] Power Costs D-6	[5] Salaries & Wages D-7	[6] Not Used D-8	[7] Not Used D-9	[8] Rate Case Expenses D-10	[9] Uncollectibles Expense D-11	[10] COVID-19 Costs D-12	[11] Not Used D-13	[12] Sub-Total Adjustments	[13] Total Proforma
	OPERATING REVENUES														
	Customer & Distribution Revenue														
1	Residential	440	$ 28,459		$ 1,720									$ 1,720	$ 30,179
2	Commercial & Industrial	442	12,853		522									522	13,375
3	Public Streets & Highway Lighting	444	521		9									9	530
4	Other Sales to Public Authorities	445	17		0									0	17
5	Sales for Resale	447	4		0									0	4
	Non-Distribution and Operating Revenue													-	-
6	Residential	457	82,917		4,170									4,170	87,087
7	Commercial & Industrial	457	19,187		966									966	20,153
8	Public Streets & Highway Lighting	457	228		1									1	229
9	Other Sales to Public Authorities	489	2		0									0	2
10	Sales for Resale	489	12		-									-	12
11	Forfeited Discounts	450	520		-									-	520
12	Miscellaneous Service Revenues	451	16		-									-	16
13	Rent from Electric Properties	454	567		-									-	567
14	Interest on Undercollection - Refunded	456	-											-	-
15	Rate Increase		-											-	-
16	Total Operating Revenues		145,303		7,388	-	-	-	-	-	-	-	-	7,388	152,691
	OPERATING EXPENSES														-
17	Other Power Supply Expenses		85,951			-	-							-	85,951
18	Transmission		-			-	-							-	-
19	Distribution		13,259	-			15		-				-	15	13,274
20	Customer Accounts		9,463				9							9	9,472
21	Uncollectible Expense		2,577								662			662	3,239
22	Customer Information & Services		1,275				0							0	1,275
23	Sales		-				0							0	0
24	Administrative & General		8,220				9	-		(59)		-		(50)	8,170
25	Depreciation & Amortization		9,075											-	9,075
26	Taxes other than income taxes		9,375											-	9,375
														-	-
27	Total Operating Expenses		$ 139,195	$ -	$ -	$ -	$ 33	$ -	$ -	$ (59)	$ 662	$ -	$ -	$ 636	$ 139,831
28	Net Operating Income Before Income Tax		$ 6,108	$ -	$ 7,388	$ -	$ (33)	$ -	$ -	$ 59	$ (662)	$ -	$ -	$ 6,753	$ 12,861

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Summary of Pro Forma Adjustments

Line #	Description	[1] From Page 1 Sub-total	[2]	[3] Benefits Adjustments D-14	[4] Other Adjustments D-15	[5] Universal Service D-16	[6] GRT Adjustment D-17	[7] Power Supply Exp Adj D-18	[8] EE&C Program D-19	[9] Not Used D-20	[10] Depreciation D-21	[11] Taxes Other Than Income D-31	[12]	[13] TOTAL Adjusted
	OPERATING REVENUES													
	Customer & Distribution Revenue													
29	Residential	$ 30,179												$ 30,179
30	Commercial & Industrial	13,375												13,375
31	Public Streets & Highway Lighting	530												530
32	Other Sales to Public Authorities	17												17
33	Sales for Resale	4												4
	Non-Distribution and Operating Revenue													-
34	Residential	87,087												87,087
35	Commercial & Industrial	20,153												20,153
36	Public Streets & Highway Lighting	229												229
37	Other Sales to Public Authorities	2												2
38	Sales for Resale	12												12
39	Forfeited Discounts	520												520
40	Miscellaneous Service Revenues	16												16
41	Rent from Electric Properties	567												567
42	Interest on Undercollection - Refunded	-												-
43	Rate Increase	-												-
44	Total Operating Revenues	152,691	-	-	-	-	-	-	-	-	-	-	-	152,691
	OPERATING EXPENSES													
45	Other Power Supply Expenses	85,951					-	5,225						91,176
46	Transmission	-												-
47	Distribution	13,274			-									13,274
48	Customer Accounts	9,472			66	96								9,634
49	Uncollectible Expense	3,239												3,239
50	Customer Information & Services	1,275							(89)					1,186
51	Sales	0												0
52	Administrative & General	8,170		427										8,598
53	Depreciation & Amortization	9,075									(522)			8,553
54	Taxes other than income taxes	9,375					310					34		9,718
55	Total Operating Expenses	$ 139,831	$ -	$ 427	$ 66	$ 96	$ 310	$ 5,225	$ (89)	$ -	$ (522)	$ 34	$ -	$ 145,378
56	Net Operating Income Before Income Tax	$ 12,861	$ -	$ (427)	$ (66)	$ (96)	$ (310)	$ (5,225)	$ 89	$ -	$ 522	$ (34)	$ -	$ 7,313

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Schedule D-5
Witness: S. A. Epler
Page 1 of 1

Adjustment - Revenue Adjustments

		[1]	[2]	[3]	[4]	[5]	[6]
				PRO FORMA ADJUSTMENTS			
Line #	Description	Reference Or Account Number	2024 Budget	Rev Adj Annualization	Other Adjustments	Total Proforma Adjustments	Proforma Adjusted At Present Rates
				D-5A	D-5B		
	Customer & Distribution Revenue						
1	Residential	440	$ 28,459	$ 1,720		$ 1,720	$ 30,179
2	Commercial & Industrial	442	12,853	522		522	13,375
3	Public Streets & Highway Lighting	444	521	9		9	530
4	Other Sales to Public Authorities	445	17	0		0	17
5	Sales for Resale	447	4	0		0	4
6	Cust Chg & Distrib Revenue		41,854	2,252	-	2,252	44,106
	Non-Distribution and Operating Revenue						
7	Residential	456.5	82,917	4,170		4,170	87,087
8	Commercial & Industrial	456.6	19,187	966		966	20,153
9	Public Streets & Highway Lighting	456.8	228	1		1	229
10	Other Sales to Public Authorities		2	0		0	2
11	Sales for Resale		12	-		-	12
12	Revenue for Cost of Electric		102,346	5,137	-	5,137	107,483
							-
13	Total Customer Revenue		144,200	7,388	-	7,388	151,588
14	Forfeited Discounts	450	520		-	-	520
15	Miscellaneous Service Revenues	451	16		-	-	16
16	Rent from Electric Properties	454	567		-	-	567
17	Interest on Undercollection - Refunded	456.1	-			-	-
18	TOTAL REVENUES		$ 145,303	$ 7,388	$ -	$ 7,388	$ 152,691

($ in Thousands)

Adjustment - Test Year Revenue Changes

Line #	Description	[1] Factor Or Reference	[2] Budgeted Jurisdictional	[3] Revised Jurisdictional	[4] Adjustment [3] - [2]	[5] Total Adjustment
	TOTAL REVENUE					
1	Residential	440	$ 111,376	$ 117,265	$ 5,890	
2	Commercial & Industrial	442	32,041	33,529	1,489	
3	Public Streets & Highway Lighting	444	748	758	9	
4	Other Sales to Public Authorities	445	19	19	0	
5	Sales for Resale	447	16	16	0	
6	Total		$ 144,199	$ 151,588	$ 7,388	$ 7,388
	COSTS (GSR, STAS, EEC, USP, GRT)					
7	Residential		$ 82,917	$ 87,086	4,170	
8	Commercial & Industrial		19,187	20,154	966	
9	Public Streets & Highway Lighting		228	228	1	
10	Other Sales to Public Authorities		2	2	0	
11	Sales for Resale		12	12	0	
12	Total		$ 102,346	$ 107,482	$ 5,137	$ 5,137
	NET CUSTOMER & DISTRIBUTION					
13	Residential		$ 28,459	$ 30,179	$ 1,720	
14	Commercial & Industrial		12,853	13,376	522	
15	Public Streets & Highway Lighting		521	529	9	
16	Other Sales to Public Authorities		17	17	0	
17	Sales for Resale		4	4	0	
18	Total		$ 41,853	$ 44,105	$ 2,252	$ 2,252

Adjustment - Power Costs

		[1]	[2]	[3]	[4]	[5]
			PRO FORMA ADJUSTMENTS			
Line #	Description	Budgeted Electric Costs	D-18 Costs	Other Costs	Electric Cost Pro Forma Adjustments	Pro Forma Electric Costs At Pres Rates
1	Budgeted Purchased Power Costs	$ 85,951	$ 5,225	$ -	$ 5,225	$ 91,176
2	Residential				-	-
3	Commercial & Industrial				-	-
4	Public Streets & Highway Lighting				-	-
5	Other Sales to Public Authorities				-	-
6	Sales for Resale				-	-
7	Company Use of Electricity				-	-
8	**Total Purchased Power Costs**	$ 85,951	$ 5,225	$ -	$ 5,225	$ 91,176

($ in Thousands)

Adjustment - Salaries & Wages

Line #	Description	[1] Budgeted Year 09/30/24	[2] Adjustment	[3] Payroll As Distributed	[4] Annualization Adjustment	[5] Total Pro Forma Payroll
	OPERATIONS					
1	Total Other Power Supply Expenses	$ -	$ -	$ -	$ -	$ -
2	Total Transmission Expenses - Operation	-	-	-	-	-
3	Total Regional Market Expenses - Operation	-	-	-	-	-
4	Total Distribution Expenses - Operation	1,850	-	1,850	10	1,860
5	Total Customer Accounts Expense	1,677	-	1,677	9	1,686
6	Total Customer Service & Informational Expenses	28	-	28	0	28
7	Total Sales Expense	5	-	5	0	5
8	Total A&G - Operation	1,656		1,656	9	1,665
9	Total Operations	5,216	-	5,216	28	5,244
	MAINTENANCE					
10	Total Transmission Expenses - Maintenance	-	-	-	-	-
11	Total Regional Market Expenses - Maintenance	-	-	-	-	-
12	Total Distribution Expenses - Maintenance	914	-	914	5	919
13	Total A&G - Maintenance	33	-	33	0	33
14	Total Maintenance	947	-	947	5	952
15	Total Payroll to Expense	$ 6,163	$ -	$ 6,163	$ 33	$ 6,196
16	Percent Increase					0.535%

($ in Thousands)

Adjustment - Salaries & Wages

		[1]	[2]	[3]	[4]	[5]
Line #	Description	Reference Or Function	Union	Non-Exempt	Exempt	Pro Forma Total Payroll
1	Budgeted Payroll For TY 9-30-24		$ 1,311	$ 1,156	$ 3,696	$ 6,163
	Annualize for Wage Increase to 9-30-24					
2	Percent Increase		3.00%	4.00%	4.00%	
3	Union Increase At 1-1 Annualization Factor	1/1/24	25%			
4	Non-Exempt Annualization Factor	4/1/24		50%		
5	Exempt Annualization Factor	10/1/23			0%	
6	Increase for wage rate changes	L 1 * L 2 * Ls 3 to 5	10	23	0	$ 33
7	Annualized Salaries & Wages at 9-30-24 Rates	L 1 + L 6	$ 1,321	$ 1,179	$ 3,696	
8	Pro Forma Salaries & Wages for TY		$ 1,321	$ 1,179	$ 3,696	
9	Pro Forma Adjustment to S&W					$ 33
10	Annualization Factor	L 11 / L 1				0.535%

Adjustment - Rate Case Expense

		[1]	[2]	[3]
Line #	Description	Reference	Amount	Total
	Rate Case Expenditures			
1	External Consultants		$ 228	
2	External Legal		500	
3	Miscellaneous Costs		41	
4	Sub-Total	L 1 to L 3		$ 769
	Total Expenditures for Rate Case Filing			
5	TOTAL COSTS	L 4		$ 769
6	Normalized over 2 years Line 4 / Line 5, Col [2]		2	$ 385
7	Rate Case Expense included in Budget			444
8	Pro Forma Adjustment	L 5 - L 6		$ (59)

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Schedule D-11
Witness: V. K. Ressler
Page 1 of 1

Adjustment - Uncollectibles

Line #	Description	[1] Reference Or Factor		[2] Uncollectible Expense	[3] Tariff Revenue	[4] Percent [2] / [3]	[5] Total [2] / [3]
	Adjustment #1:						
1	2020		(a)	$ 2,028	$ 84,126	2.41%	
2	2021		(a)	$ 1,330	$ 89,272	1.49%	
3	2022			$ 2,133	$ 125,374	1.70%	
4	Three Year Average Sum (Line 1 to Line 3) / 3	3		$ 1,830	$ 99,591		1.838%
5	2024 Budget					$ 2,239	
	Pro Forma Adjustment						
6	Adjusted Revenues	1.838%			$ 152,108		
7	Pro Forma at Present Rate Revenue	L6: [1] * [3]				2,796	
8	Total for Test Year						**$ 557**
	Adjustment #2: (b)						
9	Deferred Uncollectibles - Fiscal 2020				$ 1,013		
10	Less: recovery since last rate case				$ 338		
11	Balance of deferred uncollectibles for Fiscal 2020				$ 675		
12	Amortization per year				338		
13	Recovery of Fiscal 2020 deferred uncollectibles included in budget				$ 338		
14	Pro Forma Adjustment						**$ -**
	Adjustment #3: (c)						
15	Deferred Uncollectibles - Fiscal 2021				$ 315		
16	Amortize over 3 years				3		
17	Amortization per year (Line 15 / Line 16)				105		
18	Recovery of Fiscal 2021 deferred uncollectibles included in budget				-		
19	Pro Forma Adjustment						**$ 105**
20	Total Uncollectible Adjustment	L8 + L14 + L19					**$ 662**

(a) Includes $315 and $1,013 in 2021 and 2020 respectively, which were recorded as regulatory assets associated with COVID-19 in accordance with the May 13, 2020 Secretarial Letter at Docket No. M-2020-3019775. These amounts are the uncollectible accounts reserves needed in excess of the $1,015 uncollectible expense built into rates (from the 2018 Electric Rate Case at Docket No. R-2017-2640058).

(b) $1,013 was deferred and recorded as a regulatory asset for Fiscal 2020 associated with COVID-19 in accordance with the May 13, 2020 Secretarial Letter at Docket No. M-2020-3019775. As approved within the settlement to the 2021 UGI Electric Rate Case at Docket No. R-2021-3023618, this amount is being amortized over 3 years.

(c) Subsequent to the filing of the 2021 UGI Electric Rate Case at Docket No. R-2021-3023618, $315 was deferred and recorded as a regulatory asset for Fiscal 2021 associated with COVID-19 in accordance with the May 13, 2020 Secretarial Letter at Docket No. M-2020-3019775. The Company is proposing to amortize this amount over 3 years and is recording an adjustment to its budgeted bad debt expense for this Fiscal 2021 deferral amortization.

Adjustment - Benefits Adjustments

Line #	Description	[1] Amount	[2] Subtotal	[3] Pro Forma Adjustment
	Pension Expense Adjustment			
1	Total budgeted pension expense		$ 293	
2	Total cash contributions per revised estimate	$ 14,256		
3	Estimated Cash Contributions attributable to UGI Electric	1,272		
4	Less: estimated capitalized portion	(445)		
5	Pension cash contributions per updated estimates		827	
6	Total Adjustment			$ 534
7	Distribution Allocation Factor			80.05%
8	Pro Forma Adjustment			$ 427

Adjustment - Other Adjustments

Line #	Description	[1] Sub-Total	[2] Total
	Customer Accounts Expense Adjustment		
1	Unrecovered Interest on Customer Deposits		$ 66

Adjustment - Universal Service

Line #	Description	[1] Amount
	Increase (Decrease) for Pro Forma TY Universal Service Expense	
		Pro Forma
1	Customer Assistance Plan Credit	$ 5,629
2	Administration Costs	158
3	LIURP	298
4	Hardship Program (Project Share)	5
5	Customer Assistance Plan Pre-program Arrearage	566
6	TOTAL	$ 6,656
7	Budget	$ 6,560
8	Total Adjustment	$ 96

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
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($ in Thousands)

Adjustment - Gross Receipts Tax

Line #	Description	[1] Amount	[2] Total
1	Revised Jurisdictional Revenue - Schedule D-5A, [3], Line 6	$ 151,588	
2	Other Operating Revenues	1,103	
3	Less: Uncollectible Expense	(3,239)	
4	Total		$ 149,452
5	Gross Receipts Tax Rate		5.90%
6	Revised Gross Receipts Tax		$ 8,818
7	Gross Receipts Tax Expense per Budget		$ 8,508
8	Pro Forma Adjustment		$ 310

Adjustment - Power Supply Expense

Line #	Description	[1] Sub-Total	[2] Total
1	Power Supply Expense	$ 92,256	
2	Adjustment for Normalized & Annualized Use/Customer - See Exhibit SAE-4(b)	696	
3	Adjustment for Normalized & Annualized Use/Customer - See Exhibit SAE-4(c)	3,941	
4	Sub-Total	$ 96,893	
5	Adjustment for Gross Receipts Tax (1 - .059)	0.941	
6	Power Supply Expense As Adjusted	$ 91,176	
7	Power Supply Expense per Budget (net of Gross Receipts Tax) (Sch D-6, Col 1)	$ 85,951	
8	Pro Forma Adjustment		$ 5,225

Adjustment - Energy Efficiency and Conservation Programs

Line #	Description	[1] Amount	[2] Sub-Total
	Energy Efficiency and Conservation Programs		
1	2024 Original Program Costs	$ 1,241	
2	Adjusted Budget	1,152	
3	Additional Expense Adjustment (Line 2 - Line 1)		(89)
4	Total Adjustment		$ (89)

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment - Depreciation expense

		[1]	[2]	[3]	[4]
Line #	Description	Account Number	Budgeted 9/30/24 Depreciation Expense	Adjustment To Annualize At New Depre Study Rates	Pro Forma Test Year Depreciation
	INTANGIBLE PLANT				
1	Organization	301	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-
4	TOTAL INTANGIBLE		-	-	-
	TRANSMISSION PLANT				
5	Land & Land Rights	350	-	-	-
6	Structures & Improvements	352	-	-	-
7	Station Equipment	353	-	-	-
8	Station Equipment - SCADA	353.2	-	-	-
9	Towers and Fixtures	354	-	-	-
10	Poles and Fixtures	355	-	-	-
11	Overhead Conductors and Devices	356	-	-	-
12	Underground Conduit	357	-	-	-
13	Underground Conductors and Devices	358	-	-	-
14	Roads and Trails	359	-	-	-
15	TOTAL TRANSMISSION		-	-	-
	DISTRIBUTION PLANT				
16	Land & Land Rights	360	-	-	-
17	Structures & Improvements	361	14	1	15
18	Station Equipment	362	271	99	370
19	Storage Battery Equipment	363	-	-	-
20	Poles, Towers and Fixtures	364	1,143	(114)	1,029
21	Overhead Conductors and Devices	365	1,634	366	2,001
22	Regulatory AFUDC	365.7	(14)	(2)	(16)
23	Underground Conduit	366	138	(2)	137
24	Underground Conductors and Devices	367	447	(14)	433
25	Transformers	368.1	359	69	428
26	Transformer Installations	368.2	225	(18)	207
27	Services	369	280	(1)	280
28	Meters	370.1	64	2	66
29	Meter Installations	370.2	25	(0)	25
30	Electronic Meters	370.3	134	(20)	115
31	Installations on Customers' Premises	371	94	(20)	74
32	Installations on Customers' Premises - EV Charging Stations	371.1	-	-	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	2	(1)	1
34	Leased Property on Customers' Premises	372	-	-	-
35	Street Lighting and Signal Systems	373	110	1	111
36	TOTAL DISTRIBUTION		4,927	347	5,275
	GENERAL & COMMON PLANT				
37	Land & Land Rights	389	-	-	-
38	Structures & Improvements	390	239	302	541
39	Office Furniture & Equipment	391	1,843	14	1,857
40	Transportation Equipment	392	183	107	290
41	Stores Equipment	393	1	(0)	1
42	Tools & Garage Equipment	394	63	(6)	57
43	Laboratory Equipment	395	14	(11)	2
44	Power Operated Equipment	396	72	(14)	58
45	Communication Equipment	397	117	(42)	75
46	Miscellaneous Equipment	398	56	6	61
47	Other Tangible Property	399	-	-	-
48	TOTAL GENERAL & COMMON PLANT		2,587	356	2,943
49	TOTAL DEPRECIATION		$ 7,515	$ 703	$ 8,218
50	CHARGED TO OTHER BUSINESS UNITS (IT-RELATED)		(42)	-	(42)
51	CHARGED TO CLEARING ACCOUNTS		$ (435)	$ (45)	$ (479)
52	NET SALVAGE AMORTIZATION		$ 782	$ 75	$ 857
53	TOTAL CLAIMED DEPRECIATION AND AMORTIZATION		$ 7,820	$ 733	$ 8,553

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment - Taxes Other Than Income Taxes

Line #	Description	[1] Account Number	[2] Factor or Reference	[3] Budget Amounts 9/30/24	[4] Pro Forma Adjustments	[5] Pro Forma Tax Expense 9/30/24
1	PURTA Taxes	408.1		$ 45	$ 31	$ 76
2	Gross Receipts Tax	408.1	D-17	8,508	310	8,818
3	PA & Local Use taxes	408.1		22	-	22
4	Social Security	408.1	D-32	469	3	472
5	FUTA	408.1	D-32	31	-	31
6	SUTA	408.1	D-32	3	-	3
7	PUC Assessment	408.1		297	-	297
8	Total			$ 9,375	$ 344	$ 9,718

($ in Thousands)

Adjustment - Payroll Taxes

Line #	Description	[1] Account Number	[2] Test Year 9/30/24 Present Rates	[3] Pro Forma Adjustments	[4] Increase in Payroll Taxes
1	Total Payroll Charged to Expense		$ 6,163	$ 33	
2	FICA Expense		469		
3	FICA Expense - Percent	L 2 / L 1	7.61%	7.61%	
4	Pro Forma FICA Expense on Pro Forma S&W	[4] L 1 * L 3			$ 3
5	FUTA Expense		31		
6	FUTA Expense - Percent	L 5 / L 1	0.51%	0.51%	
7	Pro Forma FUTA Expense on Pro Forma S&W	[4] L 1 * L 6			-
8	SUTA Expense		3		
9	SUTA Expense - Percent	L 8 / L 1	0.05%	0.05%	
10	Pro Forma SUTA Expense on Pro Forma S&W	[4] L 1 * L 9			-
11	Pro Forma Adjustment	Sum L 4 to L 10			$ 3

($ in Thousands)

Income Tax Calculation

Line #	Description	[1] Factor Or Reference	[2] Element Or Amount	[3] Pro Forma Test Year At Present Rates	[4] Revenue Increase	[5] Pro Forma Test Year At Proposed Rates
						[3] + [4]
1	Revenue			$ 152,691	$ 11,425	$ 164,116
2	Operating Expenses			(145,378)	(926)	(146,304)
3	OIBIT	L 1 + L 2		7,313	10,499	17,812
	Interest Expense					
4	Rate Base	Sch A-1	172,242			
5	Weighted Cost of Debt	Sch B-7	0.01980			
6	Synchronized Interest Expense	L 4 * L 5		(3,410)	-	(3,410)
7	Base Taxable Income	L 3 + L 6		3,903	10,499	14,402
8	Total Tax Depreciation	Sch D-34	$ 18,229			
9	Pro Forma Book Depreciation	Sch D-34	8,957			
10	State Tax Depreciation (Over) Under Book	L 9 - L 8		(9,273)		(9,273)
11	Other				-	-
12	State Taxable Income	Sum L 7 to L 11		$ (5,369)	$ 10,499	$ 5,129
13	State Income Tax (Expense)/Refund	L 12 * Rate [2]	8.99%	$ 483	$ (944)	$ (461)
14	Total Tax Depreciation	Sch D-34	$ 17,308			
15	Pro Forma Book Depreciation	Sch D-34	8,957			
16	Federal Tax Deducts (Over) Under Book	L 14 - L 13		(8,351)	-	(8,351)
17	Other				-	-
18	Federal Taxable Income	L 7 + sum L 13 to L 17		(3,965)	9,555	5,590
19	Federal Income Tax (Expense)/Refund	-L 18 * Rate [2]	21.00%	833	(2,007)	(1,174)
20	Total Tax Expense before Deferred Income Tax	L 13 + L 19		1,316	(2,951)	(1,635)
	Deferred Federal Income Taxes					
21	Total Straight Line Tax Depreciation	Sch D-34	$ 8,218			
22	Total Tax Depreciation	Sch D-34	16,526			
23	Federal Tax Deducts (Over) Under Book	L 22 - L 21		8,308	-	8,308
24	Deferred Federal Taxable Income	L 23		$ 8,308	$ -	$ 8,308
25	Federal Income Tax (Expense)/Refund	-L 24 * Rate [2]	Blended Rate [1]	(1,483)	-	(1,483)
	Deferred State Income Taxes					
26	Repairs			(694)		(694)
27	CIAC			38		38
28	State Deferred Income Tax (Expense)/Refund			(656)	-	(656)
29	Net Income Tax Expense	L20 + L 25 + L28		(823)	(2,951)	(3,774)
	Other Tax Adjustments					
30	ITC			-		-
31	Combined Income Tax Expense	L 29 + L 30		$ (823)	$ (2,951)	$ (3,774)
32	Federal Income Tax Expense	L 19 + L 25 + L 30		$ (650)	$ (2,007)	$ (2,657)
33	State Income Tax Expense	L 13 + L 28		(173)	(944)	(1,117)
34	Total Income Tax Expense	L 32 + L 33		$ (823)	$ (2,951)	$ (3,774)

[1] Due to the 2018 Tax Cuts and Jobs Act, excess deferred income tax is now being flowed back to customers which results in a deferred tax rate other than 21%.

($ in Thousands)

Tax Depreciation

Line #	Description	[1] Amount	[2] Amount	[3] Total
	Accelerated Tax Depreciation			
1	Electric Plant		$ 6,585	
2	Cost of Removal		782	
3	Repairs Tax Deduction		10,966	
4	Other Tax Basis Adjustments		(1,026)	
5	Total Federal Accelerated Tax Depreciation			$ 17,308
6	Adjustment for PA Tax Depreciation - Bonus Decoupling		922	
7	Total State Accelerated Tax Depreciation			$18,229
	Straight Line Tax Depreciation			
8	Electric Plant		$ 8,218	
9	Total Tax Depreciation			$ 8,218
	Book Depreciation			
10	Pro Forma Book Depreciation		$ 8,218	
11	Net Salvage Amortization		857	
12	Depreciation Charged to Clearing Accounts	(479)		
13	Estimated Percent of Clearing Charged to CWIP	25%		
14	Depreciation Charged to CWIP		(118)	
15	Book Depreciation for Tax Calculation			$ 8,957

($ in Thousands)

Gross Revenue Conversion Factor

Line #	Description	[1] Reference Or Factor	[2] Tax Rate	[3] Factor
GROSS REVENUE CONVERSION FACTOR				
1	GROSS REVENUE FACTOR			1.000000
2	UNCOLLECTIBLE EXPENSES			(0.018380)
3	NET REVENUES	Sum L 1 to L 2		0.981620
4	GROSS RECEIPTS TAX	[3] L 3 * Rate [2]	6.27%	(0.062700)
5	FACTOR AFTER GROSS RECEIPTS TAX			0.918920
6	STATE INCOME TAXES	[3] L 5 * Rate [2]	8.99%	(0.082611)
7	FACTOR AFTER STATE TAXES	L 5 + L 6		0.836309
8	FEDERAL INCOME TAXES	[3] L 7 * Rate [2]	21.00%	(0.175625)
9	NET OPERATING INCOME FACTOR	L 7 + L 8		0.660684
10	GROSS REVENUE CONVERSION FACTOR	1 / L 9		1.513583
11	Combined Income Tax Factor On Gross Revenues	-L 6 - L 8		25.824%
INCOME TAX FACTOR				
12	GROSS REVENUE FACTOR			1.000000
13	STATE INCOME TAXES	[3] L 10 * Rate [2]	8.9900%	(0.089900)
14	FACTOR AFTER STATE TAXES	L 10 + L 11		0.910100
15	FEDERAL INCOME TAXES	[3] L 12 * Rate [2]	21.00%	(0.191121)
16	NET OPERATING INCOME FACTOR	L 12 + L 13		0.718979
17	GROSS REVENUE CONVERSION FACTOR	1 / L 14		1.390861
18	Combined Income Tax Factor On Taxable Income	-L 11 - L 13		28.102%

UGI ELECTRIC

EXHIBIT A

FUTURE

Future Period - 12 Months Ended September 30, 2023
($ in Thousands)
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SECTION D

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Summary of Measure of Value and Revenue Increase

Line #	Description	[1] Function	[2] Reference Section	[3] Pro Forma Test Year Ended September 30, 2023 At Present Rates	[4] Increase	[5] Proposed Rates
RATE BASE						
1	Utility Plant		C-2	$ 252,941		$ 252,941
2	Accumulated Depreciation		C-3	(80,496)		(80,496)
3	Net Plant in service	L 1 + L 2		172,445	-	172,445
4	Working Capital		C-4	11,102		11,102
5	Accumulated Deferred Income Taxes		C-6	(29,114)		(29,114)
6	Customer Deposits		C-7	(949)		(949)
7	Materials & Supplies		C-8	2,152		2,152
8	TOTAL RATE BASE	Sum L 3 to L 7		$ 155,636	$ -	$ 155,636
	Operating Revenues					
9	Base Customer Charges		D-5	$ 41,335	$ 10,171	$ 51,506
10	Other Electric Revenue		D-5	103,967		103,967
11	Other Operating Revenues		D-5	1,103		1,103
12	Total Revenues	Sum L 9 to L 11		146,405	10,171	156,576
13	Operating Expenses		D-1	(139,450)	(825)	(140,275)
14	OIBIT	L 12 + L 13		6,955	9,346	16,301
15	Pro Forma Income Tax at Present Rates		D-33	(807)		
16	Pro Forma Income Tax on Revenue Increase		D-33		(2,701)	(3,508)
17	NET OPERATING INCOME	Sum L 14 to L 16		$ 6,147	$ 6,646	$ 12,793
18	RATE OF RETURN	L 17 / L 8		3.950%		8.220%
REVENUE INCREASE REQUIRED						
19	Rate of Return at Present Rates	L 18, Col 3		3.950%		
20	Rate of Return Required		B-7	8.220%		
21	Change in ROR	L 20 - L 19		4.270%		
22	Change in Operating Income	L 21 * L 8		$ 6,646		
23	Gross Revenue Conversion Factor		D-35	1.530398		
24	Change in Revenues	L 22 * L 23		$ 10,171		
25	Percent Increase -- Delivery Revenues	L 24 / L 9, C 3			24.61%	
26	Percent Increase -- Total Revenues	L 24 / L 12, C 3			6.95%	

($ in Thousands)

Balance Sheet

Line No	Description/(Account No)	[1] Budget TYE 9-30-23
	UTILITY PLANT (101 - 106, 108)	
1	Electric Utility Plant	$ 339,863
2	Other Utility Plant	
3	Total Plant In Service	339,863
4	Construction Work In Progress (107)	8,000
5	Total Utility Plant	347,863
6	Accumulated Provision for Depreciation - Electric (108)	(110,643)
7	Utility Acquisition Adjustment (114)	390
8	Accumulated Provision for Depreciation - Other (119)	-
9	Net Utility Plant	237,610
	OTHER PROPERTY INVESTMENTS	
10	Non-utility Property (121)	15
11	Accumulated Depreciation on NUP (122)	-
12	Investment in Associated & Subsidiary Companies (123.1)	-
13	Other Investments (124)	-
14	Total Other Property and Investments	15
	CURRENT AND ACCRUED ASSETS	
15	Cash & Other Temporary Investments(131-136)	566
16	Unbilled Revenues	-
17	Customer Accounts Receivable (142)	20,984
18	Other Accounts Receivable (143)	570
19	Accum Provision for Uncollectible (144)	(2,518)
20	Receivables from Associated Companies (145)	-
21	Accounts Receivable Assoc. Comp. (146)	404
22	Plant Materials & Operating Supplies (154)	2,621
23	Allowance Inventory (158.1)	682
24	Stores Expense - Undistributed (163)	181
25	Prepayments (165)	2,182
26	Accrued Utility Revenues (173)	3,500
27	Miscellaneous Current & Accrued Assets (174)	1,400
28	Derivative Instrument Assets (175)	-
29	Total Current and Accrued Assets	30,572
	DEFERRED DEBITS	
30	Unamortized Debt Expense (181)	20
31	Other Regulatory Assets (182.3)	33,421
32	Other Preliminary Survey & Investigation Charges (183.2)	-
33	Clearing Accounts (184)	-
34	Miscellaneous Deferred Debits (186)	1,166
35	Unamortized Loss on Reacquired Debt (189)	-
36	Accumulated Deferred Income Taxes (190)	16,000
37	Total Deferred Debits	50,606
38	TOTAL ASSETS AND OTHER DEBITS	$ 318,803

($ in Thousands)

Balance Sheet

Line No	Description/(Account No)	[1] Budget TYE 9-30-23
	PROPRIETARY CAPITAL	
39	Common Stock Issued (201)	$ 6,453
40	Preferred Stock Issued (204)	-
41	Premium on Capital Stock (207)	50,720
42	Capital Stock Expense (214)	-
43	Retained Earnings (215, 215.2, 216)	76,516
44	Accum Other Comprehensive Income (219)	(1,586)
45	Total Proprietary Capital	132,103
	LONG TERM DEBT	
46	Bonds (221)	-
47	Advances from Associated Companies (223)	-
48	Other Long-Term Debt (224)	78,906
49	Unamortized Premium on LTD (225)	-
50	Unamortized Discount on LTD (226)	-
51	Total Long-term Debt	78,906
	OTHER NON-CURRENT LIABILITIES	
52	Obligations under Capital Leases (227)	-
53	Advances from Associated Companies (223)	-
54	Other Long-Term Debt (224)	-
55	Unamortized Premium on LTD (225)	-
56	Unamortized Discount on LTD (226)	-
57	Accumulated Provision for Pension & Benefits (228.3)	8,592
58	Total Non-Current Liabilities	8,592
	CURRENT & ACCRUED LIABILITIES	
59	Notes Payable (231)	13,881
60	Accounts Payable (232)	11,000
61	Notes Payable to Assoc. Companies (233)	-
62	Accounts Payable to Assoc. Cos (234)	1,000
63	Customer Deposits (235)	947
64	Taxes Accrued (236)	219
65	Interest Accrued (237)	705
66	Tax Collections Payable (241)	-
67	Accrued Interest on Other Liabilities (237)	2,600
68	Tax Collections Payable (241)	-
69	Misc Current & Accrued Liabilities (242)	-
70	Total Current & Accrued Liabilities	30,352
	OTHER DEFERRED CREDITS	
71	Customer Advances for Construction (252)	-
72	Other Deferred Credits (253)	450
73	Other Regulatory Liabilities (254)	28,000
74	Deferred ITC (255)	-
75	Accumulated Deferred Income Taxes (282)	40,400
76	Accumulated Deferred Income Taxes (283)	-
77	Total Other Deferred Credits	68,850
78	TOTAL LIABILITIES & OTHER CREDITS	$ 318,803

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Statement of Net Utility Operating Income

Line No	Description	[1] Budget TYE 9-30-23	[2] Reference
	Total Operating Revenues		
1	Total Sales Revenues	$ 140,116	B-3
2	Other Operating Revenues	1,103	B-3
3	Total Revenues	141,219	
	Total Operating Expenses		
4	Operation & Maintenance Expenses	117,186	B-4
5	Depreciation & Amortization Expense	8,411	D-3
6	Taxes Other Than Income Taxes	9,112	B-5
7	Total Operating Expenses	134,709	
8	Operating Income Before Income Taxes (OIBIT)	6,510	
	Income Taxes:		
9	State	245	B-5
10	Federal	562	B-5
11	Total Income Taxes	807	
12	**Net Utility Operating Income**	$ 5,703	

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Schedule B-3
Witness: T. A. Hazenstab

Statement of Operating Revenues

Line No	Description	Account No	[1] Budget TYE 9-30-23
	Electric Operating Revenues		
1	Residential	440	$ 110,330
2	Commercial & Industrial	442	29,018
3	Public Streets & Highway Lighting	444	734
4	Other Sales to Public Authorities	445	18
5	Sales for Resale	447	16
6	Sub-Total Electric Operating Revenues		140,116
	Other Operating Revenues		
7	Forfeited Discounts	450	$ 520
8	Miscellaneous Service Revenues	451	16
9	Rent from Electric Properties	454	567
10	Interest on Over/(Under) Collections	456.1	-
11	Sub-Total Other Operating Revenues		1,103
12	**Total Operating Revenues**		$ 141,219

($ in Thousands)

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-23
	Other Power Supply Expenses		
1	Purchased Power	555.0	$ 77,867
2	Power Purchased for Storage Operations	555.1	-
3	System Control and Load Dispatching	556.0	-
4	Other Expenses	557.0	-
5	Load Dispatch - Reliability	561.1	-
6	Transmission of Electricty by Others	565.0	5,847
7	Gross Receipts Tax	408.1	-
8	Total Other Power Supply Expenses		83,714
	Transmission Expenses - Operation		
9	Operation Supervision and Engineering	560.0	-
10	Load Dispatch - Reliability	561.0	-
11	Load Dispatch - Monitor and Operate Trans. System	561.2	-
12	Load Dispatch - Transmission Service & Scheduling	561.3	-
13	Scheduling, System Control & Dispatch Service	561.4	-
14	Reliability Planning & Standards Development	561.5	-
15	Transmission Service Studies	561.6	-
16	Generation Interconnection Studies	561.7	-
17	Reliability Planning & Standards Development Services	561.8	-
18	Station Expenses	562.0	-
19	Operation of Energy Storage Equipment	562.1	-
20	Overhead Line Expense	563.0	-
21	Underground Line Expenses	564.0	-
22	Transmission of Electricty by Others	565.0	-
23	Miscellaneous Transmission Expenses	566.0	-
24	Rents	567.0	-
25	Operation Supplies and Expenses	567.1	-
26	Total Transmission Expenses - Operation		-
	Transmission Expenses - Maintenance		
27	Maintenance Supervision and Engineering	568.0	-
28	Maintenance of Structures	569.0	-
29	Maintenance of Computer Hadware	569.1	-
30	Maintenance of Computer Software	569.2	-
31	Maintenance of Communication Equipment	569.3	-
32	Maintenance of Miscellaneous Regional Trans Plant	569.4	-
33	Maintenance of Station equipment	570.0	-
34	Maintenance of Energy Storage Equipment	570.1	-
35	Maintenance of Overhead Lines	571.0	-
36	Maintenance of Underground Lines	572.0	-
37	Maintenance of Miscellaneous Transmission Plant	573.0	-
38	Maintenance of Transmission Plant	574.0	-
39	Total Transmission Expenses - Maintenance		-

($ in Thousands)

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-23
	Regional Market Expenses - Operation		
40	Operation Supervision	575.1	-
41	Day-Ahead and Real-Time Market Administration	575.2	-
42	Transmission Rights Market Administration	575.3	-
43	Capacity Market Administration	575.4	-
44	Ancillary Market Administration	575.5	-
45	Market Monitoring and Compliance	575.6	-
46	Market Facilitation, Monitoring and Compliance Serv	575.7	-
47	Rents	575.8	-
48	Total Region Market Expenses - Operation		-
	Regional Market Expenses - Maintenance		
49	Maintenance of Structures and Improvements	576.1	-
50	Maintenance of Computer Hardware	576.2	-
51	Maintenance of Computer Software	576.3	-
52	Maintenance of Communication Equipment	576.4	-
53	Maintenance of Misc Market Operation Plant	576.5	-
54	Total Region Market Expenses - Maintenance		-
	Distribution Expense - Operation		
55	Operation Supervision and Engineering	580.0	590
56	Load Dispatching	581.0	535
57	Line and Station Expenses	581.1	-
58	Station Expenses	582.0	90
59	Overhead Line Expenses	583.0	277
60	Underground Line Expenses	584.0	39
61	Operation of Energy Storage Equipment	584.1	-
62	Street Lighting and Signal System Expenses	585.0	28
63	Meter Expenses	586.0	745
64	Customer Installation Expenses	587.0	74
65	Miscellaneous Distribution Expenses	588.0	329
66	Rents	589.0	50
67	Total Distribution Expenses - Operation		2,757
	Distribution Expense - Maintenance		
68	Maintenance Supervision and Engineering	590.0	210
69	Maintenance of Structures	591.0	-
70	Maintenance of Station Equipment	592.0	196
71	Maintenance of Pipe Lines	592.1	-
72	Maintenance of Structures and Equipment	592.2	-
73	Maintenance of Overhead Lines	593.0	9,082
74	Maintenance of Underground Lines	594.0	57
75	Maintenance of Lines	594.1	-
76	Maintenance of Line Transformers	595.0	76
77	Maintenance of Street Lighting and Signal Systems	596.0	23
78	Maintenance of Meters	597.0	14
79	Maintenance of Miscellaneous Distribution Plant	598.0	21
80	Total Distribution Expenses - Maintenance		9,679
	Customer Accounts Expense - Operation		
81	Supervision	901.0	86
82	Meter Reading Expenses	902.0	207
83	Customer Records and Collection Expenses (USP)	903.0	8,754
84	Uncollectible Accounts	904.0	2,508
85	Miscellaneous Customer Accounts Expenses	905.0	67
86	Total Customer Accounts Expense - Operation		11,622

($ in Thousands)

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-23
	Customer Service & Information Expense		
87	Customer Service and Informational Expenses	906.0	-
88	Supervision	907.0	16
89	Customer Assistance Expenses	908.0	11
90	Information and Instructional Advertising Expenses	909.0	-
91	Miscellaneous Customer Service & Informational Exps (EEC)	910.0	1,412
92	Total Customer Service & Informational Exps - Operations		1,439
	Sales Expense - Operation		
93	Supervision	911.0	-
94	Demonstrating and Selling Expenses	912.0	5
95	Advertising Expenses	913.0	-
96	Miscellaneous Sales Expenses	916.0	(5)
97	Sales Expenses	917.0	-
98	Total Sales Expenses - Operation		-
	Administrative & General - Operations		
99	Administrative and General Salaries	920.0	2,716
100	Office Supplies and Expenses	921.0	1,669
101	Administrative Expenses Transferred - Credit	922.0	-
102	Outside Services Employed	923.0	1,864
103	Property Insurance	924.0	60
104	Injuries and Damages	925.0	302
105	Employee Pensions and Benefits	926.0	745
106	Franchise Requirements	927.0	-
107	Regulatory Commission Expenses	928.0	385
108	Duplicate Charges - Credit	929.0	(63)
109	General Advertising Expenses	930.1	67
110	Miscellaneous General Expenses	930.2	243
111	Rents	931.0	2
112	Transportation Expenses	933.0	-
113	Total Administrative and General Expenses - Operation		7,990
	Administrative & General - Maintenance		
114	Maintenance of General Plant	935.0	(15)
115	Total Administrative and General Expenses - Maintenance		(15)
116	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 117,186
117	Total Electric Operation Expenses		107,522
118	Total Electric Maintenance Expense		9,664
119	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 117,186

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Schedule B-5
Witness: T. A. Hazenstab

Detail of Taxes

Line No	Description	Reference	[1] Budget TYE 9-30-23
	Taxes Other Than Income Taxes		
	Non-revenue related:		
1	Pennsylvania - PURTA	D-31	$ 45
2	Gross Receipts Tax	D-31	8,267
3	PA and Local Use taxes	D-31	21
4	PUC Assessment	D-31	297
5	Subtotal		8,629
6	Payroll Taxes		
7	Social Security	D-31	448
8	SUTA	D-31	3
9	FUTA	D-31	31
10	Other		-
11	Subtotal		483
12	Total Taxes Other Than Income Taxes		$ 9,112
	Income Taxes		
13	State	D-33	$ 245
14	Federal	D-33	562
15	Total Income Taxes		$ 807

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Composite Cost of Debt

Line No	Series	[1] Issue Date	[2] Maturity Date	[3] Amount Outstanding	[4] Percent to Total	[5] Effective Interest Rate	[6] Average Weighted Cost Rate [4] * [5]
Medium Term Notes							
1	6.500%	8/14/2003	8/15/2033	$ 20,000	1.38%	6.56%	0.09%
2	6.133%	10/14/2004	10/15/2034	20,000	1.38%	6.19%	0.09%
Senior Unsecured Notes							
3	6.206%	9/15/2006	9/30/2036	100,000	6.88%	6.32%	0.43%
4	4.980%	3/26/2014	3/26/2044	175,000	12.04%	5.00%	0.60%
5	2.950%	6/30/2016	6/30/2026	100,000	6.88%	3.92%	0.27%
6	4.120%	9/30/2016	9/30/2046	200,000	13.75%	5.01%	0.69%
7	4.120%	10/31/2016	10/31/2046	100,000	6.88%	4.28%	0.29%
8	4.550%	2/1/2019	2/1/2049	150,000	10.32%	4.58%	0.47%
9	3.120%	3/19/2020	4/16/2050	150,000	10.32%	3.15%	0.32%
10	1.590%	6/15/2021	6/15/2026	100,000	6.88%	1.73%	0.12%
11	1.640%	9/15/2021	9/15/2026	75,000	5.16%	1.75%	0.09%
12	3.917%	7/12/2022	7/12/2027	89,063	6.13%	4.00%	0.25%
13	4.750%	7/15/2022	7/15/2032	90,000	6.19%	4.83%	0.30%
14	4.990%	9/15/2022	9/15/2052	85,000	5.85%	5.02%	0.29%
14	Total Long-Term Debt			$ 1,454,063	100.00%		4.30%
15	Total Long-Term Debt			$ 1,454,063	100.00%	4.30%	4.30%
16	Total Short-Term Debt			-	0.00%		0.00%
17	TOTAL			$ 1,454,063	100.00%		
18	Weighted Cost of Debt						4.30%

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Rate of Return

Line No	Description	[1] Capitalization Ratio	[2] Embedded Cost	[3] Statement Reference	[4] Return-%
1	Long-Term Debt	43.97%	4.30%	B-6	1.89%
2	Short-Term Debt	0.00%	0.00%	B-6	0.00%
3	Common Equity	56.03%	11.30%		6.33%
4	Total	100.00%			8.22%

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Schedule C-1
Witness: V. K. Ressler
Page 1 of 1

Measure of Value

		[1]	[2]	[3]	[4]	[5]
		Reference		Pro Forma Test Year Ended September 30, 2023 At		
Line #	Description	Fully Projected	# of Pages	Present Rates	Adjustments	Proposed Rates
	MEASURE OF VALUE					
1	Utility Plant	C-2	5	$ 252,941		$ 252,941
2	Accumulated Depreciation	C-3	6	(80,496)		(80,496)
3	Net Plant in service			172,445	-	172,445
4	Working Capital	C-4	9	11,102		11,102
5	Accumulated Deferred Income Taxes	C-6	1	(29,114)		(29,114)
6	Customer Deposits	C-7	1	(949)		(949)
7	Materials & Supplies	C-8	1	2,152		2,152
8	TOTAL MEASURE OF VALUE			$ 155,636	$ -	$ 155,636

($ in Thousands)

Pro Forma Electric Plant in Service

Line No	Description	[1] Account No	[2] Pro Forma 9/30/2023
	INTANGIBLE PLANT		
1	Organization	301	$ 11
2	Franchise & Consent	302	5
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		16
	TRANSMISSION PLANT		
5	Land & Land Rights	350	$ -
6	Structures & Improvements	352	-
7	Station Equipment	353	-
8	Station Equipment - SCADA	353.2	-
9	Towers and Fixtures	354	-
10	Poles and Fixtures	355	-
11	Overhead Conductors and Devices	356	-
12	Underground Conduit	357	-
13	Underground Conductors and Devices	358	-
14	Roads and Trails	359	-
15	TOTAL TRANSMISSION		-
	DISTRIBUTION PLANT		
16	Land & Land Rights	360	313
17	Structures & Improvements	361	627
18	Station Equipment	362	11,263
19	Storage Battery Equipment	363	-
20	Poles, Towers and Fixtures	364	55,047
21	Overhead Conductors and Devices	365	68,846
22	Underground Conduit	366	8,780
23	Underground Conductors and Devices	367	15,051
24	Transformers	368.1	18,263
25	Transformer Installations	368.2	11,219
26	Services	369	16,224
27	Meters	370.1	2,978
28	Meter Installations	370.2	1,980
29	Electronic Meters	370.3	5,038
30	Installations on Customers' Premises	371.0	2,219
31	Installations on Customers' Premises - EV Charging Stations	371.1	-
32	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	348
33	Leased Property on Customers' Premises	372	-
34	Street Lighting and Signal Systems	373	2,471
35	TOTAL DISTRIBUTION		220,667
	GENERAL & COMMON PLANT		
36	Land & Land Rights	389	659
37	Structures & Improvements	390	8,723
38	Office Furniture & Equipment	391	18,096
39	Transportation Equipment	392	1,826
40	Stores Equipment	393	11
41	Tools & Garage Equipment	394	1,156
42	Laboratory Equipment	395	55
43	Power Operated Equipment	396	598
44	Communication Equipment	397	692
45	Miscellaneous Equipment	398	442
46	Other Tangible Property	399	-
47	TOTAL GENERAL & COMMON PLANT		32,258
48	Total Plant		$ 252,941

($ in Thousands)

Pro Forma Plant Adjustment Summary

Line #	Description	[1] Factor Or Reference	[2] Test Year 9/30/23 Budget	[3] Adjustments	[4] Pro Forma Test Year [2] + [3]
1	Intangible Plant	Sch C-2, Page 3	$ 16	$ -	$ 16
2	Transmission Plant	Sch C-2, Page 3	-	-	-
3	Distribution Plant	Sch C-2, Page 3	220,667	-	220,667
4	General & Common Plant	Sch C-2, Page 3	32,256	2	32,258
5	Other Plant		-	-	-
6	Total Utility Plant		$ 252,939	$ 2	$ 252,941

($ in Thousands)

Pro Forma Year End Plant Balances

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2022	[3] Year Ended September 30, 2023	[4] Pro Forma Adjustment	[5] Balance
	INTANGIBLE PLANT					
1	Organization	301	$ 11	$ 11	$ -	$ 11
2	Franchise & Consent	302	5	5	-	5
3	Miscellaneous Intangible Plant	303	-	-	-	-
4	TOTAL INTANGIBLE		16	16	-	16
	TRANSMISSION PLANT					
5	Land & Land Rights	350	-	-	-	-
6	Structures & Improvements	352	-	-	-	-
7	Station Equipment	353	-	-	-	-
8	Station Equipment - SCADA	353.2	-	-	-	-
9	Towers and Fixtures	354	-	-	-	-
10	Poles and Fixtures	355	-	-	-	-
11	Overhead Conductors and Devices	356	-	-	-	-
12	Underground Conduit	357	-	-	-	-
13	Underground Conductors and Devices	358	-	-	-	-
14	Roads and Trails	359	-	-	-	-
15	TOTAL TRANSMISSION		-	-	-	-
	DISTRIBUTION PLANT					
16	Land & Land Rights	360	308	313	-	313
17	Structures & Improvements	361	627	627	-	627
18	Station Equipment	362	10,981	11,263	-	11,263
19	Storage Battery Equipment	363	-	-	-	-
20	Poles, Towers and Fixtures	364	54,077	55,047	-	55,047
21	Overhead Conductors and Devices	365	53,884	68,846	-	68,846
22	Underground Conduit	366	8,780	8,780	-	8,780
23	Underground Conductors and Devices	367	14,750	15,051	-	15,051
24	Transformers	368.1	16,660	18,263	-	18,263
25	Transformer Installations	368.2	11,198	11,219	-	11,219
26	Services	369	15,753	16,224	-	16,224
27	Meters	370.1	2,950	2,978	-	2,978
28	Meter Installations	370.2	1,972	1,980	-	1,980
29	Electronic Meters	370.3	5,038	5,038	-	5,038
30	Installations on Customers' Premises	371	2,219	2,219	-	2,219
31	Installations on Customers' Premises - EV Charging Stations	371.1	-	-	-	-
32	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	348	348	-	348
33	Leased Property on Customers' Premises	372	-	-	-	-
34	Street Lighting and Signal Systems	373	2,332	2,471	-	2,471
35	TOTAL DISTRIBUTION		201,877	220,667	-	220,667
	GENERAL & COMMON PLANT					
36	Land & Land Rights	389	659	659	-	659
37	Structures & Improvements	390	7,632	8,723	-	8,723
38	Office Furniture & Equipment	391	19,279	18,096	-	18,096
39	Transportation Equipment	392	1,633	1,826	-	1,826
40	Stores Equipment	393	11	11	-	11
41	Tools & Garage Equipment	394	1,215	1,156	-	1,156
42	Laboratory Equipment	395	73	55	-	55
43	Power Operated Equipment	396	131	598	-	598
44	Communication Equipment	397	761	692	-	692
45	Miscellaneous Equipment	398	305	440	2	442
46	Other Tangible Property	399	-	-	-	-
47	TOTAL GENERAL & COMMON PLANT		31,699	32,256	2	32,258
48	Total Plant		$ 233,592	$ 252,939	$ 2	$ 252,941

($ in Thousands)

Additions to Plant

Line #	Description	[1] Account Number	[2] Year ended September 30, 2022	[3] Year ended September 30, 2023
	Plant Additions			
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	TRANSMISSION PLANT			
5	Land & Land Rights	350	-	-
6	Structures & Improvements	352	-	-
7	Station Equipment	353	-	-
8	Station Equipment - SCADA	353.2	-	-
9	Towers and Fixtures	354	-	-
10	Poles and Fixtures	355	-	-
11	Overhead Conductors and Devices	356	-	-
12	Underground Conduit	357	-	-
13	Underground Conductors and Devices	358	-	-
14	Roads and Trails	359	-	-
15	TOTAL TRANSMISSION		-	-
	DISTRIBUTION PLANT			
16	Land & Land Rights	360	-	5
17	Structures & Improvements	361	120	-
18	Station Equipment	362	3,660	285
19	Storage Battery Equipment	363	-	-
20	Poles, Towers and Fixtures	364	3,521	1,023
21	Overhead Conductors and Devices	365	5,321	15,749
22	Underground Conduit	366	132	-
23	Underground Conductors and Devices	367	1,345	316
24	Transformers	368.1	1,104	1,850
25	Transformer Installations	368.2	289	23
26	Services	369	537	496
27	Meters	370.1	-	96
28	Meter Installations	370.2	25	11
29	Electronic Meters	370.3	230	-
30	Installations on Customers' Premises	371	107	-
31	Installations on Customers' Premises - EV Charging Stations	371.1	-	-
32	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-	-
33	Leased Property on Customers' Premises	372	-	-
34	Street Lighting and Signal Systems	373	145	169
35	TOTAL DISTRIBUTION		16,537	20,023
	GENERAL & COMMON PLANT			
36	Land & Land Rights	389	-	-
37	Structures & Improvements	390	1,445	1,280
38	Office Furniture & Equipment	391	3,294	1,123
39	Transportation Equipment	392	829	193
40	Stores Equipment	393	-	-
41	Tools & Garage Equipment	394	45	-
42	Laboratory Equipment	395	(50)	-
43	Power Operated Equipment	396	60	467
44	Communication Equipment	397	320	-
45	Miscellaneous Equipment	398	138	135
46	Other Tangible Property	399	-	-
47	TOTAL GENERAL & COMMON PLANT		6,080	3,198
48	Total Additions		$ 22,617	$ 23,221

($ in Thousands)

Retirements

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2022	[3] 2023
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	TRANSMISSION PLANT			
5	Land & Land Rights	350	-	-
6	Structures & Improvements	352	-	-
7	Station Equipment	353	-	-
8	Station Equipment - SCADA	353.2	-	-
9	Towers and Fixtures	354	-	-
10	Poles and Fixtures	355	-	-
11	Overhead Conductors and Devices	356	-	-
12	Underground Conduit	357	-	-
13	Underground Conductors and Devices	358	-	-
14	Roads and Trails	359	-	-
15	TOTAL TRANSMISSION		-	-
	DISTRIBUTION PLANT			
16	Land & Land Rights	360	-	-
17	Structures & Improvements	361	-	-
18	Station Equipment	362	-	3
19	Storage Battery Equipment	363	-	-
20	Poles, Towers and Fixtures	364	277	53
21	Overhead Conductors and Devices	365	133	787
22	Underground Conduit	366	2	-
23	Underground Conductors and Devices	367	25	15
24	Transformers	368.1	525	247
25	Transformer Installations	368.2	95	2
26	Services	369	2	25
27	Meters	370.1	28	68
28	Meter Installations	370.2	3	3
29	Electronic Meters	370.3	21	-
30	Installations on Customers' Premises	371	42	-
31	Installations on Customers' Premises - EV Charging Stations	371.1	-	-
32	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-	-
33	Leased Property on Customers' Premises	372	-	-
34	Street Lighting and Signal Systems	373	70	30
35	TOTAL DISTRIBUTION		1,225	1,233
	GENERAL & COMMON PLANT			
36	Land & Land Rights	389	-	-
37	Structures & Improvements	390	-	189
38	Office Furniture & Equipment	391	323	2,306
39	Transportation Equipment	392	-	-
40	Stores Equipment	393	-	-
41	Tools & Garage Equipment	394	1	59
42	Laboratory Equipment	395	13	18
43	Power Operated Equipment	396	-	-
44	Communication Equipment	397	136	69
45	Miscellaneous Equipment	398	-	-
46	Other Tangible Property	399	-	-
47	TOTAL GENERAL & COMMON PLANT		473	2,641
48	Total Retirements		$ 1,698	$ 3,874

($ in Thousands)

Accumulated Provision for Depreciation

Line No	Description	[1] Account Number	[2] Pro Forma 9/30/2023
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	TRANSMISSION PLANT		
5	Land & Land Rights	350	-
6	Structures & Improvements	352	-
7	Station Equipment	353	-
8	Station Equipment - SCADA	353.2	-
9	Towers and Fixtures	354	-
10	Poles and Fixtures	355	-
11	Overhead Conductors and Devices	356	-
12	Underground Conduit	357	-
13	Underground Conductors and Devices	358	-
14	Roads and Trails	359	-
15	TOTAL TRANSMISSION		-
	DISTRIBUTION PLANT		
16	Land & Land Rights	360	-
17	Structures & Improvements	361	52
18	Station Equipment	362	1,177
19	Storage Battery Equipment	363	-
20	Poles, Towers and Fixtures	364	16,932
21	Overhead Conductors and Devices	365	13,966
22	Regulatory AFUDC	365.7	(99)
23	Underground Conduit	366	2,552
24	Underground Conductors and Devices	367	4,511
25	Transformers	368.1	8,139
26	Transformer Installations	368.2	6,451
27	Services	369	7,799
28	Meters	370.1	2,055
29	Meter Installations	370.2	802
30	Electronic Meters	370.3	4,148
31	Installations on Customers' Premises	371	988
32	Installations on Customers' Premises - EV Charging Stations	371.1	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	336
34	Leased Property on Customers' Premises	372	-
35	Street Lighting and Signal Systems	373	1,058
36	TOTAL DISTRIBUTION		70,868
	GENERAL & COMMON PLANT		
37	Land & Land Rights	389	11
38	Structures & Improvements	390	2,100
39	Office Furniture & Equipment	391	6,239
40	Transportation Equipment	392	415
41	Stores Equipment	393	4
42	Tools & Garage Equipment	394	463
43	Laboratory Equipment	395	46
44	Power Operated Equipment	396	34
45	Communication Equipment	397	222
46	Miscellaneous Equipment	398	95
47	Other Tangible Property	399	-
48	TOTAL GENERAL & COMMON PLANT		9,628
49	Total Accumulated Provision for Depreciation		$ 80,496

Summary of Accumulated Depreciation

		[1]	[2]	[3]	[4]
		Factor	Test Year Ended September 30, 2023		
Line #	Description	Or Reference	Amount	Pro Forma Adjustment	Balance
1	Intangible Plant	Sch C-3, Pg 3	$ -	$ -	$ -
2	Transmission Plant	Sch C-3, Pg 3	-	-	-
3	Distribution Plant	Sch C-3, Pg 3	70,868	-	70,868
4	General & Common Plant	Sch C-3, Pg 3	9,628	-	9,628
5	Other Plant		-	-	-
6	TOTAL ACC DEPR & AMORTIZATION		$ 80,496	$ -	$ 80,496

($ in Thousands)

Accumulated Depreciation by FERC Account

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2022	[3] Year Ended September 30, 2023	[4] Pro Forma Adjustment	[5] Balance
	INTANGIBLE PLANT					
1	Organization	301	$ -	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-	-
4	TOTAL INTANGIBLE		-	-	-	-
	TRANSMISSION PLANT					
5	Land & Land Rights	350	-	-	-	-
6	Structures & Improvements	352	-	-	-	-
7	Station Equipment	353	-	-	-	-
8	Station Equipment - SCADA	353.2	-	-	-	-
9	Towers and Fixtures	354	-	-	-	-
10	Poles and Fixtures	355	-	-	-	-
11	Overhead Conductors and Devices	356	-	-	-	-
12	Underground Conduit	357	-	-	-	-
13	Underground Conductors and Devices	358	-	-	-	-
14	Roads and Trails	359	-	-	-	-
15	TOTAL TRANSMISSION		-	-	-	-
	DISTRIBUTION PLANT					
16	Land & Land Rights	360	-	-	-	-
17	Structures & Improvements	361	36	52	-	52
18	Station Equipment	362	797	1,177	-	1,177
19	Storage Battery Equipment	363	-	-	-	-
20	Poles, Towers and Fixtures	364	15,595	16,932	-	16,932
21	Overhead Conductors and Devices	365	14,111	13,966	-	13,966
22	Regulatory AFUDC	365.7	(83)	(99)	-	(99)
23	Underground Conduit	366	2,410	2,552	-	2,552
24	Underground Conductors and Devices	367	4,072	4,511	-	4,511
25	Transformers	368.1	8,046	8,139	-	8,139
26	Transformer Installations	368.2	6,196	6,451	-	6,451
27	Services	369	7,528	7,799	-	7,799
28	Meters	370.1	2,073	2,055	-	2,055
29	Meter Installations	370.2	778	802	-	802
30	Electronic Meters	370.3	4,010	4,148	-	4,148
31	Installations on Customers' Premises	371	874	988	-	988
32	Installations on Customers' Premises - EV Charging Stations	371.1	-	-	-	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	335	336	-	336
34	Leased Property on Customers' Premises	372	-	-	-	-
35	Street Lighting and Signal Systems	373	981	1,058	-	1,058
36	TOTAL DISTRIBUTION		67,758	70,868	-	70,868
	GENERAL & COMMON PLANT					
37	Land & Land Rights	389	11	11	-	11
38	Structures & Improvements	390	1,939	2,100	-	2,100
39	Office Furniture & Equipment	391	6,586	6,239	-	6,239
40	Transportation Equipment	392	229	415	-	415
41	Stores Equipment	393	3	4	-	4
42	Tools & Garage Equipment	394	458	463	-	463
43	Laboratory Equipment	395	62	46	-	46
44	Power Operated Equipment	396	5	34	-	34
45	Communication Equipment	397	113	222	-	222
46	Miscellaneous Equipment	398	39	95	-	95
47	Other Tangible Property	399	-	-	-	-
48	TOTAL GENERAL & COMMON PLANT		9,444	9,628	-	9,628
49	Total Accumulated Provision for Depreciation		$ 77,202	$ 80,496	$ -	$ 80,496

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Cost of Removal

		[1]	[2]	[3]
Line #	Description	Account Number	Year Ended September 30, 2022	2023
INTANGIBLE PLANT				
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
TRANSMISSION PLANT				
5	Land & Land Rights	350	-	-
6	Structures & Improvements	352	-	-
7	Station Equipment	353	-	-
8	Station Equipment - SCADA	353.2	-	-
9	Towers and Fixtures	354	-	-
10	Poles and Fixtures	355	-	-
11	Overhead Conductors and Devices	356	-	-
12	Underground Conduit	357	-	-
13	Underground Conductors and Devices	358	-	-
14	Roads and Trails	359	-	-
15	TOTAL TRANSMISSION		-	-
DISTRIBUTION PLANT				
16	Land & Land Rights	360	-	-
17	Structures & Improvements	361	1	-
18	Station Equipment	362	9	0
19	Storage Battery Equipment	363	-	-
20	Poles, Towers and Fixtures	364	441	80
21	Overhead Conductors and Devices	365	139	787
22	Regulatory AFUDC	365.7	-	-
23	Underground Conduit	366	1	-
24	Underground Conductors and Devices	367	16	3
25	Transformers	368.1	8	14
26	Transformer Installations	368.2	34	1
27	Services	369	40	43
28	Meters	370.1	(68)	-
29	Meter Installations	370.2	3	2
30	Electronic Meters	370.3	2	-
31	Installations on Customers' Premises	371	33	-
32	Installations on Customers' Premises - EV Charging Stations	371.1	-	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-	-
34	Leased Property on Customers' Premises	372	-	-
35	Street Lighting and Signal Systems	373	28	15
36	TOTAL DISTRIBUTION		687	946
GENERAL & COMMON PLANT				
37	Land & Land Rights	389	-	-
38	Structures & Improvements	390	0	-
39	Office Furniture & Equipment	391	-	-
40	Transportation Equipment	392	1	-
41	Stores Equipment	393	-	-
42	Tools & Garage Equipment	394	-	-
43	Laboratory Equipment	395	-	-
44	Power Operated Equipment	396	-	-
45	Communication Equipment	397	-	-
46	Miscellaneous Equipment	398	23	-
47	Other Tangible Property	399	-	-
48	TOTAL GENERAL & COMMON PLANT		24	-
49	Total Cost of Removal		$ 711	$ 946

($ in Thousands)

Negative Net Salvage Amortization

		[1]	[2]	[3]
Line #	Description	Account Number	Year Ended September 30, 2022	2023
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	TRANSMISSION PLANT			
5	Land & Land Rights	350	-	-
6	Structures & Improvements	352	-	-
7	Station Equipment	353	-	-
8	Station Equipment - SCADA	353.2	-	-
9	Towers and Fixtures	354	-	-
10	Poles and Fixtures	355	-	-
11	Overhead Conductors and Devices	356	-	-
12	Underground Conduit	357	-	-
13	Underground Conductors and Devices	358	-	-
14	Roads and Trails	359	-	-
15	TOTAL TRANSMISSION		-	-
	DISTRIBUTION PLANT			
16	Land & Land Rights	360	-	-
17	Structures & Improvements	361	0	0
18	Station Equipment	362	14	9
19	Storage Battery Equipment	363	-	-
20	Poles, Towers and Fixtures	364	434	405
21	Overhead Conductors and Devices	365	108	255
22	Regulatory AFUDC	365.7	-	-
23	Underground Conduit	366	4	3
24	Underground Conductors and Devices	367	13	12
25	Transformers	368.1	6	6
26	Transformer Installations	368.2	36	27
27	Services	369	71	65
28	Meters	370.1	(41)	(49)
29	Meter Installations	370.2	4	4
30	Electronic Meters	370.3	0	0
31	Installations on Customers' Premises	371	18	16
32	Installations on Customers' Premises - EV Charging Stations	371.1	-	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-	-
34	Leased Property on Customers' Premises	372	-	-
35	Street Lighting and Signal Systems	373	16	17
36	TOTAL DISTRIBUTION		684	772
	GENERAL & COMMON PLANT			
37	Land & Land Rights	389	-	-
38	Structures & Improvements	390	0	0
39	Office Furniture & Equipment	391	-	-
40	Transportation Equipment	392	(2)	(2)
41	Stores Equipment	393	-	-
42	Tools & Garage Equipment	394	-	-
43	Laboratory Equipment	395	-	-
44	Power Operated Equipment	396	-	-
45	Communication Equipment	397	0	0
46	Miscellaneous Equipment	398	6	6
47	Other Tangible Property	399	-	-
48	TOTAL GENERAL & COMMON PLANT		4	4
49	Total Negative Net Salvage Amortization		$ 688	$ 776

($ in Thousands)

Salvage

		[1]	[2]	[3]
Line #	Description	Account Number	Year Ended September 30, 2022	2023
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	TRANSMISSION PLANT			
5	Land & Land Rights	350	-	-
6	Structures & Improvements	352	-	-
7	Station Equipment	353	-	-
8	Station Equipment - SCADA	353.2	-	-
9	Towers and Fixtures	354	-	-
10	Poles and Fixtures	355	-	-
11	Overhead Conductors and Devices	356	-	-
12	Underground Conduit	357	-	-
13	Underground Conductors and Devices	358	-	-
14	Roads and Trails	359	-	-
15	TOTAL TRANSMISSION		-	-
	DISTRIBUTION PLANT			
16	Land & Land Rights	360	-	-
17	Structures & Improvements	361	-	-
18	Station Equipment	362	-	(0)
19	Storage Battery Equipment	363	-	-
20	Poles, Towers and Fixtures	364	-	-
21	Overhead Conductors and Devices	365	-	-
22	Regulatory AFUDC	365.7	-	-
23	Underground Conduit	366	-	-
24	Underground Conductors and Devices	367	-	-
25	Transformers	368.1	-	-
26	Transformer Installations	368.2	-	-
27	Services	369	-	-
28	Meters	370.1	-	(39)
29	Meter Installations	370.2	-	-
30	Electronic Meters	370.3	-	-
31	Installations on Customers' Premises	371	-	-
32	Installations on Customers' Premises - EV Charging Stations	371.1	-	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-	-
34	Leased Property on Customers' Premises	372	-	-
35	Street Lighting and Signal Systems	373	-	-
36	TOTAL DISTRIBUTION		-	(39)
	GENERAL & COMMON PLANT			
37	Land & Land Rights	389	-	-
38	Structures & Improvements	390	-	-
39	Office Furniture & Equipment	391	-	-
40	Transportation Equipment	392	-	-
41	Stores Equipment	393	-	-
42	Tools & Garage Equipment	394	-	-
43	Laboratory Equipment	395	-	-
44	Power Operated Equipment	396	-	-
45	Communication Equipment	397	-	-
46	Miscellaneous Equipment	398	-	-
47	Other Tangible Property	399	-	-
48	TOTAL GENERAL & COMMON PLANT		-	-
49	Total Salvage		$ -	$ (39)

Working Capital

		[1]	[2]
Line No	Description	Future 9/30/2023	Reference
1	Working Capital for O & M Expense	$ 9,082	C-4, Page 2
2	Interest Payments	(255)	C-4, Page 7
3	Tax Payment Lag Calculations	244	C-4, Page 8
4	Prepaid Expenses	2,032	C-4, Page 9
5	Total Cash Working Capital Requirements	$ 11,102	

($ in Thousands)

Summary of Working Capital

Line #	Description	Reference [1]	Test Year Expenses [2]	Factor [3]	Number of (Lead) / Lag Days [4] [2] * [3]	Totals [5]
	WORKING CAPITAL REQUIREMENT					
1	REVENUE LAG DAYS	Page 3				59.56
2	EXPENSE LAG DAYS	Page 4				
3	Payroll	Sch D-7	$ 5,929	12.00	$ 71,150	
4	Purchased Power Costs	Sch D-6	88,130	33.30	2,934,333	
5	Other Expenses	L 19 - L 2 to L 4	25,052	30.76	770,599	
6	Total	Sum (L 3 to L 5)	$ 119,111		$ 3,776,082	
7	O & M Expense Lag Days	L6, C 4 / C 2				31.70
8	Net (Lead) Lag Days	L 1 - L 7				27.86
9	Operating Expenses Per Day	L 6, C 2 / 365				$ 326
10	Working Capital for O & M Expense	L 8 * L 9				$ 9,082
11	Interest Payments	Page 7				(255)
12	Tax Payment Lag Calculations	Page 8				244
13	Prepaid Expenses	Page 9				2,032
14	Total Working Capital Requirement	Sum (L 10 to L 13)				$ 11,102
15	Pro Forma O & M Expense		$ 122,130			
	Less:					
16	Uncollectible Expense		3,018			
17	Sub-Total		3,018			
18	Pro Forma Cash O&M Expense		$ 119,111			

($ in Thousands)

Revenue Lag

Line No.	Description	[1] Reference Or Factor	[2] Accounts Receivable Balance End of Month	[3] Total Monthly Sales	[4] A/R Turnover	[5] Days Lag
				Page 2	[3] / [2]	365 / [4]
1	Annual Number of Days					365
2	September, 2021		$ 11,849			
3	October		11,097	6,197		
4	November		9,723	7,951		
5	December, 2021		11,433	10,929		
6	January, 2022		14,407	12,474		
7	February		15,705	11,066		
8	March		16,494	10,190		
9	April		15,957	8,623		
10	May		14,986	8,280		
11	June		15,976	10,966		
12	July		17,542	14,900		
13	August		19,220	13,886		
14	September, 2022		18,672	9,911		
15	Total	Sum L 2 to L 14	$193,061			
16	Number of Months	13				
17	Average Acct Rec Balance	L 15 / L 16	$14,851			
18	Total Sales for Year	Sum L 3 to L 14		$ 125,373		
19	Acct Rec Turnover Ratio	L 18 / L 17			8.44	
20	Collection Lag Day Factor	L 1 / L 19				43.25
21	Meter Read Lag Factor					1.10
22	Midpoint Lag Factor		365 /	12 /	2 =	15.21
23	Total Revenue Lag Days	Sum L 20 to L 22				**59.56**

($ in Thousands)

Summary of Expense Lag Calculations

Line No.	Description	[1] Reference Or Factor	[2] Amount	[3] (Lead) / Lag Days	[4] Weighted Dollar Value [2] * [3]	[5] (Lead) / Lag Days [4] / [2]
PAYROLL						
1	Union Payrolls	Bi-Weekly	$ 1,264	12.00		
2	Exempt & Non-Exempt	Bi-Weekly	4,665	12.00		
3	Weighted for Union	L1, C2 * C3			$ 15,173	
4	Weighted for Other	L2, C2 * C3			55,977	
5	Payroll Lag	L 3 + L 4	$ 5,929		$ 71,150	
6	Payroll Lag Days	C 4 / C 2				12.00
PURCHASE POWER COSTS						
7	Payment Lag	Page 6	$ 62,613		$ 2,084,738	
8	Power Cost Lag Days	C 4 / C 2				33.30
OTHER O & M EXPENSES						
9	OCTOBER 2021	Page 5	$ 767		$ 15,119	
10	NOVEMBER 2021	Page 5	845		31,591	
11	DECEMBER 2021	Page 5	720		29,343	
12	JANUARY 2022	Page 5	1,005		31,292	
13	FEBRUARY 2022	Page 5	797		24,522	
14	MARCH 2022	Page 5	719		17,478	
15	APRIL 2022	Page 5	573		11,770	
16	MAY 2022	Page 5	613		16,801	
17	JUNE 2022	Page 5	1,218		27,473	
18	JULY 2022	Page 5	931		20,148	
19	AUGUST 2022	Page 5	1,314		46,926	
20	SEPTEMBER 2022	Page 5	2,031		82,279	
21	TOTAL		$ 11,532		$ 354,742	
22	Other O&M Expense Lag Days	C 4 / C 2				30.76

($ in Thousands)

General Disbursements Payment Lag Summary

Line #	Description	[1] Number of CDs	[2] Cash Disbursements	[3] Dollar-Days	[4] Expense Lag-Days [3] / [2]
OCTOBER 2021					
1	Total Disbursements for Month	913	$ 4,091		
2	Total Disbursements for Expenses	352	$ 767	$ 15,119	19.72
NOVEMBER 2021					
3	Total Disbursements for Month	672	$ 2,412		
4	Total Disbursements for Expenses	221	$ 845	$ 31,591	37.39
DECEMBER 2021					
5	Total Disbursements for Month	674	$ 2,824		
6	Total Disbursements for Expenses	209	$ 720	$ 29,343	40.76
JANUARY 2022					
7	Total Disbursements for Month	922	$ 3,219		
8	Total Disbursements for Expenses	325	$ 1,005	$ 31,292	31.15
FEBRUARY 2022					
9	Total Disbursements for Month	775	$ 2,732		
10	Total Disbursements for Expenses	229	$ 797	$ 24,522	30.78
MARCH 2022					
11	Total Disbursements for Month	983	$ 10,847		
12	Total Disbursements for Expenses	297	$ 719	$ 17,478	24.30
APRIL 2022					
13	Total Disbursements for Month	776	$ 2,479		
14	Total Disbursements for Expenses	231	$ 573	$ 11,770	20.54
MAY 2022					
15	Total Disbursements for Month	722	$ 2,621		
16	Total Disbursements for Expenses	209	$ 613	$ 16,801	27.43
JUNE 2022					
17	Total Disbursements for Month	996	$ 4,896		
18	Total Disbursements for Expenses	287	$ 1,218	$ 27,473	22.56
JULY 2022					
19	Total Disbursements for Month	830	$ 4,073		
20	Total Disbursements for Expenses	229	$ 931	$ 20,148	21.63
AUGUST 2022					
21	Total Disbursements for Month	1,127	$ 4,214		
22	Total Disbursements for Expenses	434	$ 1,314	$ 46,926	35.71
SEPTEMBER 2022					
23	Total Disbursements for Month	732	$ 4,129		
24	Total Disbursements for Expenses	202	$ 2,031	$ 82,279	40.50
TOTAL TWELVE TEST MONTHS					
25	Total Test Month Expense Disbursement	3,225	$ 11,532	$ 354,742	30.76

Purchase Power Cost Payment Lag Summary

Line #	Description	[1] Number of Invoices	[2] Amount of Invoice	[3] Dollar Days	[4] Total Payment Lag-Days
1	October 2021	5	$ 2,996	$ 106,020	35.39
2	November	5	3,317	108,740	32.78
3	December	7	5,193	181,364	34.93
4	January 2022	10	6,485	205,955	31.76
5	February	9	4,847	153,103	31.59
6	March	6	5,838	223,818	38.34
7	April	8	3,281	154,404	47.06
8	May	7	2,813	100,627	35.77
9	June	11	5,922	176,574	29.82
10	July	12	7,890	244,292	30.96
11	August	10	8,979	247,333	27.55
12	September 2022	6	5,052	182,509	36.13
13	Total		$ 62,613	$ 2,084,738	
14	Purchase Power Lag Days				33.30

Interest Payments

Line No.	Description	[1] Reference Or Factor	[2] # of Days	[3] # of Days	[4] Total
1	Measure of Value at September 30, 2023	Sch C-1			$ 155,636
2	Long-term Debt Ratio	Sch B-7			43.97%
3	Embedded Cost of Long-term Debt	Sch B-6			4.30%
4	Pro forma Interest Expense	L 1 * L 2 * L 3			$ 2,943
5	Daily Amount	L 4 / L 5 [2]	365		$ 8
6	Days to mid-point of interest payments			91.25	
7	Less: Revenue Lag Days	Page 3		59.56	
8	Interest Payment lag days	L 7 - L 6			(31.7)
9	Total Interest for Working Capital	L 5 * L 8			$ (255)

Tax Lag Day Calculations

Line #	Description	[1] Payment Dates	[2] Mid-Point of Service Period	[3] Lead (Lag) Payment Days	[4] Payment Amount	[5] Weighted Lead (Lag) Dollars	[6] Payment Lead (Lag) Days	[7] Revenue (Lag) Days	[8] Net Payment Lead (Lag) Days	[9] Total Dollar Days	[10] Working Capital Amount
		Future		[1] - [2]		[3] * [4]	[5] / [4]		[6] - [7]		365
1	**FEDERAL INCOME TAX**				$ 2,329						
2	First Payment	01/15/23	04/01/23	76.00	$ 582	44,251					
3	Second Payment	03/15/23	04/01/23	17.00	582	9,898					
4	Third Payment	06/15/23	04/01/23	(75.00)	582	(43,669)					
5	Fourth Payment	09/15/23	04/01/23	(167.00)	582	(97,236)					
6	Total				$ 2,329	$ (86,755)	(37.25)	(59.56)	22.31	$ 51,960	$ 142
7	**STATE INCOME TAX**				$ 1,179						
8	First Payment	12/15/22	04/01/23	107.00	$ 295	31,533					
9	Second Payment	03/15/23	04/01/23	17.00	295	5,010					
10	Third Payment	06/15/23	04/01/23	(75.00)	295	(22,102)					
11	Fourth Payment	09/15/23	04/01/23	(167.00)	295	(49,214)		c			
12	Total				$ 1,179	(34,774)	(29.50)	(59.56)	30.06	$ 35,434	$ 97
13	**PA PROPERTY TAX**				$ 21						
14	First Payment	04/30/23	04/01/23	(29.00)	$ 10	(302)					
15	Second Payment	08/31/23	04/01/23	(152.00)	10	(1,583)					
16	Total				$ 21	(1,885)	(90.50)	(59.56)	(30.94)	$ (644)	$ (2)
17	**PURTA**				$ 76						
18	Payment	05/01/23	04/01/23	(30.00)	$ 76	(2,269)	(30.00)	(59.56)	29.56	$ 2,235	$ 6
19	Total Working Capital For Other Taxes										$ 244

Prepaid Expenses

Line #	Description	[1]	[2] TOTAL	[3] Insurance	[4] PUC Assessment	[5] Gross Receipts Tax	[6] Subscriptions	[7] Miscellaneous	[8] Maintenance & Services
1	September, 2021		1,203	$ 449	$ 203	$ -	$ 30	$ 29	$ 492
2	October		1,244	426	203	-	46	24	545
3	November		1,241	412	178	-	102	21	530
4	December, 2021		1,131	348	152	-	61	12	559
5	January, 2022		1,226	290	127	-	61	50	699
6	February		1,090	231	101	-	55	30	673
7	March		4,791	173	76	3,798	49	27	668
8	April		4,117	121	51	3,238	44	21	643
9	May		3,515	66	25	2,783	39	27	575
10	June		2,305	12	-	1,635	33	21	604
11	July		1,964	620	-	772	12	12	548
12	August		1,193	577	-	-	22	41	553
13	September, 2022		1,399	522	223	-	1	35	618
14	TOTAL		$ 26,420	$ 4,246	$ 1,338	$ 12,225	$ 556	$ 351	$ 7,705
15	Percent to Electric			100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
16	Amount to Electric			$ 4,246	$ 1,338	$ 12,225	$ 556	$ 351	$ 7,705
17	Monthly Average	13		$ 327	$ 103	$ 940	$ 43	$ 27	$ 593
18	Rate Case Amount		$ 2,032						

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Accumulated Deferred Income Taxes

Line #	Description	[1] Amount Fully Projected	[2] Total
	Accumulated Deferred Income Tax		
1	Electric Utility Plant - a/c # 282	$ (28,361)	
2	Sub-total		(28,361)
3	ADIT on CIAC	2,068	
4	Sub-total		2,068
5	Federal ADIT		(26,293)
6	State Repair Regulatory Liability	(2,820)	(2,820)
7	Pro-Rata Adjustment	0	-
8	Balance At September 30, 2023		$ (29,114)

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Customer Deposits

Line #	Description	[1] Balance at End Of Month
1	September, 2021	$ 922
2	October	$ 936
3	November	$ 950
4	December, 2021	$ 950
5	January, 2022	$ 956
6	February	$ 954
7	March	$ 958
8	April	$ 955
9	May	$ 949
10	June	$ 933
11	July	$ 941
12	August	$ 952
13	September, 2022	$ 984
14	Total	$ 12,338
15	Number of Months	13
16	Average Monthly Balance	$ 949

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Schedule C-8
Witness: V. K. Ressler

Materials & Supplies

Line #	Month	[1] Materials and Supplies
1	September, 2021	$ 1,578
2	October	$ 1,571
3	November	$ 1,514
4	December, 2021	$ 1,763
5	January, 2022	$ 1,854
6	February	$ 2,014
7	March	$ 2,232
8	April	$ 2,266
9	May	$ 2,381
10	June	$ 2,713
11	July	$ 2,758
12	August	$ 2,705
13	September, 2022	$ 2,626
14	Total	$ 27,975
15	Number of Months	13
16	Average Monthly Balance	$ 2,152

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Summary of Revenue and Expenses
Pro Forma with Proposed Revenue Increase

			[1]	[2]	[3]
		Factor	Pro Forma Test Year		
Line		Or	At	Rate	At
#	Description	Reference	Present Rates	Increase	Proposed Rates
	OPERATING REVENUES				
1	Customer & Distribution Revenue		$ 41,334	$ -	$ 41,334
2	Revenue - Cost of Purchased Power		103,968	-	103,968
3	Other Revenues		1,103	-	1,103
4	Revenue Increase			10,171	10,171
5	Total Operating Revenues		146,405	10,171	156,576
	OPERATING EXPENSES				
6	Other Power Supply Expenses		88,130		88,130
7	Transmission		-	-	-
8	Distribution		12,450	-	12,450
9	Customer Accounts		9,407	-	9,407
10	Uncollectible Expense	1.838%	3,018	187	3,205
11	Customer Information & Services		1,141	-	1,141
12	Sales		0	-	0
13	Administrative & General		7,983	-	7,983
14	Depreciation & Amortization		7,983	-	7,983
15	Taxes other than income taxes		9,338	638	9,976
16	Total Operating Expenses		139,450	825	140,275
17	Net Operating Income Before Income Tax		6,955	9,346	16,301
	Income Taxes				
18	Pro Forma Income Tax At Present Rates		807		807
19	Pro Forma Income Tax on Revenue Increase			2,701	2,701
20	Net Income (Loss)		$ 6,147	$ 6,646	$ 12,793

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Schedule D-2
Witness: T. A. Hazenstab

Summary of Pro Forma Revenue and Expense
Adjustments with Proposed Revenue Increase

Line #	Description	[1] Factor Or Reference	[2] Test Year At Present Rates: Budget For Year End 09/30/23	[3] Test Year At Present Rates: Adjustments Sch D-3 Increase (Decrease)	[4] Test Year At Present Rates: Pro Forma Adjusted For Test Year 9/30/23	[5] Proposed Increase	[6] Pro Forma Test Year With Proposed Increase
	OPERATING REVENUES			-	[2] + [3]		[4] + [5]
1	Residential	440	$ 110,330	$ 4,294	$ 114,624		$ 114,624
2	Commercial & Industrial	442	29,018	892	29,910		29,910
3	Public Streets & Highway Lighting	444	734	0	734		734
4	Other Sales to Public Authorities	445	18	0	18		18
5	Sales for Resale	447	16	(0)	16		16
6	Forfeited Discounts	450	520	-	520		520
7	Miscellaneous Service Revenues	451	16	-	16		16
8	Rent from Electric Properties	454	567	-	567		567
9	Interest on Undercollection - Refunded	456	-		-		-
10	Rate Increase		-	-	-	10,171	10,171
11	Total Operating Revenues		141,219	5,186	146,405	10,171	156,576
	OPERATING EXPENSES						
12	Other Power Supply Expenses		83,714	4,416	88,130	-	88,130
13	Transmission		-	-	-		-
14	Distribution		12,436	14	12,450		12,450
15	Customer Accounts		9,114	293	9,407		9,407
16	Uncollectible Expense	1.838%	2,508	510	3,018	187	3,205
17	Customer Information & Services		1,439	(298)	1,141		1,141
18	Sales		-	0	0		0
19	Administrative & General		7,975	9	7,983		7,983
20	Depreciation & Amortization		8,411	(428)	7,983		7,983
21	Taxes other than income taxes		9,112	226	9,338	638	9,976
22	Total Operating Expenses		134,709	4,742	139,450	825	140,275
23	Net Operating Income - BIT		$ 6,510	$ 444	$ 6,955	$ 9,346	$ 16,301

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Summary of Pro Forma Adjustments

			[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
Line #	Description		As Budgeted And Allocated	Not Used	Revenues	Power Costs	Salaries & Wages	Not Used	Not Used	Rate Case Expenses	Uncollectibles Expense	COVID-19 Costs	Not Used	Sub-Total Adjustments	Total Proforma
	OPERATING REVENUES			D-4	D-5	D-6	D-7	D-8	D-9	D-10	D-11	D-12	D-13		
	Customer & Distribution Revenue														
1	Residential	440	$ 27,529		$ 876									$ 876	$ 28,405
2	Commercial & Industrial	442	12,187		215									215	12,402
3	Public Streets & Highway Lighting	444	507		0									0	507
4	Other Sales to Public Authorities	445	16		0									0	16
5	Sales for Resale	447	4		(0)									(0)	4
	Non-Distribution and Operating Revenue													-	-
6	Residential	457	82,801		3,418									3,418	86,219
7	Commercial & Industrial	457	16,831		677									677	17,508
8	Public Streets & Highway Lighting	457	227		0									0	227
9	Other Sales to Public Authorities	489	2		0									0	2
10	Sales for Resale	489	12		-									-	12
11	Forfeited Discounts	450	520		-									-	520
12	Miscellaneous Service Revenues	451	16		-									-	16
13	Rent from Electric Properties	454	567		-									-	567
14	Interest on Undercollection - Refunded	456	-											-	-
15	Rate Increase		-											-	-
16	Total Operating Revenues		141,219		5,186	-	-	-	-	-	-	-	-	5,186	146,405
	OPERATING EXPENSES														-
17	Other Power Supply Expenses		83,714			-	-							-	83,714
18	Transmission		-			-	-							-	-
19	Distribution		12,436	-			14		-				-	14	12,450
20	Customer Accounts		9,114				9							9	9,123
21	Uncollectible Expense		2,508								510			510	3,018
22	Customer Information & Services		1,439				0							0	1,439
23	Sales		-				0							0	0
24	Administrative & General		7,975				9	-		-		-		9	7,983
25	Depreciation & Amortization		8,411											-	8,411
26	Taxes other than income taxes		9,112											-	9,112
														-	-
27	Total Operating Expenses		$ 134,709	$ -	$ -	$ -	$ 32	$ -	$ -	$ -	$ 510	$ -	$ -	$ 542	$ 135,250
28	Net Operating Income Before Income Tax		$ 6,510	$ -	$ 5,186	$ -	$ (32)	$ -	$ -	$ -	$ (510)	$ -	$ -	$ 4,644	$ 11,155

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Summary of Pro Forma Adjustments

Line #	Description	[1] From Page 1 Sub-total	[2]	[3] Benefits Adjustments D-14	[4] Other Adjustments D-15	[5] Universal Service D-16	[6] GRT Adjustment D-17	[7] Power Supply Exp Adj D-18	[8] EE&C Program D-19	[9] Not Used D-20	[10] Depreciation D-21	[11] Taxes Other Than Income D-31	[12]	[13] TOTAL Adjusted
	OPERATING REVENUES													
	Customer & Distribution Revenue													
29	Residential	$ 28,405												$ 28,405
30	Commercial & Industrial	12,402												12,402
31	Public Streets & Highway Lighting	507												507
32	Other Sales to Public Authorities	16												16
33	Sales for Resale	4												4
	Non-Distribution and Operating Revenue													-
34	Residential	86,219												86,219
35	Commercial & Industrial	17,508												17,508
36	Public Streets & Highway Lighting	227												227
37	Other Sales to Public Authorities	2												2
38	Sales for Resale	12												12
39	Forfeited Discounts	520												520
40	Miscellaneous Service Revenues	16												16
41	Rent from Electric Properties	567												567
42	Interest on Undercollection - Refunded	-												-
43	Rate Increase	-												-
44	Total Operating Revenues	146,405	-	-	-	-	-	-	-	-	-	-	-	146,405
	OPERATING EXPENSES													
45	Other Power Supply Expenses	83,714					-	4,416						88,130
46	Transmission	-												-
47	Distribution	12,450			-									12,450
48	Customer Accounts	9,123			66	218								9,407
49	Uncollectible Expense	3,018												3,018
50	Customer Information & Services	1,439							(298)					1,141
51	Sales	0												0
52	Administrative & General	7,983		-										7,983
53	Depreciation & Amortization	8,411									(428)			7,983
54	Taxes other than income taxes	9,112					193					33		9,338
55	Total Operating Expenses	$ 135,250	$ -	$ -	$ 66	$ 218	$ 193	$ 4,416	$ (298)	$ -	$ (428)	$ 33	$ -	$ 139,450
56	Net Operating Income Before Income Tax	$ 11,155	$ -	$ -	$ (66)	$ (218)	$ (193)	$ (4,416)	$ 298	$ -	$ 428	$ (33)	$ -	$ 6,955

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment - Revenue Adjustments

		[1]	[2]	[3]	[4]	[5]	[6]
				PRO FORMA ADJUSTMENTS			
Line #	Description	Reference Or Account Number	2023 Budget	Rev Adj Annualization	Other Adjustments	Total Proforma Adjustments	Proforma Adjusted At Present Rates
				D-5A	D-5B		
	Customer & Distribution Revenue						
1	Residential	440	$ 27,529	$ 876		$ 876	$ 28,405
2	Commercial & Industrial	442	12,187	215		215	12,402
3	Public Streets & Highway Lighting	444	507	0		0	507
4	Other Sales to Public Authorities	445	16	0		0	16
5	Sales for Resale	447	4	(0)		(0)	4
6	Cust Chg & Distrib Revenue		40,243	1,091	-	1,091	41,334
	Non-Distribution and Operating Revenue						
7	Residential	456.5	82,801	3,418		3,418	86,219
8	Commercial & Industrial	456.6	16,831	677		677	17,508
9	Public Streets & Highway Lighting	456.8	227	0		0	227
10	Other Sales to Public Authorities		2	0		0	2
11	Sales for Resale		12	-		-	12
12	Revenue for Cost of Electric		99,873	4,095	-	4,095	103,968
							-
13	Total Customer Revenue		140,116	5,186	-	5,186	145,302
14	Forfeited Discounts	450	520		-	-	520
15	Miscellaneous Service Revenues	451	16		-	-	16
16	Rent from Electric Properties	454	567		-	-	567
17	Interest on Undercollection - Refunded	456.1	-			-	-
18	TOTAL REVENUES		$ 141,219	$ 5,186	$ -	$ 5,186	$ 146,405

($ in Thousands)

Adjustment - Test Year Revenue Changes

Line #	Description	[1] Factor Or Reference	[2] Budgeted Jurisdictional	[3] Revised Jurisdictional	[4] Adjustment [3] - [2]	[5] Total Adjustment
TOTAL REVENUE						
1	Residential	440	$ 110,331	$ 114,624	$ 4,294	
2	Commercial & Industrial	442	29,018	29,910	892	
3	Public Streets & Highway Lighting	444	734	734	0	
4	Other Sales to Public Authorities	445	18	18	0	
5	Sales for Resale	447	15	15	(0)	
6	Total		$ 140,115	$ 145,301	$ 5,186	$ 5,186
COSTS (GSR, STAS, EEC, USP, GRT)						
7	Residential		$ 82,801	$ 86,219	3,418	
8	Commercial & Industrial		16,831	17,508	677	
9	Public Streets & Highway Lighting		227	227	0	
10	Other Sales to Public Authorities		2	2	0	
11	Sales for Resale		12	12	(0)	
12	Total		$ 99,873	$ 103,967	$ 4,095	$ 4,095
NET CUSTOMER & DISTRIBUTION						
13	Residential		$ 27,529	$ 28,405	$ 876	
14	Commercial & Industrial		12,187	12,402	215	
15	Public Streets & Highway Lighting		507	507	0	
16	Other Sales to Public Authorities		16	16	0	
17	Sales for Resale		4	4	(0)	
18	Total		$ 40,243	$ 41,334	$ 1,091	$ 1,091

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment - Power Costs

		[1]	[2]	[3]	[4]	[5]
			PRO FORMA ADJUSTMENTS			
Line #	Description	Budgeted Electric Costs	D-18 Costs	Other Costs	Electric Cost Pro Forma Adjustments	Pro Forma Electric Costs At Pres Rates
1	Budgeted Purchased Power Costs	$ 83,714	$ 4,416	$ -	$ 4,416	$ 88,130
2	Residential				-	-
3	Commercial & Industrial				-	-
4	Public Streets & Highway Lighting				-	-
5	Other Sales to Public Authorities				-	-
6	Sales for Resale				-	-
7	Company Use of Electricity				-	-
8	**Total Purchased Power Costs**	$ 83,714	$ 4,416	$ -	$ 4,416	$ 88,130

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment - Salaries & Wages

Line #	Description	[1] Budgeted Year 09/30/23	[2] Adjustment	[3] Payroll As Distributed	[4] Annualization Adjustment	[5] Total Pro Forma Payroll
	OPERATIONS					
1	Total Other Power Supply Expenses	$ -	$ -	$ -	$ -	$ -
2	Total Transmission Expenses - Operation	-	-	-	-	-
3	Total Regional Market Expenses - Operation	-	-	-	-	-
4	Total Distribution Expenses - Operation	1,768	-	1,768	9	1,777
5	Total Customer Accounts Expense	1,610	-	1,610	9	1,619
6	Total Customer Service & Informational Expenses	27	-	27	0	27
7	Total Sales Expense	5	-	5	0	5
8	Total A&G - Operation	1,667		1,667	9	1,676
9	Total Operations	5,077	-	5,077	27	5,105
	MAINTENANCE					
10	Total Transmission Expenses - Maintenance	-	-	-	-	-
11	Total Regional Market Expenses - Maintenance	-	-	-	-	-
12	Total Distribution Expenses - Maintenance	885	-	885	5	890
13	Total A&G - Maintenance	(65)	-	(65)	(0)	(65)
14	Total Maintenance	820	-	820	4	825
15	Total Payroll to Expense	$ 5,898	$ -	$ 5,898	$ 32	$ 5,929
16	Percent Increase					0.535%

($ in Thousands)

Adjustment - Salaries & Wages

Line #	Description	[1] Reference Or Function	[2] Union	[3] Non-Exempt	[4] Exempt	[5] Pro Forma Total Payroll
1	Budgeted Payroll For TY 9-30-23		$ 1,255	$ 1,106	$ 3,537	$ 5,898
	Annualize for Wage Increase to 9-30-23					
2	Percent Increase		3.00%	4.00%	4.00%	
3	Union Increase At 1-1 Annualization Factor	1/1/23	25%			
4	Non-Exempt Annualization Factor	4/1/23		50%		
5	Exempt Annualization Factor	10/1/22			0%	
6	Increase for wage rate changes	L 1 * L 2 * Ls 3 to 5	9	22	0	$ 32
7	Annualized Salaries & Wages at 9-30-23 Rates	L 1 + L 6	$ 1,264	$ 1,128	$ 3,537	
8	Pro Forma Salaries & Wages for TY		$ 1,264	$ 1,128	$ 3,537	
9	Pro Forma Adjustment to S&W					$ 32
10	Annualization Factor	L 11 / L 1				0.535%

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment - Uncollectibles

Line #	Description	[1] Reference Or Factor	[2] Uncollectible Expense	[3] Tariff Revenue	[4] Percent [2] / [3]	[5] Total [2] / [3]
	Adjustment #1:					
1	2020	**(a)**	$ 2,028	$ 84,126	2.41%	
2	2021	**(a)**	$ 1,330	$ 89,272	1.49%	
3	2022		$ 2,133	$ 125,374	1.70%	
4	Three Year Average Sum (Line 1 to Line 3) / 3	3	$ 1,830	$ 99,591		1.838%
5	2023 Budget				$ 2,170	
	Pro Forma Adjustment					
6	Adjusted Revenues	1.838%		$ 145,822		
7	Pro Forma at Present Rate Revenue	L6: [1] * [3]			2,680	
8	Total for Test Year					**$ 510**
	Adjustment #2: (b)					
9	Deferred Uncollectibles - Fiscal 2020			$ 1,013		
10	Less: recovery since last rate case			$ 338		
11	Balance of deferred uncollectibles for Fiscal 2020			$ 675		
12	Amortization per year			338		
13	Recovery of Fiscal 2020 deferred uncollectibles included in budget			$ 338		
14	Pro Forma Adjustment					**$ -**
15	Total Uncollectible Adjustment	L8 + L14				**$ 510**

(a) Includes $315 and $1,013 in 2021 and 2020 respectively, which were recorded as regulatory assets associated with COVID-19 in accordance with the May 13, 2020 Secretarial Letter at Docket No. M-2020-3019775. These amounts are the uncollectible accounts reserves needed in excess of the $1,015 uncollectible expense built into rates (from the 2018 Electric Rate Case at Docket No. R-2017-2640058).

(b) $1,013 was deferred and recorded as a regulatory asset for Fiscal 2020 associated with COVID-19 in accordance with the May 13, 2020 Secretarial Letter at Docket No. M-2020-3019775. As approved within the settlement to the 2021 UGI Electric Rate Case at Docket No. R-2021-3023618, this amount is being amortized over 3 years.

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Schedule D-15
Witness: T. A. Hazenstab

Adjustment - Other Adjustments

		[1]	[2]
Line #	Description	Sub-Total	Total
	Customer Accounts Expense Adjustment		
1	Unrecovered Interest on Customer Deposits		$ 66

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment - Universal Service

Line #	Description	[1] Amount
	Increase (Decrease) for Pro Forma TY Universal Service Expense	
		Pro Forma
1	Customer Assistance Plan Credit	$ 5,593
2	Administration Costs	156
3	LIURP	298
4	Hardship Program (Project Share)	4
5	Customer Assistance Plan Pre-program Arrearage	544
6	TOTAL	$ 6,595
7	Budget	$ 6,377
8	Total Adjustment	$ 218

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment - Gross Receipts Tax

Line #	Description	[1] Amount	[2] Total
1	Revised Jurisdictional Revenue - Schedule D-5A, [3], Line 6	$ 145,301	
2	Other Operating Revenues	1,103	
3	Less: Uncollectible Expense	(3,018)	
4	Total		$ 143,386
5	Gross Receipts Tax Rate		5.90%
6	Revised Gross Receipts Tax		$ 8,460
7	Gross Receipts Tax Expense per Budget		$ 8,267
8	Pro Forma Adjustment		$ 193

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment - Power Supply Expense

Line #	Description	[1] Sub-Total	[2] Total
1	Power Supply Expense	$ 89,926	
2	Adjustment for Normalized & Annualized Use/Customer - See Exhibit SAE-4(b)	347	
3	Adjustment for Normalized & Annualized Use/Customer - See Exhibit SAE-4(c)	3,383	
4	Sub-Total	$ 93,656	
5	Adjustment for Gross Receipts Tax (1 - .059)	0.941	
6	Power Supply Expense As Adjusted	$ 88,130	
7	Power Supply Expense per Budget (net of Gross Receipts Tax) (Sch D-6, Col 1)	$ 83,714	
8	Pro Forma Adjustment		$ 4,416

Adjustment - Energy Efficiency and Conservation Programs

Line #	Description	[1] Amount	[2] Sub-Total
	Energy Efficiency and Conservation Programs		
1	2023 Original Program Costs	$ 1,407	
2	Adjusted Budget	1,109	
3	Additional Expense Adjustment (Line 2 - Line 1)		(298)
4	Total Adjustment		$ (298)

($ in Thousands)

Adjustment - Depreciation expense

Line #	Description	[1] Account Number	[2] Budgeted 9/30/23 Depreciation Expense	[3] Adjustment To Annualize At New Depre Study Rates	[4] Pro Forma Test Year Depreciation
	INTANGIBLE PLANT				
1	Organization	301	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-
4	TOTAL INTANGIBLE		-	-	-
	TRANSMISSION PLANT				
5	Land & Land Rights	350	-	-	-
6	Structures & Improvements	352	-	-	-
7	Station Equipment	353	-	-	-
8	Station Equipment - SCADA	353.2	-	-	-
9	Towers and Fixtures	354	-	-	-
10	Poles and Fixtures	355	-	-	-
11	Overhead Conductors and Devices	356	-	-	-
12	Underground Conduit	357	-	-	-
13	Underground Conductors and Devices	358	-	-	-
14	Roads and Trails	359	-	-	-
15	TOTAL TRANSMISSION		-	-	-
	DISTRIBUTION PLANT				
16	Land & Land Rights	360	-	-	-
17	Structures & Improvements	361	14	1	15
18	Station Equipment	362	264	103	366
19	Storage Battery Equipment	363	-	-	-
20	Poles, Towers and Fixtures	364	1,121	(103)	1,018
21	Overhead Conductors and Devices	365	1,308	318	1,626
22	Regulatory AFUDC	365.7	(14)	(2)	(16)
23	Underground Conduit	366	138	(1)	138
24	Underground Conductors and Devices	367	434	(5)	429
25	Transformers	368.1	325	55	380
26	Transformer Installations	368.2	225	(11)	213
27	Services	369	272	0	272
28	Meters	370.1	61	(6)	55
29	Meter Installations	370.2	25	(0)	25
30	Electronic Meters	370.3	134	(8)	126
31	Installations on Customers' Premises	371	94	(11)	83
32	Installations on Customers' Premises - EV Charging Stations	371.1	-	-	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	2	(1)	1
34	Leased Property on Customers' Premises	372	-	-	-
35	Street Lighting and Signal Systems	373	102	4	107
36	TOTAL DISTRIBUTION		4,504	333	4,837
	GENERAL & COMMON PLANT				
37	Land & Land Rights	389	-	-	-
38	Structures & Improvements	390	206	237	442
39	Office Furniture & Equipment	391	1,663	251	1,914
40	Transportation Equipment	392	172	23	195
41	Stores Equipment	393	1	0	1
42	Tools & Garage Equipment	394	63	(4)	59
43	Laboratory Equipment	395	14	(12)	2
44	Power Operated Equipment	396	36	10	46
45	Communication Equipment	397	117	(31)	86
46	Miscellaneous Equipment	398	43	9	52
47	Other Tangible Property	399	-	-	-
48	TOTAL GENERAL & COMMON PLANT		2,314	484	2,798
49	TOTAL DEPRECIATION		$ 6,818	$ 817	$ 7,635
50	CHARGED TO OTHER BUSINESS UNITS (IT-RELATED)		(42)	-	(42)
51	CHARGED TO CLEARING ACCOUNTS		$ (388)	$ 2	$ (386)
52	NET SALVAGE AMORTIZATION		$ 907	$ (131)	$ 776
53	TOTAL CLAIMED DEPRECIATION AND AMORTIZATION		$ 7,295	$ 687	$ 7,983

UGI Utilities, Inc. - Electric Division
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($ in Thousands)

Adjustment - Taxes Other Than Income Taxes

Line #	Description	[1] Account Number	[2] Factor or Reference	[3] Budget Amounts 9/30/23	[4] Pro Forma Adjustments	[5] Pro Forma Tax Expense 9/30/23
1	PURTA Taxes	408.1		$ 45	$ 31	$ 76
2	Gross Receipts Tax	408.1	D-17	8,267	193	8,460
3	PA & Local Use taxes	408.1		21	-	21
4	Social Security	408.1	D-32	448	2	450
5	FUTA	408.1	D-32	31	-	31
6	SUTA	408.1	D-32	3	-	3
7	PUC Assessment	408.1		297	-	297
8	Total			$ 9,112	$ 226	$ 9,338

($ in Thousands)

Adjustment - Payroll Taxes

Line #	Description	[1] Account Number	[2] Test Year 9/30/23 Present Rates	[3] Pro Forma Adjustments	[4] Increase in Payroll Taxes
1	Total Payroll Charged to Expense		$ 5,898	$ 32	
2	FICA Expense		448		
3	FICA Expense - Percent	L 2 / L 1	7.60%	7.60%	
4	Pro Forma FICA Expense on Pro Forma S&W	[4] L 1 * L 3			$ 2
5	FUTA Expense		31		
6	FUTA Expense - Percent	L 5 / L 1	0.53%	0.53%	
7	Pro Forma FUTA Expense on Pro Forma S&W	[4] L 1 * L 6			-
8	SUTA Expense		3		
9	SUTA Expense - Percent	L 8 / L 1	0.05%	0.05%	
10	Pro Forma SUTA Expense on Pro Forma S&W	[4] L 1 * L 9			-
11	Pro Forma Adjustment	Sum L 4 to L 10			$ 2

($ in Thousands)

Income Tax Calculation

Line #	Description	[1] Factor Or Reference	[2] Element Or Amount	[3] Pro Forma Test Year At Present Rates	[4] Revenue Increase	[5] Pro Forma Test Year At Proposed Rates [3] + [4]
1	Revenue			$ 146,405	$ 10,171	$ 156,576
2	Operating Expenses			(139,450)	(825)	(140,275)
3	OIBIT	L 1 + L 2		6,955	9,346	16,301
	Interest Expense					
4	Rate Base	Sch A-1	155,636			
5	Weighted Cost of Debt	Sch B-7	0.01890			
6	Synchronized Interest Expense	L 4 * L 5		(2,942)	-	(2,942)
7	Base Taxable Income	L 3 + L 6		4,013	9,346	13,359
8	Total Tax Depreciation	Sch D-34	$ 15,190			
9	Pro Forma Book Depreciation	Sch D-34	8,306			
10	State Tax Depreciation (Over) Under Book	L 9 - L 8		(6,885)		(6,885)
11	Other				-	-
12	State Taxable Income	Sum L 7 to L 11		$ (2,872)	$ 9,346	$ 6,474
13	State Income Tax (Expense)/Refund	L 12 * Rate [2]	9.99%	$ 287	$ (934)	$ (647)
14	Total Tax Depreciation	Sch D-34	$ 14,628			
15	Pro Forma Book Depreciation	Sch D-34	8,306			
16	Federal Tax Deducts (Over) Under Book	L 14 - L 13		(6,322)	-	(6,322)
17	Other				-	-
18	Federal Taxable Income	L 7 + sum L 13 to L 17		(2,023)	8,413	6,390
19	Federal Income Tax (Expense)/Refund	-L 18 * Rate [2]	21.00%	425	(1,767)	(1,342)
20	Total Tax Expense before Deferred Income Tax	L 13 + L 19		712	(2,701)	(1,989)
	Deferred Federal Income Taxes					
21	Total Straight Line Tax Depreciation	Sch D-34	$ 7,635			
22	Total Tax Depreciation	Sch D-34	13,721			
23	Federal Tax Deducts (Over) Under Book	L 22 - L 21		6,086	-	6,086
24	Deferred Federal Taxable Income	L 23		$ 6,086	$ -	$ 6,086
25	Federal Income Tax (Expense)/Refund	-L 24 * Rate [2]	Blended Rate [1]	(987)	-	(987)
	Deferred State Income Taxes					
26	Repairs			(577)		(577)
27	CIAC			45		45
28	State Deferred Income Tax (Expense)/Refund			(532)	-	(532)
29	Net Income Tax Expense	L20 + L 25 + L28		(807)	(2,701)	(3,508)
	Other Tax Adjustments					
30	ITC			-		-
31	Combined Income Tax Expense	L 29 + L 30		$ (807)	$ (2,701)	$ (3,508)
32	Federal Income Tax Expense	L 19 + L 25 + L 30		$ (562)	$ (1,767)	$ (2,329)
33	State Income Tax Expense	L 13 + L 28		(245)	(934)	(1,179)
34	Total Income Tax Expense	L 32 + L 33		$ (807)	$ (2,701)	$ (3,508)

[1] Due to the 2018 Tax Cuts and Jobs Act, excess deferred income tax is now being flowed back to customers which results in a deferred tax rate other than 21%.

UGI Utilities, Inc. - Electric Division
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($ in Thousands)

Tax Depreciation

Line #	Description	[1] Amount	[2] Amount	[3] Total
	Accelerated Tax Depreciation			
1	Electric Plant		$ 5,889	
2	Cost of Removal		907	
3	Repairs Tax Deduction		8,858	
4	Other Tax Basis Adjustments		(1,026)	
5	Total Federal Accelerated Tax Depreciation			$ 14,628
6	Adjustment for PA Tax Depreciation - Bonus Decoupling		562	
7	Total State Accelerated Tax Depreciation			$15,190
	Straight Line Tax Depreciation			
8	Electric Plant		$ 7,635	
9	Total Tax Depreciation			$ 7,635
	Book Depreciation			
10	Pro Forma Book Depreciation		$ 7,635	
11	Net Salvage Amortization		776	
12	Depreciation Charged to Clearing Accounts	(428)		
13	Estimated Percent of Clearing Charged to CWIP	25%		
14	Depreciation Charged to CWIP		(105)	
15	Book Depreciation for Tax Calculation			$ 8,306

($ in Thousands)

Gross Revenue Conversion Factor

Line #	Description	[1] Reference Or Factor	[2] Tax Rate	[3] Factor
	GROSS REVENUE CONVERSION FACTOR			
1	GROSS REVENUE FACTOR			1.000000
2	UNCOLLECTIBLE EXPENSES			(0.018380)
3	NET REVENUES	Sum L 1 to L 2		0.981620
4	GROSS RECEIPTS TAX	[3] L 3 * Rate [2]	6.27%	(0.062700)
5	FACTOR AFTER GROSS RECEIPTS TAX			0.918920
6	STATE INCOME TAXES	[3] L 5 * Rate [2]	9.99%	(0.091800)
7	FACTOR AFTER STATE TAXES	L 5 + L 6		0.827120
8	FEDERAL INCOME TAXES	[3] L 7 * Rate [2]	21.00%	(0.173695)
9	NET OPERATING INCOME FACTOR	L 7 + L 8		0.653425
10	GROSS REVENUE CONVERSION FACTOR	1 / L 9		1.530398
11	Combined Income Tax Factor On Gross Revenues	-L 6 - L 8		26.550%
	INCOME TAX FACTOR			
12	GROSS REVENUE FACTOR			1.000000
13	STATE INCOME TAXES	[3] L 10 * Rate [2]	9.9900%	(0.099900)
14	FACTOR AFTER STATE TAXES	L 10 + L 11		0.900100
15	FEDERAL INCOME TAXES	[3] L 12 * Rate [2]	21.00%	(0.189021)
16	NET OPERATING INCOME FACTOR	L 12 + L 13		0.711079
17	GROSS REVENUE CONVERSION FACTOR	1 / L 14		1.406314
18	Combined Income Tax Factor On Taxable Income	-L 11 - L 13		28.892%

UGI ELECTRIC

EXHIBIT A

HISTORIC

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission

Historic Period - 12 Months Ended September 30, 2022
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Witness: T. A. Hazenstab
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Summary of Measure of Value and Revenue Increase

Line #	Description	[1] Function	[2] Reference Section	[3] Pro Forma Test Year Ended September 30, 2022 At Present Rates	[4] Increase	[5] Proposed Rates
	RATE BASE					
1	Utility Plant		C-2	$ 233,593		$ 233,593
2	Accumulated Depreciation		C-3	(77,202)		(77,202)
3	Net Plant in service	L 1 + L 2		156,391	-	156,391
4	Working Capital		C-4	10,969		10,969
5	Accumulated Deferred Income Taxes		C-6	(27,594)		(27,594)
6	Customer Deposits		C-7	(949)		(949)
7	Materials & Supplies		C-8	2,152		2,152
8	TOTAL RATE BASE	Sum L 3 to L 7		$ 140,969	$ -	$ 140,969
	OPERATING REVENUES AND EXPENSES					
	Operating Revenues					
9	Base Customer Charges		D-5	$ 39,570	$ (222)	$ 39,348
10	Other Electric Revenue		D-5	112,051		112,051
11	Other Operating Revenues		D-5	1,286		1,286
12	Total Revenues	Sum L 9 to L 11		152,907	(222)	152,685
13	Operating Expenses		D-1	(137,994)	18	(137,976)
14	OIBIT	L 12 + L 13		14,913	(204)	14,709
15	Pro Forma Income Tax at Present Rates		D-33	(3,462)		
16	Pro Forma Income Tax on Revenue Increase		D-33		59	(3,403)
17	NET OPERATING INCOME	Sum L 14 to L 16		$ 11,451	$ (145)	$ 11,306
18	RATE OF RETURN	L 17 / L 8		8.123%		8.020%
	REVENUE INCREASE REQUIRED					
19	Rate of Return at Present Rates	L 18, Col 3		8.123%		
20	Rate of Return Required		B-7	8.020%		
21	Change in ROR	L 20 - L 19		-0.103%		
22	Change in Operating Income	L 21 * L 8		$ (145)		
23	Gross Revenue Conversion Factor		D-35	1.530398		
24	Change in Revenues	L 22 * L 23		$ (222)		
25	Percent Increase -- Delivery Revenues	L 24 / L 9, C 3			-0.56%	
26	Percent Increase -- Total Revenues	L 24 / L 12, C 3			-0.15%	

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
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Balance Sheet

Line No	Description/(Account No)	[1] Actual TYE 9-30-22
	UTILITY PLANT (101 - 106, 108)	
1	Electric Utility Plant	$ 314,688
2	Other Utility Plant	-
3	Total Plant In Service	314,688
4	Construction Work In Progress (107)	8,024
5	Total Utility Plant	322,712
6	Accumulated Provision for Depreciation - Electric (108)	(100,697)
7	Utility Acquisition Adjustment (114)	390
8	Accumulated Provision for Depreciation - Other (119)	-
9	Net Utility Plant	222,405
	OTHER PROPERTY INVESTMENTS	
10	Non-utility Property (121)	15
11	Accumulated Depreciation on NUP (122)	-
12	Investment in Associated & Subsidiary Companies (123.1)	-
13	Other Investments (124)	-
14	Total Other Property and Investments	15
	CURRENT AND ACCRUED ASSETS	
15	Cash & Other Temporary Investments(131-136)	2,265
16	Unbilled Revenues	-
17	Customer Accounts Receivable (142)	18,883
18	Other Accounts Receivable (143)	859
19	Accum Provision for Uncollectible (144)	(2,238)
20	Receivables from Associated Companies (145)	-
21	Accounts Receivable Assoc. Comp. (146)	477
22	Plant Materials & Operating Supplies (154)	2,627
23	Allowance Inventory (158.1)	345
24	Stores Expense - Undistributed (163)	127
25	Prepayments (165)	1,953
26	Accrued Utility Revenues (173)	4,326
27	Miscellaneous Current & Accrued Assets (174)	1,433
28	Derivative Instrument Assets (175)	-
29	Total Current and Accrued Assets	31,058
	DEFERRED DEBITS	
30	Unamortized Debt Expense (181)	13
31	Other Regulatory Assets (182.3)	29,955
32	Other Preliminary Survey & Investigation Charges (183.2)	-
33	Clearing Accounts (184)	-
34	Miscellaneous Deferred Debits (186)	1,388
35	Unamortized Loss on Reacquired Debt (189)	-
36	Accumulated Deferred Income Taxes (190)	16,153
37	Total Deferred Debits	47,509
38	TOTAL ASSETS AND OTHER DEBITS	$ 300,987

($ in Thousands)

Balance Sheet

Line No	Description/(Account No)	[1] Actual TYE 9-30-22
	PROPRIETARY CAPITAL	
39	Common Stock Issued (201)	$ 6,026
40	Preferred Stock Issued (204)	-
41	Premium on Capital Stock (207)	50,858
42	Capital Stock Expense (214)	-
43	Retained Earnings (215, 215.2, 216)	71,682
44	Accum Other Comprehensive Income (219)	(814)
45	Total Proprietary Capital	127,752
	LONG TERM DEBT	
46	Bonds (221)	-
47	Advances from Associated Companies (223)	-
48	Other Long-Term Debt (224)	70,788
49	Unamortized Premium on LTD (225)	-
50	Unamortized Discount on LTD (226)	-
51	Total Long-term Debt	70,788
	OTHER NON-CURRENT LIABILITIES	
52	Obligations under Capital Leases (227)	-
53	Advances from Associated Companies (223)	-
54	Other Long-Term Debt (224)	-
55	Unamortized Premium on LTD (225)	-
56	Unamortized Discount on LTD (226)	-
57	Accumulated Provision for Pension & Benefits (228.3)	8,593
58	Total Non-Current Liabilities	8,593
	CURRENT & ACCRUED LIABILITIES	
59	Notes Payable (231)	7,690
60	Accounts Payable (232)	11,083
61	Notes Payable to Assoc. Companies (233)	-
62	Accounts Payable to Assoc. Cos (234)	978
63	Customer Deposits (235)	984
64	Taxes Accrued (236)	780
65	Interest Accrued (237)	599
66	Tax Collections Payable (241)	148
67	Accrued Interest on Other Liabilities (237)	2,606
68	Tax Collections Payable (241)	-
69	Misc Current & Accrued Liabilities (242)	-
70	Total Current & Accrued Liabilities	24,867
	OTHER DEFERRED CREDITS	
71	Customer Advances for Construction (252)	-
72	Other Deferred Credits (253)	422
73	Other Regulatory Liabilities (254)	28,084
74	Deferred ITC (255)	-
75	Accumulated Deferred Income Taxes (282)	40,481
76	Accumulated Deferred Income Taxes (283)	-
77	Total Other Deferred Credits	68,987
78	TOTAL LIABILITIES & OTHER CREDITS	$ 300,987

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
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($ in Thousands)

Statement of Net Utility Operating Income

Line No	Description	[1] Actual TYE 9-30-22	[2] Reference
	Total Operating Revenues		
1	Total Sales Revenues	$ 124,822	B-3
2	Other Operating Revenues	1,286	B-3
3	Total Revenues	126,108	
	Total Operating Expenses		
4	Operation & Maintenance Expenses	101,171	B-4
5	Depreciation & Amortization Expense	7,767	D-3
6	Taxes Other Than Income Taxes	8,271	B-5
7	Total Operating Expenses	117,209	
8	Operating Income Before Income Taxes (OIBIT)	8,899	
	Income Taxes:		
9	State	1,244	B-5
10	Federal	2,218	B-5
11	Total Income Taxes	3,462	
12	**Net Utility Operating Income**	$ 5,436	

UGI Utilities, Inc. - Electric Division
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Statement of Operating Revenues

Line No	Description	Account No	[1] Actual TYE 9-30-22
	Electric Operating Revenues		
1	Residential	440	$ 89,002
2	Commercial & Industrial	442	34,817
3	Public Streets & Highway Lighting	444	982
4	Other Sales to Public Authorities	445	21
5	Sales for Resale	447	-
6	Sub-Total Electric Operating Revenues		124,822
	Other Operating Revenues		
7	Forfeited Discounts	450	$ 552
8	Miscellaneous Service Revenues	451	32
9	Rent from Electric Properties	454	602
10	Interest on Undercollection - Refunded to Customers	456.1	100
11	Sub-Total Other Operating Revenues		1,286
12	**Total Operating Revenues**		$ 126,108

UGI Utilities, Inc. - Electric Division
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($ in Thousands)

Schedule B-4
Witness: T. A. Hazenstab

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Actual TYE 9-30-22
	Other Power Supply Expenses		
1	Purchased Power	555.0	$ 66,695
2	Power Purchased for Storage Operations	555.1	-
3	System Control and Load Dispatching	556.0	-
4	Other Expenses	557.0	-
5	Load Dispatch - Reliability	561.1	-
6	Transmission of Electricty by Others	565.0	4,871
7	Gross Receipts Tax	408.1	-
8	Total Other Power Supply Expenses		71,566
	Transmission Expenses - Operation		
9	Operation Supervision and Engineering	560.0	-
10	Load Dispatch - Reliability	561.0	-
11	Load Dispatch - Monitor and Operate Trans. System	561.2	-
12	Load Dispatch - Transmission Service & Scheduling	561.3	-
13	Scheduling, System Control & Dispatch Service	561.4	-
14	Reliability Planning & Standards Development	561.5	-
15	Transmission Service Studies	561.6	-
16	Generation Interconnection Studies	561.7	-
17	Reliability Planning & Standards Development Services	561.8	-
18	Station Expenses	562.0	-
19	Operation of Energy Storage Equipment	562.1	-
20	Overhead Line Expense	563.0	-
21	Underground Line Expenses	564.0	-
22	Transmission of Electricty by Others	565.0	-
23	Miscellaneous Transmission Expenses	566.0	-
24	Rents	567.0	-
25	Operation Supplies and Expenses	567.1	-
26	Total Transmission Expenses - Operation		-
	Transmission Expenses - Maintenance		
27	Maintenance Supervision and Engineering	568.0	-
28	Maintenance of Structures	569.0	-
29	Maintenance of Computer Hadware	569.1	-
30	Maintenance of Computer Software	569.2	-
31	Maintenance of Communication Equipment	569.3	-
32	Maintenance of Miscellaneous Regional Trans Plant	569.4	-
33	Maintenance of Station equipment	570.0	-
34	Maintenance of Energy Storage Equipment	570.1	-
35	Maintenance of Overhead Lines	571.0	-
36	Maintenance of Underground Lines	572.0	-
37	Maintenance of Miscellaneous Transmission Plant	573.0	-
38	Maintenance of Transmission Plant	574.0	-
39	Total Transmission Expenses - Maintenance		-

($ in Thousands)

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Actual TYE 9-30-22
	Regional Market Expenses - Operation		
40	Operation Supervision	575.1	-
41	Day-Ahead and Real-Time Market Administration	575.2	-
42	Transmission Rights Market Administration	575.3	-
43	Capacity Market Administration	575.4	-
44	Ancillary Market Administration	575.5	-
45	Market Monitoring and Compliance	575.6	-
46	Market Facilitation, Monitoring and Compliance Serv	575.7	-
47	Rents	575.8	-
48	Total Region Market Expenses - Operation		-
	Regional Market Expenses - Maintenance		
49	Maintenance of Structures and Improvements	576.1	-
50	Maintenance of Computer Hardware	576.2	-
51	Maintenance of Computer Software	576.3	-
52	Maintenance of Communication Equipment	576.4	-
53	Maintenance of Misc Market Operation Plant	576.5	-
54	Total Region Market Expenses - Maintenance		-
	Distribution Expense - Operation		
55	Operation Supervision and Engineering	580.0	326
56	Load Dispatching	581.0	268
57	Line and Station Expenses	581.1	-
58	Station Expenses	582.0	48
59	Overhead Line Expenses	583.0	187
60	Underground Line Expenses	584.0	47
61	Operation of Energy Storage Equipment	584.1	-
62	Street Lighting and Signal System Expenses	585.0	13
63	Meter Expenses	586.0	488
64	Customer Installation Expenses	587.0	107
65	Miscellaneous Distribution Expenses	588.0	238
66	Rents	589.0	117
67	Total Distribution Expenses - Operation		1,839
	Distribution Expense - Maintenance		
68	Maintenance Supervision and Engineering	590.0	154
69	Maintenance of Structures	591.0	-
70	Maintenance of Station Equipment	592.0	255
71	Maintenance of Pipe Lines	592.1	-
72	Maintenance of Structures and Equipment	592.2	-
73	Maintenance of Overhead Lines	593.0	8,246
74	Maintenance of Underground Lines	594.0	45
75	Maintenance of Lines	594.1	-
76	Maintenance of Line Transformers	595.0	66
77	Maintenance of Street Lighting and Signal Systems	596.0	73
78	Maintenance of Meters	597.0	35
79	Maintenance of Miscellaneous Distribution Plant	598.0	66
80	Total Distribution Expenses - Maintenance		8,940
	Customer Accounts Expense - Operation		
81	Supervision	901.0	19
82	Meter Reading Expenses	902.0	45
83	Customer Records and Collection Expenses (USP)	903.0	3,050
84	Uncollectible Accounts	904.0	2,443
85	Miscellaneous Customer Accounts Expenses	905.0	14
86	Total Customer Accounts Expense - Operation		5,571

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2022
($ in Thousands)

Schedule B-4
Witness: T. A. Hazenstab

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Actual TYE 9-30-22
	Customer Service & Information Expense		
87	Customer Service and Informational Expenses	906.0	-
88	Supervision	907.0	-
89	Customer Assistance Expenses	908.0	40
90	Information and Instructional Advertising Expenses	909.0	-
91	Miscellaneous Customer Service & Informational Exps (EEC)	910.0	6,123
92	Total Customer Service & Informational Exps - Operations		6,163
	Sales Expense - Operation		
93	Supervision	911.0	-
94	Demonstrating and Selling Expenses	912.0	-
95	Advertising Expenses	913.0	-
96	Miscellaneous Sales Expenses	916.0	(5)
97	Sales Expenses	917.0	-
98	Total Sales Expenses - Operation		(5)
	Administrative & General - Operations		
99	Administrative and General Salaries	920.0	1,905
100	Office Supplies and Expenses	921.0	1,647
101	Administrative Expenses Transferred - Credit	922.0	-
102	Outside Services Employed	923.0	1,583
103	Property Insurance	924.0	20
104	Injuries and Damages	925.0	210
105	Employee Pensions and Benefits	926.0	1,336
106	Franchise Requirements	927.0	-
107	Regulatory Commission Expenses	928.0	186
108	Duplicate Charges - Credit	929.0	(113)
109	General Advertising Expenses	930.1	67
110	Miscellaneous General Expenses	930.2	267
111	Rents	931.0	2
112	Transportation Expenses	933.0	-
113	Total Administrative and General Expenses - Operation		7,111
	Administrative & General - Maintenance		
114	Maintenance of General Plant	935.0	(14)
115	Total Administrative and General Expenses - Maintenance		(14)
116	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 101,171
117	Total Electric Operation Expenses		92,245
118	Total Electric Maintenance Expense		8,926
119	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 101,171

($ in Thousands)

Detail of Taxes

Line No	Description	Reference	[1] Actual TYE 9-30-22
	Taxes Other Than Income Taxes		
	Non-revenue related:		
1	Pennsylvania - PURTA	D-31	$ 42
2	Gross Receipts Tax	D-31	7,263
3	PA and Local Use taxes	D-31	62
4	PUC Assessment	D-31	254
5	Subtotal		7,621
6	Payroll Taxes		
7	Social Security	D-31	623
8	SUTA	D-31	25
9	FUTA	D-31	2
10	Other		-
11	Subtotal		650
12	Total Taxes Other Than Income Taxes		$ 8,271
	Income Taxes		
13	State	D-33	$ 1,244
14	Federal	D-33	2,218
15	Total Income Taxes		$ 3,462

($ in Thousands)

Composite Cost of Debt

Line No	Series	[1] Issue Date	[2] Maturity Date	[3] Amount Outstanding	[4] Percent to Total	[5] Effective Interest Rate	[6] Average Weighted Cost Rate [4] * [5]
Medium Term Notes							
1	6.500%	8/14/2003	8/15/2033	$ 20,000	1.37%	6.56%	0.09%
2	6.133%	10/14/2004	10/15/2034	20,000	1.37%	6.19%	0.08%
Senior Unsecured Notes							
3	6.21%	9/15/2006	9/30/2036	100,000	6.85%	6.32%	0.43%
4	4.98%	3/26/2014	3/26/2044	175,000	11.98%	5.00%	0.60%
5	2.95%	6/30/2016	6/30/2026	100,000	6.85%	3.92%	0.27%
6	4.12%	9/30/2016	9/30/2046	200,000	13.70%	5.01%	0.69%
7	4.12%	10/31/2016	10/31/2046	100,000	6.85%	4.28%	0.29%
8	4.55%	2/1/2019	2/1/2049	150,000	10.27%	4.58%	0.47%
9	3.12%	3/19/2020	4/16/2050	150,000	10.27%	3.15%	0.32%
10	1.59%	6/15/2021	6/15/2026	100,000	6.85%	1.73%	0.12%
11	1.64%	9/15/2021	9/15/2026	75,000	5.14%	1.75%	0.09%
12	3.92%	7/12/2022	7/12/2027	95,313	6.53%	4.00%	0.26%
13	4.75%	7/15/2022	7/15/2032	90,000	6.16%	4.83%	0.30%
14	4.99%	9/15/2022	9/15/2052	85,000	5.82%	5.02%	0.29%
15	Total Long-Term Debt			$ 1,460,313	100.00%		4.30%
16	Total Long-Term Debt			$ 1,460,313	100.00%	4.30%	4.30%
17	Total Short-Term Debt			-	0.00%		0.00%
18	TOTAL			$ 1,460,313	100.00%		
19	Weighted Cost of Debt						4.30%

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2022
($ in Thousands)

Schedule B-7
Witness: P. R. Moul

Rate of Return

Line No	Description	[1] Capitalization Ratio	[2] Embedded Cost	[3] Statement Reference	[4] Return-%
1	Long-Term Debt	46.88%	4.30%	B-6	2.02%
2	Short-Term Debt	0.00%	0.00%	B-6	0.00%
3	Common Equity	53.12%	11.30%		6.00%
4	Total	100.00%			8.02%

($ in Thousands)

Measure of Value

		[1]	[2]	[3]	[4]	[5]
Line		Reference		Pro Forma Test Year Ended September 30, 2022 At		
#	Description	Historic	# of Pages	Present Rates	Adjustments	Proposed Rates
MEASURE OF VALUE						
1	Utility Plant	C-2	5	$ 233,593		$ 233,593
2	Accumulated Depreciation	C-3	6	(77,202)		(77,202)
3	Net Plant in service			156,391	-	156,391
4	Working Capital	C-4	9	10,969		10,969
5	Accumulated Deferred Income Taxes	C-6	1	(27,594)		(27,594)
6	Customer Deposits	C-7	1	(949)		(949)
7	Materials & Supplies	C-8	1	2,152		2,152
8	TOTAL MEASURE OF VALUE			$ 140,969	$ -	$ 140,969

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2022
($ in Thousands)

Schedule C-2
Witness: V. K. Ressler
Page 1 of 5

Pro Forma Electric Plant in Service

Line No	Description	[1] Account No	[2] Pro Forma 9/30/2022
	INTANGIBLE PLANT		
1	Organization	301	$ 11
2	Franchise & Consent	302	5
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		16
	TRANSMISSION PLANT		
5	Land & Land Rights	350	$ -
6	Structures & Improvements	352	-
7	Station Equipment	353	-
8	Station Equipment - SCADA	353.2	-
9	Towers and Fixtures	354	-
10	Poles and Fixtures	355	-
11	Overhead Conductors and Devices	356	-
12	Underground Conduit	357	-
13	Underground Conductors and Devices	358	-
14	Roads and Trails	359	-
15	TOTAL TRANSMISSION		-
	DISTRIBUTION PLANT		
16	Land & Land Rights	360	308
17	Structures & Improvements	361	627
18	Station Equipment	362	10,981
19	Storage Battery Equipment	363	-
20	Poles, Towers and Fixtures	364	54,076
21	Overhead Conductors and Devices	365	53,883
22	Underground Conduit	366	8,780
23	Underground Conductors and Devices	367	14,751
24	Transformers	368.1	16,660
25	Transformer Installations	368.2	11,197
26	Services	369	15,754
27	Meters	370.1	2,951
28	Meter Installations	370.2	1,973
29	Electronic Meters	370.3	5,038
30	Installations on Customers' Premises	371.0	2,219
31	Installations on Customers' Premises - EV Charging Stations	371.1	-
32	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	348
33	Leased Property on Customers' Premises	372	-
34	Street Lighting and Signal Systems	373	2,332
35	TOTAL DISTRIBUTION		201,878
	GENERAL & COMMON PLANT		
36	Land & Land Rights	389	659
37	Structures & Improvements	390	7,633
38	Office Furniture & Equipment	391	19,279
39	Transportation Equipment	392	1,634
40	Stores Equipment	393	10
41	Tools & Garage Equipment	394	1,215
42	Laboratory Equipment	395	71
43	Power Operated Equipment	396	131
44	Communication Equipment	397	761
45	Miscellaneous Equipment	398	306
46	Other Tangible Property	399	-
47	TOTAL GENERAL & COMMON PLANT		31,699
48	Total Plant		$ 233,593

($ in Thousands)

Pro Forma Plant Adjustment Summary

Line #	Description	[1] Factor Or Reference	[2] Test Year 9/30/22 Actual	[3] Adjustments	[4] Pro Forma Test Year [2] + [3]
1	Intangible Plant	Sch C-2, Page 3	$ 16	$ -	$ 16
2	Transmission Plant	Sch C-2, Page 3	-	-	-
3	Distribution Plant	Sch C-2, Page 3	201,878	-	201,878
4	General & Common Plant	Sch C-2, Page 3	31,699	-	31,699
5	Other Plant		-	-	-
6	Total Utility Plant		$ 233,593	$ -	$ 233,593

($ in Thousands)

Pro Forma Year End Plant Balances

Line #	Description	[1] Account Number	[2] Amount	[3] Pro Forma Adjustment	[4] Balance
INTANGIBLE PLANT					
1	Organization	301	$ 11		$ 11
2	Franchise & Consent	302	5		5
3	Miscellaneous Intangible Plant	303	-		-
4	TOTAL INTANGIBLE		16	-	16
TRANSMISSION PLANT					
5	Land & Land Rights	350	-	-	-
6	Structures & Improvements	352	-	-	-
7	Station Equipment	353	-	-	-
8	Station Equipment - SCADA	353.2	-	-	-
9	Towers and Fixtures	354	-	-	-
10	Poles and Fixtures	355	-	-	-
11	Overhead Conductors and Devices	356	-	-	-
12	Underground Conduit	357	-	-	-
13	Underground Conductors and Devices	358	-	-	-
14	Roads and Trails	359	-	-	-
15	TOTAL TRANSMISSION		-	-	-
DISTRIBUTION PLANT					
16	Land & Land Rights	360	308		308
17	Structures & Improvements	361	627		627
18	Station Equipment	362	10,981		10,981
19	Storage Battery Equipment	363	-		-
20	Poles, Towers and Fixtures	364	54,076		54,076
21	Overhead Conductors and Devices	365	53,883		53,883
22	Underground Conduit	366	8,780		8,780
23	Underground Conductors and Devices	367	14,751		14,751
24	Transformers	368.1	16,660		16,660
25	Transformer Installations	368.2	11,197		11,197
26	Services	369	15,754		15,754
27	Meters	370.1	2,951		2,951
28	Meter Installations	370.2	1,973		1,973
29	Electronic Meters	370.3	5,038		5,038
30	Installations on Customers' Premises	371	2,219		2,219
31	Installations on Customers' Premises - EV Charging Stations	371.1	-		-
32	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	348		348
33	Leased Property on Customers' Premises	372	-		-
34	Street Lighting and Signal Systems	373	2,332		2,332
35	TOTAL DISTRIBUTION		201,878	-	201,878
GENERAL & COMMON PLANT					
36	Land & Land Rights	389	659		659
37	Structures & Improvements	390	7,633		7,633
38	Office Furniture & Equipment	391	19,279		19,279
39	Transportation Equipment	392	1,634		1,634
40	Stores Equipment	393	10		10
41	Tools & Garage Equipment	394	1,215		1,215
42	Laboratory Equipment	395	71		71
43	Power Operated Equipment	396	131		131
44	Communication Equipment	397	761		761
45	Miscellaneous Equipment	398	306		306
46	Other Tangible Property	399	-		-
47	TOTAL GENERAL & COMMON PLANT		31,699	-	31,699
48	Total Plant		$ 233,593	$ -	$ 233,593

($ in Thousands)

Additions to Plant

Line #	Description	[1] Account Number	[2] Amount
	Plant Additions		
INTANGIBLE PLANT			
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
TRANSMISSION PLANT			
5	Land & Land Rights	350	-
6	Structures & Improvements	352	-
7	Station Equipment	353	-
8	Station Equipment - SCADA	353.2	-
9	Towers and Fixtures	354	-
10	Poles and Fixtures	355	-
11	Overhead Conductors and Devices	356	-
12	Underground Conduit	357	-
13	Underground Conductors and Devices	358	-
14	Roads and Trails	359	-
15	TOTAL TRANSMISSION		-
DISTRIBUTION PLANT			
16	Land & Land Rights	360	-
17	Structures & Improvements	361	120
18	Station Equipment	362	3,661
19	Storage Battery Equipment	363	-
20	Poles, Towers and Fixtures	364	3,521
21	Overhead Conductors and Devices	365	5,321
22	Underground Conduit	366	132
23	Underground Conductors and Devices	367	1,345
24	Transformers	368.1	1,104
25	Transformer Installations	368.2	289
26	Services	369	537
27	Meters	370.1	-
28	Meter Installations	370.2	25
29	Electronic Meters	370.3	230
30	Installations on Customers' Premises	371	107
31	Installations on Customers' Premises - EV Charging Stations	371.1	-
32	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-
33	Leased Property on Customers' Premises	372	-
34	Street Lighting and Signal Systems	373	145
35	TOTAL DISTRIBUTION		16,537
GENERAL & COMMON PLANT			
36	Land & Land Rights	389	-
37	Structures & Improvements	390	1,445
38	Office Furniture & Equipment	391	3,372
39	Transportation Equipment	392	829
40	Stores Equipment	393	-
41	Tools & Garage Equipment	394	45
42	Laboratory Equipment	395	(50)
43	Power Operated Equipment	396	60
44	Communication Equipment	397	320
45	Miscellaneous Equipment	398	138
46	Other Tangible Property	399	-
47	TOTAL GENERAL & COMMON PLANT		6,159
48	Total Additions		$ 22,696

($ in Thousands)

Retirements

Line #	Description	[1] Account Number	[2] Amount
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	TRANSMISSION PLANT		
5	Land & Land Rights	350	-
6	Structures & Improvements	352	-
7	Station Equipment	353	-
8	Station Equipment - SCADA	353.2	-
9	Towers and Fixtures	354	-
10	Poles and Fixtures	355	-
11	Overhead Conductors and Devices	356	-
12	Underground Conduit	357	-
13	Underground Conductors and Devices	358	-
14	Roads and Trails	359	-
15	TOTAL TRANSMISSION		-
	DISTRIBUTION PLANT		
16	Land & Land Rights	360	-
17	Structures & Improvements	361	-
18	Station Equipment	362	-
19	Storage Battery Equipment	363	-
20	Poles, Towers and Fixtures	364	278
21	Overhead Conductors and Devices	365	133
22	Underground Conduit	366	2
23	Underground Conductors and Devices	367	25
24	Transformers	368.1	526
25	Transformer Installations	368.2	95
26	Services	369	2
27	Meters	370.1	28
28	Meter Installations	370.2	3
29	Electronic Meters	370.3	21
30	Installations on Customers' Premises	371	42
31	Installations on Customers' Premises - EV Charging Stations	371.1	-
32	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-
33	Leased Property on Customers' Premises	372	-
34	Street Lighting and Signal Systems	373	70
35	TOTAL DISTRIBUTION		1,225
	GENERAL & COMMON PLANT		
36	Land & Land Rights	389	-
37	Structures & Improvements	390	-
38	Office Furniture & Equipment	391	323
39	Transportation Equipment	392	-
40	Stores Equipment	393	-
41	Tools & Garage Equipment	394	1
42	Laboratory Equipment	395	13
43	Power Operated Equipment	396	-
44	Communication Equipment	397	136
45	Miscellaneous Equipment	398	-
46	Other Tangible Property	399	-
47	TOTAL GENERAL & COMMON PLANT		473
48	Total Retirements		$ 1,698

($ in Thousands)

Accumulated Provision for Depreciation

Line No	Description	[1] Account Number	[2] Pro Forma 9/30/2022
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	TRANSMISSION PLANT		
5	Land & Land Rights	350	-
6	Structures & Improvements	352	-
7	Station Equipment	353	-
8	Station Equipment - SCADA	353.2	-
9	Towers and Fixtures	354	-
10	Poles and Fixtures	355	-
11	Overhead Conductors and Devices	356	-
12	Underground Conduit	357	-
13	Underground Conductors and Devices	358	-
14	Roads and Trails	359	-
15	TOTAL TRANSMISSION		-
	DISTRIBUTION PLANT		
16	Land & Land Rights	360	-
17	Structures & Improvements	361	36
18	Station Equipment	362	797
19	Storage Battery Equipment	363	-
20	Poles, Towers and Fixtures	364	15,594
21	Overhead Conductors and Devices	365	14,111
22	Regulatory AFUDC	365.7	(83)
23	Underground Conduit	366	2,410
24	Underground Conductors and Devices	367	4,072
25	Transformers	368.1	8,046
26	Transformer Installations	368.2	6,196
27	Services	369	7,528
28	Meters	370.1	2,073
29	Meter Installations	370.2	778
30	Electronic Meters	370.3	4,010
31	Installations on Customers' Premises	371	874
32	Installations on Customers' Premises - EV Charging Stations	371.1	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	335
34	Leased Property on Customers' Premises	372	-
35	Street Lighting and Signal Systems	373	981
36	TOTAL DISTRIBUTION		67,758
	GENERAL & COMMON PLANT		
37	Land & Land Rights	389	11
38	Structures & Improvements	390	1,939
39	Office Furniture & Equipment	391	6,585
40	Transportation Equipment	392	229
41	Stores Equipment	393	3
42	Tools & Garage Equipment	394	458
43	Laboratory Equipment	395	62
44	Power Operated Equipment	396	5
45	Communication Equipment	397	113
46	Miscellaneous Equipment	398	39
47	Other Tangible Property	399	-
48	TOTAL GENERAL & COMMON PLANT		9,444
49	Total Accumulated Provision for Depreciation		$ 77,202

Summary of Accumulated Depreciation

		[1]	[2]	[3]	[4]
		Factor	Test Year Ended September 30, 2022		
Line #	Description	Or Reference	Amount	Pro Forma Adjustment	Balance
1	Intangible Plant	Sch C-3, Pg 3	$ -	$ -	$ -
2	Transmission Plant	Sch C-3, Pg 3	-	-	-
3	Distribution Plant	Sch C-3, Pg 3	67,758	-	67,758
4	General & Common Plant	Sch C-3, Pg 3	9,444	-	9,444
5	Other Plant		-	-	-
6	TOTAL ACC DEPR & AMORTIZATION		$ 77,202	$ -	$ 77,202

($ in Thousands)

Accumulated Depreciation by FERC Account

Line #	Description	[1] Account Number	[2] Amount	[3] Pro Forma Adjustment	[4] Balance
	INTANGIBLE PLANT				
1	Organization	301	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-
4	TOTAL INTANGIBLE		-	-	-
	TRANSMISSION PLANT				
5	Land & Land Rights	350	-	-	-
6	Structures & Improvements	352	-	-	-
7	Station Equipment	353	-	-	-
8	Station Equipment - SCADA	353.2	-	-	-
9	Towers and Fixtures	354	-	-	-
10	Poles and Fixtures	355	-	-	-
11	Overhead Conductors and Devices	356	-	-	-
12	Underground Conduit	357	-	-	-
13	Underground Conductors and Devices	358	-	-	-
14	Roads and Trails	359	-	-	-
15	TOTAL TRANSMISSION		-	-	-
	DISTRIBUTION PLANT				
16	Land & Land Rights	360	-	-	-
17	Structures & Improvements	361	36	-	36
18	Station Equipment	362	797	-	797
19	Storage Battery Equipment	363	-	-	-
20	Poles, Towers and Fixtures	364	15,594	-	15,594
21	Overhead Conductors and Devices	365	14,111	-	14,111
22	Regulatory AFUDC	365.7	(83)		(83)
23	Underground Conduit	366	2,410	-	2,410
24	Underground Conductors and Devices	367	4,072	-	4,072
25	Transformers	368.1	8,046	-	8,046
26	Transformer Installations	368.2	6,196	-	6,196
27	Services	369	7,528	-	7,528
28	Meters	370.1	2,073	-	2,073
29	Meter Installations	370.2	778	-	778
30	Electronic Meters	370.3	4,010	-	4,010
31	Installations on Customers' Premises	371	874	-	874
32	Installations on Customers' Premises - EV Charging Stations	371.1	-		-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	335	-	335
34	Leased Property on Customers' Premises	372	-	-	-
35	Street Lighting and Signal Systems	373	981	-	981
36	TOTAL DISTRIBUTION		67,758	-	67,758
	GENERAL & COMMON PLANT				
37	Land & Land Rights	389	11	-	11
38	Structures & Improvements	390	1,939		1,939
39	Office Furniture & Equipment	391	6,585		6,585
40	Transportation Equipment	392	229		229
41	Stores Equipment	393	3	-	3
42	Tools & Garage Equipment	394	458	-	458
43	Laboratory Equipment	395	62	-	62
44	Power Operated Equipment	396	5	-	5
45	Communication Equipment	397	113	-	113
46	Miscellaneous Equipment	398	39	-	39
47	Other Tangible Property	399	-	-	-
48	TOTAL GENERAL & COMMON PLANT		9,444	-	9,444
49	Total Accumulated Depreciation by FERC Account		$ 77,202	$ -	$ 77,202

($ in Thousands)

Cost of Removal

Line #	Description	[1] Account Number	[2] Amount
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	TRANSMISSION PLANT		
5	Land & Land Rights	350	-
6	Structures & Improvements	352	-
7	Station Equipment	353	-
8	Station Equipment - SCADA	353.2	-
9	Towers and Fixtures	354	-
10	Poles and Fixtures	355	-
11	Overhead Conductors and Devices	356	-
12	Underground Conduit	357	-
13	Underground Conductors and Devices	358	-
14	Roads and Trails	359	-
15	TOTAL TRANSMISSION		-
	DISTRIBUTION PLANT		
16	Land & Land Rights	360	-
17	Structures & Improvements	361	1
18	Station Equipment	362	9
19	Storage Battery Equipment	363	-
20	Poles, Towers and Fixtures	364	441
21	Overhead Conductors and Devices	365	139
22	Regulatory AFUDC	365.7	-
23	Underground Conduit	366	1
24	Underground Conductors and Devices	367	16
25	Transformers	368.1	8
26	Transformer Installations	368.2	34
27	Services	369	40
28	Meters	370.1	(68)
29	Meter Installations	370.2	3
30	Electronic Meters	370.3	2
31	Installations on Customers' Premises	371	33
32	Installations on Customers' Premises - EV Charging Stations	371.1	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-
34	Leased Property on Customers' Premises	372	-
35	Street Lighting and Signal Systems	373	28
36	TOTAL DISTRIBUTION		687
	GENERAL & COMMON PLANT		
37	Land & Land Rights	389	-
38	Structures & Improvements	390	-
39	Office Furniture & Equipment	391	-
40	Transportation Equipment	392	1
41	Stores Equipment	393	-
42	Tools & Garage Equipment	394	-
43	Laboratory Equipment	395	-
44	Power Operated Equipment	396	-
45	Communication Equipment	397	-
46	Miscellaneous Equipment	398	23
47	Other Tangible Property	399	-
48	TOTAL GENERAL & COMMON PLANT		24
49	Total Cost of Removal		$ 711

($ in Thousands)

Negative Net Salvage Amortization

Line #	Description	[1] Account Number	[2] Amount
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	TRANSMISSION PLANT		
5	Land & Land Rights	350	-
6	Structures & Improvements	352	-
7	Station Equipment	353	-
8	Station Equipment - SCADA	353.2	-
9	Towers and Fixtures	354	-
10	Poles and Fixtures	355	-
11	Overhead Conductors and Devices	356	-
12	Underground Conduit	357	-
13	Underground Conductors and Devices	358	-
14	Roads and Trails	359	-
15	TOTAL TRANSMISSION		-
	DISTRIBUTION PLANT		
16	Land & Land Rights	360	-
17	Structures & Improvements	361	-
18	Station Equipment	362	14
19	Storage Battery Equipment	363	-
20	Poles, Towers and Fixtures	364	435
21	Overhead Conductors and Devices	365	108
22	Regulatory AFUDC	365.7	-
23	Underground Conduit	366	4
24	Underground Conductors and Devices	367	13
25	Transformers	368.1	6
26	Transformer Installations	368.2	36
27	Services	369	71
28	Meters	370.1	(41)
29	Meter Installations	370.2	4
30	Electronic Meters	370.3	-
31	Installations on Customers' Premises	371	18
32	Installations on Customers' Premises - EV Charging Stations	371.1	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-
34	Leased Property on Customers' Premises	372	-
35	Street Lighting and Signal Systems	373	16
36	TOTAL DISTRIBUTION		684
	GENERAL & COMMON PLANT		
37	Land & Land Rights	389	-
38	Structures & Improvements	390	-
39	Office Furniture & Equipment	391	-
40	Transportation Equipment	392	(2)
41	Stores Equipment	393	-
42	Tools & Garage Equipment	394	-
43	Laboratory Equipment	395	-
44	Power Operated Equipment	396	-
45	Communication Equipment	397	-
46	Miscellaneous Equipment	398	6
47	Other Tangible Property	399	-
48	TOTAL GENERAL & COMMON PLANT		4
49	Total Negative Net Salvage Amortization		$ 688

($ in Thousands)

Salvage

Line #	Description	[1] Account Number	[2] Amount
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	TRANSMISSION PLANT		
5	Land & Land Rights	350	-
6	Structures & Improvements	352	-
7	Station Equipment	353	-
8	Station Equipment - SCADA	353.2	-
9	Towers and Fixtures	354	-
10	Poles and Fixtures	355	-
11	Overhead Conductors and Devices	356	-
12	Underground Conduit	357	-
13	Underground Conductors and Devices	358	-
14	Roads and Trails	359	-
15	TOTAL TRANSMISSION		-
	DISTRIBUTION PLANT		
16	Land & Land Rights	360	-
17	Structures & Improvements	361	-
18	Station Equipment	362	-
19	Storage Battery Equipment	363	-
20	Poles, Towers and Fixtures	364	-
21	Overhead Conductors and Devices	365	-
22	Regulatory AFUDC	365.7	-
23	Underground Conduit	366	-
24	Underground Conductors and Devices	367	-
25	Transformers	368.1	-
26	Transformer Installations	368.2	-
27	Services	369	-
28	Meters	370.1	-
29	Meter Installations	370.2	-
30	Electronic Meters	370.3	-
31	Installations on Customers' Premises	371	-
32	Installations on Customers' Premises - EV Charging Stations	371.1	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-
34	Leased Property on Customers' Premises	372	-
35	Street Lighting and Signal Systems	373	-
36	TOTAL DISTRIBUTION		-
	GENERAL & COMMON PLANT		
37	Land & Land Rights	389	-
38	Structures & Improvements	390	-
39	Office Furniture & Equipment	391	-
40	Transportation Equipment	392	-
41	Stores Equipment	393	-
42	Tools & Garage Equipment	394	-
43	Laboratory Equipment	395	-
44	Power Operated Equipment	396	-
45	Communication Equipment	397	-
46	Miscellaneous Equipment	398	-
47	Other Tangible Property	399	-
48	TOTAL GENERAL & COMMON PLANT		-
49	Total Salvage		$ -

Working Capital

Line No	Description	[1] Historic 9/30/2022	[2] Reference
1	Working Capital for O & M Expense	$ 8,933	C-4, Page 2
2	Interest Payments	(246)	C-4, Page 7
3	Tax Payment Lag Calculations	250	C-4, Page 8
4	Prepaid Expenses	2,032	C-4, Page 9
5	Total Cash Working Capital Requirements	$ 10,969	

($ in Thousands)

Summary of Working Capital

Line #	Description	[1] Reference	[2] Test Year Expenses	[3] Factor	[4] Number of (Lead) / Lag Days [2] * [3]	[5] Totals
	WORKING CAPITAL REQUIREMENT					
1	REVENUE LAG DAYS	Page 3				59.60
2	EXPENSE LAG DAYS	Page 4				
3	Payroll	Sch D-7	$ 5,327	12.00	$ 63,922	
4	Purchased Power Costs	Sch D-6	90,419	33.30	3,010,530	
5	Other Expenses	L 19 - L 2 to L 4	21,926	30.76	674,446	
6	Total	Sum (L 3 to L 5)	$ 117,672		$ 3,748,898	
7	O & M Expense Lag Days	L6, C 4 / C 2				31.86
8	Net (Lead) Lag Days	L 1 - L 7				27.74
9	Operating Expenses Per Day	L 6, C 2 / 365				$ 322
10	Working Capital for O & M Expense	L 8 * L 9				$ 8,933
11	Interest Payments	Page 7				(246)
12	Tax Payment Lag Calculations	Page 8				250
13	Prepaid Expenses	Page 9				2,032
14	Total Working Capital Requirement	Sum (L 10 to L 13)				$ 10,969
15	Pro Forma O & M Expense		$ 120,779			
	Less:					
16	Uncollectible Expense		3,107			
17	Sub-Total		3,107			
18	Pro Forma Cash O&M Expense		$ 117,672			

($ in Thousands)

Revenue Lag

Line No.	Description	[1] Reference Or Factor	[2] Accounts Receivable Balance End of Month	[3] Total Monthly Sales	[4] A/R Turnover	[5] Days Lag
				Page 2	[3] / [2]	365 / [4]
1	Annual Number of Days					365
2	September, 2021		$ 11,849			
3	October		11,097	6,197		
4	November		9,723	7,951		
5	December, 2021		11,433	10,929		
6	January, 2022		14,407	12,474		
7	February		15,705	11,066		
8	March		16,494	10,190		
9	April		15,957	8,623		
10	May		14,986	8,280		
11	June		15,976	10,966		
12	July		17,542	14,900		
13	August		19,220	13,886		
14	September, 2022		18,672	9,911		
15	Total	Sum L 2 to L 14	$193,061			
16	Number of Months	13				
17	Average Acct Rec Balance	L 15 / L 16	$14,851			
18	Total Sales for Year	Sum L 3 to L 14		$ 125,374		
19	Acct Rec Turnover Ratio	L 18 / L 17			8.44	
20	Collection Lag Day Factor	L 1 / L 19				43.25
21	Meter Read Lag Factor					1.10
22	Midpoint Lag Factor		366 /	12 /	2 =	15.25
23	Total Revenue Lag Days	Sum L 20 to L 22				**59.60**

($ in Thousands)

Summary of Expense Lag Calculations

Line No.	Description	[1] Reference Or Factor	[2] Amount	[3] (Lead) / Lag Days	[4] Weighted Dollar Value [2] * [3]	[5] (Lead) / Lag Days [4] / [2]
	PAYROLL					
1	Union Payrolls	Bi-Weekly	$ 1,181	12.00		
2	Exempt & Non-Exempt	Bi-Weekly	4,146	12.00		
3	Weighted for Union	L1, C2 * C3			$ 14,167	
4	Weighted for Other	L2, C2 * C3			49,756	
5	Payroll Lag	L 3 + L 4	$ 5,327		$ 63,922	
6	Payroll Lag Days	C 4 / C 2				12.00
	PURCHASE POWER COSTS					
7	Payment Lag	Page 6	$ 62,613		$ 2,084,738	
8	Power Cost Lag Days	C 4 / C 2				33.30
	OTHER O & M EXPENSES					
9	OCTOBER 2021	Page 5	$ 767		$ 15,119	
10	NOVEMBER 2021	Page 5	845		31,591	
11	DECEMBER 2021	Page 5	720		29,343	
12	JANUARY 2022	Page 5	1,005		31,292	
13	FEBRUARY 2022	Page 5	797		24,522	
14	MARCH 2022	Page 5	719		17,478	
15	APRIL 2022	Page 5	573		11,770	
16	MAY 2022	Page 5	613		16,801	
17	JUNE 2022	Page 5	1,218		27,474	
18	JULY 2022	Page 5	931		20,148	
19	AUGUST 2022	Page 5	1,314		46,926	
20	SEPTEMBER 2022	Page 5	2,031		82,279	
21	TOTAL		$ 11,532		$ 354,743	
22	Other O&M Expense Lag Days	C 4 / C 2				30.76

($ in Thousands)

General Disbursements Payment Lag Summary

Line #	Description	[1] Number of CDs	[2] Cash Disbursements	[3] Dollar-Days	[4] Expense Lag-Days [3] / [2]
OCTOBER 2021					
1	Total Disbursements for Month	913	$ 4,091		
2	Total Disbursements for Expenses	352	$ 767	$ 15,119	19.72
NOVEMBER 2021					
3	Total Disbursements for Month	672	$ 2,412		
4	Total Disbursements for Expenses	221	$ 845	$ 31,591	37.39
DECEMBER 2021					
5	Total Disbursements for Month	674	$ 2,824		
6	Total Disbursements for Expenses	209	$ 720	$ 29,343	40.76
JANUARY 2022					
7	Total Disbursements for Month	922	$ 3,219		
8	Total Disbursements for Expenses	325	$ 1,005	$ 31,292	31.15
FEBRUARY 2022					
9	Total Disbursements for Month	775	$ 2,732		
10	Total Disbursements for Expenses	229	$ 797	$ 24,522	30.78
MARCH 2022					
11	Total Disbursements for Month	983	$ 10,847		
12	Total Disbursements for Expenses	297	$ 719	$ 17,478	24.30
APRIL 2022					
13	Total Disbursements for Month	776	$ 2,479		
14	Total Disbursements for Expenses	231	$ 573	$ 11,770	20.54
MAY 2022					
15	Total Disbursements for Month	722	$ 2,621		
16	Total Disbursements for Expenses	209	$ 613	$ 16,801	27.43
JUNE 2022					
17	Total Disbursements for Month	996	$ 4,896		
18	Total Disbursements for Expenses	287	$ 1,218	$ 27,474	22.56
JULY 2022					
19	Total Disbursements for Month	830	$ 4,073		
20	Total Disbursements for Expenses	229	$ 931	$ 20,148	21.63
AUGUST 2022					
21	Total Disbursements for Month	1,127	$ 4,214		
22	Total Disbursements for Expenses	434	$ 1,314	$ 46,926	35.71
SEPTEMBER 2022					
23	Total Disbursements for Month	732	$ 4,129		
24	Total Disbursements for Expenses	202	$ 2,031	$ 82,279	40.50
TOTAL TWELVE TEST MONTHS					
25	Total Test Month Expense Disbursement	3,225	$ 11,532	$ 354,743	30.76

Purchase Power Cost Payment Lag Summary

Line #	Description	[1] Number of Invoices	[2] Amount of Invoice	[3] Dollar Days	[4] Total Payment Lag-Days
1	October 2021	5	$ 2,996	$ 106,020	35.39
2	November	5	3,317	108,740	32.78
3	December	7	5,193	181,364	34.93
4	January 2022	10	6,485	205,955	31.76
5	February	9	4,847	153,103	31.59
6	March	6	5,838	223,818	38.34
7	April	8	3,281	154,404	47.06
8	May	7	2,813	100,627	35.77
9	June	11	5,922	176,574	29.82
10	July	12	7,890	244,292	30.96
11	August	10	8,979	247,333	27.55
12	September 2022	6	5,052	182,509	36.13
13	Total		$ 62,613	$ 2,084,738	
14	Purchase Power Lag Days				33.30

Interest Payments

Line No.	Description	[1] Reference Or Factor	[2] # of Days	[3] # of Days	[4] Total
1	Measure of Value at September 30, 2022	Sch C-1			$ 140,969
2	Long-term Debt Ratio	Sch B-7			46.88%
3	Embedded Cost of Long-term Debt	Sch B-6			4.30%
4	Pro forma Interest Expense	L 1 * L 2 * L 3			$ 2,842
5	Daily Amount	L 4 / L 5 [2]	365		$ 8
6	Days to mid-point of interest payments			91.25	
7	Less: Revenue Lag Days	Page 3		59.60	
8	Interest Payment lag days	L 7 - L 6			(31.7)
9	Total Interest for Working Capital	L 5 * L 8			$ (246)

Tax Lag Day Calculations

Line #	Description	[1] Payment Dates	[2] Mid-Point of Service Period	[3] Lead (Lag) Payment Days	[4] Payment Amount	[5] Weighted Lead (Lag) Dollars	[6] Payment Lead (Lag) Days	[7] Revenue (Lag) Days	[8] Net Payment Lead (Lag) Days	[9] Total Dollar Days	[10] Working Capital Amount
				[1] - [2]		[3] * [4]	[5] / [4]		[6] - [7]		365
1	**FEDERAL INCOME TAX**				$ 2,180						
2	First Payment	01/05/22	04/01/22	86.00	$ 545	46,870					
3	Second Payment	03/15/22	04/01/22	17.00	545	9,265					
4	Third Payment	06/15/22	04/01/22	(75.00)	545	(40,875)					
5	Fourth Payment	09/15/22	04/01/22	(167.00)	545	(91,015)					
6	Total				$ 2,180	$ (75,755)	(34.75)	(59.60)	24.85	$ 54,173	$ 148
7	**STATE INCOME TAX**				$ 1,224						
8	First Payment	12/15/21	04/01/22	107.00	$ 306	32,744					
9	Second Payment	03/15/22	04/01/22	17.00	306	5,202					
10	Third Payment	06/15/22	04/01/22	(75.00)	306	(22,952)					
11	Fourth Payment	09/15/22	04/01/22	(167.00)	306	(51,106)		c			
12	Total				$ 1,224	(36,111)	(29.50)	(59.60)	30.10	$ 36,845	$ 101
13	**PA PROPERTY TAX**				$ 62						
14	First Payment	03/31/22	04/01/22	1.00	$ 31	31					
15	Second Payment	09/30/22	04/01/22	(182.00)	31	(5,685)					
16	Total				$ 62	(5,654)	(90.50)	(59.60)	(30.90)	$ (1,930)	$ (5)
17	**PURTA**				$ 76						
18	Payment	05/01/22	04/01/22	(30.00)	$ 76	(2,270)	(30.00)	(59.60)	29.60	$ 2,239	$ 6
19	Total Working Capital For Other Taxes										$ 250

Prepaid Expenses

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Line #	Description		TOTAL	Insurance	PUC Assessment	Gross Receipts Tax	Subscriptions	Miscellaneous	Maintenance & Services
1	September, 2021		1,203	$ 449	$ 203	$ -	$ 30	$ 29	$ 492
2	October		1,244	426	203	-	46	24	545
3	November		1,241	412	178	-	102	21	530
4	December, 2021		1,131	348	152	-	61	12	559
5	January, 2022		1,226	290	127	-	61	50	699
6	February		1,090	231	101	-	55	30	673
7	March		4,791	173	76	3,798	49	27	668
8	April		4,117	121	51	3,238	44	21	643
9	May		3,515	66	25	2,783	39	27	575
10	June		2,305	12	-	1,635	33	21	604
11	July		1,964	620	-	772	12	12	548
12	August		1,193	577	-	-	22	41	553
13	September, 2022		1,399	522	223	-	1	35	618
14	TOTAL		$ 26,420	$ 4,246	$ 1,338	$ 12,225	$ 556	$ 351	$ 7,705
15	Percent to Electric			100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
16	Amount to Electric			$ 4,246	$ 1,338	$ 12,225	$ 556	$ 351	$ 7,705
17	Monthly Average	13		$ 327	$ 103	$ 940	$ 43	$ 27	$ 593
18	Rate Case Amount		$ 2,032						

($ in Thousands)

Accumulated Deferred Income Taxes

Line #	Description	[1] Amount	[2] Total
	Accumulated Deferred Income Tax		
1	Electric Utility Plant - a/c # 282	(27,195)	
2	Sub-total		(27,195)
3	ADIT on CIAC	1,950	
4	Sub-total		1,950
5	Federal ADIT		(25,245)
6	State Repair Regulatory Liability	(2,349)	(2,349)
7	Pro-Rata Adjustment	0	-
8	Balance At September 30, 2022		$ (27,594)

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2022
($ in Thousands)

Customer Deposits

Line #	Description	[1] Balance at End Of Month
1	September, 2021	$ 922
2	October	$ 936
3	November	$ 950
4	December, 2021	$ 950
5	January, 2022	$ 956
6	February	$ 954
7	March	$ 958
8	April	$ 955
9	May	$ 949
10	June	$ 933
11	July	$ 941
12	August	$ 952
13	September, 2022	$ 984
14	Total	$ 12,338
15	Number of Months	13
16	Average Monthly Balance	$ 949

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2022
($ in Thousands)

Materials & Supplies

Line #	Month	[1] Materials and Supplies
1	September, 2021	$ 1,578
2	October	$ 1,571
3	November	$ 1,514
4	December, 2021	$ 1,763
5	January, 2022	$ 1,854
6	February	$ 2,014
7	March	$ 2,232
8	April	$ 2,266
9	May	$ 2,381
10	June	$ 2,713
11	July	$ 2,758
12	August	$ 2,705
13	September, 2022	$ 2,626
14	Total	$ 27,975
15	Number of Months	13
16	Average Monthly Balance	$ 2,152

($ in Thousands)

Summary of Revenue and Expenses
Pro Forma with Proposed Revenue Increase

Line #	Description	Factor Or Reference	Pro Forma Test Year [1] At Present Rates	[2] Rate Increase	[3] At Proposed Rates
	OPERATING REVENUES				
1	Customer & Distribution Revenue		$ 39,574	$ -	$ 39,574
2	Revenue - Cost of Purchased Power		112,047	-	112,047
3	Other Revenues		1,286	-	1,286
4	Revenue Increase			(222)	(222)
5	Total Operating Revenues		152,907	(222)	152,685
	OPERATING EXPENSES				
6	Other Power Supply Expenses		90,419		90,419
7	Transmission		-	-	-
8	Distribution		10,790	-	10,790
9	Customer Accounts		3,133	-	3,133
10	Uncollectible Expense	1.838%	3,107	(4)	3,103
11	Customer Information & Services		6,163	-	6,163
12	Sales		(5)	-	(5)
13	Administrative & General		7,172	-	7,172
14	Depreciation & Amortization		7,331	-	7,331
15	Taxes other than income taxes		9,884	(14)	9,870
16	Total Operating Expenses		137,994	(18)	137,976
17	Net Operating Income Before Income Tax		14,913	(204)	14,709
	Income Taxes				
18	Pro Forma Income Tax At Present Rates		3,462		3,462
19	Pro Forma Income Tax on Revenue Increase			(59)	(59)
20	Net Income (Loss)		$ 11,451	$ (145)	$ 11,306

($ in Thousands)

Summary of Pro Forma Revenue and Expense Adjustments with Proposed Revenue Increase

Line #	Description	[1] Factor Or Reference	[2] Test Year At Present Rates: Pro Forma For Year End 09/30/22	[3] Adjustments Sch D-3 Increase (Decrease)	[4] Pro Forma Adjusted For Test Year 9/30/22	[5] Proposed Increase	[6] Pro Forma Test Year With Proposed Increase
	OPERATING REVENUES			-	[2] + [3]		[4] + [5]
1	Residential	440	$ 89,002	$ 22,017	$ 111,019		$ 111,019
2	Commercial & Industrial	442	34,817	4,723	39,540		39,540
3	Public Streets & Highway Lighting	444	982	60	1,042		1,042
4	Other Sales to Public Authorities	445	21	(1)	20		20
5	Sales for Resale	447	-	0	0		0
6	Forfeited Discounts	450	552	-	552		552
7	Miscellaneous Service Revenues	451	32	-	32		32
8	Rent from Electric Properties	454	602	-	602		602
9	Interest on Undercollection - Refunded	456	100		100		100
10	Rate Increase		-	-	-	(222)	(222)
11	Total Operating Revenues		126,108	26,799	152,907	(222)	152,685
	OPERATING EXPENSES						
12	Other Power Supply Expenses		71,566	18,853	90,419	-	90,419
13	Transmission		-	-	-		-
14	Distribution		10,779	11	10,790		10,790
15	Customer Accounts		3,128	5	3,133		3,133
16	Uncollectible Expense	1.838%	2,443	664	3,107	(4)	3,103
17	Customer Information & Services		6,163	0	6,163		6,163
18	Sales		(5)	-	(5)		(5)
19	Administrative & General		7,097	75	7,172		7,172
20	Depreciation & Amortization		7,767	(436)	7,331		7,331
21	Taxes other than income taxes		8,271	1,612	9,884	(14)	9,870
22	Total Operating Expenses		117,209	20,784	137,994	(18)	137,976
23	Net Operating Income - BIT		$ 8,899	$ 6,015	$ 14,913	$ (204)	$ 14,709

($ in Thousands)

Summary of Pro Forma Adjustments

Line #	Description		[1] Test Year And Allocated	[2] Not Used	[3] Revenues	[4] Power Costs	[5] Salaries & Wages	[6] Not Used	[7] Not Used	[8] Not Used	[9] Uncollectibles Expense	[10] Not Used	[11] Not Used	[12] Sub-Total Adjustments	[13] Total Proforma
	OPERATING REVENUES			D-4	D-5	D-6	D-7	D-8	D-9	D-10	D-11	D-12	D-13		
	Customer & Distribution Revenue														
1	Residential	440	$ 26,945		$ 551									$ 551	$ 27,496
2	Commercial & Industrial	442	11,152		147									147	11,299
3	Public Streets & Highway Lighting	444	757		0									0	757
4	Other Sales to Public Authorities	445	17		(0)									(0)	17
5	Sales for Resale	447	5		0									0	5
	Non-Distribution and Operating Revenue													-	-
6	Residential	457	62,057		21,466									21,466	83,523
7	Commercial & Industrial	457	23,665		4,576									4,576	28,241
8	Public Streets & Highway Lighting	457	225		59									59	284
9	Other Sales to Public Authorities	489	4		(1)									(1)	3
10	Sales for Resale	489	(5)		-									-	(5)
11	Forfeited Discounts	450	552		-									-	552
12	Miscellaneous Service Revenues	451	32		-									-	32
13	Rent from Electric Properties	454	602		-									-	602
14	Interest on Undercollection - Refunded	456	100											-	100
15	Rate Increase		-											-	-
16	Total Operating Revenues		126,108		26,799	-	-	-	-	-	-	-	-	26,799	152,907
	OPERATING EXPENSES														-
17	Other Power Supply Expenses		71,566			-	-							-	71,566
18	Transmission		-			-	-							-	-
19	Distribution		10,779	-			11		-				-	11	10,790
20	Customer Accounts		3,128				5							5	3,133
21	Uncollectible Expense		2,443								664			664	3,107
22	Customer Information & Services		6,163				0							0	6,163
23	Sales		(5)				-							-	(5)
24	Administrative & General		7,097				9	-		-		-		9	7,106
25	Depreciation & Amortization		7,767											-	7,767
26	Taxes other than income taxes		8,271											-	8,271
														-	-
27	Total Operating Expenses		$ 117,209	$ -	$ -	$ -	$ 25	$ -	$ -	$ -	$ 664	$ -	$ -	$ 689	$ 117,898
28	Net Operating Income Before Income Tax		$ 8,899	$ -	$ 26,799	$ -	$ (25)	$ -	$ -	$ -	$ (664)	$ -	$ -	$ 26,110	$ 35,009

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2022
($ in Thousands)

Summary of Pro Forma Adjustments

Line #	Description	[1] From Page 1 Sub-total	[2]	[3] Not Used	[4] Other Adjustments	[5] Not Used	[6] GRT Adjustment	[7] Power Supply Exp Adj	[8] Not Used	[9] Not Used	[10] Depreciation	[11] Taxes Other Than Income	[12]	[13] TOTAL Adjusted
	OPERATING REVENUES			D-14	D-15	D-16	D-17	D-18	D-19	D-20	D-21	D-31		
	Customer & Distribution Revenue													
29	Residential	$ 27,496												$ 27,496
30	Commercial & Industrial	11,299												11,299
31	Public Streets & Highway Lighting	757												757
32	Other Sales to Public Authorities	17												17
33	Sales for Resale	5												5
	Non-Distribution and Operating Revenue													-
34	Residential	83,523												83,523
35	Commercial & Industrial	28,241												28,241
36	Public Streets & Highway Lighting	284												284
37	Other Sales to Public Authorities	3												3
38	Sales for Resale	(5)												(5)
39	Forfeited Discounts	552												552
40	Miscellaneous Service Revenues	32												32
41	Rent from Electric Properties	602												602
42	Interest on Undercollection - Refunded	100												100
43	Rate Increase	-												-
44	Total Operating Revenues	152,907	-	-	-	-	-	-	-	-	-	-	-	152,907
	OPERATING EXPENSES													
45	Other Power Supply Expenses	71,566					-	18,853						90,419
46	Transmission	-												-
47	Distribution	10,790			-									10,790
48	Customer Accounts	3,133			-	-								3,133
49	Uncollectible Expense	3,107												3,107
50	Customer Information & Services	6,163							-					6,163
51	Sales	(5)												(5)
52	Administrative & General	7,106		-	66									7,172
53	Depreciation & Amortization	7,767									(436)			7,331
54	Taxes other than income taxes	8,271					1,575					37		9,884
55	Total Operating Expenses	$ 117,898	$ -	$ -	$ 66	$ -	$ 1,575	$ 18,853	$ -	$ -	$ (436)	$ 37	$ -	$ 137,994
56	Net Operating Income Before Income Tax	$ 35,009	$ -	$ -	$ (66)	$ -	$ (1,575)	$ (18,853)	$ -	$ -	$ 436	$ (37)	$ -	$ 14,913

($ in Thousands)

Adjustment - Revenue Adjustments

Line #	Description	[1] Reference Or Account Number	[2] 2022 Pro Forma	[3] PRO FORMA ADJUSTMENTS Rev Adj Annualization D-5A	[4] Other Adjustments D-5B	[5] Total Proforma Adjustments	[6] Proforma Adjusted At Present Rates
	Customer & Distribution Revenue						
1	Residential	440	$ 26,945	$ 551		$ 551	$ 27,496
2	Commercial & Industrial	442	11,152	147		147	11,299
3	Public Streets & Highway Lighting	444	757	0		0	757
4	Other Sales to Public Authorities	445	17	(0)		(0)	17
5	Sales for Resale	447	5	0		0	5
6	Cust Chg & Distrib Revenue		38,876	698	-	698	39,574
	Non-Distribution and Operating Revenue						
7	Residential	456.5	62,057	21,466		21,466	83,523
8	Commercial & Industrial	456.6	23,665	4,576		4,576	28,241
9	Public Streets & Highway Lighting	456.8	225	59		59	284
10	Other Sales to Public Authorities		4	(1)		(1)	3
11	Sales for Resale		(5)	-		-	(5)
12	Revenue for Cost of Electric		85,946	26,101	-	26,101	112,047
							-
13	Total Customer Revenue		124,822	26,799	-	26,799	151,621
14	Forfeited Discounts	450	552		-	-	552
15	Miscellaneous Service Revenues	451	32		-	-	32
16	Rent from Electric Properties	454	602		-	-	602
17	Interest on Undercollection - Refunded	456.1	100			-	100
18	TOTAL REVENUES		$ 126,108	$ 26,799	$ -	$ 26,799	$ 152,907

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2022
($ in Thousands)

Schedule D-5A
Witness: S. A. Epler

Adjustment - Test Year Revenue Changes

Line #	Description	[1] Factor Or Reference	[2] Pro Forma Jurisdictional	[3] Revised Jurisdictional	[4] Adjustment [3] - [2]	[5] Total Adjustment
	TOTAL REVENUE					
1	Residential	440	$ 89,002	$ 111,019	$ 22,017	
2	Commercial & Industrial	442	34,817	39,540	4,723	
3	Public Streets & Highway Lighting	444	982	1,042	60	
4	Other Sales to Public Authorities	445	21	20	(0.91)	
5	Sales for Resale	447	0	4	4.00	
6	Total		$ 124,822	$ 151,625	$ 26,803	$ 26,803
	COSTS (GSR, Transmission, STAS, EEC, USP, GRT)					
7	Residential		$ 62,057	$ 83,523	21,466	
8	Commercial & Industrial		23,665	28,241	4,576	
9	Public Streets & Highway Lighting		225	284	59	
10	Other Sales to Public Authorities		4	3	(1)	
11	Sales for Resale		(5)	(1)	4	
12	Total		$ 85,946	$ 112,051	$ 26,105	$ 26,105
	NET CUSTOMER & DISTRIBUTION					
13	Residential		$ 26,945	$ 27,496	$ 551	
14	Commercial & Industrial		11,152	11,299	147	
15	Public Streets & Highway Lighting		757	757	0	
16	Other Sales to Public Authorities		17	17	(0)	
17	Sales for Resale		5	5	0	
18	Total		$ 38,876	$ 39,574	$ 698	$ 698

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment - Power Costs

		[1]	[2]	[3]	[4]	[5]
			PRO FORMA ADJUSTMENTS			
Line #	Description	Actual Electric Costs	D-18 Costs	Other Costs	Electric Cost Pro Forma Adjustments	Pro Forma Electric Costs At Pres Rates
1	Budgeted Purchased Power Costs	$ 71,566	$ 18,853	$ -	$ 18,853	$ 90,419
2	Residential				-	-
3	Commercial & Industrial				-	-
4	Public Streets & Highway Lighting				-	-
5	Other Sales to Public Authorities				-	-
6	Sales for Resale				-	-
7	Company Use of Electricity				-	-
8	**Total Purchased Power Costs**	$ 71,566	$ 18,853	$ -	$ 18,853	$ 90,419

($ in Thousands)

Adjustment - Salaries & Wages

Line #	Description	[1] Pro Forma Year 09/30/22	[2] Adjustment	[3] Payroll As Distributed	[4] Annualization Adjustment	[5] Total Pro Forma Payroll
	OPERATIONS					
1	Total Other Power Supply Expenses	$ -	$ -	$ -	$ -	$ -
2	Total Transmission Expenses - Operation	-	-	-	-	-
3	Total Regional Market Expenses - Operation	-	-	-	-	-
4	Total Distribution Expenses - Operation	1,121	-	1,121	5	1,126
5	Total Customer Accounts Expense	1,086	-	1,086	5	1,091
6	Total Customer Service & Informational Expenses	40	-	40	0	40
7	Total Sales Expense	-	-	-	-	-
8	Total A&G - Operation	1,858		1,858	9	1,867
9	Total Operations	4,105	-	4,105	19	4,124
	MAINTENANCE					
10	Total Transmission Expenses - Maintenance	-	-	-	-	-
11	Total Regional Market Expenses - Maintenance	-	-	-	-	-
12	Total Distribution Expenses - Maintenance	1,178	-	1,178	5	1,183
13	Total A&G - Maintenance	19	-	19	0	19
14	Total Maintenance	1,197	-	1,197	6	1,203
15	Total Payroll to Expense	$ 5,302	$ -	$ 5,302	$ 25	$ 5,327
16	Percent Increase					0.466%

($ in Thousands)

Adjustment - Salaries & Wages

Line #	Description	[1] Reference Or Function	[2] Union	[3] Non - Exempt	[5] Exempt	[6] Total Payroll
1	Payroll For TY 9-30-22		$ 1,172	$ 1,060	$ 3,070	$ 5,302
	Annualize for Wage Increase to 9-30-22					
2	Percent Increase		3.00%	3.00%	3.00%	
3	Union Increase At 1-1 Annualization Factor	1/1/22	25%			
4	Non-Exempt Annualization Factor	4/1/22		50%		
5	Exempt Annualization Factor	10/1/22			0%	
6	Increase for wage rate changes	L 1 * L 2 * Ls 3 to 5	9	16	0	$ 25
7	Annualized Salaries & Wages at 9-30-22 Rates	L 1 + L 6	$ 1,181	$ 1,076	$ 3,070	
8	Annualization of other changes FY2022		0	0	$ -	
9	Pro Forma Salaries & Wages for TY		$ 1,181	$ 1,076	$ 3,070	
10	Pro Forma Adjustment to S&W					$ 25
11	Annualization Factor	L 11 / L 1				0.466%

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment - Uncollectibles

Line #	Description	[1] Reference Or Factor	[2] Uncollectible Expense	[3] Tariff Revenue	[4] Percent [2] / [3]	[5] Total [2] / [3]
	Adjustment #1					
1	2020	**(a)**	$ 2,028	$ 84,126	2.41%	
2	2021	**(a)**	$ 1,330	$ 89,272	1.49%	
3	2022		$ 2,133	$ 125,374	1.70%	
4	Three Year Average Sum (Line 1 to Line 3) / 3	3	$ 1,830	$ 99,591		1.838%
5	2022 Actual				$ 2,133	
	Pro Forma Adjustment					
6	Adjusted Revenues	1.838%		$ 152,173		
7	Pro Forma at Present Rate Revenue	L6: [1] * [3]			2,797	
8	Total for Test Year					**$ 664**
	Adjustment #2 (b)					
9	Balance of deferred uncollectibles for Fiscal 2020			$ 1,013		
10	Amortization during Fiscal 2022			310		
11	Recovery of Fiscal 2020 deferred uncollectibles included in Actuals			310		
12	Pro Forma Adjustment					**$ -**
13	Total Uncollectible Adjustment	L8 + L12				**$ 664**

(a) Includes $315 and $1,013 in 2021 and 2020 respectively, which were recorded as regulatory assets associated with COVID-19 in accordance with the May 13, 2020 Secretarial Letter at Docket No. M-2020-3019775. These amounts are the uncollectible accounts reserves needed in excess of the $1,015 uncollectible expense built into rates (from the 2018 Electric Rate Case at Docket No. R-2017-2640058).

(b) $1,013 was deferred and recorded as a regulatory asset for Fiscal 2020 associated with COVID-19 in accordance with the May 13, 2020 Secretarial Letter at Docket No. M-2020-3019775. As approved within the settlement to the 2021 UGI Electric Rate Case at Docket No. R-2021-3023618, this amount is being amortized over 3 years.

Adjustment - Other Adjustments

Line #	Description	[1] Sub-Total	[2] Total
	Customer Accounts Expense Adjustment		
1	Unrecovered Interest on Customer Deposits		$ 66

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment - Gross Receipts Tax

		[1]	[2]
Line #	Description	Amount	Total
1	Revised Jurisdictional Revenue - Schedule D-5A, [3], Line 6	$ 151,625	
2	Other Operating Revenues	1,286	
3	Less: Uncollectible Expense	(3,107)	
4	Total		$ 149,804
5	Gross Receipts Tax Rate		5.90%
6	Revised Gross Receipts Tax		$ 8,838
7	Gross Receipts Tax Expense per Budget		$ 7,263
8	Pro Forma Adjustment		$ 1,575

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment - Power Supply Expense

Line #	Description	[1] Sub-Total	[2] Total
1	Power Supply Expense	$ 71,574	
2	Adjustment for Normalized & Annualized Use/Customer - See Exhibit SAE-6(b)	6	
3	Adjustment for Normalized & Annualized Use/Customer - See Exhibit SAE-6(c)	2,317	
4	Adjustment for Rate Annualization - See Exhibit SAE-6(d)	22,191	
5	Sub-Total	$ 96,088	
6	Adjustment for Gross Receipts Tax (1 - .059)	0.941	
7	Power Supply Expense As Adjusted	$ 90,419	
8	Power Supply Expense per Budget (net of Gross Receipts Tax) (Sch D-6, Col 1)	$ 71,566	
9	Pro Forma Adjustment		$ 18,853

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment - Depreciation expense

Line #	Description	[1] Account Number	[2] Actual 9/30/22 Depreciation Expense	[3] Adjustment To Annualize At New Depre Study Rates	[4] Pro Forma Test Year Depreciation
	INTANGIBLE PLANT				
1	Organization	301	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-
4	TOTAL INTANGIBLE		-	-	-
	TRANSMISSION PLANT				
5	Land & Land Rights	350	-	-	-
6	Structures & Improvements	352	-	-	-
7	Station Equipment	353	-	-	-
8	Station Equipment - SCADA	353.2	-	-	-
9	Towers and Fixtures	354	-	-	-
10	Poles and Fixtures	355	-	-	-
11	Overhead Conductors and Devices	356	-	-	-
12	Underground Conduit	357	-	-	-
13	Underground Conductors and Devices	358	-	-	-
14	Roads and Trails	359	-	-	-
15	TOTAL TRANSMISSION		-	-	-
	DISTRIBUTION PLANT				
16	Land & Land Rights	360	-	-	-
17	Structures & Improvements	361	18	(3)	15
18	Station Equipment	362	287	77	365
19	Storage Battery Equipment	363	-	-	-
20	Poles, Towers and Fixtures	364	1,048	(22)	1,026
21	Overhead Conductors and Devices	365	1,219	(57)	1,163
22	Regulaotry AFUDC	365.7	(14)		(16)
23	Underground Conduit	366	136	2	138
24	Underground Conductors and Devices	367	432	8	440
25	Transformers	368.1	324	8	332
26	Transformer Installations	368.2	313	(91)	221
27	Services	369	286	(21)	265
28	Meters	370.1	75	(24)	52
29	Meter Installations	370.2	27	(2)	25
30	Electronic Meters	370.3	143	(6)	137
31	Installations on Customers' Premises	371	84	10	94
32	Installations on Customers' Premises - EV Charging Stations	371.1	-	-	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	4	(2)	2
34	Leased Property on Customers' Premises	372	-	-	-
35	Street Lighting and Signal Systems	373	79	24	103
36	TOTAL DISTRIBUTION		4,461	(98)	4,361
	GENERAL & COMMON PLANT				
37	Land & Land Rights	389	-	-	-
38	Structures & Improvements	390	150	158	308
39	Office Furniture & Equipment	391	1,422	551	1,973
40	Transportation Equipment	392	138	39	177
41	Stores Equipment	393	1	0	1
42	Tools & Garage Equipment	394	61	1	63
43	Laboratory Equipment	395	11	(9)	2
44	Power Operated Equipment	396	6	4	10
45	Communication Equipment	397	54	90	144
46	Miscellaneous Equipment	398	18	22	41
47	Other Tangible Property	399	-	-	-
48	TOTAL GENERAL & COMMON PLANT		1,862	857	2,719
49	TOTAL DEPRECIATION		$ 6,323	$ 759	$ 7,079
50	CHARGED TO OTHER BUSINESS UNITS (IT-RELATED)		(42)	-	(42)
51	CHARGED TO CLEARING ACCOUNTS		$ (260)	$ (134)	$ (394)
52	NET SALVAGE AMORTIZATION		$ 655	$ 33	$ 688
53	TOTAL CLAIMED DEPRECIATION AND AMORTIZATION		$ 6,676	$ 658	$ 7,331

($ in Thousands)

Adjustment - Taxes Other Than Income Taxes

		[1]	[2]	[3]	[4]	[5]
Line #	Description	Account Number	Factor or Reference	Actual Amounts 9/30/22	Pro Forma Adjustments	Pro Forma Tax Expense 9/30/22
1	PURTA Taxes	408.1		$ 42	$ 34	$ 76
2	Gross Receipts Tax	408.1	D-17	7,263	1,575	8,838
3	PA & Local Use taxes	408.1		62	-	62
4	Social Security	408.1	D-32	623	3	626
5	FUTA	408.1	D-32	2	-	2
6	SUTA	408.1	D-32	25	-	25
7	PUC Assessment	408.1		254	-	254
8	Total			$ 8,271	$ 1,612	$ 9,884

($ in Thousands)

Adjustment - Payroll Taxes

Line #	Description	[1] Account Number	[2] Test Year 9/30/22 Present Rates	[3] Pro Forma Adjustments	[4] Increase in Payroll Taxes
1	Total Payroll Charged to Expense		$ 5,302	$ 25	
2	FICA Expense		623		
3	FICA Expense - Percent	L 2 / L 1	11.75%	11.75%	
4	Pro Forma FICA Expense on Pro Forma S&W	[4] L 1 * L 3			$ 3
5	FUTA Expense		2		
6	FUTA Expense - Percent	L 5 / L 1	0.05%	0.05%	
7	Pro Forma FUTA Expense on Pro Forma S&W	[4] L 1 * L 6			-
8	SUTA Expense		25		
9	SUTA Expense - Percent	L 8 / L 1	0.47%	0.47%	
10	Pro Forma SUTA Expense on Pro Forma S&W	[4] L 1 * L 9			-
11	Pro Forma Adjustment	Sum L 4 to L 10			$ 3

($ in Thousands)

Income Tax Calculation

Line #	Description	[1] Factor Or Reference	[2] Element Or Amount	[3] Pro Forma Test Year At Present Rates	[4] Revenue Increase	[5] Pro Forma Test Year At Proposed Rates [3] + [4]
1	Revenue			$ 152,907	$ (222)	$ 152,685
2	Operating Expenses			(137,994)	18	(137,976)
3	OIBIT	L 1 + L 2		14,913	(204)	14,709
	Interest Expense					
4	Rate Base	Sch A-1	140,969			
5	Weighted Cost of Debt	Sch B-7	0.02020			
6	Synchronized Interest Expense	L 4 * L 5		(2,848)	-	(2,848)
7	Base Taxable Income	L 3 + L 6		12,065	(204)	11,861
8	Total Tax Depreciation	Sch D-34	$ 8,750			
9	Pro Forma Book Depreciation	Sch D-34	7,660			
10	State Tax Depreciation (Over) Under Book	L 9 - L 8		(1,090)		(1,090)
11	Other				-	-
12	State Taxable Income	Sum L 7 to L 11		$ 10,976	$ (204)	$ 10,772
13	State Income Tax (Expense)/Refund	L 12 * Rate [2]	9.99%	$ (1,096)	$ 20	$ (1,076)
14	Total Tax Depreciation	Sch D-34	$ 8,804			
15	Pro Forma Book Depreciation	Sch D-34	7,660			
16	Federal Tax Deducts (Over) Under Book	L 14 - L 13		(1,144)	-	(1,144)
17	Other				-	-
18	Federal Taxable Income	L 7 + sum L 13 to L 17		9,825	(184)	9,642
19	Federal Income Tax (Expense)/Refund	-L 18 * Rate [2]	21.00%	(2,063)	39	(2,025)
20	Total Tax Expense before Deferred Income Tax	L 13 + L 19		(3,159)	59	(3,101)
	Deferred Federal Income Taxes					
21	Total Straight Line Tax Depreciation	Sch D-34	$ -			
22	Total Tax Depreciation	Sch D-34	8,015			
23	Federal Tax Deducts (Over) Under Book	L 22 - L 21		8,015	-	8,015
24	Deferred Federal Taxable Income	L 23		$ 8,015	$ -	$ 8,015
25	Federal Income Tax (Expense)/Refund	-L 24 * Rate [2]	Blended Rate [1]	(155)	-	(155)
	Deferred State Income Taxes					
26	Repairs			(296)		(296)
27	CIAC			148		148
28	State Deferred Income Tax (Expense)/Refund			(148)	-	(148)
29	Net Income Tax Expense	L20 + L 25 + L28		(3,462)	59	(3,404)
	Other Tax Adjustments					
30	ITC			-		-
31	Combined Income Tax Expense	L 29 + L 30		$ (3,462)	$ 59	$ (3,404)
32	Federal Income Tax Expense	L 19 + L 25 + L 30		$ (2,218)	$ 39	$ (2,180)
33	State Income Tax Expense	L 13 + L 28		(1,244)	20	(1,224)
34	Total Income Tax Expense	L 32 + L 33		$ (3,462)	$ 59	$ (3,404)

[1] Due to the 2018 Tax Cuts and Jobs Act, excess deferred income tax is now being flowed back to customers which results in a deferred tax rate other than 21%.

($ in Thousands)

Tax Depreciation

Line #	Description	[1] Amount	[2] Amount	[3] Total
	Accelerated Tax Depreciation			
1	Electric Plant		$ 4,102	
2	Cost of Removal		789	
3	Repairs Tax Deduction		5,965	
4	Other Tax Basis Adjustments		(2,052)	
5	Total Federal Accelerated Tax Depreciation			$ 8,804
6	Adjustment for PA Tax Depreciation - Bonus Decoupling		(54)	
7	Total State Accelerated Tax Depreciation			$8,750
	Straight Line Tax Depreciation			
8	Electric Plant		$ -	
9	Total Tax Depreciation			$ -
	Book Depreciation			
10	Pro Forma Book Depreciation		$ 7,079	
11	Net Salvage Amortization		688	
12	Depreciation Charged to Clearing Accounts	(436)		
13	Estimated Percent of Clearing Charged to CWIP	25%		
14	Depreciation Charged to CWIP		(107)	
15	Book Depreciation for Tax Calculation			$ 7,660

($ in Thousands)

Gross Revenue Conversion Factor

Line #	Description	[1] Reference Or Factor	[2] Tax Rate	[3] Factor
	GROSS REVENUE CONVERSION FACTOR			
1	GROSS REVENUE FACTOR			1.000000
2	UNCOLLECTIBLE EXPENSES			(0.018380)
3	NET REVENUES	Sum L 1 to L 2		0.981620
4	GROSS RECEIPTS TAX	[3] L 3 * Rate [2]	6.27%	(0.062700)
5	FACTOR AFTER GROSS RECEIPTS TAX			0.918920
6	STATE INCOME TAXES	[3] L 5 * Rate [2]	9.99%	(0.091800)
7	FACTOR AFTER STATE TAXES	L 5 + L 6		0.827120
8	FEDERAL INCOME TAXES	[3] L 7 * Rate [2]	21.00%	(0.173695)
9	NET OPERATING INCOME FACTOR	L 7 + L 8		0.653425
10	GROSS REVENUE CONVERSION FACTOR	1 / L 9		1.530398
11	Combined Income Tax Factor On Gross Revenues	-L 6 - L 8		26.550%
	INCOME TAX FACTOR			
12	GROSS REVENUE FACTOR			1.000000
13	STATE INCOME TAXES	[3] L 10 * Rate [2]	9.9900%	(0.099900)
14	FACTOR AFTER STATE TAXES	L 10 + L 11		0.900100
15	FEDERAL INCOME TAXES	[3] L 12 * Rate [2]	21.00%	(0.189021)
16	NET OPERATING INCOME FACTOR	L 12 + L 13		0.711079
17	GROSS REVENUE CONVERSION FACTOR	1 / L 14		1.406314
18	Combined Income Tax Factor On Taxable Income	-L 11 - L 13		28.892%

UGI ELECTRIC

EXHIBIT B

RATE OF RETURN

UGI Utilities, Inc. – Electric Division

Exhibit to Accompany the

Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

Concerning

Fair Rate of Return

UGI Utilities, Inc. – Electric Division
Index of Schedules

UGI Utilities, Inc.
Proposed Rate of Return
Estimated at September 30, 2024

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	45.41%	4.35%	1.98%
Common Equity	54.59%	11.30%	6.17%
Total	100.00%		8.15%

Indicated levels of fixed charge coverage assuming that
the Company could actually achieve its proposed rate of return:

Pre-tax coverage of interest expense based upon a
28.1021% composite federal and state income tax rate
(10.56% ÷ 1.98%) 5.33 x

Post-tax coverage of interest expense
(8.15% ÷ 1.98%) 4.12 x

UGI Utilities, Inc.

Cost of Equity
as of October 30, 2022

Market Models (DCF, RP & CAPM)

Discounted Cash Flow (DCF)					D_1/P_0 (1)	+	g (2)	+	lev. (3)	=	k
Electric Group					3.48%	+	6.00%	+	0.97%	=	10.45%
Risk Premium (RP)							I (4)	+	RP (5)	=	k
Electric Group							5.50%	+	6.25%	=	11.75%
Capital Asset Pricing Model (CAPM)	Rf (6)	+	ß (7)	x (			Rm-Rf (8)	) +	size (9)	=	k
Electric Group	4.00%	+	1.08	x (			10.12%	) +	1.02%	=	15.95%

Book Value Method

	Historical	Forecast	Average
Comparable Earnings (CE) (10)			
Comparable Earnings Group	12.8%	13.4%	13.10%

References:
(1) Schedule 07
(2) Schedule 09
(3) Schedule 10
(4) A-rated public utility bond yield comprised of a 2.00% risk-free rate of return and a yield spread of 1.50% (Schedule 11 page
(5) Schedule 12
(6) Schedule 13 page 2
(7) Schedule 10
(8) Schedule 13 page 2
(9) Schedule 13 page 3
(10) Schedule 14 pages 2

UGI Utilities, Inc.
Capitalization and Financial Statistics
2017-2021, Inclusive

	2021	2020	2019	2018	2017	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 2,712.0	$ 2,435.0	$ 2,207.5	$ 1,951.6	$ 1,765.8	
Short-Term Debt	$ 130.0	$ 141.0	$ 166.0	$ 189.5	$ 170.0	
Total Capital	$ 2,842.0	$ 2,576.0	$ 2,373.5	$ 2,141.1	$ 1,935.8	
Capital Structure Ratios						
Based on Permanent Captial:						Average
Long-Term Debt	47.5%	46.0%	44.4%	42.9%	42.5%	44.7%
Common Equity (1)	52.5%	54.0%	55.6%	57.1%	57.5%	55.3%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	49.9%	49.0%	48.2%	48.0%	47.6%	48.5%
Common Equity (1)	50.1%	51.0%	51.8%	52.0%	52.4%	51.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity (1)	10.7%	10.7%	11.4%	14.0%	11.8%	11.7%
Operating Ratio (2)	77.4%	77.8%	78.5%	78.5%	75.2%	77.5%
Coverage incl. AFUDC (3)						
Pre-tax: All Interest Charges	4.44 x	4.24 x	4.55 x	5.54 x	5.68 x	4.89 x
Post-tax: All Interest Charges	3.65 x	3.52 x	3.68 x	4.47 x	3.89 x	3.84 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	4.44 x	4.24 x	4.55 x	5.54 x	5.68 x	4.89 x
Post-tax: All Interest Charges	3.65 x	3.52 x	3.68 x	4.47 x	3.89 x	3.84 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Effective Income Tax Rate	22.8%	22.3%	24.4%	23.5%	38.3%	26.3%
Internal Cash Generation/Construction (4)	69.4%	68.7%	67.8%	86.8%	75.6%	73.7%
Gross Cash Flow/ Avg. Total Debt (5)	22.9%	23.5%	24.9%	33.9%	33.9%	27.8%
Gross Cash Flow Interest Coverage (6)	6.53 x	6.15 x	6.58 x	8.70 x	7.91 x	7.17 x
Common Dividend Coverage (7)	8.77 x	5.66 x	13.55 x	6.61 x	5.00 x	7.92 x

See Page 2 for Notes.

UGI Utilities, Inc.
Capitalization and Financial Statistics
2017-2021, Inclusive

Notes:

(1) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.

(2) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.

(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFUDC) as a percentage of average total debt.

(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.

(7) Common dividend coverage is the relationship of internally generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Certified financial statements

Electric Group
Capitalization and Financial Statistics [1]
2017-2021, Inclusive

	2021	2020	2019	2018	2017	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 55,240.3	$ 54,211.8	$ 52,064.3	$ 46,943.9	$ 44,307.3	
Short-Term Debt	$ 1,777.2	$ 1,638.4	$ 1,473.9	$ 1,960.6	$ 1,270.5	
Total Capital	$ 57,017.5	$ 55,850.2	$ 53,538.2	$ 48,904.5	$ 45,577.8	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	24 x	26 x	20 x	19 x	19 x	22 x
Market/Book Ratio	197.3%	186.0%	197.4%	187.8%	195.6%	192.8%
Dividend Yield	3.8%	4.0%	3.7%	3.9%	3.7%	3.8%
Dividend Payout Ratio	79.7%	96.3%	69.7%	70.5%	68.9%	77.0%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	52.3%	54.1%	52.0%	52.2%	54.3%	53.0%
Preferred Stock	2.1%	2.3%	2.1%	1.5%	1.0%	1.8%
Common Equity [2]	45.5%	43.6%	45.9%	46.4%	44.7%	45.2%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	53.8%	55.5%	53.4%	54.0%	55.7%	54.5%
Preferred Stock	2.1%	2.2%	2.0%	1.4%	1.0%	1.7%
Common Equity [2]	44.1%	42.3%	44.6%	44.6%	43.4%	43.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	7.5%	7.4%	8.7%	10.2%	11.1%	9.0%
Operating Ratio [3]	84.9%	79.3%	78.7%	76.7%	73.6%	78.6%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	2.89 x	2.70 x	3.00 x	3.48 x	3.38 x	3.09 x
Post-tax: All Interest Charges	2.60 x	2.47 x	2.66 x	2.97 x	3.23 x	2.79 x
Overall Coverage: All Int. & Pfd. Div.	2.58 x	2.46 x	2.65 x	2.91 x	3.23 x	2.77 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	2.81 x	2.61 x	2.91 x	3.39 x	3.28 x	3.00 x
Post-tax: All Interest Charges	2.52 x	2.38 x	2.57 x	2.89 x	3.14 x	2.70 x
Overall Coverage: All Int. & Pfd. Div.	2.51 x	2.37 x	2.57 x	2.83 x	3.13 x	2.68 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	8.2%	6.5%	4.8%	5.5%	4.2%	5.8%
Effective Income Tax Rate	15.9%	9.2%	17.3%	20.0%	-13.9%	9.7%
Internal Cash Generation/Construction [5]	61.2%	60.3%	67.1%	78.0%	75.0%	68.3%
Gross Cash Flow/ Avg. Total Debt [6]	14.7%	15.4%	17.4%	19.3%	20.3%	17.4%
Gross Cash Flow Interest Coverage [7]	5.17 x	4.84 x	4.84 x	5.45 x	5.69 x	5.20 x
Common Dividend Coverage [8]	3.08 x	3.09 x	3.38 x	3.75 x	4.06 x	3.47 x

See Page 2 for Notes.

Electric Group
Capitalization and Financial Statistics
2017-2021, Inclusive

Notes:
(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(7) Gross Cash Flow plus interest charges divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection:
The Electric Group includes companies that: (i) have publicly-traded common stock, (ii) are contained in The Value Line Investment Survey and are classified in the Electric Utility East group, (iii) are not currently the target of an announced merger or acquisition, (iv) are not engaged in the construction of a nuclear generating plant or have not recently cancelled the construction of a nuclear generating plant, and (v) have not recently reduced its common dividend.

		Corporate Credit Ratings		Stock	Value Line
Ticker	Company	Moody's	S&P	Traded	Beta
AGR	AVANGRID, Inc (AGR)	A3	A-	NYSE	0.85
ED	Consolidated Edison Inc (ED)	Baa1	A-	NYSE	0.75
D	Dominion Energy, Inc. (D)	A2	BBB+	NYSE	0.80
DUK	Duke Energy Corporation (DUK)	A2	BBB+	NYSE	0.85
ES	Eversource Energy (ES)	A2	A	NYSE	0.90
EXC	Exelon Corp (EXC)	A2	BBB+	NDQ	NMF
FE	FirstEnergy Corp (FE)	A3	BBB	NYSE	0.85
NEE	NextEra Energy Inc (NEE)	A1	A	NYSE	0.95
PPL	PPL Corp (PPL)	A3	A	NYSE	1.10
PEG	Public Service Enterprise Group I	A3	A-	NYSE	0.90
	Average	A3	A-		0.88

Note: Ratings are those of utility subsidiaries

Source of Information: Standard & Poor's Utility COMPUSTAT
Moody's Investors Service
Standard & Poor's Corporation

Standard & Poor's Public Utilities
Capitalization and Financial Statistics [1]
2017-2021, Inclusive

	2021	2020	2019	2018	2017	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 40,154.3	$ 38,732.9	$ 36,461.6	$ 32,871.6	$ 30,827.6	
Short-Term Debt	$ 1,397.4	$ 1,154.1	$ 1,221.9	$ 1,420.3	$ 1,076.1	
Total Capital	$ 41,551.7	$ 39,887.0	$ 37,683.5	$ 34,291.9	$ 31,903.7	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	22 x	23 x	20 x	21 x	20 x	21 x
Market/Book Ratio	219.9%	218.2%	220.9%	204.4%	214.4%	215.6%
Dividend Yield	3.5%	3.6%	3.2%	3.5%	3.3%	3.4%
Dividend Payout Ratio	72.9%	78.0%	62.7%	68.7%	65.2%	69.5%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	57.4%	58.1%	56.7%	55.0%	56.8%	56.8%
Preferred Stock	2.3%	2.6%	2.4%	2.5%	1.4%	2.2%
Common Equity [2]	40.4%	39.4%	41.0%	42.5%	41.8%	41.0%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	58.9%	59.4%	58.1%	57.0%	58.4%	58.3%
Preferred Stock	2.2%	2.5%	2.3%	2.4%	1.4%	2.1%
Common Equity [2]	38.9%	38.1%	39.6%	40.7%	40.3%	39.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	9.4%	10.2%	10.3%	10.3%	9.4%	9.9%
Operating Ratio [3]	83.1%	79.8%	79.3%	79.8%	77.0%	79.8%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.16 x	2.80 x	3.05 x	2.94 x	3.42 x	3.07 x
Post-tax: All Interest Charges	2.87 x	2.60 x	3.10 x	2.59 x	2.86 x	2.80 x
Overall Coverage: All Int. & Pfd. Div.	2.81 x	2.55 x	3.04 x	2.55 x	2.84 x	2.76 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	3.06 x	2.70 x	2.95 x	2.84 x	3.31 x	2.97 x
Post-tax: All Interest Charges	2.78 x	2.50 x	3.00 x	2.48 x	2.75 x	2.70 x
Overall Coverage: All Int. & Pfd. Div.	2.72 x	2.46 x	2.94 x	2.44 x	2.73 x	2.66 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	7.4%	6.8%	6.0%	7.3%	7.3%	7.0%
Effective Income Tax Rate	10.6%	9.9%	12.2%	19.0%	28.2%	16.0%
Internal Cash Generation/Construction [5]	60.5%	58.6%	65.9%	66.2%	78.7%	66.0%
Gross Cash Flow/ Avg. Total Debt [6]	15.0%	15.9%	17.5%	17.4%	19.9%	17.1%
Gross Cash Flow Interest Coverage [7]	5.17 x	4.90 x	4.97 x	4.98 x	5.57 x	5.12 x
Common Dividend Coverage [8]	3.47 x	3.52 x	5.56 x	4.80 x	4.33 x	4.34 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2017-2021, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(7) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities
Company Identities

	Ticker	Credit Rating [1] Moody's	S&P	Common Stock Traded	Value Line Beta
Alliant Energy Corporation	LNT	Baa1	A-	NYSE	0.85
Ameren Corporation	AEE	Baa1	BBB+	NYSE	0.80
American Electric Power	AEP	Baa1	A-	NYSE	0.75
American Water Works	AWK	Baa1	A	NYSE	0.85
CenterPoint Energy	CNP	Baa1	BBB+	NYSE	1.15
CMS Energy	CMS	A3	A-	NYSE	0.80
Consolidated Edison	ED	Baa1	A-	NYSE	0.75
Dominion Energy	D	A2	BBB+	NYSE	0.85
DTE Energy Co.	DTE	A2	A-	NYSE	0.95
Duke Energy	DUK	A2	BBB+	NYSE	0.85
Edison Int'l	EIX	Baa2	BBB	NYSE	0.95
Entergy Corp.	ETR	Baa1	BBB+	NYSE	0.95
Evergy, Inc.	EVRG	Baa1	A-	NYSE	0.95
Eversource	ES	A2	A	NYSE	0.90
Exelon Corp.	EXC	A2	BBB+	NYSE	0.95
FirstEnergy Corp.	FE	A3	BBB	NYSE	0.85
NextEra Energy Inc.	NEE	A1	A	NYSE	0.90
NiSource Inc.	NI	Baa2	BBB+	NYSE	0.85
NRG Energy Inc.	NRG	Ba1	BB+	NYSE	1.15
Pinnacle West Capital	PNW	A3	BBB+	NYSE	0.90
PPL Corp.	PPL	A3	A	NYSE	1.10
Public Serv. Enterprise Inc.	PEG	A3	A-	NYSE	0.90
Sempra Energy	SRE	A3	BBB+	NYSE	0.95
Southern Co.	SO	Baa1	BBB+	NYSE	0.95
WEC Energy Corp.	WEC	A2	A-	NYSE	0.80
Xcel Energy Inc	XEL	A2	A-	NYSE	0.80
Average for S&P Utilities		A3	BBB+		0.90

Note: [1] Ratings are those of utility subsidiaries

Source of Information: Moody's Investors Service, Inc.
S&P Global Inc.
The Value Line Investment Survey

UGI Utilities, Inc.
Capitalization and Related Capital Structure Ratios
Actual at September 30, 2022 and Estimated at September 30, 2023 and September 30, 2024

	Actual at September 30, 2022				Estimated at September 30, 2023				Estimated at September 30, 2024			
		Capital Structure Ratios					Capital Structure Ratios				Capital Structure Ratios	
	Amount Outstanding ($000)	Incl. S-T Debt	Excl. S-T Debt		Amount Outstanding ($000)		Incl. S-T Debt	Excl. S-T Debt	Amount Outstanding ($000)		Incl. S-T Debt	Excl. S-T Debt
Long-Term Debt [1]	$ 1,460,313	45.95%	46.88%		$ 1,454,063	[2]	42.87%	43.97%	$ 1,672,813	[2]	45.41%	45.41%
Common Equity												
Common Stock	60,259				60,259				60,259			
Other Paid-In Capital	508,580				508,580				508,580			
Retained Earnings [3]	1,085,981				1,284,398	[4]			1,442,468	[4]		
Total Common Equity	1,654,820	52.07%	53.12%		1,853,237		54.64%	56.03%	2,011,307		54.59%	54.59%
Total Permanent Capital	3,115,133	98.02%	100.00%		3,307,300		97.51%	100.00%	3,684,120		100.00%	100.00%
Avg. Net Short-Term Debt [5]	62,964	1.98%			84,680		2.50%		-		0.00%	
Total Capital Employed	$ 3,178,097	100.00%			$ 3,391,980		100.01%		$ 3,684,120		100.00%	

Notes:

	2022	2023	2024
[1] Includes current portion of long-term debt.			
[2] Reflects change in long-term debt consisting of:			
Principal payments		$ (6,250)	$ (6,250)
New issues			$ 225,000
[3] Excludes Accumulated Other Comprehensive Income of:	$ (16,648)	$ (16,648)	$ (16,648)
[4] Reflects change in retained earnings consisting of:			
Net income		$ 198,417	$ 213,070
Common Dividends		$ -	$ (55,000)
[5] Average Short-Term Debt			
Balance	$ 164,333	$ 214,739	$ 130,860
Less: CWIP	(101,369)	(130,059)	(137,750)
Net	$ 62,964	$ 84,680	$ (6,890)

Source of Information: Company provided data

UGI Utilities, Inc.
Calculation of the Embedded Cost of Long-Term Debt
Actual at September 30, 2022

Series	Date of Maturity	Principal Amount Outstanding ($000)	Percent to Total	Effective Cost Rate [1]	Weighted Cost Rate
Medium Term Notes					
6.500%	08/15/33	$ 20,000	1.37%	6.56%	0.09%
6.133%	10/15/34	20,000	1.37%	6.19%	0.08%
Senior Notes					
6.206%	09/30/36	100,000	6.85%	6.32%	0.43%
4.980%	03/26/44	175,000	11.98%	5.00%	0.60%
2.950%	06/30/26	100,000	6.85%	3.92%	0.27%
4.120%	09/30/46	200,000	13.70%	5.01%	0.69%
4.120%	10/31/46	100,000	6.85%	4.28%	0.29%
4.550%	02/01/49	150,000	10.27%	4.58%	0.47%
3.120%	04/16/50	150,000	10.27%	3.15%	0.32%
1.590%	06/15/26	100,000	6.85%	1.73%	0.12%
1.640%	09/15/26	75,000	5.14%	1.75%	0.09%
3.917%	07/12/27	95,313	6.53%	4.00%	0.26%
4.750%	07/15/32	90,000	6.16%	4.83%	0.30%
4.990%	09/15/52	85,000	5.82%	5.02%	0.29%
Total Long-Term Debt		$ 1,460,313	100.00%		4.30%

Notes: [1] As calculated on page 4 of this schedule.

Source of Information: Company provided data

UGI Utilities, Inc.
Calculation of the Embedded Cost of Long-Term Debt
Estimated at September 30, 2023

Series	Date of Maturity	Principal Amount Outstanding ($000)	Percent to Total	Effective Cost Rate [1]	Weighted Cost Rate
Medium Term Notes					
6.500%	08/15/33	$ 20,000	1.38%	6.56%	0.09%
6.133%	10/15/34	20,000	1.38%	6.19%	0.09%
Senior Notes					
6.206%	09/30/36	100,000	6.88%	6.32%	0.43%
4.980%	03/26/44	175,000	12.04%	5.00%	0.60%
2.950%	06/30/26	100,000	6.88%	3.92%	0.27%
4.120%	09/30/46	200,000	13.76%	5.01%	0.69%
4.120%	10/31/46	100,000	6.88%	4.28%	0.29%
4.550%	02/01/49	150,000	10.32%	4.58%	0.47%
3.120%	04/16/50	150,000	10.32%	3.15%	0.32%
1.590%	06/15/26	100,000	6.88%	1.73%	0.12%
1.640%	09/15/26	75,000	5.16%	1.75%	0.09%
3.917%	07/12/27	89,063	6.13%	4.00%	0.25%
4.750%	07/15/32	90,000	6.19%	4.83%	0.30%
4.990%	09/15/52	85,000	5.85%	5.02%	0.29%
Total Long-Term Debt		$ 1,454,063	100.00%		4.30%

Notes: [1] As calculated on page 4 of this schedule.

Source of Information: Company provided data

UGI Utilities, Inc.
Calculation of the Embedded Cost of Long-Term Debt
Estimated at September 30, 2024

Series	Date of Maturity	Principal Amount Outstanding ($000)	Percent to Total	Effective Cost Rate [1]	Weighted Cost Rate
Medium Term Notes					
6.500%	08/15/33	$ 20,000	1.20%	6.56%	0.08%
6.133%	10/15/34	20,000	1.20%	6.19%	0.07%
Senior Notes					
6.206%	09/30/36	100,000	5.98%	6.32%	0.38%
4.980%	03/26/44	175,000	10.46%	5.00%	0.52%
2.950%	06/30/26	100,000	5.98%	3.92%	0.23%
4.120%	09/30/46	200,000	11.96%	5.01%	0.60%
4.120%	10/31/46	100,000	5.98%	4.28%	0.26%
4.550%	02/01/49	150,000	8.97%	4.58%	0.41%
3.120%	04/16/50	150,000	8.97%	3.15%	0.28%
1.590%	06/15/26	100,000	5.98%	1.73%	0.10%
1.640%	09/15/26	75,000	4.48%	1.75%	0.08%
3.917%	07/12/27	82,813	4.95%	4.00%	0.20%
4.750%	07/15/32	90,000	5.38%	4.83%	0.26%
4.990%	09/15/52	85,000	5.08%	5.02%	0.26%
4.551%	10/31/53	225,000	13.45%	4.60%	0.62%
Total Long-Term Debt		$ 1,672,813	100.00%		4.35%

Notes: [1] As calculated on page 4 of this schedule.

Source of Information: Company provided data

UGI Utilities, Inc.
Calculation of the Effective Cost of Long-Term Debt by Series

Series	Date of Issue	Date of Maturity	Average Term in Years (1)	Principal Amount Issued	Premium/ Discount & Expense ($000)	Net Proceeds	Net Proceeds Ratio	Effective Cost Rate (2)
Medium Term Notes								
6.500%	08/14/03	08/15/33	30	$ 20,000	$ 150	$ 19,850	99.25%	6.56%
6.133%	10/14/04	10/15/34	30	20,000	150	19,850	99.25%	6.19%
Senior Notes								
6.206%	11/14/06	09/30/36	30	100,000	1,485	98,515	98.52%	6.32%
4.980%	03/26/14	03/26/44	30	175,000	642	174,358	99.63%	5.00%
2.950%	06/30/16	06/30/26	10	100,000	7,949	92,051	92.05%	3.92%
4.120%	09/30/16	09/30/46	30	200,000	27,366	172,634	86.32%	5.01%
4.120%	10/31/16	10/31/46	30	100,000	2,710	97,290	97.29%	4.28%
4.550%	02/28/19	02/01/49	30	150,000	713	149,288	99.53%	4.58%
3.120%	03/19/20	04/16/50	30	150,000	835	149,165	99.44%	3.15%
1.590%	06/15/21	06/15/26	5	100,000	680	99,320	99.32%	1.73%
1.640%	09/15/21	09/15/26	5	75,000	390	74,611	99.48%	1.75%
3.917%	07/12/22	07/12/27	5	96,875	370	96,505	99.62%	4.00%
4.750%	07/15/22	07/15/32	10	90,000	585	89,415	99.35%	4.83%
4.990%	09/15/22	09/15/52	30	85,000	442	84,558	99.48%	5.02%
4.551% (3)	10/31/23	10/31/53	30	225,000	1,800	223,200	99.20%	4.60%

Notes: (1) Determined by taking into account the effect of the annual sinking fund requirements which are met by the retirement of principal which reduce the term of each issue.
(2) The effective cost for each issue is the yield to maturity using as inputs the average term of issue, coupon rate, and net proceeds ratio.
(3) Estimated

Source of Information: Company provided data

Monthly Dividend Yields for
Electric Group
for the Twelve Months Ending October 2022

Company	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	12-Month Average	6-Month Average	3-Month Average
AVANGRID, Inc (AGR)	3.51%	3.54%	3.79%	3.92%	3.78%	4.00%	3.73%	3.83%	3.63%	3.59%	4.23%	4.36%			
Consolidated Edison Inc (ED)	4.00%	3.65%	3.68%	3.69%	3.35%	3.43%	3.19%	3.34%	3.20%	3.24%	3.70%	3.62%			
Dominion Energy, Inc. (D)	3.57%	3.22%	3.33%	3.38%	3.15%	3.29%	3.20%	3.35%	3.27%	3.29%	3.88%	3.84%			
Duke Energy Corporation (DUK)	4.07%	3.78%	3.78%	3.93%	3.54%	3.60%	3.51%	3.69%	3.69%	3.77%	4.35%	4.36%			
Eversource Energy (ES)	2.96%	2.65%	2.86%	3.14%	2.90%	2.93%	2.76%	3.03%	2.91%	2.87%	3.27%	3.35%			
Exelon Corp (EXC)	4.08%	3.73%	3.29%	3.17%	2.84%	2.90%	2.75%	2.99%	2.92%	3.08%	3.62%	3.53%			
FirstEnergy Corp (FE)	4.15%	3.77%	3.75%	3.74%	3.42%	3.63%	3.64%	4.09%	3.83%	3.96%	4.24%	4.18%			
NextEra Energy Inc (NEE)	1.78%	1.65%	2.19%	2.17%	2.01%	2.40%	2.25%	2.20%	2.02%	2.00%	2.17%	2.20%			
PPL Corp (PPL)	6.05%	5.54%	2.71%	3.08%	2.81%	3.19%	3.00%	3.32%	3.11%	3.11%	3.56%	3.41%			
Public Service Enterprise Group Inc (PEG)	3.29%	3.06%	3.26%	3.36%	3.09%	3.11%	3.17%	3.42%	3.31%	3.38%	3.85%	3.87%			
Average	**3.75%**	**3.46%**	**3.26%**	**3.36%**	**3.09%**	**3.25%**	**3.12%**	**3.33%**	**3.19%**	**3.23%**	**3.69%**	**3.67%**	**3.37%**	**3.37%**	**3.53%**

Note: Monthly dividend yields are calculated by dividing the annualized quarterly dividend by the month-end closing stock price adjusted by the fraction of the ex-dividend.

Source of Information: https://finance.yahoo.com
https://www.nasdaq.com

Forward-looking Dividend Yield

		D_0/P_0		D_1/P_0
	1/2 Growth	D_0/P_0	(.5g)	D_1/P_0
		3.37%	1.030000	3.47%
	Discrete	D_0/P_0	Adj.	D_1/P_0
		3.37%	1.037227	3.50%
	Quarterly	D_0/P_0	Adj.	D_1/P_0
		0.8425%	1.014674	3.46%
	Average			3.48%
	Growth rate			6.00%
	K			9.48%

$$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$$

$$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$$

$$K = \left[\left(1 + \frac{D_0(1+g)^{.25}}{P_0}\right)^4 - 1\right] + g$$

Historical Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

	Earnings per Share		Dividends per Share		Book Value per Share		Cash Flow per Share	
	Value Line		Value Line		Value Line		Value Line	
Electric Group	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year
AVANGRID, Inc.	3.00%	-	0.50%	-	-	-	3.50%	-
Consol. Edison	2.00%	2.50%	3.00%	2.50%	4.50%	4.00%	4.50%	4.50%
Dominion Energy, Inc.	3.50%	3.50%	4.50%	5.50%	8.50%	5.00%	4.50%	4.00%
Duke Energy	4.50%	3.00%	3.50%	3.00%	1.00%	2.00%	5.00%	4.00%
Eversource Energy	5.50%	6.00%	6.50%	8.50%	4.50%	6.50%	7.50%	3.50%
Exelon Corp.	4.50%	-2.50%	4.00%	-3.50%	4.50%	5.00%	6.50%	2.00%
FirstEnergy Corp.	-1.00%	-1.00%	1.50%	-3.50%	-10.50%	-7.00%	-6.50%	-4.50%
NextEra Energy	9.50%	7.00%	12.00%	10.50%	9.00%	8.50%	7.00%	7.00%
PPL Corp.	-8.00%	-2.00%	2.00%	1.50%	1.50%	0.50%	-5.00%	-1.50%
Public Serv. Enterprise	3.50%	1.00%	4.50%	3.50%	3.50%	5.00%	2.50%	2.00%
Average	2.70%	1.94%	4.20%	3.11%	2.94%	3.28%	2.95%	2.33%

Source of Information: Value Line Investment Survey, August 12, 2022

Analysts' Five-Year Projected Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

			Value Line				
Electric Group	**I/B/E/S First Call**	**Zacks**	**Earnings Per Share**	**Dividends Per Share**	**Book Value Per Share**	**Cash Flow Per Share**	**Percent Retained to Common Equity**
AVANGRID, Inc.	3.92%	5.90%	3.00%	1.50%	1.00%	3.00%	1.50%
Consol. Edison	4.93%	2.00%	4.00%	2.50%	3.50%	4.00%	3.00%
Dominion Energy, Inc.	6.42%	6.30%	5.00%	1.00%	5.00%	4.00%	4.50%
Duke Energy	5.47%	6.00%	5.00%	2.00%	2.50%	5.00%	3.00%
Eversource Energy	5.74%	6.20%	6.50%	6.50%	4.50%	6.00%	3.50%
Exelon Corp.	8.50%	7.10%	NMF	NMF	NMF	NMF	4.00%
FirstEnergy Corp.	-2.42%	6.70%	3.00%	2.50%	7.00%	3.50%	6.00%
NextEra Energy	9.35%	9.70%	10.00%	10.00%	6.00%	6.50%	5.50%
PPL Corp.	17.47%	NA	3.00%	-5.50%	4.00%	2.00%	3.00%
Public Serv. Enterprise	3.10%	3.10%	4.00%	5.50%	2.00%	4.00%	4.50%
Average	6.25%	5.89%	4.83%	2.89%	3.94%	4.22%	3.85%

Source of Information : Yahoo Finance, October 25, 2022
Zacks, October 25, 2022
Value Line Investment Survey, August 26, 2022

Electric Group

Financial Risk Adjustment

		AVANGRID Inc (AGR)	Consolidated Edison Inc (ED)	Dominion Energy, Inc. (D)	Duke Energy Corporation (DUK)	Eversource Energy (ES)	Exelon Corp(EXC)	FirstEnergy Corp (FE)	NextEra Energy Inc (NEE)	PPL Corp (PPL)	Public Service Enterprise Group Inc	Average
Fiscal Year		12/31/21	12/31/21	12/31/21	12/31/21	12/31/21	12/31/21	12/31/21	12/31/21	12/31/21	12/31/21	
Capitalization at Fair Values												
	Debt(D)	9,155,000	26,287,000	42,417,000	69,683,000	19,636,300	43,592,000	27,043,000	57,290,000	12,955,000	17,546,000	32,560,430
	Preferred(P)	0	0	3,393,000	1,962,000	166,300	0	0	0	0	0	552,130
	Equity(E)	19,282,017	28,240,920	57,584,480	80,668,100	31,333,803	40,336,996	23,717,159	183,991,990	22,097,467	33,631,922	52,088,485
	Total	28,437,017	54,527,920	103,394,480	152,313,100	51,136,403	83,928,996	50,760,159	241,281,990	35,052,467	51,177,922	85,201,045
Capital Structure Ratios												
	Debt(D)	32.19%	48.21%	41.02%	45.75%	38.40%	51.94%	53.28%	23.74%	36.96%	34.28%	40.58%
	Preferred(P)	0.00%	0.00%	3.28%	1.29%	0.33%	0.00%	0.00%	0.00%	0.00%	0.00%	0.49%
	Equity(E)	67.81%	51.79%	55.69%	52.96%	61.27%	48.06%	46.72%	76.26%	63.04%	65.72%	58.93%
	Total	100.00%	100.00%	99.99%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Common Stock												
	Issued		354,000.000				981,291.000				534,000.000	
	Treasury		23,000.000				2,000.000				30,000.000	
	Outstanding	386,568.104	331,000.000	733,000.000	769,000.000	344,403.196	979,291.000	570,261.104	1,963,000.000	735,112.000	504,000.000	
	Market Price	$49.88	$85.32	$78.56	$104.90	$90.98	$41.19	$41.59	$93.73	$30.06	$66.73	
Capitalization at Carrying Amounts												
	Debt(D)	8,294,000	23,044,000	37,382,000	63,835,000	18,216,700	38,697,000	23,946,000	52,745,000	11,140,000	15,919,000	29,321,870
	Preferred(P)	0	0	3,393,000	1,962,000	155,600	0	0	0	0	0	551,060
	Equity(E)	19,076,000	20,037,000	25,525,000	47,334,000	14,599,844	34,393,000	8,675,000	37,202,000	13,723,000	14,438,000	23,500,284
	Total	27,370,000	43,081,000	66,300,000	113,131,000	32,972,144	73,090,000	32,621,000	89,947,000	24,863,000	30,357,000	53,373,214
Capital Structure Ratios												
	Debt(D)	30.30%	53.49%	56.38%	56.43%	55.25%	52.94%	73.41%	58.64%	44.81%	52.44%	53.41%
	Preferred(P)	0.00%	0.00%	5.12%	1.73%	0.47%	0.00%	0.00%	0.00%	0.00%	0.00%	0.73%
	Equity(E)	69.70%	46.51%	38.50%	41.84%	44.28%	47.06%	26.59%	41.36%	55.19%	47.56%	45.86%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Betas	Value Line	0.85	0.75	0.80	0.85	0.90	NMF	0.85	0.95	1.10	0.90	0.88

Hamada	Bl	=	Bu	[1+	(1 - t)	D/E	+	P/E	]
	0.88	=	Bu	[1+	(1-0.35)	0.6886	+	0.0083	]
	0.88	=	Bu	[1+	0.65	0.6886	+	0.0083	]
	0.88	=	Bu	1.4559					
	0.60	=	Bu						

Hamada	Bl	=	0.60	[1+	(1 - t)	D/E	+	P/E	]
	Bl	=	0.60	[1+	0.65	1.1646	+	0.0159	]
	Bl	=	0.60	1.7729					
	Bl	=	1.06						

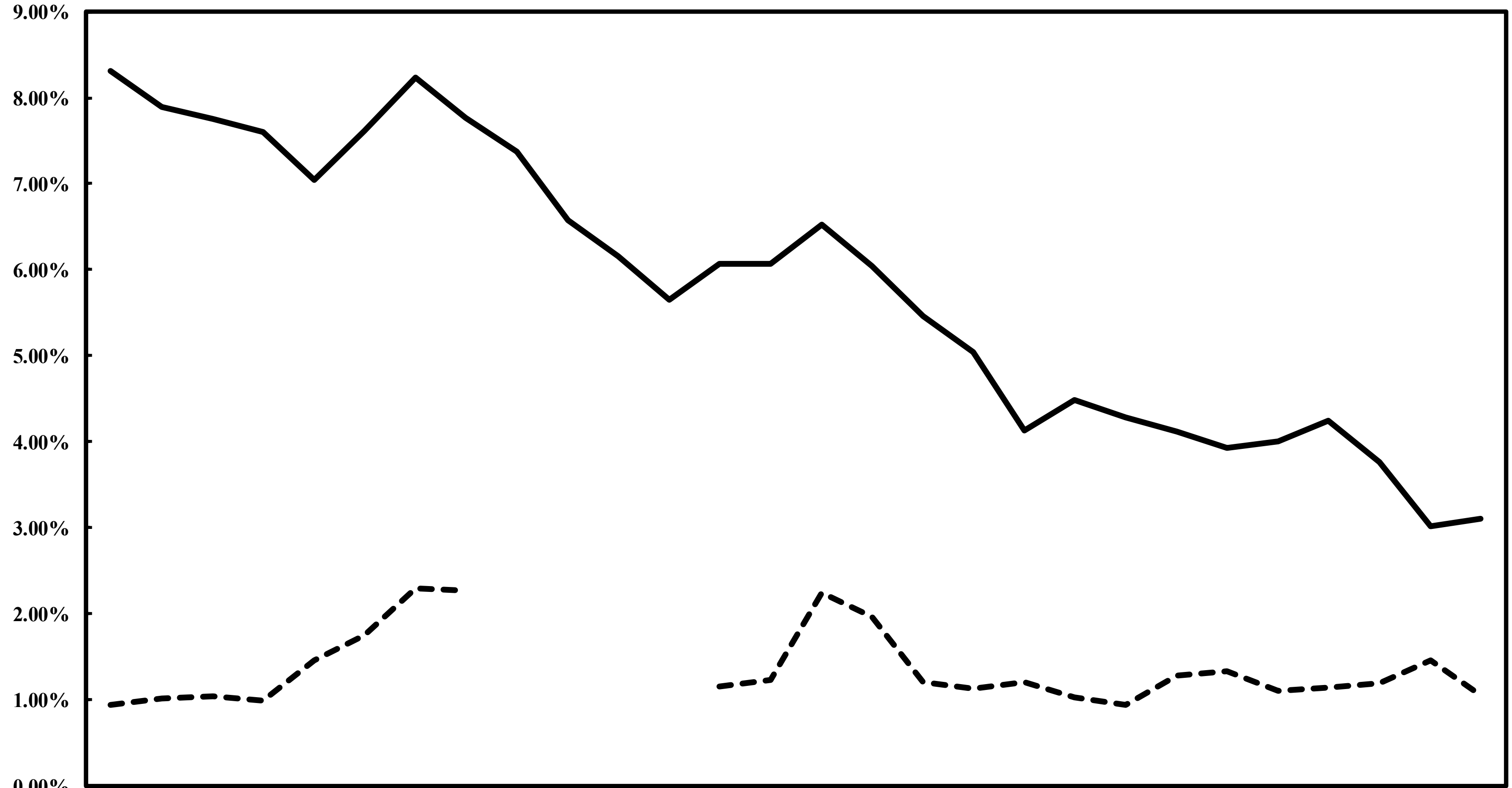
M&M	ku	=	ke	-	(((	ku	-	i	)	1-t	)	D	/	E	) - (	ku	- d	)	P	/	E
	8.10%	=	9.48%	-	(((	8.10%	-	5.05%	)	0.65	)	40.58%	/	58.93%	) - (	8.10%	- 5.68%	)	0.49%	/	58.93%
	8.10%	=	9.48%	-	(((	3.05%			)	0.65	)	0.6886			) - (	2.42%		)	0.0083		
	8.10%	=	9.48%	-	((	1.98%					)	0.6886			) - (	2.42%		)	0.0083		
	8.10%	=	9.48%	-		1.36%									-	0.02%					

M&M	ke	=	ku	+	(((	ku	-	i	)	1-t	)	D	/	E	) + (	ku	- d	)	P	/	E
	10.45%	=	8.10%	+	(((	8.10%	-	5.05%	)	0.65	)	53.41%	/	45.86%	) + (	8.10%	- 5.68%	)	0.73%	/	45.86%
	10.45%	=	8.10%	+	(((	3.05%			)	0.65	)	1.1646			) + (	2.42%		)	0.0159		
	10.45%	=	8.10%	+	((	1.98%					)	1.1646			) + (	2.42%		)	0.0159		
	10.45%	=	8.10%	+		2.31%									+	0.04%					

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2016-2020 and 2021
and the Twelve Months Ended October 2022

Years	**Aa Rated**	**A Rated**	**Baa Rated**	**Average**
2016	3.73%	3.93%	4.68%	4.11%
2017	3.82%	4.00%	4.38%	4.07%
2018	4.09%	4.25%	4.67%	4.34%
2019	3.61%	3.77%	4.19%	3.86%
2020	2.79%	3.02%	3.39%	3.07%
Five-Year Average	3.61%	3.79%	4.26%	3.89%
2021	2.97%	3.11%	3.36%	3.15%
Months				
Nov-21	2.91%	3.02%	3.25%	3.06%
Dec-21	3.01%	3.13%	3.36%	3.17%
Jan-22	3.19%	3.33%	3.57%	3.46%
Feb-22	3.56%	3.68%	3.95%	3.73%
Mar-22	3.81%	3.98%	4.28%	4.02%
Apr-22	4.10%	4.32%	4.61%	4.34%
May-22	4.55%	4.75%	5.07%	4.79%
Jun-22	4.65%	4.86%	5.22%	4.91%
Jul-22	4.57%	4.78%	5.15%	4.84%
Aug-22	4.54%	4.76%	5.09%	4.80%
Sep-22	5.08%	5.28%	5.61%	5.33%
Oct-22	5.68%	5.88%	6.18%	5.91%
Twelve-Month Average	4.14%	4.31%	4.61%	4.36%
Six-Month Average	4.85%	5.05%	5.39%	5.10%
Three-Month Average	5.10%	5.31%	5.63%	5.35%

Yields on
A-rated Public Utility Bonds and
Spreads over 30-Year Treasuries



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
A-rated Public Utility	8.31	7.89	7.75	7.60	7.04	7.62	8.24	7.76	7.37	6.58	6.16	5.65	6.07	6.07	6.53	6.04	5.46	5.04	4.13	4.48	4.28	4.12	3.93	4.00	4.25	3.77	3.02	3.11
Spread vs. 30-year	0.94	1.01	1.04	0.99	1.46	1.75	2.30	2.27					1.16	1.23	2.25	1.96	1.21	1.13	1.21	1.03	0.94	1.28	1.33	1.10	1.14	1.19	1.46	1.06

A rated Public Utility Bonds over 30-Year Treasuries

Year	A-rated Public Utility	30-Year Treasuries Yield	Spread
Jan-99	6.97%	5.16%	1.81%
Feb-99	7.09%	5.37%	1.72%
Mar-99	7.26%	5.58%	1.68%
Apr-99	7.22%	5.55%	1.67%
May-99	7.47%	5.81%	1.66%
Jun-99	7.74%	6.04%	1.70%
Jul-99	7.71%	5.98%	1.73%
Aug-99	7.91%	6.07%	1.84%
Sep-99	7.93%	6.07%	1.86%
Oct-99	8.06%	6.26%	1.80%
Nov-99	7.94%	6.15%	1.79%
Dec-99	8.14%	6.35%	1.79%
Jan-00	8.35%	6.63%	1.72%
Feb-00	8.25%	6.23%	2.02%
Mar-00	8.28%	6.05%	2.23%
Apr-00	8.29%	5.85%	2.44%
May-00	8.70%	6.15%	2.55%
Jun-00	8.36%	5.93%	2.43%
Jul-00	8.25%	5.85%	2.40%
Aug-00	8.13%	5.72%	2.41%
Sep-00	8.23%	5.83%	2.40%
Oct-00	8.14%	5.80%	2.34%
Nov-00	8.11%	5.78%	2.33%
Dec-00	7.84%	5.49%	2.35%
Jan-01	7.80%	5.54%	2.26%
Feb-01	7.74%	5.45%	2.29%
Mar-01	7.68%	5.34%	2.34%
Apr-01	7.94%	5.65%	2.29%
May-01	7.99%	5.78%	2.21%
Jun-01	7.85%	5.67%	2.18%
Jul-01	7.78%	5.61%	2.17%
Aug-01	7.59%	5.48%	2.11%
Sep-01	7.75%	5.48%	2.27%
Oct-01	7.63%	5.32%	2.31%
Nov-01	7.57%	5.12%	2.45%
Dec-01	7.83%	5.48%	2.35%
Jan-02	7.66%	5.45%	2.21%
Feb-02	7.54%	5.40%	2.14%
Mar-02	7.76%		
Apr-02	7.57%		
May-02	7.52%		
Jun-02	7.42%		
Jul-02	7.31%		
Aug-02	7.17%		
Sep-02	7.08%		
Oct-02	7.23%		
Nov-02	7.14%		
Dec-02	7.07%		
Jan-03	7.07%		
Feb-03	6.93%		
Mar-03	6.79%		
Apr-03	6.64%		
May-03	6.36%		
Jun-03	6.21%		
Jul-03	6.57%		
Aug-03	6.78%		
Sep-03	6.56%		
Oct-03	6.43%		
Nov-03	6.37%		
Dec-03	6.27%		
Jan-04	6.15%		
Feb-04	6.15%		
Mar-04	5.97%		
Apr-04	6.35%		
May-04	6.62%		
Jun-04	6.46%		
Jul-04	6.27%		
Aug-04	6.14%		
Sep-04	5.98%		
Oct-04	5.94%		
Nov-04	5.97%		
Dec-04	5.92%		

Year	A-rated Public Utility	30-Year Treasuries Yield	Spread
Jan-05	5.78%		
Feb-05	5.61%		
Mar-05	5.83%		
Apr-05	5.64%		
May-05	5.53%		
Jun-05	5.40%		
Jul-05	5.51%		
Aug-05	5.50%		
Sep-05	5.52%		
Oct-05	5.79%		
Nov-05	5.88%		
Dec-05	5.80%		
Jan-06	5.75%		
Feb-06	5.82%	4.54%	1.28%
Mar-06	5.98%	4.73%	1.25%
Apr-06	6.29%	5.06%	1.23%
May-06	6.42%	5.20%	1.22%
Jun-06	6.40%	5.15%	1.25%
Jul-06	6.37%	5.13%	1.24%
Aug-06	6.20%	5.00%	1.20%
Sep-06	6.00%	4.85%	1.15%
Oct-06	5.98%	4.85%	1.13%
Nov-06	5.80%	4.69%	1.11%
Dec-06	5.81%	4.68%	1.13%
Jan-07	5.96%	4.85%	1.11%
Feb-07	5.90%	4.82%	1.08%
Mar-07	5.85%	4.72%	1.13%
Apr-07	5.97%	4.87%	1.10%
May-07	5.99%	4.90%	1.09%
Jun-07	6.30%	5.20%	1.10%
Jul-07	6.25%	5.11%	1.14%
Aug-07	6.24%	4.93%	1.31%
Sep-07	6.18%	4.79%	1.39%
Oct-07	6.11%	4.77%	1.34%
Nov-07	5.97%	4.52%	1.45%
Dec-07	6.16%	4.53%	1.63%
Jan-08	6.02%	4.33%	1.69%
Feb-08	6.21%	4.52%	1.69%
Mar-08	6.21%	4.39%	1.82%
Apr-08	6.29%	4.44%	1.85%
May-08	6.28%	4.60%	1.68%
Jun-08	6.38%	4.69%	1.69%
Jul-08	6.40%	4.57%	1.83%
Aug-08	6.37%	4.50%	1.87%
Sep-08	6.49%	4.27%	2.22%
Oct-08	7.56%	4.17%	3.39%
Nov-08	7.60%	4.00%	3.60%
Dec-08	6.52%	2.87%	3.65%
Jan-09	6.39%	3.13%	3.26%
Feb-09	6.30%	3.59%	2.71%
Mar-09	6.42%	3.64%	2.78%
Apr-09	6.48%	3.76%	2.72%
May-09	6.49%	4.23%	2.26%
Jun-09	6.20%	4.52%	1.68%
Jul-09	5.97%	4.41%	1.56%
Aug-09	5.71%	4.37%	1.34%
Sep-09	5.53%	4.19%	1.34%
Oct-09	5.55%	4.19%	1.36%
Nov-09	5.64%	4.31%	1.33%
Dec-09	5.79%	4.49%	1.30%
Jan-10	5.77%	4.60%	1.17%
Feb-10	5.87%	4.62%	1.25%
Mar-10	5.84%	4.64%	1.20%
Apr-10	5.81%	4.69%	1.12%
May-10	5.50%	4.29%	1.21%
Jun-10	5.46%	4.13%	1.33%
Jul-10	5.26%	3.99%	1.27%
Aug-10	5.01%	3.80%	1.21%
Sep-10	5.01%	3.77%	1.24%
Oct-10	5.10%	3.87%	1.23%
Nov-10	5.37%	4.19%	1.18%
Dec-10	5.56%	4.42%	1.14%

Year	A-rated Public Utility	30-Year Treasuries Yield	Spread
Jan-11	5.57%	4.52%	1.05%
Feb-11	5.68%	4.65%	1.03%
Mar-11	5.56%	4.51%	1.05%
Apr-11	5.55%	4.50%	1.05%
May-11	5.32%	4.29%	1.03%
Jun-11	5.26%	4.23%	1.03%
Jul-11	5.27%	4.27%	1.00%
Aug-11	4.69%	3.65%	1.04%
Sep-11	4.48%	3.18%	1.30%
Oct-11	4.52%	3.13%	1.39%
Nov-11	4.25%	3.02%	1.23%
Dec-11	4.33%	2.98%	1.35%
Jan-12	4.34%	3.03%	1.31%
Feb-12	4.36%	3.11%	1.25%
Mar-12	4.48%	3.28%	1.20%
Apr-12	4.40%	3.18%	1.22%
May-12	4.20%	2.93%	1.27%
Jun-12	4.08%	2.70%	1.38%
Jul-12	3.93%	2.59%	1.34%
Aug-12	4.00%	2.77%	1.23%
Sep-12	4.02%	2.88%	1.14%
Oct-12	3.91%	2.90%	1.01%
Nov-12	3.84%	2.80%	1.04%
Dec-12	4.00%	2.88%	1.12%
Jan-13	4.15%	3.08%	1.07%
Feb-13	4.18%	3.17%	1.01%
Mar-13	4.20%	3.16%	1.04%
Apr-13	4.00%	2.93%	1.07%
May-13	4.17%	3.11%	1.06%
Jun-13	4.53%	3.40%	1.13%
Jul-13	4.68%	3.61%	1.07%
Aug-13	4.73%	3.76%	0.97%
Sep-13	4.80%	3.79%	1.01%
Oct-13	4.70%	3.68%	1.02%
Nov-13	4.77%	3.80%	0.97%
Dec-13	4.81%	3.89%	0.92%
Jan-14	4.63%	3.77%	0.86%
Feb-14	4.53%	3.66%	0.87%
Mar-14	4.51%	3.62%	0.89%
Apr-14	4.41%	3.52%	0.89%
May-14	4.26%	3.39%	0.87%
Jun-14	4.29%	3.42%	0.87%
Jul-14	4.23%	3.33%	0.90%
Aug-14	4.13%	3.20%	0.93%
Sep-14	4.24%	3.26%	0.98%
Oct-14	4.06%	3.04%	1.02%
Nov-14	4.09%	3.04%	1.05%
Dec-14	3.95%	2.83%	1.12%
Jan-15	3.58%	2.46%	1.12%
Feb-15	3.67%	2.57%	1.10%
Mar-15	3.74%	2.63%	1.11%
Apr-15	3.75%	2.59%	1.16%
May-15	4.17%	2.96%	1.21%
Jun-15	4.39%	3.11%	1.28%
Jul-15	4.40%	3.07%	1.33%
Aug-15	4.25%	2.86%	1.39%
Sep-15	4.39%	2.95%	1.44%
Oct-15	4.29%	2.89%	1.40%
Nov-15	4.40%	3.03%	1.37%
Dec-15	4.35%	2.97%	1.38%
Jan-16	4.27%	2.86%	1.41%
Feb-16	4.11%	2.62%	1.49%
Mar-16	4.16%	2.68%	1.48%
Apr-16	4.00%	2.62%	1.38%
May-16	3.93%	2.63%	1.30%
Jun-16	3.78%	2.45%	1.33%
Jul-16	3.57%	2.23%	1.34%
Aug-16	3.59%	2.26%	1.33%
Sep-16	3.66%	2.35%	1.31%
Oct-16	3.77%	2.50%	1.27%
Nov-16	4.08%	2.86%	1.22%
Dec-16	4.27%	3.11%	1.16%

Year	A-rated Public Utility	30-Year Treasuries Yield	Spread
Jan-17	4.14%	3.02%	1.12%
Feb-17	4.18%	3.03%	1.15%
Mar-17	4.23%	3.08%	1.15%
Apr-17	4.12%	2.94%	1.18%
May-17	4.12%	2.96%	1.16%
Jun-17	3.94%	2.80%	1.14%
Jul-17	3.99%	2.88%	1.11%
Aug-17	3.86%	2.80%	1.06%
Sep-17	3.87%	2.78%	1.09%
Oct-17	3.91%	2.88%	1.03%
Nov-17	3.83%	2.80%	1.03%
Dec-17	3.79%	2.77%	1.02%
Jan-18	3.86%	2.88%	0.98%
Feb-18	4.09%	3.13%	0.96%
Mar-18	4.13%	3.09%	1.04%
Apr-18	4.17%	3.07%	1.10%
May-18	4.28%	3.13%	1.15%
Jun-18	4.27%	3.05%	1.22%
Jul-18	4.27%	3.01%	1.26%
Aug-18	4.26%	3.04%	1.22%
Sep-18	4.32%	3.15%	1.17%
Oct-18	4.45%	3.34%	1.11%
Nov-18	4.52%	3.36%	1.16%
Dec-18	4.37%	3.10%	1.27%
Jan-19	4.35%	3.04%	1.31%
Feb-19	4.25%	3.02%	1.23%
Mar-19	4.16%	2.98%	1.18%
Apr-19	4.08%	2.94%	1.14%
May-19	3.98%	2.82%	1.16%
Jun-19	3.82%	2.57%	1.25%
Jul-19	3.69%	2.57%	1.12%
Aug-19	3.29%	2.12%	1.17%
Sep-19	3.37%	2.16%	1.21%
Oct-19	3.39%	2.19%	1.20%
Nov-19	3.43%	2.28%	1.15%
Dec-19	3.40%	2.30%	1.10%
Jan-20	3.29%	2.22%	1.07%
Feb-20	3.11%	1.97%	1.14%
Mar-20	3.50%	1.46%	2.04%
Apr-20	3.19%	1.27%	1.92%
May-20	3.14%	1.38%	1.76%
Jun-20	3.07%	1.49%	1.58%
Jul-20	2.74%	1.31%	1.43%
Aug-20	2.73%	1.36%	1.37%
Sep-20	2.84%	1.42%	1.42%
Oct-20	2.95%	1.57%	1.38%
Nov-20	2.85%	1.62%	1.23%
Dec-20	2.77%	1.67%	1.10%
Jan-21	2.91%	1.82%	1.09%
Feb-21	3.09%	2.04%	1.05%
Mar-21	3.44%	2.34%	1.10%
Apr-21	3.30%	2.30%	1.00%
May-21	3.33%	2.32%	1.01%
Jun-21	3.16%	2.16%	1.00%
Jul-21	2.95%	1.94%	1.01%
Aug-21	2.95%	1.92%	1.03%
Sep-21	2.96%	1.94%	1.02%
Oct-21	3.09%	2.06%	1.03%
Nov-21	3.02%	1.94%	1.08%
Dec-21	3.13%	1.85%	1.28%
Jan-22	3.33%	2.10%	1.23%
Feb-22	3.68%	2.25%	1.43%
Mar-22	3.98%	2.41%	1.57%
Apr-22	4.32%	2.81%	1.51%
May-22	4.75%	3.07%	1.68%
Jun-22	4.86%	3.25%	1.61%
Jul-22	4.78%	3.10%	1.68%
Aug-22	4.76%	3.13%	1.63%
Sep-22	5.28%	3.56%	1.72%
Oct-22	5.88%	4.04%	1.84%
Average:	12-months		1.52%
	6-months		1.69%
	3-months		1.73%

Common Equity Risk Premiums
Years 1926-2021

	Large Common Stocks	Long-Term Corp. Bonds	Equity Risk Premium	Long-Term Govt. Bonds Yields
Low Interest Rates	12.09%	5.28%	6.81%	2.80%
Average Across All Interest Rates	12.33%	6.40%	5.93%	4.92%
High Interest Rates	12.57%	7.52%	5.05%	7.03%

Source of Information: 2022 SBBI Yearbook Stocks, Bonds, Bills, and Inflation

Basic Series
Annual Total Returns (except yields)

Year	Large Common Stocks	Long-Term Corp. Bonds	Long-Term Govt. Bonds Yields
2020	18.40%	15.40%	1.37%
2021	28.71%	-2.66%	1.88%
1940	-9.78%	3.39%	1.94%
1945	36.44%	4.08%	1.99%
1941	-11.59%	2.73%	2.04%
1949	18.79%	3.31%	2.09%
1946	-8.07%	1.72%	2.12%
1950	31.71%	2.12%	2.24%
2019	31.49%	19.95%	2.25%
1939	-0.41%	3.97%	2.26%
1948	5.50%	4.14%	2.37%
1947	5.71%	-2.34%	2.43%
1942	20.34%	2.60%	2.46%
1944	19.75%	4.73%	2.46%
2012	16.00%	10.68%	2.46%
2014	13.69%	17.28%	2.46%
1943	25.90%	2.83%	2.48%
1938	31.12%	6.13%	2.52%
2017	21.83%	12.25%	2.54%
1936	33.92%	6.74%	2.55%
2011	2.11%	17.95%	2.55%
2015	1.38%	-1.02%	2.68%
1951	24.02%	-2.69%	2.69%
1954	52.62%	5.39%	2.72%
2016	11.96%	6.70%	2.72%
1937	-35.03%	2.75%	2.73%
1953	-0.99%	3.41%	2.74%
1935	47.67%	9.61%	2.76%
1952	18.37%	3.52%	2.79%
2018	-4.38%	-4.73%	2.84%
1934	-1.44%	13.84%	2.93%
1955	31.56%	0.48%	2.95%
2008	-37.00%	8.78%	3.03%
1932	-8.19%	10.82%	3.15%
1927	37.49%	7.44%	3.17%
1957	-10.78%	8.71%	3.23%
1930	-24.90%	7.98%	3.30%
1933	53.99%	10.38%	3.36%
1928	43.61%	2.84%	3.40%
1929	-8.42%	3.27%	3.40%
1956	6.56%	-6.81%	3.45%
1926	11.62%	7.37%	3.54%
2013	32.39%	-7.07%	3.78%
1960	0.47%	9.07%	3.80%
1958	43.36%	-2.22%	3.82%
1962	-8.73%	7.95%	3.95%
1931	-43.34%	-1.85%	4.07%
2010	15.06%	12.44%	4.14%
1961	26.89%	4.82%	4.15%
1963	22.80%	2.19%	4.17%
1964	16.48%	4.77%	4.23%
1959	11.96%	-0.97%	4.47%
1965	12.45%	-0.46%	4.50%
2007	5.49%	2.60%	4.50%
1966	-10.06%	0.20%	4.55%
2009	26.46%	3.02%	4.58%
2005	4.91%	5.87%	4.61%
2002	-22.10%	16.33%	4.84%
2004	10.88%	8.72%	4.84%
2006	15.79%	3.24%	4.91%
2003	28.68%	5.27%	5.11%
1998	28.58%	10.76%	5.42%
1967	23.98%	-4.95%	5.56%
2000	-9.10%	12.87%	5.58%
2001	-11.89%	10.65%	5.75%
1971	14.30%	11.01%	5.97%
1968	11.06%	2.57%	5.98%
1972	18.99%	7.26%	5.99%
1997	33.36%	12.95%	6.02%
1995	37.58%	27.20%	6.03%
1970	3.86%	18.37%	6.48%
1993	10.08%	13.19%	6.54%
1996	22.96%	1.40%	6.73%
1999	21.04%	-7.45%	6.82%
1969	-8.50%	-8.09%	6.87%
1976	23.93%	18.65%	7.21%
1973	-14.69%	1.14%	7.26%
1992	7.62%	9.39%	7.26%
1991	30.47%	19.89%	7.30%
1974	-26.47%	-3.06%	7.60%
1986	18.67%	19.85%	7.89%
1994	1.32%	-5.76%	7.99%
1977	-7.16%	1.71%	8.03%
1975	37.23%	14.64%	8.05%
1989	31.69%	16.23%	8.16%
1990	-3.10%	6.78%	8.44%
1978	6.57%	-0.07%	8.98%
1988	16.61%	10.70%	9.19%
1987	5.25%	-0.27%	9.20%
1985	31.73%	30.09%	9.56%
1979	18.61%	-4.18%	10.12%
1982	21.55%	42.56%	10.95%
1984	6.27%	16.86%	11.70%
1983	22.56%	6.26%	11.97%
1980	32.50%	-2.76%	11.99%
1981	-4.92%	-1.24%	13.34%

Yields for Treasury Constant Maturities
Yearly for 2017-2021
and the Twelve Months Ended October 2022

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year	30-Year
2017	1.20%	1.40%	1.58%	1.91%	2.16%	2.33%	2.65%	2.90%
2018	2.33%	2.53%	2.63%	2.75%	2.85%	2.91%	3.02%	3.11%
2019	2.05%	1.97%	1.94%	1.96%	2.05%	2.14%	2.40%	2.58%
2020	0.38%	0.40%	0.43%	0.54%	0.73%	0.89%	1.35%	1.56%
2021	0.10%	0.27%	0.46%	0.86%	1.19%	1.44%	1.98%	2.05%
Five-Year Average	1.21%	1.31%	1.41%	1.60%	1.80%	1.94%	2.28%	2.44%
Months								
Nov-21	0.18%	0.51%	0.82%	1.20%	1.45%	1.56%	1.97%	1.94%
Dec-21	0.30%	0.68%	0.95%	1.23%	1.40%	1.47%	1.90%	1.85%
Jan-22	0.55%	0.98%	1.25%	1.54%	1.70%	1.76%	2.15%	2.10%
Feb-22	1.00%	1.44%	1.65%	1.81%	1.91%	1.93%	2.31%	2.25%
Mar-22	1.34%	1.91%	2.09%	2.11%	2.15%	2.13%	2.51%	2.41%
Apr-22	1.89%	2.54%	2.72%	2.78%	2.80%	2.75%	2.99%	2.81%
May-22	2.06%	2.62%	2.79%	2.87%	2.92%	2.90%	3.26%	3.07%
Jun-22	2.65%	3.00%	3.15%	3.19%	3.21%	3.14%	3.48%	3.25%
Jul-22	3.02%	3.04%	3.03%	2.96%	2.97%	2.90%	3.35%	3.10%
Aug-22	3.28%	3.25%	3.23%	3.03%	2.98%	2.90%	3.35%	3.13%
Sep-22	3.89%	3.86%	3.88%	3.70%	3.64%	3.52%	3.82%	3.56%
Oct-22	4.43%	4.38%	4.38%	4.18%	4.09%	3.98%	4.28%	4.04%
Twelve-Month Average	2.05%	2.35%	2.50%	2.55%	2.60%	2.58%	2.95%	2.79%
Six-Month Average	3.22%	3.36%	3.41%	3.32%	3.30%	3.22%	3.59%	3.36%
Three-Month Average	3.87%	3.83%	3.83%	3.64%	3.57%	3.47%	3.82%	3.58%

Source: Federal Reserve statistical release H.15

Measures of the Risk-Free Rate & Corporate Bond Yields

The forecast of Treasury and Corporate yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated June 1, 2022 and November 1, 2022

		Treasury					Corporate	
Year	Quarter	1-Year Bill	2-Year Note	5-Year Note	10-Year Note	30-Year Bond	Aaa Bond	Baa Bond
2022	Fourth	4.5%	4.4%	4.2%	4.0%	4.0%	5.3%	6.3%
2023	First	4.7%	4.5%	4.3%	4.0%	4.1%	5.5%	6.5%
2023	Second	4.7%	4.4%	4.1%	3.9%	4.1%	5.4%	6.5%
2023	Third	4.5%	4.1%	4.0%	3.8%	4.0%	5.4%	6.4%
2023	Fourth	4.3%	3.9%	3.8%	3.7%	3.9%	5.3%	6.3%
2024	First	4.0%	3.7%	3.6%	3.6%	3.9%	5.1%	3.2%
Long-range CONSENSUS								
2023		3.2%	3.4%	3.5%	3.5%	3.8%	5.0%	6.0%
2024		3.0%	3.2%	3.4%	3.5%	3.8%	5.0%	5.9%
2025		2.9%	3.1%	3.3%	3.4%	3.8%	4.9%	5.8%
2026		2.9%	3.1%	3.3%	3.5%	3.9%	5.0%	5.9%
2027		2.8%	3.0%	3.3%	3.5%	3.8%	5.0%	5.9%
2028		2.8%	3.0%	3.2%	3.4%	3.8%	4.9%	5.9%
Averages:								
	2023-2027	2.9%	3.1%	3.3%	3.5%	3.8%	4.9%	5.9%
	2028-2032	2.8%	3.0%	3.3%	3.5%	3.9%	5.0%	5.9%

Measures of the Market Premium

Value Line Return

As of:	Dividend Yield		Median Appreciation Potential		Median Total Return
4-Nov-22	2.2%	+	15.02%	=	17.22%

DCF Result for the S&P 500 Composite

D/P	(	1+.5g	)	+	g	=	k
1.74%	(	1.0635	)	+	12.7%	=	14.55%

Summary

Value Line			17.22%
S&P 500			14.55%
Average			15.89%
Risk-free Rate of Return (Rf)			4.00%
Forecast Market Premium			11.89%
Historical Market Premium			
Avg. to Low Interest Rates	(Rm)	(Rf)	
1926-2021 Arith. mean	12.21%	3.86%	8.35%
Average - Forecast/Historical			10.12%

Exhibit 7.8: Size-Decile Portfolios of the NYSE/NYSE MKT/NASDAQ Long-Term Returns in Excess of CAPM
1926–2016

Size Grouping	OLS Beta	Arithmetic Mean	Return in Excess of Risk-free Rate (actual)	Return in Excess of Risk-free Rate (as predicted by CAPM)	Size Premium
Mid-Cap (3–5)	1.12	13.82%	8.80%	7.79%	1.02%
Low-Cap (6–8)	1.22	15.26%	10.24%	8.49%	1.75%
Micro-Cap (9–10)	1.35	18.04%	13.02%	9.35%	3.67%
Breakdown of Deciles 1–10					
1-Largest	0.92	11.05%	6.04%	6.38%	-0.35%
2	1.04	12.82%	7.81%	7.19%	0.61%
3	1.11	13.57%	8.55%	7.66%	0.89%
4	1.13	13.80%	8.78%	7.80%	0.98%
5	1.17	14.62%	9.60%	8.09%	1.51%
6	1.17	14.81%	9.79%	8.14%	1.66%
7	1.25	15.41%	10.39%	8.67%	1.72%
8	1.30	16.14%	11.12%	9.04%	2.08%
9	1.34	16.97%	11.96%	9.28%	2.68%
10-Smallest	1.39	20.27%	15.25%	9.66%	5.59%

Betas are estimated from monthly returns in excess of the 30-day U.S. Treasury bill total return, January 1926–December 2016. Historical riskless rate measured by the 91-year arithmetic mean income return component of 20-year government bonds (5.02%). Calculated in the context of the CAPM by multiplying the equity risk premium by beta. The equity risk premium is estimated by the arithmetic mean total return of the S&P 500 (11.95%) minus the arithmetic mean income return component of 20-year government bonds (5.02%) from 1926–2016. Source: Morningstar *Direct* and CRSP. Calculated based on data from CRSP US Stock Database and CRSP US Indices Database ©2017 Center for Research. Used with permission. All calculations performed by Duff & Phelps, LLC.

Comparable Earnings Approach
Using Non-Utility Companies with
Timeliness of 2, 3, 4 & 5; Safety Rank of 1, 2 & 3; Financial Strength of B+, B++, A, A+ & A++;
Price Stability of 75 to 100; Betas of .75 to 1.10; and Technical Rank of 2, 3, 4 & 5

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
Abbott Laboratories	Med Supp Non-Invasive	3	1	A++	90	0.90	3
AbbVie Inc	Drug	3	3	A	80	0.90	3
Agilent Technologies	Precision Instrument	2	2	A	90	0.95	3
Air Products and Chemicals Inc	Chemical (Diversified)	3	1	A++	90	0.90	4
Alamo Group	Machinery	2	3	B+	75	1.05	5
AMERCO	Trucking	3	2	B++	90	0.95	5
AmerisourceBergen Corp	Med Supp Non-Invasive	2	2	A	85	0.85	3
Amphenol Corp	Electronics	3	1	A	95	1.05	3
Analog Devices Inc	Semiconductor	2	1	A+	85	1.00	3
ANSYS Inc	Computer Software	3	2	A++	75	0.95	3
AO Smith Corp	Machinery	3	2	B++	90	0.90	4
Arrow Electronics Inc	Electronics	2	3	A	75	1.15	4
Assurant Inc	Financial Svcs. (Div.)	3	2	A	95	0.90	3
Badger Meter Inc	Precision Instrument	2	3	B++	75	1.10	4
Balchem Corp.	Chemical (Specialty)	2	2	B++	90	0.75	5
Bank of New York Mellon Corporation	Bank	2	2	A	80	1.10	3
Becton Dickinson and Company	Med Supp Invasive	3	1	A++	95	0.80	3
Booz Allen Hamilton Holding Corporatio	Industrial Services	3	3	B++	90	0.85	3
Boston Scientific Corp	Med Supp Invasive	2	3	B++	80	1.10	3
Brady Corp	Diversified Co.	3	3	B++	85	0.95	4
CDW Corp.	IT Services	2	3	B++	85	1.05	3
Charter Communic.	Cable TV	1	2	B++	75	0.95	4
Chemed Corporation	Diversified Co.	2	2	A	95	0.80	3
Cisco Systems Inc	Telecom. Equipment	3	1	A++	95	0.90	4
CME Group Inc	Brokers & Exchanges	3	2	A	90	0.90	3
Cognizant Technology Solutions Corp	IT Services	3	2	A+	85	1.00	4
Comcast Corporation	Cable TV	2	1	A+	95	0.80	3
Copart Inc	Retail Automotive	2	2	A	75	1.05	3
CSG Systems International Inc	IT Services	3	2	B+	95	0.75	3
CSX Corporation	Railroad	2	3	B++	85	1.05	3
Cummins Inc	Heavy Truck & Equip	3	2	A+	80	1.10	4
Dolby Laboratories Inc	Entertainment Tech	2	2	A	90	0.95	3
Donaldson Co	Machinery	3	2	A	85	1.10	4
Ecolab Inc	Chemical (Specialty)	3	2	A+	75	1.15	3
Eli Lilly and Co	Drug	2	1	A++	85	0.75	3
Equifax Inc	Information Services	3	3	A	75	1.05	3
ESCO Technologies Inc	Diversified Co.	3	3	B+	85	1.00	3
Fidelity Nat'l Info.	Financial Svcs. (Div.)	1	2	B++	85	1.00	3
First Commonwealth Financial Corp	Bank	3	3	B+	75	1.00	4
First Republic Bank	Bank	2	3	B++	80	1.05	3
Fiserv Inc	IT Services	1	2	B++	85	1.00	3
Fortive Corp.	Precision Instrument	3	3	B++	75	1.15	3
GATX Corp	Railroad	3	3	B+	85	0.95	4
Gentex Corp	Auto Parts	3	2	B++	90	0.95	3
Globe Life Inc.	Insurance (Life)	3	1	A+	85	1.10	3
Graco Inc	Machinery	3	2	A	95	1.05	4
Hanover Insurance Group Inc	Insurance (Prop/Cas.)	3	2	A	95	0.95	3
Honeywell International Inc	Diversified Co.	3	1	A++	90	1.15	4
IDEX Corporation	Machinery	2	2	B++	95	1.00	3
Intercontinental Exch.	Brokers & Exchanges	2	1	A	95	0.95	3
J B Hunt Transport Services Inc	Trucking	3	1	A+	80	0.95	3
Jacobs Solutions	Engineering & Const	3	2	A	80	1.10	4
JP Morgan Chase and Co	Bank	2	2	A+	80	1.15	4
Kadant Inc	Diversified Co.	2	3	B++	80	1.00	4
Knight-Swift Trans.	Trucking	3	3	B++	75	0.85	5
Leidos Holdings Inc	Industrial Services	3	3	B++	75	1.05	4
Lennox International Inc	Machinery	3	3	B+	85	1.00	3
Loews Corporation	Financial Svcs. (Div.)	3	2	B++	85	1.10	4
Markel Corp	Insurance (Prop/Cas.)	3	2	A	80	1.15	4
Mastercard Incorporated	Financial Svcs. (Div.)	1	1	A++	75	1.15	3
McCormick and Co	Food Processing	3	1	A+	95	0.75	3
McKesson Corp	Med Supp Non-Invasive	2	1	A++	85	0.90	3
Mettler Toledo International Inc	Precision Instrument	2	2	B++	80	1.00	4
Microsoft Corporation	Computer Software	1	1	A++	95	0.90	3
Moodys Corp	Information Services	1	3	B++	80	1.10	3
MSA Safety	Machinery	2	2	A	85	1.00	4
MSC Industrial Direct Co Inc	Machinery	3	3	B++	90	0.95	3
MSCI Inc	Information Services	3	3	B+	75	1.05	3
Nordson Corp	Machinery	3	3	A	75	1.15	4
Norfolk Southern Corp	Railroad	3	2	A+	85	1.05	3
O Reilly Automotive Inc	Retail Automotive	3	3	B++	85	0.95	3
Old Republic International Corp	Insurance (Prop/Cas.)	3	3	B+	75	1.10	4
Oracle Corp	Computer Software	3	1	A++	95	0.85	4
Packaging Corp	Packaging & Container	2	2	A	85	0.95	3
PerkinElmer Inc	Precision Instrument	3	2	B++	75	0.95	4
Philip Morris International Inc	Tobacco	3	3	B++	75	0.95	3
Pool Corporation	Recreation	3	2	A	80	0.90	4
Raytheon Technologies	Aerospace/Defense	3	1	A++	80	1.10	3
RLI Corp	Insurance (Prop/Cas.)	3	2	A	95	0.80	3
Roper Tech.	Machinery	2	1	A+	95	1.00	3
S&P Global	Information Services	1	2	A	90	1.00	3
SBA Communications	Wireless Networking	1	3	B++	80	0.85	3
Schneider National	Trucking	3	3	B++	85	0.80	3
Selective Insurance Group Inc	Insurance (Prop/Cas.)	3	3	B+	90	0.85	3
Sensient Technologies Corp	Food Processing	3	2	B++	90	0.95	3
SS&C Techn. Hldgs	Computer Software	1	3	B+	75	1.15	3
Starbucks Corporation	Restaurant	2	1	A++	85	1.05	3
Stepan Company	Chemical (Specialty)	2	3	B++	85	0.80	4
T Rowe Price Group Inc	Asset Management	3	2	A+	80	1.10	4
Tetra Tech	Environmental	3	3	B++	75	1.00	3
The Travelers Companies Inc	Insurance (Prop/Cas.)	3	1	A++	95	0.95	3
Toro Co	Machinery	3	2	B++	90	1.05	4
Transmission Holdings Inc	Auto Parts	3	3	B+	75	1.05	5
TransUnion	Information Services	2	3	B+	75	1.10	3
Tyler Technologies	IT Services	2	2	A+	80	0.85	3
Union Pacific Corp	Railroad	2	1	A++	90	1.05	3
United Parcel Service	Air Transport	3	1	A+	80	0.85	3
US Bancorp	Bank (Midwest)	3	2	A	75	1.15	3
Valmont Industries	Diversified Co.	3	2	A	75	1.05	3
VeriSign Inc	Internet	1	2	A	90	0.95	5
Visa Inc	Financial Svcs. (Div.)	1	1	A++	90	1.05	3
Walgreens Boots	Retail Store	2	3	A	75	0.85	4
Walt Disney Co	Entertainment	1	2	A	80	1.05	3
Washington Federal Inc	Thrift	3	3	B+	80	1.00	5
Waters Corp	Precision Instrument	3	2	A	85	0.95	4
Watts Water Technologies Inc	Machinery	1	2	B++	90	1.00	4
WR Berkley Corp	Insurance (Prop/Cas.)	3	2	A	90	1.05	3
Xylem Inc	Machinery	3	3	B++	80	1.10	3
Zoetis Inc	Drug	3	2	B++	90	1.00	3
Average		2	2	A	84	0.98	3
Electric Group	Average	3	2	A	88	0.88	3

Source of Information: Value Line Investment Survey for Windows, October 2022

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2017-2021 and
Projected 3-5 Year Returns

Company	2017	2018	2019	2020	2021	Average	Projected 2025-27
Abbott Laboratories	14.2%	16.8%	18.7%	20.0%	26.2%	19.2%	24.5%
AbbVie Inc	NMF	-	-	NMF	NMF	-	NMF
Agilent Technologies	15.9%	19.9%	20.8%	21.0%	24.7%	20.5%	19.5%
Air Products and Chemicals Inc	13.7%	15.1%	16.5%	15.4%	14.8%	15.1%	17.5%
Alamo Group	12.1%	14.5%	11.0%	9.1%	11.0%	11.5%	15.5%
AMERCO	9.0%	10.0%	7.0%	12.6%	18.7%	11.5%	10.5%
AmerisourceBergen Corp	63.2%	48.8%	52.2%	52.2%	864.3%	216.1%	NMF
Amphenol Corp	24.7%	30.0%	25.5%	22.3%	24.9%	25.5%	23.5%
Analog Devices Inc	16.6%	20.4%	16.3%	15.2%	6.8%	15.1%	12.0%
ANSYS Inc	15.5%	19.4%	16.4%	14.3%	14.5%	16.0%	17.0%
AO Smith Corp	22.9%	26.2%	22.2%	18.7%	26.6%	23.3%	38.0%
Arrow Electronics Inc	13.7%	14.7%	13.2%	12.0%	21.5%	15.0%	18.5%
Assurant Inc	12.2%	4.9%	6.8%	7.4%	11.2%	8.5%	8.5%
Badger Meter Inc	12.5%	14.8%	14.3%	13.7%	15.1%	14.1%	19.0%
Balchem Corp.	14.6%	11.4%	10.7%	10.2%	11.0%	11.6%	13.5%
Bank of New York Mellon Corporation	8.9%	10.5%	10.7%	7.9%	8.7%	9.3%	9.0%
Becton Dickinson and Company	16.0%	13.6%	15.2%	12.1%	16.5%	14.7%	13.0%
Booz Allen Hamilton Holding Corporation	55.0%	58.8%	56.4%	50.8%	54.5%	55.1%	33.5%
Boston Scientific Corp	18.0%	17.7%	13.0%	4.6%	10.2%	12.7%	21.5%
Brady Corp	13.7%	14.9%	15.4%	13.0%	13.5%	14.1%	14.5%
CDW Corp.	53.2%	65.9%	76.7%	60.8%	NMF	64.2%	67.0%
Charter Communic.	1.5%	3.4%	5.3%	13.5%	33.1%	11.4%	45.0%
Chemed Corporation	26.1%	33.9%	31.7%	32.9%	49.5%	34.8%	30.5%
Cisco Systems Inc	18.2%	29.4%	41.1%	36.0%	33.0%	31.5%	32.5%
CME Group Inc	18.1%	7.6%	8.1%	8.0%	9.6%	10.3%	9.5%
Cognizant Technology Solutions Corp	21.0%	23.4%	20.3%	17.0%	18.1%	20.0%	24.0%
Comcast Corporation	14.4%	16.5%	17.4%	13.3%	15.7%	15.5%	16.0%
Copart Inc	27.6%	26.3%	30.1%	24.5%	25.2%	26.7%	24.5%
CSG Systems International Inc	17.9%	18.3%	20.9%	13.9%	16.6%	17.5%	24.0%
CSX Corporation	14.0%	26.3%	28.1%	21.1%	26.1%	23.1%	33.5%
Cummins Inc	24.5%	29.4%	31.0%	22.7%	25.1%	26.5%	28.0%
Dolby Laboratories Inc	9.4%	12.6%	11.1%	9.5%	11.9%	10.9%	12.5%
Donaldson Co	26.6%	31.0%	29.9%	26.0%	25.2%	27.7%	25.0%
Ecolab Inc	18.1%	17.9%	17.9%	NMF	15.6%	17.4%	26.5%
Eli Lilly and Co	39.1%	58.3%	NMF	NMF	82.8%	60.1%	77.0%
Equifax Inc	22.8%	22.6%	26.6%	27.0%	26.4%	25.1%	17.5%
ESCO Technologies Inc	8.6%	9.0%	9.9%	7.5%	6.7%	8.3%	10.0%
Fidelity Nat'l Info.	5.0%	8.3%	0.6%	0.3%	0.9%	3.0%	8.5%
First Commonwealth Financial Corp	8.1%	11.0%	10.0%	6.9%	12.5%	9.7%	9.5%
First Republic Bank	9.7%	9.8%	9.4%	9.1%	9.3%	9.5%	10.5%
Fiserv Inc	40.4%	55.9%	8.4%	9.3%	12.1%	25.2%	12.5%
Fortive Corp.	27.6%	13.9%	9.8%	3.7%	6.6%	12.3%	13.0%
GATX Corp	10.4%	11.2%	10.9%	6.5%	9.0%	9.6%	9.0%
Gentex Corp	18.0%	23.5%	21.9%	17.7%	18.6%	19.9%	26.0%
Globe Life Inc.	9.4%	13.0%	10.3%	8.4%	8.2%	9.9%	9.5%
Graco Inc	34.9%	43.6%	31.7%	25.7%	25.7%	32.3%	20.0%
Hanover Insurance Group Inc	6.8%	9.9%	11.4%	11.1%	11.4%	10.1%	10.5%
Honeywell International Inc	31.8%	33.2%	32.2%	28.8%	30.4%	31.3%	43.0%
IDEX Corporation	17.9%	21.1%	19.6%	15.6%	17.2%	18.3%	19.0%
Intercontinental Exch.	10.4%	12.1%	12.7%	12.8%	12.8%	12.2%	10.5%
J B Hunt Transport Services Inc	22.6%	29.7%	24.9%	19.5%	24.4%	24.2%	17.0%
Jacobs Solutions	8.8%	10.6%	12.7%	12.3%	13.8%	11.6%	15.0%
JP Morgan Chase and Co	10.4%	12.7%	13.9%	10.4%	16.4%	12.8%	12.0%
Kadant Inc	15.3%	16.3%	14.4%	11.7%	16.2%	14.8%	12.5%
Knight-Swift Trans.	9.2%	8.4%	6.6%	8.0%	12.1%	8.9%	9.0%
Leidos Holdings Inc	17.0%	20.3%	22.0%	21.8%	22.0%	20.6%	19.5%
Lennox International Inc	NMF	-	-	-	-	-	NMF
Loews Corporation	4.5%	3.6%	4.7%	0.3%	6.0%	3.8%	7.5%
Markel Corp	0.6%	NMF	16.2%	6.4%	16.5%	9.9%	8.5%
Mastercard Incorporated	89.5%	NMF	NMF	101.1%	114.0%	101.5%	NMF
McCormick and Co	21.4%	20.9%	20.8%	19.4%	18.7%	20.2%	16.0%
McKesson Corp	27.0%	33.0%	53.3%	53.3%	NMF	41.7%	NMF
Mettler Toledo International Inc	81.9%	83.6%	NMF	NMF	NMF	82.8%	NMF
Microsoft Corporation	33.3%	36.6%	36.0%	37.4%	43.2%	37.3%	40.0%
Moodys Corp	-	NMF	NMF	122.4%	84.7%	103.6%	24.0%
MSA Safety	23.6%	27.7%	25.9%	22.4%	22.1%	24.3%	22.5%
MSC Industrial Direct Co Inc	18.7%	20.8%	20.0%	20.1%	23.4%	20.6%	22.5%
MSCI Inc	75.8%	-	-	NMF	NMF	75.8%	NMF
Nordson Corp	27.0%	24.1%	21.5%	18.2%	21.0%	22.4%	21.5%
Norfolk Southern Corp	11.6%	17.4%	17.9%	16.0%	22.0%	17.0%	25.0%
O Reilly Automotive Inc	NMF	NMF	NMF	NMF	NMF	-	NMF
Old Republic International Corp	6.8%	10.9%	9.1%	10.9%	13.5%	10.2%	12.0%
Oracle Corp	21.5%	29.0%	60.3%	NMF	NMF	36.9%	NMF
Packaging Corp	25.0%	27.6%	22.7%	16.9%	24.8%	23.4%	18.0%
PerkinElmer Inc	12.9%	15.6%	16.3%	24.9%	18.6%	17.7%	12.5%
Philip Morris International Inc	-	-	-	-	-	-	NMF
Pool Corporation	74.9%	104.9%	63.8%	57.4%	60.7%	72.3%	38.5%
Raytheon Technologies	17.8%	16.0%	17.1%	4.6%	8.8%	12.9%	11.5%
RLI Corp	8.7%	11.4%	11.8%	10.4%	14.5%	11.4%	12.5%
Roper Tech.	11.0%	15.9%	14.4%	12.9%	13.1%	13.5%	9.5%
S&P Global	NMF	NMF	NMF	NMF	NMF	-	17.0%
SBA Communications	-	-	-	NMF	NMF	-	NMF
Schneider National	20.6%	12.6%	6.6%	10.3%	16.7%	13.4%	17.5%
Selective Insurance Group Inc	10.8%	12.2%	12.0%	9.1%	13.5%	11.5%	14.5%
Sensient Technologies Corp	17.7%	18.3%	14.2%	11.7%	14.1%	15.2%	13.5%
SS&C Techn. Hldgs	15.2%	15.5%	19.8%	20.1%	21.8%	18.5%	21.0%
Starbucks Corporation	55.2%	NMF	NMF	NMF	NMF	55.2%	NMF
Stepan Company	12.4%	14.4%	11.6%	12.9%	12.8%	12.8%	13.0%
T Rowe Price Group Inc	26.4%	29.0%	30.0%	30.8%	34.2%	30.1%	21.5%
Tetra Tech	13.3%	15.4%	17.8%	17.0%	16.8%	16.1%	22.5%
The Travelers Companies Inc	8.6%	10.7%	9.8%	9.2%	12.2%	10.1%	10.0%
Toro Co	43.4%	40.7%	31.9%	29.6%	35.6%	36.2%	43.0%
Transmission Holdings Inc	50.7%	97.0%	77.3%	39.6%	69.7%	66.9%	27.0%
TransUnion	20.6%	25.2%	23.9%	22.7%	17.0%	21.9%	14.5%
Tyler Technologies	13.2%	14.6%	13.1%	11.5%	12.8%	13.0%	15.5%
Union Pacific Corp	18.7%	29.2%	32.7%	32.5%	46.1%	31.8%	55.5%
United Parcel Service	NMF	NMF	NMF	NMF	NMF	-	56.0%
US Bancorp	12.4%	13.9%	13.3%	9.3%	14.5%	12.7%	15.5%
Valmont Industries	14.2%	16.1%	13.8%	14.8%	16.9%	15.2%	14.5%
VeriSign Inc	-	-	-	-	-	-	NMF
Visa Inc	25.4%	30.3%	34.8%	30.0%	32.8%	30.7%	38.0%
Walgreens Boots	20.0%	23.0%	23.5%	20.2%	18.1%	21.0%	17.5%
Walt Disney Co	21.7%	25.8%	11.7%	NMF	2.3%	15.4%	11.5%
Washington Federal Inc	8.7%	10.2%	10.3%	8.6%	8.2%	9.2%	9.0%
Waters Corp	27.0%	39.9%	-	NMF	NMF	33.5%	29.0%
Watts Water Technologies Inc	12.5%	14.4%	14.2%	12.3%	16.0%	13.9%	17.0%
WR Berkley Corp	5.2%	9.5%	9.6%	7.1%	14.3%	9.1%	15.0%
Xylem Inc	17.1%	18.9%	18.5%	12.6%	14.0%	16.2%	13.5%
Zoetis Inc	66.8%	69.8%	64.8%	48.9%	49.3%	59.9%	43.0%
Average						25.8%	20.9%
Median						17.0%	17.0%
Average (excluding companies with values >20%)						12.8%	13.4%

Comparable Earnings Approach
Screening Parameters

Timeliness Rank

The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

UGI ELECTRIC

EXHIBIT E

PROOF OF REVENUE

UGI Utilities, Inc. - Electric Division
Proof of Revenue Summary - Total Revenue
for 12-months Ended September 30, 2024

Rate	Customers	Fixtures	Sales	Total Present Revenue	Proposed Revenue	Revenue Change	Percent Change from Present Revenue	Percent of Total Rate Increase
R	54,998		610,229,801	$ 117,079,865	$ 127,786,219	$ 10,706,354	9.1%	93.7%
GS-1	5,275		32,013,892	$ 6,493,626	$ 7,190,481	$ 696,855	10.7%	6.1%
GS-4	2,330		115,648,153	$ 14,320,768	$ 14,321,024	$ 256	0.0%	0.0%
GS-5	56		1,011,703	$ 152,923	$ 169,740	$ 16,818	11.0%	0.1%
FCP	7		763,235	$ 19,104	$ 24,137	$ 5,033	26.3%	0.0%
Lighting		9,120	7,066,465	$ 1,842,691	$ 1,842,504	$ (186)	0.0%	0.0%
LP	211		289,197,391	$ 11,679,885	$ 11,680,154	$ 269	0.0%	0.0%
Total - Rate Class	**62,877**		**1,055,930,640**	**$ 151,588,862**	**$ 163,014,260**	**$ 11,425,398**	**7.5%**	
Other Operating Revenue				$ 1,102,849	$ 1,102,849	$ -		
Total Revenue				**$ 152,691,711**	**$ 164,117,109**	**$ 11,425,398**	**7.5%**	

UGI Utilities, Inc. - Electric Division
Residential Service - Rate Schedule R
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2024

Description	Number of Bills (1)	Pro Forma Consumption kWh (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Customer Charge	659,976		$ 9.50	$ 6,269,772	$ 13.50	$ 8,909,676	$ 2,639,904	
Distribution Charge		610,229,801	$ 0.03907	$ 23,841,678	$ 0.05535	$ 33,776,220	$ 9,934,541	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 11,707	0.00%	$ -	$ (11,707)	
Generation Supply Rate (GSR) - Rider B		605,209,142	$ 0.12902	$ 78,084,084	$ 0.12902	$ 78,084,084	$ -	
Universal Service Program (USP) - Rider C		578,800,352	$ 0.01150	$ 6,656,204	$ 0.01150	$ 6,656,204	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider E		610,229,801	$ 0.00059	$ 360,036	$ 0.00059	$ 360,036	$ -	
Distribution System Improvement Charge (DSIC) - Rider G			5.00%	$ 1,856,384	0.00%	$ -	$ (1,856,384)	
Total - Rate R	**659,976**	**610,229,801**		**$ 117,079,865**		**$ 127,786,219**	**$ 10,706,354**	**9.1%**
Choice Power Supply		*5,020,659*	*$ 0.12902*	*$ 647,765*	*$ 0.12902*	*$ 647,765*	*$ -*	
Total - Rate R (including Choice Power Supply)	**659,976**	**610,229,801**		**$ 117,727,630**		**$ 128,433,984**	**$ 10,706,354**	

UGI Utilities, Inc. - Electric Division
General Service - Rate Schedule GS-1 - General Service Customers
Demand under 5 kW
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2024

Description	Number of Bills (1)	Pro Forma Consumption kWh (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Customer Charge	63,300		$ 13.00	$ 822,900	$ 14.00	$ 886,200	$ 63,300	
Distribution Charge		32,013,892	$ 0.05237	$ 1,676,568	$ 0.07615	$ 2,437,858	$ 761,290	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 649	0.00%	$ -	$ (649)	
Generation Supply Rate (GSR) - Rider B		29,640,094	$ 0.12902	$ 3,824,165	$ 0.12902	$ 3,824,165	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider E		32,013,892	$ 0.00132	$ 42,258	$ 0.00132	$ 42,258	$ -	
Distribution System Improvement Charge (DSIC) - Rider G			5.00%	$ 127,086	0.00%	$ -	$ (127,086)	
Total - GS-1	**63,300**	**32,013,892**		**$ 6,493,626**		**$ 7,190,481**	**$ 696,855**	**10.7%**
Choice Power Supply		*2,373,798*	*$ 0.12902*	*$ 306,267*	*$ 0.12902*	*$ 306,267*	*$ -*	
Total - GS-1 (including Choice Power Supply)	**63,300**	**32,013,892**		**$ 6,799,894**		**$ 7,496,749**	**$ 696,855**	

UGI Utilities, Inc. - Electric Division
General Service - Rate Schedule GS-4 - General Service Customers
Demand over 5 kW
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2024

Description	Number of Bills (1)	Pro Forma Consumption kWh (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Customer Charge	27,960		$ 15.00	$ 419,400	$ 15.00	$ 419,400	$ -	
Distribution Charges								
First 200 hours of demand		74,604,193	$ 0.02882	$ 2,150,093	$ 0.03126	$ 2,332,127	$ 182,034	
Next 300 hours of demand		38,214,145	$ 0.01816	$ 693,969	$ 0.01968	$ 752,054	$ 58,086	
All over 500 hours of demand		2,829,815	$ 0.01513	$ 42,815	$ 0.01640	$ 46,409	$ 3,594	
Total Distribution		115,648,153		$ 2,886,877		$ 3,130,590	$ 243,714	
Demand Charges								
First 20 kW		297,099	$ 3.59000	$ 1,066,585	$ 3.59000	$ 1,066,585	$ -	
Over 20 kW		143,179	$ 2.20000	$ 314,994	$ 2.20000	$ 314,994	$ -	
Total Demand		440,278		$ 1,381,579		$ 1,381,579	$ -	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 1,432	0.00%	$ -	$ (1,432)	
Generation Supply Rate (GSR) - Rider B		84,753,679	$ 0.10898	$ 9,236,799	$ 0.10898	$ 9,236,799	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider E		115,648,153	$ 0.00132	$ 152,656	$ 0.00132	$ 152,656	$ -	
Distribution System Improvement Charge (DSIC) - Rider G			5.00%	$ 242,026	0.00%	$ -	$ (242,026)	
Total - GS-4	**27,960**	**115,648,153**		**$ 14,320,768**		**$ 14,321,024**	**$ 256**	**0.0%**
Choice Power Supply		*30,894,474*	*$ 0.10898*	*$ 3,367,005*	*$ 0.10898*	*$ 3,367,005*	*$ -*	
Total - GS-4 (including Choice Power Supply)	**27,960**	**115,648,153**		**$ 17,687,773**		**$ 17,688,029**	**$ 256**	

UGI Utilities, Inc. - Electric Division
General Service - Rate Schedule GS-5 - General Service Customers
Volunteer Fire Company and Non-Profit Senior Citizen Center, Rescue Squad and Ambulance Service
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2024

Description	Number of Bills (1)	Pro Forma Consumption kWh (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Customer Charge	672		$ 9.50	$ 6,384	$ 13.50	$ 9,072	$ 2,688	
Distribution Charges		1,011,703	$ 0.03907	$ 39,527	$ 0.05535	$ 55,998	$ 16,471	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 15	0.00%	$ -	$ (15)	
Generation Supply Rate (GSR) - Rider B		806,648	$ 0.12902	$ 104,074	$ 0.12902	$ 104,074	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider E		1,011,703	$ 0.00059	$ 597	$ 0.00059	$ 597	$ -	
Distribution System Improvement Charge (DSIC) - Rider G			5.00%	$ 2,325	0.00%	$ -	$ (2,325)	
Total - GS-5	**672**	**1,011,703**		**$ 152,923**		**$ 169,740**	**$ 16,818**	**11.0%**
Choice Power Supply		*205,055*	*$ 0.12902*	*$ 26,456*	*$ 0.12902*	*$ 26,456*	*$ -*	
Total - GS-5 (including Choice Power Supply)	**672**	**1,011,703**		**$ 179,379**		**$ 196,197**	**$ 16,818**	

UGI Utilities, Inc. - Electric Division
Flood Control Power Service - Rate Schedule FCP
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2024

Description	Number of Bills (1)	Pro Forma Consumption kWh (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Distribution Charges								
Rate FCP								
1st 100 kWh		84	$ 4.69000	$ 394	$ 6.31000	$ 530	$ 136	
Over 100 kWh		763,235	$ 0.02200	$ 16,791	$ 0.02961	$ 22,599	$ 5,808	
Total Rate FCP		763,319		$ 17,185		$ 23,129	$ 5,944	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 2	0.00%	$ -	$ (2)	
Generation Supply Rate (GSR) - Rider B		-	$ 0.12902	$ -	$ 0.12902	$ -	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider E		763,319	$ 0.00132	$ 1,008	$ 0.00132	$ 1,008	$ -	
Distribution System Improvement Charge (DSIC) - Rider G			5.00%	$ 910	0.00%	$ -	$ (910)	
Total - FCP	**84**	**763,319**		**$ 19,104**		**$ 24,137**	**$ 5,033**	**26.3%**
Choice Power Supply		*763,319*	*$ 0.12902*	*$ 98,483*	*$ 0.12902*	*$ 98,483*		
Total - FCP (including Choice Power Supply)	**84**	**763,319**		**$ 117,588**		**$ 122,620**	**$ 5,033**	

UGI Utilities, Inc. - Electric Division
Large Power Service - Rate Schedule LP
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2024

Description	Number of Bills (1)	Pro Forma Consumption kWh (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Distribution Charges								
First 100 hours of demand		75,476,166	$ 0.02199	$ 1,659,721	$ 0.02341	$ 1,766,897	$ 107,176	
Next 200 hours of demand		111,304,800	$ 0.01588	$ 1,767,520	$ 0.01691	$ 1,882,164	$ 114,644	
Next 200 hours of demand		61,722,574	$ 0.01453	$ 896,829	$ 0.01547	$ 954,848	$ 58,019	
All over 500 hours of demand		40,693,851	$ 0.01365	$ 555,471	$ 0.01455	$ 592,096	$ 36,624	
Total Distribution		289,197,391		$ 4,879,541		$ 5,196,005	$ 316,464	
Demand Charges								
First 100 kW		2,532	$ 135.80	$ 343,846	$ 135.80	$ 343,846	$ -	
Next 400 kW		289,777	$ 0.94000	$ 272,390	$ 0.94000	$ 272,390	$ -	
Over 500 kW		231,454	$ 0.69000	$ 159,703	$ 0.69000	$ 159,703	$ -	
Total Demand		523,763		$ 775,939		$ 775,939	$ -	
Power Factor & Secondary Service Charges				$ 57,989		$ 57,989	$ -	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 1,168	0.00%	$ -	$ (1,168)	
Generation Supply Rate (GSR) - Rider B		78,819,050	$ 0.06424	$ 5,063,150	$ 0.06424	$ 5,063,150	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider E		289,197,391	$ 0.00203	$ 587,071	$ 0.00203	$ 587,071	$ -	
Distribution System Improvement Charge (DSIC) - Rider G			5.00%	$ 315,027	0.00%	$ -	$ (315,027)	
Total - LP	**2,532**	**289,197,391**		**$ 11,679,885**		**$ 11,680,154**	**$ 269**	**0.0%**
Choice Power Supply		*210,378,341*	*$ 0.06424*	*$ 13,514,209*	*$ 0.06424*	*$ 13,514,209*	*$ -*	
Total - LP (including Choice Power Supply)	**2,532**	**289,197,391**		**$ 25,194,094**		**$ 25,194,363**	**$ 269**	

UGI Utilities, Inc. - Electric Division
Outdoor Lighting Service - Rate Schedule OL - Residential
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2024

Description	Number of Fixture Charges (1)	Pro Forma Consumption kWh (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Fixture Charge								
Flood Lighting								
11,000 Lumen	12		$ 7.20	$ 86	$ 7.20	$ 86	$ -	
20,000 Lumen	-		$ 8.05	$ -	$ 8.05	$ -	$ -	
60,000 Lumen	-		$ 8.24	$ -	$ 8.24	$ -	$ -	
Street Lighting								
7,000 Lumen	5,088		$ 4.54	$ 23,100	$ 4.54	$ 23,100	$ -	
11,000 Lumen	24		$ 7.20	$ 173	$ 7.20	$ 173	$ -	
20,000 Lumen	12		$ 8.05	$ 97	$ 8.05	$ 97	$ -	
60,000 Lumen	-		$ 8.24	$ -	$ 8.24	$ -	$ -	
Total Fixture Charges	5,136			$ 23,455		$ 23,455	$ -	
Distribution Charges								
Flood Lighting								
11,000 Lumen		1,160	$ 0.03962	$ 46	$ 0.04812	$ 56	$ 10	
20,000 Lumen		-	$ 0.03962	$ -	$ 0.04812	$ -	$ -	
60,000 Lumen		-	$ 0.03962	$ -	$ 0.04812	$ -	$ -	
Street Lighting								
7,000 Lumen		343,658	$ 0.03962	$ 13,616	$ 0.04812	$ 16,537	$ 2,921	
11,000 Lumen		2,320	$ 0.03962	$ 92	$ 0.04812	$ 112	$ 20	
20,000 Lumen		1,771	$ 0.03962	$ 70	$ 0.04812	$ 85	$ 15	
60,000 Lumen		-	$ 0.03962	$ -	$ 0.04812	$ -	$ -	
Total Distribution Charges		348,911		$ 13,824		$ 16,790	$ 2,966	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 8	0.00%	$ -	$ (8)	
Generation Supply Rate (GSR) - Rider B		344,850	$ 0.12902	$ 44,493	$ 0.12902	$ 44,493	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider E		348,911	$ 0.00059	$ 206	$ 0.00059	$ 206	$ -	
Distribution System Improvement Charge (DSIC) - Rider G			5.00%	$ 1,874	0.00%	$ -	$ (1,874)	
Total - OL - R	**5,136**	**348,911**		**$ 83,860**		**$ 84,943**	**$ 1,083**	**1.3%**
Choice Power Supply		*4,061*	*$ 0.12902*	*$ 524*	*$ 0.12902*	*$ 524*	*$ -*	
Total - OL - R (including Choice Power Supply)	**5,136**	**348,911**		**$ 84,384**		**$ 85,467**	**$ 1,083**	

UGI Utilities, Inc. - Electric Division
Outdoor Lighting Service - Rate Schedule OL - Commercial/Industrial
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2024

Description	Number of Fixture Charges (1)	Pro Forma Consumption kWh (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Fixture Charge								
Flood Lighting								
11,000 Lumen	60		$ 6.79	$ 407	$ 6.79	$ 407	$ -	
20,000 Lumen	144		$ 7.43	$ 1,070	$ 7.43	$ 1,070	$ -	
60,000 Lumen	-		$ 6.69	$ -	$ 6.69	$ -	$ -	
Street Lighting								
7,000 Lumen	2,964		$ 4.26	$ 12,627	$ 4.26	$ 12,627	$ -	
11,000 Lumen	36		$ 6.79	$ 244	$ 6.79	$ 244	$ -	
20,000 Lumen	180		$ 7.43	$ 1,337	$ 7.43	$ 1,337	$ -	
60,000 Lumen	12		$ 6.69	$ 80	$ 6.69	$ 80	$ -	
Total Fixture Charges	3,396			$ 15,766		$ 15,766	$ -	
Distribution Charges								
Flood Lighting								
11,000 Lumen		5,801	$ 0.04776	$ 277	$ 0.05626	$ 326	$ 49	
20,000 Lumen		21,257	$ 0.04776	$ 1,015	$ 0.05626	$ 1,196	$ 181	
60,000 Lumen		-	$ 0.04776	$ -	$ 0.05626	$ -	$ -	
Street Lighting								
7,000 Lumen		199,907	$ 0.04776	$ 9,548	$ 0.05626	$ 11,247	$ 1,699	
11,000 Lumen		3,481	$ 0.04776	$ 166	$ 0.05626	$ 196	$ 30	
20,000 Lumen		26,571	$ 0.04776	$ 1,269	$ 0.05626	$ 1,495	$ 226	
60,000 Lumen		4,462	$ 0.04776	$ 213	$ 0.05626	$ 251	$ 38	
Total Distribution Charges		261,479		$ 12,488		$ 14,711	$ 2,223	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 6	0.00%	$ -	$ (6)	
Generation Supply Rate (GSR) - Rider B		247,378	$ 0.12902	$ 31,917	$ 0.12902	$ 31,917	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider E		261,479	$ 0.00132	$ 345	$ 0.00132	$ 345	$ -	
Distribution System Improvement Charge (DSIC) - Rider G			5.00%	$ 1,430	0.00%	$ -	$ (1,430)	
Total - OL - C/I	**3,396**	**261,479**		**$ 61,952**		**$ 62,739**	**$ 786**	**1.3%**
Choice Power Supply		*14,101*	*$ 0.12902*	*$ 1,819*	*$ 0.12902*	*$ 1,819*	*$ -*	
Total - OL - C/I (including Choice Power Supply)	**3,396**	**261,479**		**$ 63,772**		**$ 64,558**	**$ 786**	

UGI Utilities, Inc. - Electric Division
Sodium Outdoor Lighting Service - Rate Schedule SOL - Residential
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2024

Description	Number of Fixture Charges (1)	Pro Forma Consumption kWh (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Fixture Charge								
Flood Lighting								
16,000 Lumen	264		$ 7.96	$ 2,101	$ 7.96	$ 2,101	$ -	
25,000 Lumen	60		$ 8.35	$ 501	$ 8.35	$ 501	$ -	
50,000 Lumen	12		$ 10.42	$ 125	$ 10.42	$ 125	$ -	
Street Lighting								
9,500 Lumen	2,520		$ 7.87	$ 19,832	$ 7.87	$ 19,832	$ -	
16,000 Lumen	156		$ 7.96	$ 1,242	$ 7.96	$ 1,242	$ -	
25,000 Lumen	12		$ 8.35	$ 100	$ 8.35	$ 100	$ -	
50,000 Lumen	-		$ 10.42	$ -	$ 10.42	$ -	$ -	
Total Fixture Charges	3,024			$ 23,902		$ 23,902	$ -	
Distribution Charges								
Flood Lighting								
16,000 Lumen		18,769	$ 0.03962	$ 744	$ 0.04812	$ 903	$ 160	
25,000 Lumen		6,540	$ 0.03962	$ 259	$ 0.04812	$ 315	$ 56	
50,000 Lumen		2,015	$ 0.03962	$ 80	$ 0.04812	$ 97	$ 17	
Street Lighting								
9,500 Lumen		126,274	$ 0.03962	$ 5,003	$ 0.04812	$ 6,076	$ 1,073	
16,000 Lumen		11,091	$ 0.03962	$ 439	$ 0.04812	$ 534	$ 94	
25,000 Lumen		1,308	$ 0.03962	$ 52	$ 0.04812	$ 63	$ 11	
50,000 Lumen		-	$ 0.03962	$ -	$ 0.04812	$ -	$ -	
Total Distribution Charges		165,997		$ 6,577		$ 7,988	$ 1,411	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 5	0.00%	$ -	$ (5)	
Generation Supply Rate (GSR) - Rider B		165,997	$ 0.12902	$ 21,417	$ 0.12902	$ 21,417	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider E		165,997	$ 0.00059	$ 98	$ 0.00059	$ 98	$ -	
Distribution System Improvement Charge (DSIC) - Rider G		165,997	5.00%	$ 1,529	0.00%	$ -	$ (1,529)	
Total - SOL - R	**3,024**	**165,997**		**$ 53,528**		**$ 53,404**	**$ (123)**	**-0.2%**
Choice Power Supply		*-*	*$ 0.12902*	*$ -*	*$ 0.12902*	*$ -*	*$ -*	
Total - SOL - R (including Choice Power Supply)	**3,024**	**165,997**		**$ 53,528**		**$ 53,404**	**$ (123)**	

UGI Utilities, Inc. - Electric Division
Sodium Outdoor Lighting Service - Rate Schedule SOL - Commercial/Industrial
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2024

Description	Number of Fixture Charges (1)	Pro Forma Consumption kWh (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Fixture Charge								
Flood Lighting								
16,000 Lumen	2,016		$ 7.65	$ 15,422	$ 7.65	$ 15,422	$ -	
25,000 Lumen	2,928		$ 7.88	$ 23,073	$ 7.88	$ 23,073	$ -	
50,000 Lumen	2,328		$ 9.72	$ 22,628	$ 9.72	$ 22,628	$ -	
Street Lighting								
9,500 Lumen	2,568		$ 7.66	$ 19,671	$ 7.66	$ 19,671	$ -	
16,000 Lumen	900		$ 7.65	$ 6,885	$ 7.65	$ 6,885	$ -	
25,000 Lumen	612		$ 7.88	$ 4,823	$ 7.88	$ 4,823	$ -	
50,000 Lumen	132		$ 9.72	$ 1,283	$ 9.72	$ 1,283	$ -	
Total Fixture Charges	11,484			$ 93,785		$ 93,785	$ -	
Distribution Charges								
Flood Lighting								
16,000 Lumen		143,327	$ 0.04776	$ 6,845	$ 0.05626	$ 8,064	$ 1,218	
25,000 Lumen		319,134	$ 0.04776	$ 15,242	$ 0.05626	$ 17,955	$ 2,713	
50,000 Lumen		390,865	$ 0.04776	$ 18,668	$ 0.05626	$ 21,990	$ 3,322	
Street Lighting								
9,500 Lumen		128,680	$ 0.04776	$ 6,146	$ 0.05626	$ 7,240	$ 1,094	
16,000 Lumen		63,985	$ 0.04776	$ 3,056	$ 0.05626	$ 3,600	$ 544	
25,000 Lumen		66,704	$ 0.04776	$ 3,186	$ 0.05626	$ 3,753	$ 567	
50,000 Lumen		22,162	$ 0.04776	$ 1,058	$ 0.05626	$ 1,247	$ 188	
Total Distribution Charges		1,134,858		$ 54,201		$ 63,847	$ 9,646	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 28	0.00%	$ -	$ (28)	
Generation Supply Rate (GSR) - Rider B		950,127	$ 0.12902	$ 122,585	$ 0.12902	$ 122,585	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider E		1,134,858	$ 0.00132	$ 1,498	$ 0.00132	$ 1,498	$ -	
Distribution System Improvement Charge (DSIC) - Rider G			5.00%	$ 7,474	0.00%	$ -	$ (7,474)	
Total - SOL - C/I	**11,484**	**1,134,858**		**$ 279,571**		**$ 281,715**	**$ 2,144**	**0.8%**
Choice Power Supply		*184,731*	*$ 0.12902*	*$ 23,834*	*$ 0.12902*	*$ 23,834*	*$ -*	
Total - SOL - C/I (including Choice Power Supply)	**11,484**	**1,134,858**		**$ 303,405**		**$ 305,549**	**$ 2,144**	

UGI Utilities, Inc. - Electric Division
Metal Halide Outdoor Lighting Service - Rate Schedule MHOL - Residential
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2024

Description	Number of Fixture Charges (1)	Pro Forma Consumption kWh (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Fixture Charge								
Flood Lighting								
20,500 Lumen	96		$ 9.05	$ 869	$ 9.05	$ 869	$ -	
36,000 Lumen	216		$ 9.20	$ 1,987	$ 9.20	$ 1,987	$ -	
110,000 Lumen	120		$ 16.11	$ 1,933	$ 16.11	$ 1,933	$ -	
Street Lighting								
9,000 Lumen	1,260		$ 8.07	$ 10,168	$ 8.07	$ 10,168	$ -	
12,900 Lumen	60		$ 6.83	$ 410	$ 6.83	$ 410	$ -	
13,000 Lumen	-		$ 6.36	$ -	$ 6.36	$ -	$ -	
20,500 Lumen	36		$ 9.05	$ 326	$ 9.05	$ 326	$ -	
36,000 Lumen	48		$ 9.20	$ 442	$ 9.20	$ 442	$ -	
Total Fixture Charges	1,836			$ 16,135		$ 16,135	$ -	
Distribution Charges								
Flood Lighting								
20,500 Lumen		9,359	$ 0.03962	$ 371	$ 0.04812	$ 450	$ 80	
36,000 Lumen		32,903	$ 0.03962	$ 1,304	$ 0.04812	$ 1,583	$ 280	
110,000 Lumen		43,869	$ 0.03962	$ 1,738	$ 0.04812	$ 2,111	$ 373	
Street Lighting								
9,000 Lumen		63,106	$ 0.03962	$ 2,500	$ 0.04812	$ 3,037	$ 536	
12,900 Lumen		3,859	$ 0.03962	$ 153	$ 0.04812	$ 186	$ 33	
13,000 Lumen		-	$ 0.03962	$ -	$ 0.04812	$ -	$ -	
20,500 Lumen		3,509	$ 0.03962	$ 139	$ 0.04812	$ 169	$ 30	
36,000 Lumen		7,312	$ 0.03962	$ 290	$ 0.04812	$ 352	$ 62	
Total Distribution Charges		163,916		$ 6,494		$ 7,888	$ 1,393	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 4	0.00%	$ -	$ (4)	
Generation Supply Rate (GSR) - Rider B		90,518	$ 0.12902	$ 11,679	$ 0.12902	$ 11,679	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider E		163,916	$ 0.00059	$ 97	$ 0.00059	$ 97	$ -	
Distribution System Improvement Charge (DSIC) - Rider G			5.00%	$ 1,136	0.00%	$ -	$ (1,136)	
Total - MHOL - R	**1,836**	**163,916**		**$ 35,544**		**$ 35,798**	**$ 253**	**0.7%**
Choice Power Supply		*73,399*	*$ 0.12902*	*$ 9,470*	*$ 0.12902*	*$ 9,470*	*$ -*	
Total - MHOL - R (including Choice Power Supply)	**1,836**	**163,916**		**$ 45,014**		**$ 45,267**	**$ 253**	

UGI Utilities, Inc. - Electric Division
Metal Halide Outdoor Lighting Service - Rate Schedule MHOL - Commercial/Industrial
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2024

Description	Number of Fixture Charges (1)	Pro Forma Consumption kWh (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Fixture Charge								
Flood Lighting								
20,500 Lumen	708		$ 8.65	$ 6,124	$ 8.65	$ 6,124	$ -	
36,000 Lumen	2,280		$ 8.57	$ 19,540	$ 8.57	$ 19,540	$ -	
110,000 Lumen	432		$ 14.58	$ 6,299	$ 14.58	$ 6,299	$ -	
Street Lighting								
9,000 Lumen	684		$ 7.86	$ 5,376	$ 7.86	$ 5,376	$ -	
12,900 Lumen	108		$ 6.57	$ 710	$ 6.57	$ 710	$ -	
13,000 Lumen	684		$ 6.07	$ 4,152	$ 6.07	$ 4,152	$ -	
20,500 Lumen	180		$ 8.65	$ 1,557	$ 8.65	$ 1,557	$ -	
36,000 Lumen	372		$ 8.57	$ 3,188	$ 8.57	$ 3,188	$ -	
Total Fixture Charges	5,448			$ 46,945		$ 46,945	$ -	
Distribution Charges								
Flood Lighting								
20,500 Lumen		69,019	$ 0.04776	$ 3,296	$ 0.05626	$ 3,883	$ 587	
36,000 Lumen		347,309	$ 0.04776	$ 16,587	$ 0.05626	$ 19,540	$ 2,952	
110,000 Lumen		157,929	$ 0.04776	$ 7,543	$ 0.05626	$ 8,885	$ 1,342	
Street Lighting								
9,000 Lumen		34,257	$ 0.04776	$ 1,636	$ 0.05626	$ 1,927	$ 291	
12,900 Lumen		6,946	$ 0.04776	$ 332	$ 0.05626	$ 391	$ 59	
13,000 Lumen		47,696	$ 0.04776	$ 2,278	$ 0.05626	$ 2,683	$ 405	
20,500 Lumen		17,547	$ 0.04776	$ 838	$ 0.05626	$ 987	$ 149	
36,000 Lumen		55,350	$ 0.04776	$ 2,644	$ 0.05626	$ 3,114	$ 470	
Total Distribution Charges		736,054		$ 35,154		$ 41,410	$ 6,256	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 18	0.00%	$ -	$ (18)	
Generation Supply Rate (GSR) - Rider B		706,702	$ 0.12902	$ 91,179	$ 0.12902	$ 91,179	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider E		736,054	$ 0.00132	$ 972	$ 0.0013	$ 972	$ -	
Distribution System Improvement Charge (DSIC) - Rider G			5.00%	$ 4,154	0.00%	$ -	$ (4,154)	
Total - MHOL - C/I	**5,448**	**736,054**		**$ 178,421**		**$ 180,506**	**$ 2,085**	**1.2%**
Choice Power Supply		*29,352*	*$ 0.12902*	*$ 3,787*	*$ 0.12902*	*$ 3,787*	*$ -*	
Total - MHOL - C/I (including Choice Power Supply)	**5,448**	**736,054**		**$ 182,208**		**$ 184,293**	**$ 2,085**	

UGI Utilities, Inc. - Electric Division
Light Emitting Diode Outdoor Lighting Service - Rate Schedule LED-OL - Residential
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2024

Description	Number of Fixture Charges (1)	Pro Forma Consumption kWh (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Fixture Charge								
Flood Lighting								
85-100 Watts	84		$ 15.42	$ 1,295	$ 15.42	$ 1,295	$ -	
170-210 Watts	24		$ 22.64	$ 543	$ 22.64	$ 543	$ -	
250-280 Watts	-		$ 26.08	$ -	$ 26.08	$ -	$ -	
Street Lighting								
50-60 Watts	2,352		$ 10.29	$ 24,202	$ 10.29	$ 24,202	$ -	
100-110 Watts	48		$ 12.16	$ 584	$ 12.16	$ 584	$ -	
140-160 Watts	12		$ 14.00	$ 168	$ 14.00	$ 168	$ -	
250-280 Watts	-		$ 21.25	$ -	$ 21.25	$ -	$ -	
Standard Decorative Lighting								
60-80 Watts	-		$ -	$ -	$ 11.77	$ -	$ -	
Total Fixture Charges	2,520			$ 26,792		$ 26,792	$ -	
Distribution Charges								
Flood Lighting								
85-100 Watts		2,632	$ 0.03962	$ 104	$ 0.04812	$ 127	$ 22	
170-210 Watts		1,544	$ 0.03962	$ 61	$ 0.04812	$ 74	$ 13	
250-280 Watts		-	$ 0.03962	$ -	$ 0.04812	$ -	$ -	
Street Lighting								
50-60 Watts		43,794	$ 0.03962	$ 1,735	$ 0.04812	$ 2,107	$ 372	
100-110 Watts		1,708	$ 0.03962	$ 68	$ 0.04812	$ 82	$ 15	
140-160 Watts		610	$ 0.03962	$ 24	$ 0.04812	$ 29	$ 5	
250-280 Watts		-	$ 0.03962	$ -	$ 0.04812	$ -	$ -	
Standard Decorative Lighting								
60-80 Watts		-	$ -	$ -	$ 0.04812	$ -	$ -	
Total Distribution Charges		50,288		$ 1,992		$ 2,420	$ 427	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 4	0.00%	$ -	$ (4)	
Generation Supply Rate (GSR) - Rider B		50,288	$ 0.12902	$ 6,488	$ 0.12902	$ 6,488	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider E		50,288	$ 0.00059	$ 30	$ 0.00059	$ 30	$ -	
Distribution System Improvement Charge (DSIC) - Rider G			5.00%	$ 1,441	0.00%	$ -	$ (1,441)	
Total - LED-OL - R	**2,520**	**50,288**		**$ 36,747**		**$ 35,730**	**$ (1,017)**	**-2.8%**
Choice Power Supply		-	*$ 0.12902*	$ -	*$ 0.12902*	$ -	$ -	
Total - LED-OL - R (including Choice Power Supply)	**2,520**	**50,288**		**$ 36,747**		**$ 35,730**	**$ (1,017)**	

UGI Utilities, Inc. - Electric Division
Light Emitting Diode Outdoor Lighting Service - Rate Schedule LED-OL - Commercial/Industrial
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2024

Description	Number of Fixture Charges (1)	Pro Forma Consumption kWh (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Fixture Charge								
Flood Lighting								
85-100 Watts	456		$ 15.42	$ 7,032	$ 15.42	$ 7,032	$ -	
170-210 Watts	588		$ 22.64	$ 13,312	$ 22.64	$ 13,312	$ -	
250-280 Watts	660		$ 26.08	$ 17,213	$ 26.08	$ 17,213	$ -	
Street Lighting								
50-60 Watts	18,636		$ 10.29	$ 191,764	$ 10.29	$ 191,764	$ -	
100-110 Watts	480		$ 12.16	$ 5,837	$ 12.16	$ 5,837	$ -	
140-160 Watts	900		$ 14.00	$ 12,600	$ 14.00	$ 12,600	$ -	
250-280 Watts	264		$ 21.25	$ 5,610	$ 21.25	$ 5,610	$ -	
Standard Decorative Lighting								
60-80 Watts	-		$ -	$ -	$ 11.77	$ -	$ -	
Total Fixture Charges	21,984			$ 253,368		$ 253,368	$ -	
Distribution Charges								
Flood Lighting								
85-100 Watts		14,289	$ 0.04776	$ 682	$ 0.05626	$ 804	$ 121	
170-210 Watts		37,828	$ 0.04776	$ 1,807	$ 0.05626	$ 2,128	$ 322	
250-280 Watts		59,235	$ 0.04776	$ 2,829	$ 0.05626	$ 3,333	$ 503	
Street Lighting								
50-60 Watts		347,405	$ 0.04776	$ 16,592	$ 0.05626	$ 19,545	$ 2,953	
100-110 Watts		17,079	$ 0.04776	$ 816	$ 0.05626	$ 961	$ 145	
140-160 Watts		45,751	$ 0.04776	$ 2,185	$ 0.05626	$ 2,574	$ 389	
250-280 Watts		23,694	$ 0.04776	$ 1,132	$ 0.05626	$ 1,333	$ 201	
Standard Decorative Lighting								
60-80 Watts		-	$ -	$ -	$ 0.05626	$ -	$ -	
Total Distribution Charges		545,281		$ 26,043		$ 30,677	$ 4,635	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 36	0.00%	$ -	$ (36)	
Generation Supply Rate (GSR) - Rider B		473,181	$ 0.12902	$ 61,050	$ 0.12902	$ 61,050	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider E		545,281	$ 0.00132	$ 720	$ 0.0013	$ 720	$ -	
Distribution System Improvement Charge (DSIC) - Rider G			5.00%	$ 14,007	0.00%	$ -	$ (14,007)	
Total - LED-OL - C/I	**21,984**	**545,281**		**$ 355,222**		**$ 345,815**	**$ (9,407)**	**-2.6%**
Choice Power Supply		*72,100*	*$ 0.12902*	*$ 9,302*	*$ 0.12902*	*$ 9,302*	*$ -*	
Total - LED-OL - C/I (including Choice Power Supply)	**21,984**	**545,281**		**$ 364,524**		**$ 355,117**	**$ (9,407)**	

UGI Utilities, Inc. - Electric Division
Street Lighting Service - Rate Schedule SL
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2024

Description	Number of Fixture Charges (1)	Pro Forma Consumption kWh (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Fixture Charge								
Street Lighting								
3,750 Lumen	3,132		$ 3.88	$ 12,152	$ 3.88	$ 12,152	$ -	
7,000 Lumen	11,232		$ 4.05	$ 45,490	$ 4.05	$ 45,490	$ -	
11,000 Lumen	24		$ 6.37	$ 153	$ 6.37	$ 153	$ -	
20,000 Lumen	36		$ 7.65	$ 275	$ 7.65	$ 275	$ -	
60,000 Lumen	-		$ 6.43	$ -	$ 6.43	$ -	$ -	
Total Fixture Charges	14,424			$ 58,070		$ 58,070	$ -	
Distribution Charges								
Street Lighting								
3,750 Lumen		132,502	$ 0.04776	$ 6,328	$ 0.05626	$ 7,455	$ 1,126	
7,000 Lumen		760,457	$ 0.04776	$ 36,319	$ 0.05626	$ 42,783	$ 6,464	
11,000 Lumen		2,315	$ 0.04776	$ 111	$ 0.05626	$ 130	$ 20	
20,000 Lumen		5,301	$ 0.04776	$ 253	$ 0.05626	$ 298	$ 45	
60,000 Lumen		-	$ 0.04776	$ -	$ 0.05626	$ -	$ -	
Total Distribution Charges		900,575		$ 43,011		$ 50,666	$ 7,655	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 15	0.00%	$ -	$ (15)	
Generation Supply Rate (GSR) - Rider B		305,358	$ 0.12902	$ 39,397	$ 0.12902	$ 39,397	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider E		900,575	$ 0.00132	$ 1,189	$ 0.0013	$ 1,189	$ -	
Distribution System Improvement Charge (DSIC) - Rider G			5.00%	$ 5,114	0.00%	$ -	$ (5,114)	
Total - SL	**14,424**	**900,575**		**$ 146,796**		**$ 149,322**	**$ 2,527**	**1.7%**
Choice Power Supply		*595,217*	*$ 0.12902*	*$ 76,795*	*$ 0.12902*	*$ 76,795*	*$ -*	
Total - SL (including Choice Power Supply)	**14,424**	**900,575**		**$ 223,591**		**$ 226,117**	**$ 2,527**	

UGI Utilities, Inc. - Electric Division
Sodium Street Lighting Service - Rate Schedule SSL
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2024

Description	Number of Fixture Charges (1)	Pro Forma Consumption kWh (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Fixture Charge								
Street Lighting								
9,500 Lumen	21,468		$ 7.51	$ 161,225	$ 7.51	$ 161,225	$ -	
16,000 Lumen	6,588		$ 7.58	$ 49,937	$ 7.58	$ 49,937	$ -	
25,000 Lumen	6,060		$ 8.57	$ 51,934	$ 8.57	$ 51,934	$ -	
50,000 Lumen	1,752		$ 9.10	$ 15,943	$ 9.10	$ 15,943	$ -	
Total Fixture Charges	35,868			$ 279,039		$ 279,039	$ -	
Distribution Charges								
Street Lighting								
9,500 Lumen		1,075,738	$ 0.04776	$ 51,377	$ 0.05626	$ 60,521	$ 9,144	
16,000 Lumen		468,371	$ 0.04776	$ 22,369	$ 0.05626	$ 26,351	$ 3,981	
25,000 Lumen		660,504	$ 0.04776	$ 31,546	$ 0.05626	$ 37,160	$ 5,614	
50,000 Lumen		294,156	$ 0.04776	$ 14,049	$ 0.05626	$ 16,549	$ 2,500	
Total Distribution Charges		2,498,769		$ 119,341		$ 140,581	$ 21,240	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 55	0.00%	$ -	$ (55)	
Generation Supply Rate (GSR) - Rider B		1,010,931	$ 0.12902	$ 130,430	$ 0.12902	$ 130,430	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider E		2,498,769	$ 0.00132	$ 3,298	$ 0.0013	$ 3,298	$ -	
Distribution System Improvement Charge (DSIC) - Rider G			5.00%	$ 20,084	0.00%	$ -	$ (20,084)	
Total - SSL	**35,868**	**2,498,769**		**$ 552,248**		**$ 553,349**	**$ 1,100**	**0.2%**
Choice Power Supply		*1,487,838*	*$ 0.12902*	*$ 191,961*	*$ 0.12902*	*$ 191,961*	*$ -*	
Total - SSL (including Choice Power Supply)	**35,868**	**2,498,769**		**$ 744,209**		**$ 745,309**	**$ 1,100**	

UGI Utilities, Inc. - Electric Division
Metal Halide Street Lighting Service - Rate Schedule MHSL
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2024

Description	Number of Fixture Charges (1)	Pro Forma Consumption kWh (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Fixture Charge								
Street Lighting								
9,000 Lumen	2,028		$ 6.71	$ 13,608	$ 6.71	$ 13,608	$ -	
12,900 Lumen	804		$ 5.42	$ 4,358	$ 5.42	$ 4,358		
13,000 Lumen	84		$ 4.92	$ 413	$ 4.92	$ 413	$ -	
20,500 Lumen	156		$ 7.29	$ 1,137	$ 7.29	$ 1,137	$ -	
36,000 Lumen	408		$ 6.20	$ 2,530	$ 6.20	$ 2,530	$ -	
Total Fixture Charges	3,480			$ 22,046		$ 22,046	$ -	
Distribution Charges								
Street Lighting								
9,000 Lumen		101,570	$ 0.04776	$ 4,851	$ 0.05626	$ 5,714	$ 863	
12,900 Lumen		51,709	$ 0.04776	$ 2,470	$ 0.05626	$ 2,909	$ 440	
13,000 Lumen		5,857	$ 0.04776	$ 280	$ 0.05626	$ 330	$ 50	
20,500 Lumen		15,208	$ 0.04776	$ 726	$ 0.05626	$ 856	$ 129	
36,000 Lumen		62,150	$ 0.04776	$ 2,968	$ 0.05626	$ 3,497	$ 528	
Total Distribution Charges		236,494		$ 11,295		$ 13,305	$ 2,010	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 5	0.00%	$ -	$ (5)	
Generation Supply Rate (GSR) - Rider B		134,796	$ 0.12902	$ 17,391	$ 0.12902	$ 17,391	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider E		236,494	$ 0.00132	$ 312	$ 0.0013	$ 312	$ -	
Distribution System Improvement Charge (DSIC) - Rider G			5.00%	$ 1,683	0.00%	$ -	$ (1,683)	
Total - MHSL	**3,480**	**236,494**		**$ 52,732**		**$ 53,054**	**$ 322**	**0.6%**
Choice Power Supply		*101,698*	*$ 0.12902*	*$ 13,121*	*$ 0.12902*	*$ 13,121*	*$ -*	
Total - MHSL (including Choice Power Supply)	**3,480**	**236,494**		**$ 65,853**		**$ 66,175**	**$ 322**	

UGI Utilities, Inc. - Electric Division
Light Emitting Diode Lighting Service - Rate Schedule LED-CO
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2024

Description	Number of Fixture Charges (1)	Pro Forma Consumption kWh (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Fixture Charge								
Street Lighting								
50-60 Watts	444		$ 2.00	$ 888	$ 2.00	$ 888	$ -	
100-110 Watts	300		$ 2.00	$ 600	$ 2.00	$ 600	$ -	
140-160 Watts	96		$ 2.00	$ 192	$ 2.00	$ 192	$ -	
250-280 Watts	-		$ 2.00	$ -	$ 2.00	$ -	$ -	
Total Fixture Charges	840			$ 1,680		$ 1,680	$ -	
Distribution Charges								
Street Lighting								
50-60 Watts		8,288	$ 0.04776	$ 396	$ 0.05626	$ 466	$ 70	
100-110 Watts		10,674	$ 0.04776	$ 510	$ 0.05626	$ 601	$ 91	
140-160 Watts		4,880	$ 0.04776	$ 233	$ 0.05626	$ 275	$ 41	
250-280 Watts		-	$ 0.04776	$ -	$ 0.05626	$ -	$ -	
Total Distribution Charges		23,843		$ 1,139		$ 1,341	$ 203	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 1	0.00%	$ -	$ (1)	
Generation Supply Rate (GSR) - Rider B		23,843	$ 0.12902	$ 3,076	$ 0.12902	$ 3,076	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider E		23,843	$ 0.00132	$ 31	$ 0.0013	$ 31	$ -	
Distribution System Improvement Charge (DSIC) - Rider G			5.00%	$ 143	0.00%	$ -	$ (143)	
Total - LED-CO	**840**	**23,843**		**$ 6,070**		**$ 6,129**	**$ 60**	**1.0%**

BOOK IX

UGI UTILITIES, INC. – ELECTRIC DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI ELECTRIC EXHIBIT F
CURRENT TARIFFS
UGI UTILITIES, INC. – ELECTRIC DIVISION
PA P.U.C. NOS. 6 & 2S

UGI UTILITIES, INC. – ELECTRIC DIVISION
PA P.U.C. NO. 6, SUPPLEMENT NO. 51
PA P.U.C. NO. 2S, SUPPLEMENT NO. 7

DOCKET NO. R-2022-3037368

Issued: January 27, 2023 **Effective: March 28, 2023**

UGI ELECTRIC EXHIBIT F
CURRENT TARIFF

ELECTRIC SERVICE TARIFF - PA P.U.C. NO. 6

UGI UTILITIES, INC. – ELECTRIC DIVISION

ELECTRIC SERVICE TARIFF

RULES AND RATES
FOR ELECTRIC DISTRIBUTION SERVICE AND
CHOICE AGGREGATION SERVICE

in the following service territory:

LUZERNE COUNTY

City of Nanticoke, and Boroughs of Courtdale, Dallas, Edwardsville, Forty-Fort, Harvey's Lake, Kingston, Larksville, Luzerne, New Columbus, Plymouth, Pringle, Shickshinny, Sugar Notch, Swoyersville, Warrior Run, West Wyoming and Wyoming.

First Class Townships of Hanover and Newport, and Second Class Townships, of Lehman, Plymouth, Ross and Union.

WYOMING COUNTY

Townships of Monroe and Noxen

Issued: December 21, 2022

Effective for Bills Rendered on and after January 1, 2023. Issued in accordance with the following Commission Orders: Docket No. R-2021-3023618 entered October 28, 2021, Docket No. M-2012-2293611 entered October 27, 2022 and Secretarial Letter at Docket No. M-2022-3037019 issued December 15, 2022.

Issued by:
Paul J. Szykman
Chief Regulatory Officer
1 UGI Drive
Denver, PA 17517

https://www.ugi.com/tariffs

NOTICE

This tariff makes changes and increases to existing rates (see page 2).

LIST OF CHANGES MADE BY THIS SUPPLEMENT
(Page Numbers Refer to Official Tariff)

Rider G, DSIC - Distribution System Improvement Charge, Page 50
- Distribution System Improvement Charge is increased.
- Revised to include Commission Order detail.

Rider G, DSIC – Distribution System Improvement Charge, Pages 51 & 52
- Revised to reflect formula and definition revisions per the Commission's Supplemental Implementation Order at Docket No. M-2012-2293611.

Rider G, DSIC – Distribution System Improvement Charge, Page 52(a)
- Revised to reflect the reorganization of information from Page 52.

LIST OF CHANGES MADE BY THIS SUPPLEMENT – (Continued)
(Page Numbers Refer to Official Tariff)

Rate Schedule GS-1 – General Service, Page 62.
- The customer charge and distribution charge have been increased.
- The footer has been changed to reflect an effective date for service rendered.

Rate Schedule GS-4 – General Service (5 kW minimum), Page 63.
- The distribution charge has been increased.
- The footer has been changed to reflect an effective date for service rendered.

Rate Schedule GS-5 – General Service, Page 65.
- The customer charge and distribution charge have been increased.
- Footer has been changed to reflect an effective date for service rendered.

Rate Schedule LP – Large Power Service, Page 66 - 67.
- The distribution charge has been increased on Page 66.
- The footer on Page 67 has been changed to reflect an effective date for service rendered.

Rate Schedule HTP - High Tension Power Service, Page 68.
- Revised language addressing availability of rate, character of service, rate table, minimum monthly charge, and surcharges and riders.
- The footer has been changed to reflect an effective date for service rendered.

Rate Schedule SL – Street Lighting Service, Page 69.
- The distribution charge has been increased.
- The footer has been changed to reflect an effective date for service rendered.

Rate Schedule SSL – Sodium Street Lighting Service, Page 71.
- The distribution charge has been increased.
- The footer has been changed to reflect an effective date for service rendered.

Rate Schedule MHSL – Metal Halide Street Lighting Service, Page 73.
- The distribution charge has been increased.
- The footer has been changed to reflect an effective date for service rendered.

Rate Schedule LED-SL – Light-Emitting Diode Street Lighting Service, Page 75.
- The distribution charge has been increased.
- The footer has been changed to reflect an effective date for service rendered.

Rate Schedule LED-CO – Customer-Owned Light-Emitting Diode Street Lighting Service, Page 77.
- The distribution charge has been increased.
- The footer has been changed to reflect an effective date for service rendered.

Rate Schedule FCP – Flood Control Power Service, Page 80.
- The distribution charge has been increased.
- The footer has been changed to reflect an effective date for service rendered.

Rate Schedule BLR – Borderline Resale Service, Page 81.
- The footer has been changed to reflect an effective date for service rendered.

Page Intentionally Left Blank, Page 82.
- Rate Schedule EV-C – Electric Vehicle – Company Owned Charging has been withdrawn.

TABLE OF CONTENTS

(C) Indicates Change

TABLE OF CONTENTS (Continued)

(C) Indicates Change

DEFINITIONS – GENERAL

Applicant:	Any person, corporation or other entity that (i) desires Electric Service from the Company, (ii) complies completely with all Company requirements for obtaining Electric Service, (iii) has filed and is awaiting Company approval of its application for Electric Service, and (iv) is not yet lawfully receiving Electric Service from the Company.
Automatic Meter Reading (AMR):	Metering using technologies that automatically read and collect data from metering devices and transfer that data to a central database for billing and other purposes and does not include a Remote Meter Reading Device.
Commercial Customer:	A Customer who is not classified as an Industrial Customer or a Residential Customer.
Company:	UGI Utilities, Inc. – Electric Division
Creditworthiness:	An assessment of an Applicant's or Customer's ability to meet bill payment obligations for Electric Service.
Customer:	Any person, corporation or other entity receiving Electric Service from the Company.
Discontinuance of Service:	The cessation of Electric Service with the consent of Customer.
EGS:	A supplier of electric generation that has been licensed by the PUC to sell electricity directly to retail customers within the Commonwealth of Pennsylvania in accordance with the Electric Generation Customer Choice and Competition Act, 66 Pa.C.S. § 2801 *et seq*. and has met all requirements specified in the Company's Electric Generation Supplier Coordination Tariff.
Electric Service: or service	The provision of electric distribution service in accordance with statutory and PUC requirements.
Industrial Customer:	A Customer engaged in the process which creates or changes raw materials or unfinished materials into another form or product.
Occupant:	A natural person who resides in the premises to which Electric Service is provided.
PUC:	The Pennsylvania Public Utility Commission
Remote Meter Reading Device:	A device which by electrical impulse or otherwise transmits readings from a meter, usually located within a residence, to a more accessible location outside a residence. The term does not include AMR and devices that permit direct interrogation of the meter.
Residential Applicant:	A person who is (1) a natural person at least 18 years of age not currently receiving Electric Service who applies for residential Electric Service or (2) an adult Occupant whose name appears on the mortgage, deed or lease of the property for which the residential Electric Service is requested. The term does not include (1) a Residential Customers who seeks to transfer Electric Service between locations in the Company's service territory, or (2) a Residential Customer who, within 30 days after Termination of Discontinuance of Service, seeks to have Electric Service reconnected within the Company's service territory.

DEFINITIONS – GENERAL (continued)

Residential Customer:	A Customer who is either (1) a natural person at least 18 years of age in whose name a residential account is listed and who is primarily responsible for payment of bills rendered for Electric Service, or (2) any adult Occupant whose name appears on the mortgage, deed or lease of the property for which residential Electric Service is requested. A Residential Customer shall be further defined to include a Customer receiving the Company's Electric Service to a single-family dwelling or building, through one meter to four or fewer dwelling units in a multi-family dwelling, or premises used as a single family dwelling and for one or more business uses, provided the proprietor of the business resides in the single family dwelling, and the business uses less than fifty percent of the anticipated electric usage served through a single meter. A Residential Customer shall remain a Customer after Discontinuance of Service or Termination of Service until a final bill for service is past due. The term includes a person who, within 30 days after Termination or Discontinuation of Service, seeks to have service reconnected at the same location or transferred to another location within the Company's service territory.
Tariff:	The rates, rules, and regulations set forth herein, as may be amended, modified or superseded from time to time.
Termination of Service:	The cessation of Electric Service, whether temporary or permanent, without the consent of the Customer.
Unauthorized Use of Service:	Unreasonable interference or diversion of service, including meter tampering (any act which affects the proper registration of service through a meter), by-passing unmetered service that flows through a device connected between a service line and customer-owned facilities and unauthorized service restoral.
User Without Contract:	A person or entity which takes or accepts electric service without knowledge or approval of Company, other than the Unauthorized Use of Service as defined above.

RULES AND REGULATIONS

1. GENERAL

1-a Tariff Availability. A copy of this Tariff is on file with the PUC and is available on Company's website at https://www.ugi.com/tariffs and on the PUC's website at https://www.puc.pa.gov/filing-resources/tariffs/electric-tariffs/. This Tariff may be amended from time-to-time in accordance with the rules of the PUC. (C)

1-b Scope and Application of Tariff. The Tariff, which is subject to a PUC-established review and approval process, contains rates, rules and regulations governing the supply by Company of Electric Service to all Customers, including, as applicable, Users Without Contract and those engaged in the Unauthorized use of Service. It is the responsibility of Company and each of its employees to apply the provisions of the Tariff without unlawful privilege or advantage to any Customer, and mandatory provisions of the Tariff may not be modified by Company, any Company employee or representative, or Customer, whether by written agreement or otherwise, without the approval of the PUC. The failure by the Company to enforce any of the provisions of this Tariff shall not be deemed a waiver of its right to do so.

1-c Application of Rates: The rates in this Tariff are based upon supply to one Customer through one meter at the same or contiguous property. Each service to a different location and/or of a different rate classification shall be billed as a separate Customer. Customers who take service at two or more locations on the same or contiguous property under the same rate schedule may, by request, have their use of combined for billing purposes; Customers electing to take advantage of this rule shall pay the cost of all additional service connections required unless, in the Company's sole judgment, the Company's investment in such connections is warranted by the revenue anticipated from the service to be supplied. The Company will provide Customers with a written explanation regarding its analysis of the arrangement's economics. Customers may not pool together for purposes of qualifying for a rate schedule.

1-d Liability and Legal Remedies: The Customer will indemnify, defend and hold harmless the Company against all claims, demands, costs or expenses for loss, damage or injury to person or property in any manner either directly or indirectly connected with or growing out of the supply or use of electric by the Customer at or on the Customer's side of the point of delivery. Neither the Company nor the Customer will be liable to each other for any act or omission caused either directly or indirectly by strikes, labor troubles, accidents, litigation, federal, state or municipal laws or interference, or other causes not a result of each party's own negligence or intentional misconduct.

(C) Indicates Change

RULES AND REGULATIONS (continued)

2. APPLICATION AND CONTRACT FOR SERVICE

2-a Contract for Service. Every Applicant for Electric Service may be required to sign a contract specifying the intended use of service, the applicable rate schedule and other service conditions. A contract between the Company and the Customer is valid only when accepted in writing by a duly authorized Company representative; provided, however, the acceptance or use of service is deemed a request for the supply of such service and constitutes a contract to pay for the service under these rules and the applicable rate schedule.

2-b Right to Reject Application. The Company may reject any application for Electric Service not available under a standard rate, or which involves excessive service cost, or which might affect the supply of Electric Service to other Customers, or for other good and sufficient reasons.

2-c Commencement of Service. The Company may activate service on request or Company may, for the convenience of a new Customer, leave a service energized at a premise which has become vacant. The Customer shall notify the Company the date service is desired or use of service has begun and shall provide information necessary for Company to properly supply service and apply the provisions of this Tariff.

2-d Short-Term Contracts. Service may be supplied under a rate applicable for the character of Electric Service required for periods less than the standard contract period, subject to guaranteed revenue.

2-e Service for Construction or Emergency. Company will supply service for construction or emergency purposes only when the Company has available unsold capacity of supply equipment, subject to a charge collected in advance to cover the cost of the supply and discontinuance of such service.

2-f Permit for Right-of-Way. When the Customer is so located that right-of-way permit across private property of another is required, the contract or service period shall be the same as the period provided by the right-of-way permit.

2-g Supplemental Energy Sources. Supplemental use of renewable energy sources such as wood, solar, wind and water is permitted in conjunction with service supplied under any rate schedule of this Tariff without violating the total electric space and/or water heating requirement of the rate. Any Customer system of this type that produces electric energy may not be operated concurrently with service supplied by the Company except under written agreement setting forth the conditions of such operation.

RULES AND REGULATIONS (continued)

3. GUARANTEE OF PAYMENT

3-a Deposits for Non-Residential Accounts. A cash deposit may be required from an Applicant to secure payment of bills. In addition, the Company may require a deposit, letter of credit or other adequate assurance of payment, or any combination thereof, from a Non-Residential Customer if the Non-Residential Customer has been delinquent in payment of any bill in the preceding twelve (12) months or the Company otherwise has reasonable grounds to require security for payment of bills. The Company may require an existing non-residential Customer to post a deposit to reestablish credit whenever the Customer has been delinquent in the payment of any two (2) consecutive bills or three (3) or more bills within the previous twelve (12) months.

3-b Additional Security from Large Volume Customers.

(a) Whether or not the Company could otherwise require security for payment, the Company may require a deposit, letter of credit, other adequate assurance of payment, or any combination thereof, to the extent the Customer has projected usage in excess of 900,000 kWh per month. Such security may be established for an amount as determined by the Company.

(b) In addition, the Company may take one or more of the following actions:

(1) With the agreement of the Customer, reduce the meter reading and billing period to less than one month, and require payment in no less than three calendar days from billing.

(2) Require payment by certified check or wire transfer; or

(3) Impose other procedures reasonably designed to reduce potential exposure to credit risk.

(c) The Company may, in its discretion, specify the manner in which security and payments shall be credited and applied to past due or current bills or to replenish security.

3-c Deposits for Residential Accounts. The Company may require a cash deposit from a Residential Applicant or Residential Customer to secure payment of bills for regulated distribution service based upon the following:

(i) A Residential Applicant or Residential Customer whose service was terminated for any of the following reasons:

(1) Nonpayment of an undisputed delinquent account;
(2) failure to complete payment of a deposit, providing a guarantee or establish credit;
(3) failure to permit access to meters, service connections or other property of Company for the purposes of replacement, maintenance, repair, or meter reading;
(4) Unauthorized Use of Service on or about the affected dwelling;
(5) failure to comply with the material terms of a payment arrangement;
(6) fraud or material misrepresentation of identity for the purposes of obtaining utility service;
(7) tampering with meters, including, but not limited to, bypassing a meter or removal of an automatic meter reading device or other Company equipment; or
(8) violating tariff provisions on file with the PUC so as to endanger the safety of a person or the integrity of the Company's delivery system.

RULES AND REGULATIONS (continued)

3. GUARANTEE OF PAYMENT

(ii) Any Residential Applicant who is unable to establish creditworthiness to the satisfaction of Company through the use of a generally accepted credit scoring methodology which employs standards for using the methodology that falls within the range of general industry practice and specifically assesses the risk of utility bill payment.

(iii) A Residential Customer who fails to comply with the material terms or condition of a settlement or payment arrangement.

(iv) A Residential Customer who has been delinquent in the payment of two (2) consecutive bills, or three (3) or more bills within the preceding twelve (12) months.

(v) The Company has established separate credit procedures and standards for Residential Applicants and Residential Customers who are victims with a protection from abuse order or for whom there is a court order from a court of competent jurisdiction in this Commonwealth which provides clear evidence of domestic violence. These procedures shall be publicly posted on the Company's website and maintained on file in each of the business offices of the Company and made available, upon request, for inspection by members of the public.

3-d Amount of Deposits. For Residential Applicants, the deposit shall not be more than one sixth of the Residential Applicant's estimated annual bill, with such estimated annual bill determined at the time the deposit is required. In lieu of a cash deposit from a Residential Applicant, the Company may accept a written third-party guaranty on behalf of the Residential Applicant, provided that the guarantor establishes credit with the Company under Section 3-c and the terms of the written guaranty are approved in writing by the Company, with such approval not to be unreasonably withheld. For Residential Customers, the amount of the cash deposit shall not be more than the estimated charges for service based on the Residential Customer's prior consumption for the period equal to one average billing period plus one average month, not to exceed two (2) months. For non-residential Customers, the deposit shall not be more than the bill for the estimated usage for one average monthly billing period plus that for the highest monthly billing period within the most recent twelve (12) months.

3-e Payment Period for Deposits.

(i) Any Non-Residential Applicant seeking to establish service at a new or different service location or seeking to reconnect service at the same service location previously terminated or discontinued, shall pay the required deposit in full prior to the provision of service.

(ii) Any Residential Applicant or Residential Customer seeking to establish service at a new or different location or seeking to reconnect service at the same service location previously terminated or discontinued shall pay at least the required deposit in full within 90 days. A Residential Applicant or Residential Customer may elect to pay the required deposit in three installments as follows: 50% of the required deposit billed upon the establishment or reconnection of service, with 25% of the required deposit to be billed by the Company 30 days after the establishment or reconnection of service and the remaining 25% billed 60 days after the establishment or reconnection of service. Nothing shall preclude the Residential Applicant or Residential Customer from electing to pay the deposit in full before or on the due date.

RULES AND REGULATIONS (continued)

3. GUARANTEE OF PAYMENT

(iii) Any Customer receiving service from the Company shall pay the required deposit in full on or before the due date. A Residential Customer may elect to pay the required deposit in three installments as follows: 50% of the required deposit billed upon the determination by the Company under 3-b(iii) and (iv) above that the deposit is required, with 25% to be billed by the Company 30 days after the determination and the remaining 25% billed 60 days after the determination.

3-f Deposit Hold Period for Residential Customers and Refund of Deposits. A timely payment history is established when the Residential Customer has paid in full and on time for twelve (12) consecutive months. The Company may hold a deposit on a Residential Customer's account until a timely payment history is established (the "Deposit Hold Period"). At the end of the Deposit Hold Period, Company shall credit the deposit, plus accrued interest, to the Residential Customer's Account. Deposits credited after the end of the Deposit Hold Period shall first be applied to any past due amounts. If service is terminated or discontinued before the end of the Deposit Hold Period, Company shall deduct any outstanding balance from the deposit and return any positive balance to the Residential Customer within sixty (60) days.

3-g Refund Provision - Non-Residential Customers. A deposit secured from a non-residential Customer shall be returned after such Customer has paid bills for service for twelve (12) consecutive months without having service terminated and without having paid the bill after the date when due on more than two (2) occasions. The non-residential Customer my elect to have the deposit applied to the account in order to reduce bills for service in lieu of a cash refund. Upon termination or discontinuance of service, the Company shall promptly apply the deposit, including accrued interest, to any outstanding balance for service and refund the remaining to the non-residential Customer.

3-h Adjustments. The amount of the deposit may be adjusted when there is a change in consumption that will significantly change the amount of the deposit as computed in Rule 3-a and 3-c.

3-i Interest on Deposits. Deposits from all Customers shall bear interest computed at the simple annual interest rate determined by the Secretary of Revenue for interest on underpayment of tax under Section 806 of the Act of April 19, 1929 (P.L. 343, No. 176), known as The Fiscal Code which will be credited annually to the Customer's deposit or account. The interest rate in effect when the deposit is required to be paid shall remain in effect until the later of the date the deposit is refunded or credited or December 31 of each year. On January 1 of each year, the new interest rate for that year will apply to the deposit. Deposits shall cease to bear interest upon termination or discontinuance of service.

3-j Prior Debts.

(i) Non-Residential Customers. As a condition of furnishing, transferring or reconnecting service to a Non-Residential Applicant or Non-Residential Customer, the Company may require payment of any outstanding balance on any account for which the Non-Residential Applicant or Non-Residential Customer is legally responsible.

RULES AND REGULATIONS (continued)

3. GUARANTEE OF PAYMENT

(ii) Residential Customers. As a condition of furnishing, transferring or reconnecting service to a Residential Applicant or Residential Customer, the Company may require payment of any outstanding balance which accrued within the past four years on any account for which the Residential Applicant or Residential Customer is legally responsible. The foregoing four-year limitation shall not apply if the outstanding balance includes past due amounts that the Company was not aware of due to Unauthorized Use of Service, fraud or theft; in which case, the Company may require payment of all such past due amounts without regard to the four-year limitation. The Company may render a make-up bill to a Residential Customer for previously unbilled service which accrued within the past four (4) years resulting from billing error, meter failure, leakage that could not reasonably have been detected or loss of service. If the make-up bill exceeds the otherwise normal estimated bill for the billing period during which the make-up bill is issued by at least 50% or at least $50, whichever is greater, the Company shall, at the option of the Customer, amortize the bill at least as long as: (1) the period during which the excess amount accrued; or (2) necessary so that the quantity of service billed in any one billing period is not greater than the normal estimated quantity for that period plus 50%.

(iii) The Company may utilize all means of determining an Applicant's or Customer's liability for any outstanding balances, including, but not limited to, the following: (1) use of Company records that contain confidential information previously provided to the Company, (2) information contained on a valid mortgage, lease or deed, (3) other information contained in the Company's records that indicate that the Applicant was an adult Occupant during the time the balances accrued, (4) use of commercially available consumer credit reporting service, (5) use of commercially available skip tracing software that contains records of names and addresses, and (6) use of information contained in credit reporting data utilized by the Company.

RULES AND REGULATIONS (continued)

4. CUSTOMER'S INSTALLATION

4-a Furnish Description of Installation. Before wiring any building or purchasing any electrical equipment, Customer shall furnish a list of the electrical equipment which is to be connected to Company's lines and give the location of the proposed installation.

4-b Character of Service and Point of Delivery. Upon the receipt of the information required by Rule 4-a, Company will advise the character of service, and will designate the location of its meter or meters and other service equipment, and the point where Customer shall terminate his service wiring.

4-c Underwriter's Inspection. The Company will not start to render service until Customer's installation is completed in accordance with Company's standard requirements, and until a certificate of approval has been issued by the Fire Underwriter's Association and/or other approved inspection companies or municipalities having jurisdiction in Company's territory.

4-d Reverse Phase Relay. The Customer must install at his expense reverse phase relay or equipment devices in cases where phase reversals may cause injury or damage.

4-e Motors. The Company reserves the right to refuse service to single phase motors rated more than five (5) horsepower and to polyphase motor installations having a total rating less than five (5) horsepower.

4-f Light Sources. Where the Customer's installation includes neon lamps, mercury vapor lamps, fluorescent lamps or similar lighting devices having low power factor characteristics, Customer will be required to provide at his own expense power factor corrective equipment which will maintain the power factor of such lighting devices at not less than ninety percent (90%) lagging.

4-g Loss of Phase Protection. Any Customer receiving polyphase service should examine their utilization equipment to determine if the loss of one or more phases could cause injury or damage. Where injury or damage could occur, due to loss of one or more phases, the Customer, at their own expense, should install polyphase protection.

RULES AND REGULATIONS (continued)

5. SERVICE AND SUPPLY SYSTEM EXTENSIONS

5-a Customer's Wiring. Customer's service wiring must be brought to a location designated or approved by the Company. On an overhead service installation, the Customer's service entrance wires must extend sufficiently beyond the service head for attachment to the Company's service lines. Company provided underground service lines will be connected to the line side terminals in the Customer's meter trough. All connections between the Company's and the Customer's service equipment shall be made by the Company without cost to the Customer. All facilities on the Customer's side of the point of connection to the Company's service equipment shall be furnished, installed, owned, maintained, and replaced by the Customer.

5-b Change or Relocation of Company Facilities. Where the Company has facilities with adequate capacity in place to serve any existing or proposed Customer load, alterations, changes or relocation of service lines, Company supplied facilities or transformer substations, including relocating any existing Company owned overhead facilities to underground, shall be at the expense of the Customer when any of such changes are requested by the Customer. Pole removal and relocation charges shall be determined as described in Rule 19. The Company may waive these charges when in its sole judgment the line relocation is required to accommodate new building construction. In the event that the Company shall be required by any public authority to place underground any portion of its supply lines or facilities, or relocate any poles or supply lines, the Customer shall bear the entire cost of relocating the point of connection to the Company's service line to a location readily accessible from the new poles or supply lines.

5-c Company's Service Line. On overhead construction the Company's service line is defined as the section of line between the Company's support structure and the Customer's support structure; on underground construction the Company's service line is defined as the section of line from the Customer's service entrance equipment to the Company's nearest secondary equipment or transformer. On overhead construction, the Company will install at its expense for the exclusive use of the Customer, the meter and service line. Installing additional service lines to the same premises shall be at the expense of the Customer unless it is to the mutual advantage of the Customer and the Company for the Company to provide such additional service lines. Such additional service lines shall remain Company property.

The Company will extend an underground service line to a residential Customer subject to Rule 5-g. The Company will not extend an underground service line to a non-residential Customer.

5-d Supply Line Provided by Company. The Company will install at its expense when possible and practical using standard construction the first twenty-five hundred (2500) feet of single-phase overhead supply line along public road right-of-way required to serve a new permanent residential, commercial, or industrial Customer and up to a maximum of five hundred (500) feet of single-phase overhead supply and service line on private right-of-way not along public road right-of-way. The new customer requesting an overhead supply line extension along private right-of-way shall furnish without expense to the Company a right-of-way over all affected properties satisfactory to the Company for the erection, maintenance, replacement, and operation of the overhead supply line extension, including but not limited to, providing ground line clearing of trees, brush and other obstructions, rough grading and access by mechanical construction equipment. Rule 5-f sets forth the terms and conditions under which the Company will extend overhead to a new Customer, a polyphase supply line or a single-phase supply line in excess of these established limits. The Company may delay the construction of any supply line extension until the new Customer has substantially completed the building and installation of equipment necessary to receive and use permanent service.

RULES AND REGULATIONS (continued)

5. SERVICE AND SUPPLY SYSTEM EXTENSIONS

5-e Supply Line Extensions to Seasonal Residential Customers and Temporary Commercial and Industrial Customers. Seasonal residential Customers and temporary commercial and industrial Customers shall pay for new supply line extensions in advance, an aid to construction equal to the estimated cost of construction of the required facilities. For temporary extensions, the aid shall include the estimated removal costs less anticipated salvage values. Where the Customer requires the Company's service or supply line to be disconnected but the Company facilities left in place, the Customer shall pay for the cost of each reconnection and disconnection prior to each reconnection.

5-f Single-Phase Supply Line Extensions and Polyphase Line Extensions Exceeding Established Limits.

(1) Single-phase overhead supply line extensions - The Company will provide single-phase overhead supply line extensions to serve permanent residential, commercial, and industrial Customers in excess of twenty-five hundred (2500) feet along public road right-of-way and/or in excess of five hundred (500) feet on private right-of-way not along public road right-of-way provided the Customer pays in advance an aid to construction equal to the estimated cost to extend the excess facilities.

(2) Polyphase overhead supply line extensions - The Company will determine the necessary minimum annual revenue guarantee or aid in construction when warranted, required for all polyphase extensions regardless of length. The minimum annual revenue guarantee shall be calculated by dividing the estimated polyphase line extension cost by five (5). This minimum annual revenue guarantee will be compared, on an annual basis, to the customer’s actual billings for distribution services, over the five (5) year period following the commencement of service to the customer through the polyphase overhead supply line extension. Any shortfall between a customer’s actual billings for distribution services and the minimum annual revenue guarantee will be assessed to the customer. Aids in construction will be utilized in lieu of minimum annual revenue guarantees when the Company has concluded that the polyphase line extension is associated with a speculative project, where the Company has determined the customer/developer is a credit risk, or when the customer/developer prefers to pay an aid to construction rather than the minimum annual revenue guarantee. The aid to construction will be calculated by subtracting the customer’s projected five (5) year distribution service billing revenue from the estimated polyphase line extension cost. The result of this calculation will be the required aid to construction that shall be paid to the Company before construction of the extension is undertaken. On an annual basis, over the five (5) year period following the commencement of service to the customer through the polyphase overhead supply line extension, the customer’s projected annual distribution service billing revenue will be compared to the Company’s actual distribution charges billed to the customer. Any shortfall between the estimated annual distribution billing used in the calculation of the aid to construction and the customer’s actual distribution billing will be assessed to the customer. On a case-by-case basis, the Company may allow a customer to pay, via installments, any required aid to construction. The terms and conditions of such arrangements shall be at the sole discretion of the Company. In cases where installment payment of an aid to construction is permitted, the customer will, unless the Company otherwise agrees, be required to provide financial security to the Company in a form acceptable to the Company.

RULES AND REGULATIONS (continued)

5. SERVICE AND SUPPLY SYSTEM EXTENSIONS

5-g Company Provided Underground Service and Supply Facilities. The Company may provide underground service and supply facilities to a new Customer, except as provided in Rule 5-i below, when, in the Company's opinion, the circumstances justify the investment. In such a case, the Customer at its sole expense must provide service entrance equipment suitable to receive service from underground equipment. On request of a new Customer, the company may establish an underground system on private right-of-way on condition that: (a) The Customer pays the Company, in advance the entire cost of underground facilities in excess of five hundred (500) feet; (b) The Customer provides all trenching and backfilling and conduit required to establish an underground system according to the Company's specifications; (c) the supply line to be installed underground is not located along public road right-of-way; and, (d) the Customer provides the Company a suitable right-of-way over all properties crossed by the new line.

5-h Customer Owned Underground Service Line. Where in the opinion of the Company it is not practical for the Company to provide an underground service line, the Customer may at its own expense furnish its own underground service line from the Customer's meter location to a point specified by the Company. Such Customer owned service lines shall be built to Company specifications. Sufficient wire shall be provided for the Company to terminate the Customer owned service line to the Company supply facilities. The Company will terminate the Customer owned service lines to its supply facilities without charge to the Customer. The Customer shall be responsible for ownership, operation, maintenance, relocation, and replacement of such Customer supplied service line.

5-i Underground Electric Service in New Residential Developments. Company shall install underground distribution and service facilities in new residential developments as required in the PUC regulations at 52 Pa. Code §§57.81 – 57.88 or any successor thereto. Such service shall only be provided for new residential developments being developed pursuant to a recorded plot plan with five or more adjoining unoccupied lots to be used for single-family residences, detached or otherwise, mobile homes or apartment houses, all of which are intended for year-around occupancy. Tracts of land which are subdivided, but not developed into utility-ready lots by a bona fide developer shall not qualify for the service. Applicants for such service must:

(1) Request electric service at such time that the lines may be installed before curbs, pavements and sidewalks are laid; carefully coordinate scheduling of the Company's line and facility installation with the general project construction schedule, including coordination with any other Company sharing the same trench; keep the route of lines clear of machinery and other obstructions when the line installation crew is scheduled to appear; and otherwise cooperate with the Company to avoid unnecessary cost and delay; and

(2) At its own cost, provide the Company with a copy of the recorded development plot plan identifying property boundaries, and with easements satisfactory to the Company for occupancy by distribution, service and street-light lines and related facilities; and

RULES AND REGULATIONS (continued)

5. SERVICE AND SUPPLY SYSTEM EXTENSIONS

(3) At its own cost, clear the ground in which the lines and related facilities are to be laid of trees, stumps and other obstructions, provide the excavating and backfilling subject to the inspection and approval of the Company, and rough grade it to within six inches of final grade, so that the Company's part of the installation shall consist only of laying of the lines and installing other service-related facilities. Excavating and backfilling performed or provided by the applicant shall follow the Company's underground construction standards and specifications set forth by the Company in written form and presented to the applicant at the time of application for service and presentation of the recorded plot plan to the Company. If the Company's specifications have not been met by the applicant's excavating and backfilling, such excavating and backfilling shall be corrected or redone by the applicant or its authorized agent. Failure to comply with the Company's construction standards and specifications permits the Company to refuse service until such standards and specification are met.

5-j Other Extension. The Company's obligation to extend its facilities to a new point of delivery, other than as set forth above, is limited to the assumption of new investment to the extent warranted by the revenue anticipated from the service to be supplied. Where the anticipated revenue does not warrant the investment required to serve, the Company will determine for each case what guarantees of revenue, financing or term of contract shall be required of the Customer.

5-k Taxes on Contributions. For any contributions or other like amounts received from an Applicant or Customer which constitute taxable income as defined by the Internal Revenue Service, the Company shall maintain a segregated deferred income tax account for inclusion in rate base in a future rate proceeding. Such income taxes associated with a contribution or other like amount will not be charged to the Applicant or Customer.

5-l Service to Electric Vehicle Supply Equipment. Where Company provides service to Qualified Electric Vehicle Charging Stations (“Qualified EV Charging Stations”) which will be accessible to the public for **(C)** charging access, the Company shall provide all required investment without contribution and will design and install the required infrastructure facilities necessary for operation of such Qualified EV Charging Stations (including any new conductor replacement, transformers, services, and meters; inclusive of any make ready work). Such facilities shall be provided at no required contribution to the customer as part of an EV infrastructure which will end September 30, 2026. Qualified EV Charging Stations may be supplied electricity by an EGS.

5-m Qualified EV Charging Stations shall be defined as one (1) to four (4) DC Fast Charge (“DCFC”) **(C)** stations of 50kW or greater, or at least four (4) Level 2 charging stations, which are compatible with the Company’s distribution system and are located within 400 feet of a Company 3-phase primary distribution circuit line, or in another location where the Company, in its sole discretion, anticipates that adequate public availability and access is being provided. DCFC installation locations may also be inclusive of one or more adjacent Level 2 charging stations. All qualifying chargers must have smart or network capabilities and be tested for safety by a national testing laboratory such as UL. Qualifying Level 2 chargers must be ENERGY STAR certified.

(C) Indicates Change

RULES AND REGULATIONS (continued)

6. METER INSTALLATION

6-a Meters Supplied by Company. The Company will furnish, install, maintain and own any meter or transformer required for measurement of the service supplied.

6-b Meter Location. The location of the Company's facilities shall in all cases be determined by the Company. The Customer shall provide, without charge to Company, a suitable place for the meter transformer or other equipment of the Company. Such place shall provide convenient access for the Company's meter readers or inspectors.

6-c Capacity of Company's Meters. The meters, transformers, service connections and equipment supplied by the Company for each Customer have a definite load capacity and no additions to the equipment or load connected thereto will be allowed except by the consent of the Company.

6-d Right to Remove Company's Equipment. All meters, transformers or other equipment supplied by the Company shall remain its exclusive property. The Company shall have the right to remove all its property from the premises of the Customer at any time after the Termination or Discontinuance of Service.

6-e Customer's Responsibility for Damage. Customer shall be responsible for meters, transformers, equipment and connections, and shall reimburse the Company for any damage done them while on Customer's premises.

6-f Reverse Registration. The Company may, by ratchet or other device, control its meter so as to prevent reverse registration.

6-g Customer Request for an Advanced Meter. If a Customer wishes to replace their billing metering equipment the Company will offer, provide, and support a selection of qualified advanced meters and metering related devices compatible with its existing infrastructure.
A list of the Company's approved advanced meters and metering related devices, as well as the incremental cost associated with the purchase and installation of each, appears in the Pennsylvania Public Utility Commission's Advanced Meter Catalog. The Company shall install such meters and/or devices upon the request of the Customer or the Customer's electric generation supplier within a reasonable amount of time and at the expense of either the Customer or their generation supplier. The Customer or the Customer's electric generation supplier must pay in advance the incremental costs associated with the requested advanced meter and/or meter related device. The Company will own and maintain all such advanced metering equipment. A Customer or their electric generation supplier may also be assessed a bill surcharge to cover the net incremental cost of reading, operating, and maintaining a qualified advanced meter or meter related device.

6-h Automatic Meter Reading. All meter readings by an AMR shall be deemed actual readings.

RULES AND REGULATIONS (continued)

7. METER ERRORS AND TESTS

7-a Adjustment of Error. Should the meter or meters become defective or fail to register correctly, the amount of energy used shall be determined by a test of the meter or meters, by the registration of a meter or meters replacing the defective meter or meters during the period next following or by the amount of energy used during a corresponding period the preceding year.

7-b Meter Tests. The Company at its expense will make periodic tests and inspections of its meters in accordance with PUC rules. A Customer may request additional tests or inspections, and Company reserves the right to charge for such additional tests or inspections in accordance with PUC rules. A Customer may request Company to perform a meter reading to confirm the accuracy of an AMR device when a Customer disconnects service or requests new service.

RULES AND REGULATIONS (continued)

8. MAINTENANCE OF SERVICE BY COMPANY

8-a Continuity of Service. The Company will use reasonable diligence to provide a regular and uninterrupted supply of service, but should the supply be interrupted by the Company for the purpose of making repairs, changes, or improvements in any part of its system for the general good of the service or the safety of the public, or should the supply of service be varied, interrupted or fail by reason of accident, strike, legal process, State or Municipal interference, or any other cause whatsoever beyond its control, the Company shall not be liable for damages, direct or consequential, resulting from such variation, interruption or failure. Company may without liability, interrupt service to any Customer or Customers in the event of an emergency threatening the integrity of its system if, in its sole judgement, such action will prevent or alleviate the emergency condition. Due to the sensitive nature of computers and other electronically controlled equipment, the Customer should provide protection against variations in supply

8-b Notice of Trouble. The Customer shall notify the Company promptly of any defect in service or of any trouble or accidents to the electric supply.

8-c Emergency Load Control.

(i) A load emergency situation exists whenever:

(A) The demands for power on all or part of the Company's system exceed or threaten to exceed the capacity then actually and lawfully available to supply the demands.

(B) System instability or cascading outages could result from actual or expected transmission overloads or other contingencies.

(C) The conditions exist in the system or another public utility or power pool with which the Company's system is interconnected which could cause a reduction in the capacity available to the Company from that source or threaten the integrity of the Company's system.

(ii) In this case, the Company shall take the reasonable steps as the time available permits to bring the demands within the then-available capacity or to otherwise control load. The steps shall include, but are not limited to, reduction or interruption of service to one or more customers, in accordance with the Company's procedures for controlling load.

8-d Emergency Energy Conservation. An emergency energy conservation situation exists whenever events result or, in the judgment of the Company, threaten to result in a restriction of the fuel supplies available to the Company or its energy vendors, so that the amount of electric energy which the Company is able to supply is or will be adversely affected. In the event of an emergency energy conservation situation, the Company shall take reasonable measures that it believes necessary and proper to conserve available fuel supplies. The measures may include, but are not limited to, reduction, interruption or suspension of service to one or more of its customers or classes of customers in accordance with the Company's procedure for emergency energy conservation.

RULES AND REGULATIONS (continued)

9. CUSTOMER'S USE OF SERVICE

9-a Resale of Service

(1) Electric energy purchased under this Tariff shall not be redistributed, submetered, resold or otherwise charged to a third party except as provided herein.

(2) A person or business entity contracting for service to a single premise under a general service rate schedule may supply the electric energy requirements of tenants of the premises as part of the total rental charge provided that the charge for electric energy is not separately itemized and does not fluctuate according to the electric energy consumption of the tenant. This provision is limited to locations where the tenant is classified as general service at all locations served prior to January 1, 1980.

(3) A person or business entity contracting for service to a single premise may be specifically authorized by written agreement to redistribute, resell and submeter electric energy to tenants in accordance with Company provisions including but not limited to the following: that the practice of resale is limited to the premises as described in the contract for electric service; that service to the premises is through a single meter under the applicable general service rate schedule; that the charges for electric service to such tenants do not exceed the Company's applicable rate for like and contemporary service; and that all facilities installed beyond the Company's point of delivery to redistribute energy to third parties are acceptable to the Company. This provision is limited to locations where the tenant is classified as general service at all locations served prior to January 1, 1980.

(4) Master metering will not be permitted on any building consisting of multiple dwelling units constructed after January 1, 1980. The Company will supply energy to each customer through Company owned meters at the applicable rate schedules. This rule will not apply where:

A. It is in conflict with State or Federal Housing Regulations.
B. Where it can be demonstrated that individual metering will prevent or discourage the use of renewable resources.

9-b Fluctuations. Electric service must not be used by Customer in such a manner as to cause unusual voltage fluctuations or disturbances in the Company's supply system. In case of violation of this rule the Company may discontinue service or require Customer to modify his installation and/or equip it with approved controlling devices.

9-c Use Other than Stated in Contract. The Company's Electric Service shall not be used for any purpose or in any place other than that stipulated in the Customer's contract for service except by written consent of the Company.

9-d Unbalanced Load. The Customer shall at all times take and use energy in such manner that the load will be taken equally between phases. Should this not be possible, and the unbalancing equal or exceed ten (10) percent of the lesser phase, the Company reserves the right to compute the demand for billing purposes on the assumption that the load on each phase is equal to that on the greatest phase.

9-e Change of Installation. The Customer shall give immediate written notice to the Company of any proposed increase or decrease in its installation.

9-f Service Charges. Except to the extent otherwise prohibited by statute or PUC regulation, whenever a Customer or Applicant is responsible under this tariff for preparing a site for work to be performed by a Company, does not do so, and as a consequence a dispatched Company resource must be recalled without performing the anticipated work, Company may bill the Customer or Applicant for the reasonable costs incurred in dispatching and recalling the Company resource.

RULES AND REGULATIONS (continued)

9. CUSTOMER'S USE OF SERVICE

(C) 9-g Electric Vehicle Charging. In accordance with the Commission's Final Policy Statement Order entered on November 8, 2018 at Docket No. M-2017-2604382, the electricity sales by a person, corporation or other entity, not a public utility, owning and operating an electric vehicle charging facility for the sole purpose of recharging an electric vehicle battery for compensation shall not be construed to be sales to residential customers and therefore do not fall under the pricing requirements of 66 Pa. C.S. § 1313. Such sales are therefore not considered a resale of service as defined in this tariff rule 9-a.

For purposes of third-party owned electric vehicle charging stations, owning and operating an Electric Vehicle charging station shall not be considered redistribution as defined under 66 Pa. C.S. § 1313. Electric vehicles are defined as any vehicle licensed to operate on public roadways that are propelled in whole or in part by electrical energy stored on-board for the purpose of propulsion. Types of electric vehicles include, but are not limited to, plug-in hybrid electric vehicles and battery electric vehicles. Electric service to electric vehicle charging stations shall be provided in accordance with the Company's Service and Supply System Extension.

The station must be designed to protect for back flow of electricity to the Company's electrical distribution circuit as required by Company rules. The Company shall not be liable for any damages associated with operation of the charging station. For stations dedicated solely for the purpose of charging electric vehicles wherein a third party owns the charger and allows an electric vehicle owner to use their facility to charge an electric vehicle, the owner of the charging facility shall notify the Company at least one hundred twenty (120) days in advance of the planned installation date and may be required to install metering for the station as determined by the Company. The third -party owner of the station shall be responsible for all applicable Tariff rates, fees and charges. For such installations, the electric vehicle owner shall be responsible for all fees imposed by the owner of the station for charging the electric vehicle.

(C) Indicates Change

RULES AND REGULATIONS (continued)

10. DEFECTS IN CUSTOMER'S INSTALLATION

10-a Right to Inspect. The Company shall have the right, but shall not be obligated to, examine the Customer's installation at the time service is first supplied or at any later time.

10-b Defective Installations. The Company shall operate and maintain only those electrical facilities which are installed and owned by the Company. If at any time the wiring, fixtures or appliances of the Customer are found to be defective or dangerous by the Company's employees, service may be refused or discontinued until the Customer has the condition corrected.

10-c Customer's Responsibility. The Company assumes no responsibility for any damage done by or resulting from any defect in the wiring, fixtures, or appliances of the Customer. In the event that any loss or damage ot the property of the Company, or any accident or injury to persons or property is caused by or results from the negligence or wrongful act of the Customer, his agents, or employees, the cost of the necessary repairs or replacement shall be paid by the Customer to the Company and any liability otherwise resulting shall be assumed by the Customer.

RULES AND REGULATIONS (continued)

11. RIGHT-OF-WAY AND ACCESS TO PREMISES

11-a Provided by Customer. Customer shall provide without charge a right-of-way acceptable to the Company across property owned or controlled by Customer. When the premises of Customer is so located that right-of-way across the property of another is required for the supply of service, Customer shall reimburse Company for any and all special, or rental charges that may be made for such right-of-way permit.

11-b Access to Premises. The authorized agents or employees of the Company, wearing and/or displaying the identification card of the Company, shall have free access at all reasonable times to the premises of the Customer for the purpose of inspecting, removing or repairing any of the property of the Company situated thereon. Installations on Customer's premises shall be open to Company's inspection at all reasonable times. Authorized agents of the Company shall have immediate access to any premises whenever they believe an unsafe or hazardous condition exists.

RULES AND REGULATIONS (continued)

12. TAMPERING WITH COMPANY'S PROPERTY

12-a Tampering Expressly Forbidden. No person except a duly authorized employee of the Company or other person duly authorized by the Company shall make any connection or disconnection, either temporary or permanent, between service leads of Customer and service wires and equipment of the Company, or set, change, remove or interfere with or make any connections to the Company's meter or other property or any wiring between the Company's meter and the service wires of the Company.

12-b Liability for Tampering. In the event of the Company's meters or other property being tampered or interfered with, the Customer, User Without Contract or person engaged in the Unauthorized Use of Service being supplied through such equipment shall pay the amount which the Company may estimate is due for service used but not registered on the Company's meter, and for any repairs or replacements required as well as for costs of inspections, investigations, and such changes in Customer's installation as may be required by the Company for its protection.

RULES AND REGULATIONS (continued)

13. PAYMENT TERMS

13-a Billing Period. The Company shall bill monthly. When periods are substantially greater or less than one month, bills will be computed by prorating on the basis of the actual period covered by meter readings. Failure to receive a bill will not release a Customer from payment obligation. For Residential Customers, the billing month is a period of not less than 26 or greater than 35 days. An initial bill for a new Residential Customer may be less than 26 days or greater than 35 days; provided however, if an initial bill exceeds 60 days the Residential Customer shall be given the opportunity to amortize the amount over a period equal to the period covered by the initial bill without penalty. A final bill due to the discontinuance may be less than 26 days or greater than 35 days but may never exceed 42 days. In cases involving termination, a final bill may be less than 26 days. In addition, bills for less than 26 days or more than 35 days shall be permitted if they result from rebilling initiated by the Company or Customer dispute to correct a billing problem. Bills for less than 26 days or more than 35 days shall be permitted if they result from a meter reading route change initiated by the Company.

13-b Net Payment Period. Bills are due upon presentation, and the net bills are contingent upon prompt payment. Should payment not be made within the time specified for payment of the net amount, an additional charge will be made as specified in the rate statement, subject to the right of the Company to waive this charge for any Customer once in each calendar year for reasons deemed by the Company to be good and sufficient. The due date for payment of the net amount will be shown upon each bill and will be at least 15 days for Non-residential and 20 days for Residential customers from the date of transmittal of the bill, except on bills to United States Government, Commonwealth of Pennsylvania or any of their agencies, municipal, religious, charitable and educational institutions not conducted for profit, the net payment period shall be thirty (30) days after date of presentation.

When the due date for residential service occurs from the 21st day of the month through the 5th day of the following month, the due date may be extended to the 6th day of the latter month for Customers on fixed incomes receiving Social Security or equivalent monthly checks on or about the 1st of the month. Such requests for due day extensions must be made by signed application at the Company office and must be renewed annually.

13-c Date of Payment. When Residential Customers bills are paid through the mail the date of the postmark will be considered the date of the payment. When Residential Customers' bills are paid through electronic transmission, the effective date of payment shall be the date of actual receipt of payment by the Company. When Residential Customers' bills are paid at a branch office or an Authorized Payment Agent, the effective date of payment shall be the date of actual receipt of payment at that location. For purposes of this section, an "Authorized Payment Agent" shall mean an agent expressly authorized by Company to accept payments from Customers on Company's behalf.

13-d Estimated Bills. The Company reserves the right to read meters on bimonthly or quarterly schedules and to render standard bills for the recorded use of service based upon the time interval between meter readings. At its option, when meters are read bimonthly or quarterly, the Company may render estimated bills on a monthly basis for the periods when meter readings are not obtained. Standard Company payment terms shall apply to these bills. The Company may estimate the bill of any Customer if extreme weather conditions, emergencies, equipment failures, work stoppages, failure to gain access or other circumstances prevent actual meter reading.

13-e Budget Billing – Residential Customers may elect an optional billing procedure which averages the **(C)**
estimated Company regulated service costs over a revolving twelve (12) month Budget Billing plan. These Customers will be billed for the use of electric service during the next eleven (11) months

(C) Indicates Change

RULES AND REGULATIONS (continued)

13. PAYMENT TERMS

beginning with whatever month that they select. Company will review the Budget Billing amount on the fourth (4th), seventh (7th) and tenth (10th) months annually adjusting upward or downward the Budget Billing amount based on actual charges to date and projected charges to the end of the twelve (12) month Budget Billing. The twelfth bill will be for usage for the month, with an adjustment for the difference between payments made and actual charges for electric service for the prior eleven (11) months, inclusive. At the conclusion of the budget billing year, any resulting reconciliation amount exceeding $100 may be amortized over a twelve (12) month period upon Residential Customer request.

HUD Financed Housing: Budget Billing for service, as described above, is available to master metered electrically heated multifamily dwelling units during the time that such unit is either owned by the Federal Department of Housing and Urban Development or subject to a first mortgage held or guaranteed by that agency.

13-f Late Payment Charge. Late payment charges will be applied as follows to the balance due which is not paid by the due date including amounts billed by the Company on behalf of electric suppliers other than the Company. Residential Customers will be charged a late payment charge of one and one half (1 1/2) percent per month on the balance due not paid by the due date; provided that, for a Residential Customer's payment by mail, the Company shall not impose a late payment charge unless payment is received more than 5 days after the due date. Non-Residential Customers will be charged five (5) percent per month on the balance due not paid by the due date and an additional one and one half (1 1/2) percent per month for each month thereafter.

13-g Joint Billing. Joint Billing provides Customers with one combined account and a combined invoice that displays charges for both their gas and electric service and pertains to Customers that are the same class as described below and receive both electric service from the Company and gas service from UGI Utilities, Inc. – North Rate District ("UGI North") at the same premises. Joint billing shall become available to eligible customers beginning with their billing cycle occurring after a scheduled upgrade to the Company's customer information system which is expected to occur in September of 2017. Eligible customers shall be Residential Customers receiving service under Rate Schedule R, who are also Residential Customers of UGI North receiving natural gas distribution service under UGI North Rate Schedules R and RT, and Commercial and Industrial Customers receiving service under Rate Schedules GS1, GS4, and GS5 who are also Commercial and Industrial Customers of UGI North receiving natural gas distribution service under UGI North Rate Schedules N and NT, unless they elect otherwise in writing or through mutual agreement with the Company. Eligible Customers shall be combined into a single customer account for service received from the Company and UGI North and shall receive combined bills separately listing charges from each company. The Company and UGI North shall, for such combined accounts, and subject to applicable statutory and applicable regulatory requirements, establish a reasonable hierarchy of categories for the posting of partial payments to such joint accounts, and within each such category payments shall first be posted, as applicable, to the Company or Electric Generation Supplier charges before being posted to UGI North or Natural Gas Suppler charges. **(C)**

(C) Indicates Change

RULES AND REGULATIONS (continued)

(C)

13. PAYMENT TERMS

13-h Payment of Refunds. Refunds due to customers greater than two dollars ($2) shall be mailed to the Customer. Refunds less than two dollars ($2) may be picked up at the office within sixty (60) days. After sixty (60) days, the refund shall be applied to Operation Share.

13-i Return Check Service Charge. The Company may impose a service charge of the greater of thirty-five dollars ($35.00) or maximum allowed by Commonwealth of Pennsylvania for each check received in payment of bill(s) which is dishonored and returned by the bank upon which it is drawn. The Company may require a Customer to tender non-electronic payment after the Customer tenders two (2) consecutive electronic payments that are subsequently dishonored, revoked, canceled or otherwise not authorized.

(C) Indicates Change

RULES AND REGULATIONS (continued)

14. TERMINATION OR DISCONNECTION BY COMPANY

14-a Termination of Service. The Company may terminate service on reasonable notice and remove its equipment in case of (i) nonpayment of an undisputed delinquent account, (ii) failure to complete payment of a deposit, provide a guarantee of payment or establish credit, (iii) failure to permit access to meters, service connections or other property for the purpose of replacement, maintenance, repair or meter reading, (iv) failure to comply with the material terms of a payment arrangement, or (v) violation of Tariff Rules and Regulations. The Company may terminate service promptly and without notice for (i) Unauthorized Use of Service delivered on or about the affected dwelling, (ii) fraud or material misrepresentation of the customer’s identify for the purpose of obtaining service, (iii) abuse of or tampering with the meters, connections or other equipment of the Company, (iv) violating tariff Rules and Regulations which endanger the safety of a person or the integrity of the Company’s distribution system, (v) tendering payment for reconnection of service that is subsequently dishonored, revoked, canceled or otherwise not authorized and which has not been cured or otherwise made in full payment within three business days of the Company’s notice, or (vi) after receiving termination notice from the Company, tendering payment which is subsequently dishonored under 13 Pa. C.S. § 3502, or, in the case of an electronic payment, that is subsequently dishonored, revoked, canceled or otherwise not authorized and which has not been cured or otherwise made in full payment within three business days of the Company’s notice.

14-b Safety Shut-Off. The Company may disconnect without notice if the Customer's installation has become dangerous or defective, or if upon examination of the Customer's installation by fire underwriters' association having jurisdiction, a certificate of approval is refused.

14-c Income Verification. For Residential Customers, the Company will accept the following as verification of household income in determining the eligibility of an account under Chapter 56 for termination during the period of December 1 through March 31: (i) recent pay stubs or W-2 forms, (ii) access card or statement from Department of Public Welfare (“DPW”), (iii) if a source of income is rental income, then a verified copy of rent receipt(s), (iv) if the Residential Customer receives social security payments, pension payments, disability payments, Supplemental Security Income (SSI) payments, or any other source of fixed income with direct deposit, then a copy of bank statement or benefit letter, (v) child support and/or alimony support verification letter, (vi) if the Residential Customer receives payments from unemployment benefits or workers’ compensation, then a copy of the determination letter or check stub, (vii) previous year’s income tax statement, (viii) a filed 1099 form showing any interest income, annuity or dividends, and (ix) a verification letter from DPW of any approved cash or crisis grant applicable to the current heating season.

14-d Reconnection Charge. When service has been disconnected under the provisions of Rule 14-a and 14-b, the Company may require a deposit as a condition of reconnection of service as well as full payment of outstanding company charges. The Company will not condition the reconnection of services on the Customer’s payment of outstanding electric generation supplier charges unless those charges are the result of services provided by the supplier of last resort. In addition, prior to reconnection, one of the following charges may apply.

Reconnection During Normal Working Hours	$28.00
Reconnection Other Times	$108.00

RULES AND REGULATIONS (continued)

15. DISCONTINUANCE OF SERVICE BY CUSTOMER

15-a Notice to Discontinue. Any Customer who is about to vacate any premises supplied with Electric Service or for any reason wishes to have Electric Service discontinued shall give at least seven (7) days' notice to the Company and any non-Customer Occupant specifying the date on which it is desired that service be discontinued. In the absence of such notice the Customer shall be responsible for all services rendered. If a Residential Customer requests a discontinuance of Electric Service at the Residential Customer's residence, and the Residential Customer and the members of the Residential Customer's household are the only Occupants, the Company may discontinue Electric Service without additional notice to the affected premise. If a Customer (other than a landlord ratepayer) requests discontinuance of Electric Service at either (i) a dwelling other than the Customer's residence, or (ii) at a single meter, multi-family residence, whether or not the Customer's residence, then the Customer must state in writing (under penalty of law) that the premises are unoccupied. If the premises are occupied, the Customer's written notice requesting discontinuance of service must be endorsed by all affected Occupants. If the foregoing conditions are not met, the Company may discontinue service at the affected premises upon notice to the affected premises in accordance with Chapter 56. The Customer shall be liable for Electric Service consumed until transfer of the account or the meter shut off.

15-b Final Bill. The final bill for service is due and payable immediately after notice to discontinue and final reading of the meter.

RULES AND REGULATIONS (continued)

16. ADMINISTRATION OF RATES

16-a Load Inspections. Where the supply of Electric Service is under rates which base the billing demand or minimum charge upon the Customer's connected load, Company's representative shall have access to the premises at reasonable times to inspect and count the connected load.

16-b Billing Changes. Where demands are reassessed, or redetermined, or power factor recomputed or remeasured or Customers are found to be on an improper rate, as the result of investigation made at Customer's request or by routine inspection, the change of billing to the new demand or power factor, or to the proper rate will apply to the bill for the month during which the investigation is made.

16-c Change in Rate. Company will, after notice of service conditions, compute bills under the applicable rate most advantageous to the Customer, and will notify the Customer in writing or by new contract of the change in rate contemplated, provided that not more than one such change of rate shall be made in any twelve (12) month period, except as provided in Rule 16-d.

16-d Billing During Periods of Construction or Emergency. Company reserves the right to base its bills for service upon the applicable rate most advantageous to the Customer or to modify or waive the requirements of the applicable rate as to billing demand, minimum billing demand and/or minimum monthly charge when:

(1) Customer is forced to suspend operations in part or entirely due to fire or flood;

(2) Unusual high demands are established by emergency pumping, or other abnormal load conditions;

(3) Customer's plant is under construction or gradual electrification;

(4) Government Orders, applicable to special classes of Customers, require changes in such Customer's loads. Written request for relief must be made is all cases except (4), stating fully the circumstances on which the request is based. If appropriate, the Contract term shall be extended for a period equal to that of the relief granted.

RULES AND REGULATIONS (continued)

17. NET METERING

17-a Applicability. This rule sets forth the eligibility, terms and conditions applicable to Customers with installed qualifying renewable customer-owned generation using a net metering system.

(1) Customer-generators served under Rate Schedules R, GS-1, GS-4, GS-5, and LP who install a device or devices which are, in the Company's judgment, subject to Commission review a bona fide technology for use in generating electricity from qualifying Tier I or Tier II alternative energy sources pursuant to Alternative Energy Portfolio Standards Act No. 2004-213 (Act 213) or Commission regulations and which will be operated in parallel with the Company's system are eligible for net metering.

(2) This rule is available to installations where any portion of the electricity generated by the renewable energy generating system offsets part or all of the customer-generator's requirements for electricity.

(3) A renewable customer-generator, under this rule, is a non-utility owner or operator of a net metered distributed generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service (Rate R) or not larger than 3,000 kilowatts at other customer service locations (Rate GS-1, GS-4, GS-5, and LP), except for a Customer whose system is above 3 megawatts and up to 5 megawatts who may qualify its alternative energy system for customer-generator status if, as set forth in the Commission's regulations: (a) the Customer makes its system available to operate in parallel with the grid during grid emergencies; or (b) the Customer's system is located within a microgrid.

(4) To qualify for net metering, the customer-generator must, among other things, have electric load, independent of the alternative energy system, behind the meter and point of interconnection of the alternative energy system. To be independent of the alternative energy system, the electric load must have a purpose other than to support the operation, maintenance or administration of the alternative energy system.

(5) Qualifying renewable energy installations are limited to Tier I and Tier II alternative energy sources as defined by Act 213 and Commission Regulations. The Customer's equipment must conform to the Commission's Interconnection Standards and Regulations pursuant to Act 213. The net metering rules are not applicable when the source of supply is service purchased from a neighboring electric utility under Borderline Service.

(6) Service is available upon request to renewable customer-generators on a first come, first served basis so long as the total rated generating capacity installed by renewable customer-generator facilities does not adversely impact service to other Customers and does not compromise the protection scheme(s) employed on the Company's electric distribution system.

(7) Review and approval of all customer-generator applications and interconnections shall be in accordance with the Commission's regulations.

17-b Metering Provisions. A Customer may select one of the following metering options in conjunction with service under applicable Rate Schedule R, GS-1, GS-4, GS-5, and LP.

(1) A customer-generator facility used for net metering shall be equipped with a single bi-directional meter that can measure and record the flow of electricity in both directions at the same rate. If the Customer agrees, a dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense.

RULES AND REGULATIONS (continued)

17. NET METERING

(2) If the customer-generator's existing electric metering equipment does not meet the requirements under option (1) above, the Company shall install new metering equipment for the customer-generator at the Company's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator. The customer-generator has the option of utilizing a qualified meter service provider to install metering equipment for the measurement of generation at the customer-generator's expense.

(3) Additional metering equipment for the purpose of qualifying alternative energy credits owned by the customer-generator shall be paid for by the customer-generator. The Company shall take title to the alternative energy credits produced by a customer-generator where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits. The Company shall, prior to taking title to any alternate energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer-generator for the disposition of those credits.

(4) Virtual meter aggregation on properties owned or leased and operated by the same customer-generator shall be allowed for purposes of net metering. Virtual meter aggregation shall be limited to meters located on properties owned or leased and operated by the same customer-generator within two (2) miles of the boundaries of the customer-generator's property and within the Company's service territory. All service locations to be aggregated must be Company service location accounts held by the same individual or legal entity receiving retail electric service from the Company and have measureable load independent of any alternative energy system. Physical meter aggregation shall be at the customer-generator's expense. The Company shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the Company at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing his account on a virtual meter aggregation basis.

17-c Billing Provisions. The following billing provisions apply to customer-generators in conjunction with service under applicable Rate Schedule R, GS-1, GS-4, GS-5, and LP.

(1) The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at full retail rate, consistent with Commission regulations. If a customer-generator supplies more electricity to the electric distribution system than the Company delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's kilowatt-hour usage in subsequent billing periods at the full retail rate. Any excess kilowatt hours that are not offset by electricity used by the customer-generator in subsequent billing periods shall continue to accumulate until the end of the year. At the end of each year, the Company will compensate the customer-generator for any remaining excess kilowatt-hours generated by the customer-generator that were not previously credited against the customer-generator's usage in prior billing periods at the Company's Price to Compare rate. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

RULES AND REGULATIONS (continued)

17. NET METERING

(2) If the Company supplies more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

(3) The credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs must be stated in the service agreement between the customer-generator and the EGS. The Company shall credit customer-generators who are EGS customers for each kilowatt-hour of electricity produced at the Company's unbundled distribution kilowatt-hour rate. The distribution kilowatt-hour rate credit shall be applied monthly against kilowatt-hour distribution usage. If the customer-generator supplies more electricity to the electric distribution system than the Company delivers to the customer-generator in any billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's unbundled kilowatt-hour distribution usage in subsequent billing periods until the end of the year when all remaining unused kilowatt-hour distribution credits shall be zeroed-out. Distribution credits are not carried forward into the next year.

(4) For customer-generators involved in virtual meter aggregation programs, a credit shall be applied first to the meter through which the generating facility supplies electricity to the distribution system, then through the remaining meters for the customer-generator's account equally at each meter's designated rate. Virtual meter aggregation is the combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by the same customer-generator by means of the Company's billing process, rather than through physical rewiring of the customer-generator's property for a physical, single point of contact. The customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

17-d Application. Customer-generators seeking to receive service under the provisions of this rule must submit a written application to the Company demonstrating compliance with the Net Metering provisions and quantifying the total rated generating capacity of the customer-generator facility.

17-e Minimum Charge. The Minimum Charges under Rate Schedule R, GS-1, GS-4, GS-5, and LP apply for installations under the net metering rules.

17-f Applicable Charges and Fees. Bills rendered by the Company under this rule shall be subject to charges and fees applicable to Rate Schedules R, GS-1, GS-4, GS-5, and LP.

RULES AND REGULATIONS (continued)

18. CUSTOMER CO-GENERATION

18-a General. The Company will purchase the output of customer owned generation provided that the customer does not qualify for or elects not to connect to Company's system under the Net Metering rules, Section 17:

(1) The facility uses a renewable resource or is a co-generation facility as defined in the Public Utilities Regulatory Policies Act (PURPA) section 292.

(2) The Customer's system is installed in accordance with the Company specifications and is not detrimental to the Company's distribution facilities or other Customers.

(2) The Customer compensates the Company for the cost of interconnection above that which would be required for normal service.

18-b Operations. These guidelines state the minimum technical requirements for safe parallel operation of Customer-owned generation.

(1) Certain protective devices including an intertie circuit breaker will be specified by the Company and must be installed at any location where a Customer desires to operate generation in parallel with the Company's system. The protection to be applied will be designed to separate the Customer from the Company's system:

A. For faults on the Company's system within the zone of protection encompassing the Customer intertie point and which produce in feed from the Customer into the Company fault.
B. For faults on the Customer's system.
C. Whenever the Company's feeder circuit breaker(s) is opened at the Company source.

(2) The Customer is fully responsible for protecting his equipment in such a manner that faults or other disturbances on the Company's system or the Customer's system do not cause damage to his equipment.

(3) All Customer installations shall adhere to the applicable national and local codes, rules and regulations.

(4) Switching of the intertie breaker must be under the operating control of the Company. The Company reserves the right to open the intertie breaker without prior notice to the Customer for any of the following reasons:

A. System emergency.
B. Inspection of Customer's generating equipment or protective equipment reveals an unsafe condition.
C. The Customer's generating equipment interferes with other Customers or with the generation of the Company's system.
D. An outage is scheduled on the Company's supply line.

(5) In connection with normal Company routine switching operations:

A. The Customer shall be solely responsible for synchronizing his generator with the Company frequency and voltage. This includes synchronizing his generator after momentary feeder outages.
B. The Customer will not be permitted to energize or maintain supply to a de-energized Company circuit.

RULES AND REGULATIONS (continued)

18. CUSTOMER CO-GENERATION

(6) Other Requirements.

A. The Customer has the responsibility for routine maintenance of his generating and protective equipment. Complete maintenance records must be maintained by the Customer and be available for Company review. The failure of the Customer to provide proper routine maintenance will result in the Customer being required to cease parallel operation by opening either his generator circuit breaker or intertie breaker until such maintenance is performed.

B. The interconnection of the Customer's generating equipment with the Company system shall not cause any reduction in the quality of service being provided to other Customers. No abnormal voltages, frequencies harmonics or interruptions will be permitted. The maximum wave form distortion caused by the Customer including a maximum 1% phase voltage imbalance shall be limited to 5% measured at the Customer Company interconnection. The Company will be the sole judge of what equipment is necessary to establish a safe and proper interconnection.

C. If the Customer's load power factor is less than 95%, a power factor penalty may be assessed for qualifying facilities over 100 kW. The rate and provisions for this penalty will be the same as indicated in the tariff for Customers receiving normal service.

D. Direct current generators may be operated in parallel with the Company through a synchronous inverter. The inverter installation shall be designed such that a Company system interruption will result in the removal of the inverter in feed to the Company. Harmonics generated by a Dc generator-inverter combination must not cause any reduction in the quality of service provided to other Company Customers, and must adhere to the previously specified 5% limit on waveform distortion.

E. All Customer generators must be isolated from all other Company Customers by a power transformer.

F. The maximum size single-phase and three-phase generator permitted on the Company's distribution system will be determined by location.

18-c Standard Rate Schedules for Qualifying Facilities of 500 kW or Less.

All qualifying facilities with a capacity of 500 kW or less shall be compensated for energy sold to the Company by a standard rate schedule. The qualifying facility will be given the option of three (3) different standard rate schedules on which to be compensated. These are:

(1) Actual Monthly Costs - This is a rate based on the actual monthly energy costs incurred by the Company for purchased power from its principal supplier. The Company will compute the actual energy rate from its principal supplier on a monthly basis. The amount of compensation for energy sold to the Company will then be computed based on the output of the qualifying facility for that month. The output of a qualifying facility for a particular month will be based upon the Company's then current meter reading schedules.

(2) Capacity and Energy Based on Estimated Costs - This is a rate based on the estimated cost of both capacity and energy for purchased power from the Company's principal supplier. The rate at which a qualifying facility will be compensated under this rate schedule is on file with the Pennsylvania Public Utility Commission and is available for public inspection at the offices of the Company. Compensation for both energy and capacity will only be made for the output sold to the Company on weekdays between the hours of 6:00 a.m. to 12:00 midnight. For all other hours, compensation will be at the energy rate only.

RULES AND REGULATIONS (continued)

18. CUSTOMER CO-GENERATION

In order to receive these rates, the qualifying facility will enter into a contract with the Company. The annual rates on file at the time of the signing of contract will determine the level of compensation for the duration of the contract. The minimum term of the contract is three (3) years. When the contract terminates, the rate of compensation will be based on the rates in effect when the contract is renegotiated. The estimated rates will be updated annually and will be filed with the Pennsylvania Public Utility Commission.

(3) Capacity and Energy Based on Levelized Costs - This is a levelized rate based on the estimated cost of both capacity and energy for purchased power from the Company's principal supplier. The rate at which a qualifying facility would be compensated under this rate schedule is on file with the Pennsylvania Public Utility Commission and is available for public inspection at the offices of the Company. Compensation for both energy and capacity will only be made for the output sold to the Company on weekdays between the hours of 6:00 a.m. to 12:00 midnight. For all other hours, compensation will be at the energy rate only.

In order to receive these rates, the qualifying facility will enter into a contract with the Company. The levelized rate on file at the time of the signing of the contract will determine the level of compensation for the duration of the contract.

The minimum term of the contract is three (3) years. When the contract terminates, the rate of compensation will be based on the rates in effect when the contract is renegotiated. The estimated rate will be updated annually and will be filed with The Pennsylvania Public Utility Commission.

18-d Net Energy Billing. Qualifying facilities of less than 50 kW may request net energy billing. Under net energy billing, the energy taken by the qualifying facility from the Company will be billed net of the energy supplied by the qualifying facility to the Company. In order to have net energy billing, the following rules will apply.

(1) Residential

A. For those qualifying facilities where it is determined by estimate or test, the normal loading will greatly exceed the output capability of the generator only one (1) normal kWh meter may be installed. Since no OUT kWh meter would be installed, there shall be no compensation for the generator output.

B. Where there is both IN and OUT flow, IN and Out kWh metering will be installed at the service entrance equipment. The normal monthly billing will be the sum of the IN minus the OUT kWh meter. When this number is a positive value, the Customer's normal bill will be at the applicable rate schedule. Where the sum of the IN minus the OUT kWh meter is a negative value, the customer's normal bill will be limited to the Customer charge at the applicable rate schedule. The compensation the qualifying facility receives for the excess will be at the rate schedule chosen by the qualifying facility.

Where it is determined, the normal billing from the Company to the qualifying facility is insufficient to recover the cost for the installation of distribution facilities, the qualifying facility shall be billed a one-time charge to recover the excess cost of these distribution facilities. This charge shall be determined after twelve (12) months of continuous operation of the qualifying facility’s generator and normal loading cycle.

RULES AND REGULATIONS (continued)

18. CUSTOMER CO-GENERATION

C. If the Customer desires to sell all the output from his generator, there will be no net energy billing; therefore, the Customer's normal load and generation output will be metered separately. Maintenance service for the Customer's generating facility may be either from the Customer's normal service or from a separate IN kWh meter located at the Customer's generating facility.

(2) Commercial - Industrial

A. Net energy billing will be limited to Customers served on the Company's GS-1 or GS-4 rate schedules.

B. For those Customers desiring net billing, an IN and OUT kWh meter will be installed at the service entrance equipment. When the sum of the IN kWh meter minus the OUT kWh meter is a positive number, the Customer's normal billing will beat the applicable rate schedule. Where the sum of the IN minus the OUT kWh meter is a negative value, the Customer's normal bill will be limited to the Customer charge. Where it is determined, the normal billing from the Company to the qualifying facilities is insufficient to recover the cost for the installation of distribution facilities, the qualifying facility shall be billed a one-time charge to recover the excess cost of those distribution facilities. This charge shall be determined after l2 months of continuous operation of the qualifying facility’s generator and normal loading cycle.

C. If the Customer desires to sell all the output from his generator, there will be no net energy billing; therefore, the Customer's normal load and generation output will be metered separately. Maintenance service for the generating facility may be either from the Customer's normal service or from a separate IN kWh meter located at the Customer's generating facility.

18-e Maintenance, Supplemental or Standby Power. Qualifying facilities requiring such service will be billed on the company's current tariff at the appropriate rate schedule. These include GS-1, GS-4 and the LP rate schedules.

18-f Payment Terms. All credits due a qualifying facility shall be paid by the Company on the 20th of the month for power sold to the Company the preceding month.

RULES AND REGULATIONS (continued)

19. POLE REMOVAL AND RELOCATION CHARGES

19-a For the purpose of this Rule only, the following terms shall have the meanings indicated for them.

(1) "Contractor Costs" - The amount paid by the Company to a contractor for work performed on a pole removal or relocation.

(2) "Direct Labor Costs" - The pay and expenses of Company employees directly attributable to work performed on pole removals or relocations, excluding construction overheads or payroll taxes, workmen's compensation expenses or similar expenses.

(3) "Direct Material Costs" - The purchase price of materials used in performing a pole removal or relocation, excluding related stores expenses. In computing direct materials costs, proper allowance shall be made for unused materials, materials recovered from temporary structures, and for discounts allowed and realized in the purchase of materials.

(4) "Pole Removal or Relocation" - The removal or relocation of distribution or transmission line poles and their associated attachments made under the request of a residential property owner who is not entitled to receive condemnation damages to cover the cost of the pole removal or relocation. The term does not include pole repairs or replacements necessitated by the intentional or negligent conduct of a party.

19-b When a Residential Customer requests the Company to remove or relocate a Company pole on said Customer's residential property the Residential Customer shall be required to pay the contractor costs, direct labor costs, and direct material costs associated with the pole removal or relocation less an amount equal to any maintenance expenses avoided as a result of such work. The Company shall provide the Residential Customer with an estimate of the above costs for performing such work and the Residential Customer shall pay that amount to the Company prior to construction. After completion of the work, the Company shall bill, or refund to, the Residential Customer the difference between the estimated cost and the actual direct cost of such work.

19-c In all other respects, non-residential Customers or parties that request the removal, relocation or changes to Company facilities shall bear the total cost and expenses of the work, including the total direct and indirect costs. Where required by the company, the non-residential Customer or party shall pay to the Company in advance the estimated cost to perform such work. After completion of the work, the Company shall bill, or refund to the non-residential Customer or party, the difference between the estimated cost and the total direct and indirect cost of such work.

19-d All Customers or parties that request the removal, relocation or change of Company facilities shall furnish, without expense to the Company, satisfactory rights-of-way acceptable to the Company for the construction, maintenance and operation of the relocated facilities.

RIDER A

STATE TAX ADJUSTMENT SURCHARGE

The State Tax Adjustment Surcharge is applicable to the net monthly rates and minimum charges contained in this Tariff. The surcharge shown below will be recomputed when a tax rate used in the calculation changes and/or the Company implements a change in rates.

The recomputation of the surcharge will be submitted to the PUC within 10 days after the occurrence of a reason for surcharge recomputation shown above. If the recomputed surcharge is less than the one in effect the Company will, and if more may, submit a tariff or supplement to reflect such recomputed surcharge, the effective date of which shall be 10 days after the filing.

Rider A - State Tax Adjustment Surcharge is 0.01%. **(I)**

(I) Indicates Increase

RIDER B

GENERATION SUPPLY SERVICE SURCHARGE

(C) Company will supply Default Generation Supply Service (GSS) to customers in the Company's service territory not receiving service from an EGS. The rules and rates contained herein apply to service provided on and after June 1, 2021.

For customers served through the Company's GSS, a Generation Supply Rate (GSR) shall be applied to each kilowatt hour of energy used by the customer. Separate GSRs shall be calculated and apply to the rate schedules listed below.

GSR-1 shall apply to Rate Schedules R, GS-1, GS-5, FCP, BLR, OL, SOL, MHOL, LED-OL, SL, SSL, MHSL, LED-SL and LED-CO.

GSR-1 shall also apply to Rate Schedules GS-4 and LP where the customer's annual peak load is less than 100 kW.

GSR-2 shall apply to Rate Schedules GS-4, LP, and HTP where the customer's annual peak load is greater than or equal to 100 kW.

(C) Customer's highest billing demand in the twelve-month period ending September 30, 2020 shall be the annual peak load determinant for purposes of applying the GSR. For new customers without a twelve-month billing history, the billing demand shall be based on the Company's estimate using factors such as, but not limited to, similarly equipped buildings, similarly utilized buildings and square footage.

(C) The GSR-1 rate shall be calculated every three months beginning June 1, 2021. The GSR-1 rate shall be filed with the Commission with at least thirty days' notice prior to each three-month period and shall be posted on the Company's website. If the GSR-1 calculation results in a change in rate that is less than 2%, the Company, in its sole discretion, may file with the Commission a GSR-1 rate that is unchanged from the prior period.

$$\text{GSR-1} = \left[\frac{EC}{SEC} + \frac{ECA}{SECA} + \frac{Int}{Sint} \right] \times \frac{1}{(1-T)} \quad \text{where}$$

EC = Projected direct and indirect purchased power costs incurred by the Company to acquire electric supply for the GSR-1 group for the next three-month period including, a load following service, wholesale energy costs, alternative energy credits, capacity costs, transmission costs, and all other PJM bill line item expenses/credits excluding network transmission service credits and firm point-to-point transmission service credits/expenses. EC also includes administrative costs, legal costs, taxes, and any other applicable costs of providing default service for the GSR-1 group. The estimated EC shall be reduced by the estimated transmission revenues to be collected in accordance with the applicable rate schedules included in the GSR-1 group.

(C) Indicates Change

RIDER B

GENERATION SUPPLY SERVICE SURCHARGE (continued)

ECA = Net over or under collection of the EC defined above to be refunded/recovered. The ECA will be reconciled quarterly based on actual EC revenues received and actual EC costs incurred for the three-month period ending two months prior to the filed GSR effective date. Any over/under collection plus related interest, existing as of May 31, 2021, applicable to GSR-1 customers shall be included in the ECA component of the GSR-1 beginning June 1, 2021. The over/under collection existing as of May 31, 2021 shall be allocated to GSR-1 and GSR-2 customers based on the percentage of the actual sales during the period of the over/under collection attributed to those customers classified as GSR-1 and GSR-2 as of June 1, 2021. In the event the ECA would result in less than (or equal to) a five percent (5%) change in the average total residential bill, the Company will refund/recover the balance over a three-month period. In the event the ECA would result in more than a five percent (5%) change in the average total residential bill for default service, the Company will refund/recover the balance over a six, nine, or twelve month period (as determined by the Company).

Int = When revenues exceed costs, the over collections shall be refunded to customers with interest. When costs exceed revenues, the under collections shall be collected from customers with interest. Interest on over collections and under collections shall be computed at the prime rate of interest for commercial banking, not to exceed the legal rate of interest, in effect on the last day of the month the over collection or under collection occurs, as reported in the Wall Street Journal. Interest shall be computed monthly from the month the over collection or under collection occurs to the effective month that the over collection is refunded or the under collection is collected.

T = The Pennsylvania Gross Receipts Tax Rate reflected in the Company’s base rates, expressed in decimal form.

SEC = The Company’s projected sales for all default service customers on rate schedules included in the GSR-1 group for the next three-month period, in kilowatt hours.

SECA = The Company’s projected sales for all default service customers on rate schedules included in the GSR-1 group for the refund/recover period, in kilowatt hours.

Sint = The Company’s projected sales for all default service customers on rate schedules included in the GSR-1 group for the twelve-month period beginning December 1, in kilowatt hours.

The current GSR-1 rate is:

12.902 ¢/kWh **(I)**

GSR-2 shall be calculated for each default service customer in this group. Company shall bill each customer on a calendar month based upon actual costs incurred to serve the customer. The costs will be allocated as follows:

Energy costs incurred by the Company to acquire electric supply shall be calculated for each GSR-2 customer by multiplying the customer’s actual hourly energy use, adjusted for losses, by the Company real-time Locational Marginal Price (LMP) during each hour of the billing month.

(I) Indicates Increase

RIDER B

GENERATION SUPPLY SERVICE SURCHARGE (continued)

Other power costs incurred by the Company to acquire electric supply for the GSR-2 group for the month shall be allocated to each GSR-2 customer based on metered sales. Other power costs include alternative energy credits and all PJM bill line item expenses/credits excluding the following: costs for capacity services, transmission services, network transmission service credits and firm point-to-point transmission service credits/expenses. Other costs included are administrative costs, legal costs, taxes, and any other applicable costs of providing default service for the GSR-2 group. The actual costs shall be reduced by the actual transmission revenues to be collected in accordance with the applicable rate schedules included in the GSR-2 group.

Cost for capacity and transmission services based on the PJM bill line item expenses/credits applicable to these services shall be allocated to each customer in the GSR-2 group. The capacity costs shall include the PJM bill line items for locational reliability, capacity transfer rights, RPM auction, and capacity resource deficiency. The capacity costs shall be allocated to each customer based on each customer's peak load contribution (PLC). The transmission costs shall include the PJM bill line items for network integration transmission service charges, transmission enhancement service charges/credits, and non-firm point-to-point transmission service charges/credits. The transmission costs shall be allocated to each customer based on each customer's network service peak load value (NSPL). Any expense/credit line items added by PJM related to these services shall be allocated based on the Customer's applicable PLC and NSPL.

(C) Any over/under collection plus related interest, existing as of May 31, 2021, applicable to GSR-2
(C) customers that migrate from rate GSR-1 shall be refunded/recovered from those customers directly over 12
(C) billing periods beginning September 1, 2021. The over/under collection existing as of May 31, 2021 shall be
allocated to GSR-1 and GSR-2 customers based on the percentage of the actual sales during the period of
(C) the over/under collection attributed to those customers classified as GSR-1 and GSR-2 as of June 1, 2021.

(C) Customers who undergo reverse migration, switching from GSR-2 to GSR-1 during the DSP IV term, will be
exempted from any over/under collections as reflected in the Company's E-factor (existing as of May 31,
2021) for a period of 12 months after returning to GSR-1.

All costs for GSR-2 customers shall include the Pennsylvania Gross Receipts Tax Rate reflected in the Company's base rates.

Price to Compare: The Price-To-Compare ("PTC") for GSR-1 shall include the Energy Charge
(C) ("EC"), and the Energy Cost Adjustment ("ECA")~~,~~ contained in UGI's tariff. The Price-To-Compare shall also
include the State Tax Surcharge in Rider A. PTC is not applicable to GSR-2.

Annual Reconciliation Statement: On June 30 of each year, Company will file with the Commission, its Annual Reconciliation Statement for the GSR-1 rate for the preceding 12 months ending May 31.

(C) Indicates Change

RIDER C
UNIVERSAL SERVICE PROGRAM RIDER

APPLICABILITY AND PURPOSE
This Rider shall be applicable to all residential customers except customers in the Company's Customer Assistance Program ("CAP"). This Rider has been established to recover costs related to the Company's Universal Service and Conservation Programs, excluding internal administrative costs.

RATE
In addition to the charges provided in this tariff, an amount shall be added to the otherwise applicable charge for each kWh of sales volumes or distribution volumes distributed by the Company to customers receiving service under Rate Schedule R.

The USP rate: 1.150 ¢/kWh **(I)**

CALCULATION OF RATE
The Rider USP rate shall be calculated to recover costs for the following programs: Low Income Usage Reduction Program (LIURP); Customer Assistance Program (CAP); Hardship Funds; and any other replacement or Commission-mandated Universal Service Program or low income program that is implemented during the period that the Rider is in effect.

LIURP costs will be calculated based on the projected number of Level 1 income homes to be weatherized. Hardship Fund costs will be calculated on the projected level of an allocated share of administrative funds incurred by the UGI Operation Share Energy Fund.

CAP costs will be calculated to include
1) the projected CAP credit; and
2) projected CAP customer application and administrative costs paid to external agencies that would not have been incurred in the absence of CAP; and
3) projected CAP pre-program arrearage forgiveness.

CAP Credit shall be defined as the difference between the total calculated Rate R bill, excluding Rider USP, and the CAP bill and an adjustment for unearned credit amounts based upon the current discounts at normalized annual volumes of the then-current CAP participants and the projected CAP Credit for projected customer additions to CAP during the period that the CAP Rider rate will be in effect at the average discount of current CAP participants at normalized annual volumes.

QUARTERLY ADJUSTMENT
Any time that the Company makes a change in base rates or GSR rate affecting residential customers, the Company shall recalculate the Rider USP rate pursuant to the calculation described above to reflect the Company's current data for the components used in the USP rate calculation. The Company shall file the updated rate with the PUC to be effective one (1) day after filing.

ANNUAL RECONCILIATION
On or before November 1 of each year, the Company shall file with the PUC data showing the reconciliation of actual revenues received under this Rider and actual recoverable costs incurred for the preceding twelve months ended September. The resulting over/undercollection (plus interest calculated at 6% annually) will be reflected in the CAP quarterly rate adjustment to be effective December 1. Actual recoverable costs shall reflect actual CAP costs, actual application costs, actual pre-program arrearage forgiveness, actual LIURP costs, actual Hardship Administrative costs. Actual recoverable CAP credit costs and pre-program arrearage forgiveness shall be based upon actual CAP credits granted and pre-program arrearage forgiveness granted less a 7.40% adjustment for amounts granted to participants in excess of 3,231 enrollees. The 7.40% adjustment related to CAP credits and pre-program arrearage forgiveness will be based on the following:

(I) Indicates Increase

RIDER C

UNIVERSAL SERVICE PROGRAM RIDER (Continued)

For each reconciliation period, the average annual CAP credit per participant will be determined by dividing the total actual CAP credits granted during the reconciliation period by the average monthly number of participants receiving CAP credits during the reconciliation period. The average monthly number of participants receiving CAP credits exceeding 3,231 will be multiplied by the average annual CAP credit granted per participant and then multiplied by 0.0740 in order to determine the amount of the CAP Credits recovered through Rider USP. **(C)**

For each reconciliation period, the average pre-program arrearage forgiveness per participant will be determined by dividing the total actual pre-program arrearage forgiven during the reconciliation period by the number of participants receiving pre-program arrearage forgiveness. The number of participants receiving pre-program arrearage forgiveness exceeding 3,231 will be multiplied by the average pre-program arrearage forgiveness per participant and then multiplied by 0.0740 in order to determine the amount of the pre-program arrearage forgiveness which will not be recovered through Rider USP. **(C)**

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RIDER E

ENERGY EFFICIENCY AND CONSERVATION RIDER

GENERAL. The Company shall recover costs related to the Company's Phase III Energy Efficiency and Conservation Plan ("Phase III EECP") for 2019-2024 through a Phase III Energy Efficiency and Conservation Rider ("Phase III EEC Rider"). The rates under the Phase III EEC Rider shall be computed separately for each of the three customer classes listed below. The Phase III EEC Rider Rate for each class shall be as follows:

Customer Class	Rate Schedules	Phase III EEC Rider Rate (*¢/kWh)*	
Class 1 – Residential	R, GS-5 and the residential portion of Rate Schedules OL, SOL, MHOL, or successor rate schedules	0.059	**(D)**
Class 2 – Non Residential	All Non-Residential Rate Schedules except for Rate Schedules LP and HTP	0.132	**(D)**
Class 3 – Non Residential	LP and HTP	0.203	**(I)**

The Phase III EEC Rider shall apply to all customers whether they are receiving generation service from the Company or not and shall be subject to the State Tax Surcharge.

CALCULATION. The Phase III EEC Rider shall be determined as follows:

1. Costs to be recovered shall include Company incurred costs to implement its Commission approved Phase III EECP during each plan year, including all costs incurred to develop and administer the Company's Phase III EECP from June 1, 2019 until May 31, 2024. The costs of each Phase III EECP program shall be directly assigned to the applicable customer class based upon projected spending levels.
2. The Residential Phase III EEC Rider rate shall be calculated in accordance with the formula below and shall be rounded to the third decimal:

Residential Phase III EEC Rider Rate = ((Cr / Sr) – (Er / Sr)) / (1-T) where

Cr = Projected Annual Residential Phase III EECP Costs.

Sr = Projected Annual Residential Class Sales.

Er = Net over or under collection of the Residential Phase III EEC Rider resulting from the difference between the Phase III EEC Rider revenues received and the Phase III EECP costs incurred. The over or under collection shall be calculated annually and include the actual over or under collection for the reconciliation period.

T = Total Pennsylvania gross receipts tax rate as reflected in the Company's base rates, expressed in decimal form.

(D) Indicates Decrease (I) Indicates Increase

RIDER E

ENERGY EFFICIENCY AND CONSERVATION RIDER (continued) (C)

1. The Phase III Non-Residential EEC Rider rates shall be calculated in accordance with the formula below and shall be rounded to the third decimal:

   Non-Residential Phase III EEC Rider Rate = ((Cn / Sn) – (En / Sn)) / (1-T) where

   Cn = Projected Annual Non-Residential Phase III EECP Costs.

   Sn = Projected Annual Non-Residential Class Sales.

   En = Net over or under collection of the Non-Residential Phase III EEC Rider resulting from the difference between the Phase III EEC Rider revenues received and the Phase III EECP costs incurred. The over or under collection shall be calculated annually and include the actual over or under collection for the reconciliation period. (C)

   T = Total Pennsylvania gross receipts tax rate as reflected in the Company's base rates, expressed in decimal form.

   Class 2 and Class 3 Non-Residential Phase III EEC Rider rates shall be calculated and reconciled separately.

4. The Residential and Non-Residential rates under the Phase III EEC Rider shall become effective on September 1. The Residential and Non-Residential rates under the Phase III EEC Rider shall be updated and reconciled annually thereafter and filed with the Commission effective on thirty (30) days' notice. The Company reserves the right to make an interim filing to adjust the rates under the Phase III EEC Rider to be effective on sixty (60) days' notice. (C)
5. Overcollections or undercollections existing at the end of the last year of the Phase II EE&C Plan (as of May 31, 2019) will be recovered/refunded over the one-year period following the end of the Phase II EE&C Plan. Any remaining balance will be recovered/refunded through the Phase III EEC Rider's E-Factor. Overcollections or undercollections existing as of the last year of the Phase III EE&C Plan will be recovered/refunded over the one-year period following the end of the Phase III EE&C Plan ("Final Reconciliation Year"). If it is known that there will be a Phase IV EE&C Plan at the end of the Final Reconciliation Year related to Phase III, any remaining balance will be recovered/refunded through the Phase IV EEC Rider's E-Factor. If there will be no Phase IV EE&C Plan, any balance remaining for a customer class at the end of the Final Reconciliation Year will be trued up through a one-time bill credit issued to the applicable customers during the second full billing month following the end of the Final Reconciliation Year. (C)

(C) Indicates Change

RIDER F

POWER FACTOR CHARGE

APPLICABILITY

A power factor charge will be applied to all Customers served under rates LP, GS-4, HTP and BLR with a maximum monthly demand greater than 100 kW. The equipment necessary to measure power factor will be installed at locations where it has been determined by test or by estimate that the Customer's power factor is below the allowable power factor, if indicated annual revenue from the application of the power factor charge is $100 or more. The Company may retest the Customer's power factor from time to time to assure compliance with this provision.

CHARGE

The average power factor will be computed each month from the registration of metering equipment installed in accordance with the Company's standard practice. In any month in which the average power factor is less than the allowable power factor of ninety (90) per cent, a power factor charge shall be added to the monthly bill determined in accordance with the formula:

A. For secondary metered service:

$$\left(\frac{\text{Allowable Power Factor}}{\text{Average Power Factor}}\right) - 1 \times \$1.17 \times \text{Billing Demand} + \$6 \text{ Meter Charge}$$

B. For primary metered service:

$$\left(\frac{\text{Allowable Power Factor}}{\text{Average Power Factor}}\right) - 1 \times \$\,.77 \times \text{Billing Demand} + \$6 \text{ Meter Charge}$$

The State Tax Adjustment Surcharge included in this Tariff is applied to power factor charges.

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(C) Indicates Change

RIDER G

DSIC – DISTRIBUTION SYSTEM IMPROVEMENT CHARGE

In addition to the net charges provided for in this Tariff, a charge of 1.20% will apply consistent with the Commission Order dated October 27, 2022 at Docket No. M-2012-2293611, approving the DSIC. **(I, C)**

A.1 Purpose. To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new customers are not recoverable through the DSIC.

A.2 Eligible Property.

The DSIC-eligible property will consist of the following:

- Poles and Tower (Acct. 364);
- Overhead conductors (Acct. 365)
- Underground Conduit and Conductors (Accts. 366 & 367)
- Line Transformers (Acct. 368)
- Substation Equipment (Acct. 362)
- Any fixture or device related to eligible property listed above, including insulators, circuit breakers, fuses, reclosers, grounding wires, crossarms and brackets, relays, capacitors, convertors and condensers;
- Unreimbursed costs related to highway relocation projects where an electric distribution company must relocate its facilities; and
- Other related capitalized costs.

A.3 Effective Date. The DSIC will become effective for bills rendered on and after January 1, 2023. **(C)**

A.4 Computation of the DSIC. The DSIC will be updated on a quarterly basis to reflect eligible plant additions placed in service during the three-month periods ending one month prior to the effective date of each DSIC update.

Thus, changes in the DSIC rate will occur as follows:

Effective Date of Change	Date to which DSIC-Eligible Plant Additions Reflected
April 1	December 1 through February 28
July 1	March 1 through May 31
October 1	June 1 through August 31
January 1	September 1 through November 30

(C) Indicates Change (I) Indicates Increase

RIDER G

DSIC – DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (Continued)

A.5 Determination of Fixed Costs. The fixed costs of eligible distribution system improvements will consist of depreciation and pre-tax return, calculated as follows:

1. Depreciation: The depreciation expense shall be calculated by applying the annual accrual rates employed in the Company's most recent base rate case for the plant accounts in which each retirement unit of DSIC-eligible property is recorded to the original cost of DSIC-eligible property.
2. Pre-Tax Return: The pre-tax return shall be calculated using the statutory state and federal income tax rates, the Utility's actual capital structure and actual cost rates for long-term debt and preferred stock as of the last day for the three-month period ending one month prior to the effective date of the DSIC and subsequent updates. The cost of equity will be the equity return rate approved in the last fully litigated base rate proceeding for which a final order was entered not more than two years prior to the effective date of the DSIC. If more than two years shall have elapsed between the entry of such a final order and the effective date of the DSIC, then the equity return rate used in the calculation will be the equity return rate calculated by the Commission in the most recent Quarterly Report on the Earnings of the Jurisdictional Utilities released by the Commission.

A.6 Application of DSIC. The DSIC will be expressed as a percentage carried to two decimal places and will be applied to the total amount billed to each customer for distribution service under the otherwise applicable rates and charges, excluding amounts billed for the State Tax Adjustment Surcharge (STAS).

To calculate the DSIC, one-fourth of the annual fixed costs associated with all property eligible for cost recovery under the DSIC will be divided by the projected revenue for distribution service (including all applicable clauses and riders) for the quarterly period during which the charge will be collected, exclusive of STAS.

Formula: The formula for the calculation of the DSIC is as follows:

$$DSIC = \frac{((DSI*PTRR)+STFT+Dep+e) * 1/(1-T)}{PQR}$$ **(C)**

Where:

DSI = Original cost of eligible distribution system improvement projects net of accrued depreciation and associated accumulated deferred income taxes pertaining to property-related book/tax depreciation timing differences resulting from the use of accelerated depreciation per Internal Revenue Code, 26 U.S. Code § 168. **(C)**

PTRR = Pre-tax return rate applicable to DSIC-eligible property.

STFT = State Tax Flow Through: pre-tax flow through calculated on book-tax timing differences between accelerated tax depreciation and book depreciation net of federal tax. **(C)**

Dep = Depreciation expenses related to DSIC-eligible property.

e = Amount calculated under the annual reconciliation feature or Commission audit, as described below.

(C) Indicates Change

RIDER G

DSIC – DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (Continued)

T = Pennsylvania Gross Receipts Tax rate in effect during the billing month, expressed in decimal form. **(C)**

PQR = Projected quarterly revenues for distribution service (including all applicable clauses and riders) from existing customers plus netted revenue from any customers which will be gained or lost by the beginning of the applicable service period.

Revenues will be determined as one-fourth (1/4) of projected annual revenues as determined in accordance A.8.5.

<u>A.7 Quarterly Updates.</u> Supporting data for each quarterly update will be filed with the Commission and served upon the Commission's Bureau of Audits, Bureau of Investigation and Enforcement, the Office of Consumer Advocate, and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the update.

<u>A.8 Customer Safeguards.</u>

1. <u>Cap:</u> The DSIC is capped at 5.0% of the amount billed to customers for distribution service (including all applicable clauses and riders) as determined on an annualized basis.
2. <u>Audit/Reconciliation:</u> The DSIC is subject to audit at intervals determined by the Commission. Any cost determined by the Commission not to comply with any provision of 66 Pa C.S. § 1350, et seq., shall be credited to customer accounts. The DSIC is subject to annual reconciliation based on a reconciliation period consisting of the twelve months ending December 31 of each year or the Company may elect to subject the DSIC to quarterly reconciliation but only upon request and approval by the Commission. The revenue received under the DSIC for the reconciliation period will be compared to the Company's eligible costs for that period. The difference between revenue and costs will be recouped or refunded, as appropriate, in accordance with Section 1307(e), over a one-year period commencing on April 1 of each year or in the next quarter if permitted by the Commission. If DSIC revenues exceed DSIC-eligible costs, such over-collections will be refunded with interest. Interest on over-collections and credits will be calculated at the residential mortgage lending specified by the Secretary of Banking in accordance with the Loan Interest and Protection Law (41 P.S. § 101, et seq.) and will be refunded in the same manner as an over-collection. The Company is not permitted to accrue interest on under collections.
3. <u>New Base Rates:</u> The DSIC will be reset to zero upon application of new base rates to customer billings that provide for prospective recovery of the annual costs that had previously been recovered under the DSIC. Thereafter, only the fixed costs of new eligible plant additions that have not previously been reflected in the Company's rates or rate base will be reflected in the quarterly updates of the DSIC.
4. <u>Customer Notice:</u> Customers shall be notified of changes in the DSIC by including appropriate information on the first bill they receive following any change. An explanatory bill insert shall also be included with the first billing.
5. <u>All Customer Classes:</u> The DSIC shall be applied equally to all customer classes, except that the Company may reduce or eliminate the Rider DSIC to any customer with competitive alternatives who have negotiated contracts with the Company, if it is reasonably necessary to do so.

(C) Indicates Change

RIDER G

(C)

DSIC – DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (Continued)

1. Earnings Reports: The DSIC will also be reset to zero, if, in any quarter, data filed with Commission in the Company's then most recent Annual or Quarterly Earnings reports show that the Company would earn a rate of return that would exceed the allowable rate of return used to calculate its fixed costs under the DSIC as described in the pre-tax return section. The Company shall file a tariff supplement implementing the reset to zero due to overearning on one-days' notice and such supplement shall be filed simultaneously with the filing of the most recent Annual or Quarterly Earnings reports indicating that the Company has earned a rate of return that would exceed the allowable rate of return used to calculate its fixed costs.
2. Residual E-Factor Recovery Upon Reset To Zero: The Company shall file with the Commission interim rate revisions to resolve the residual over/under collection or E-factor amount after the DSIC rate has been reset to zero. The Company can collect or credit the residual over/under collection balance when the DSIC rate is reset to zero. The Company shall refund any overcollection to customers and is entitled to recover any undercollections as set forth in Section A.8.2. Once the Company determines the specific amount of the residual over or under collection amount after the DSIC rate is reset to zero, the utility shall file a tariff supplement with supporting data to address that residual amount. The tariff supplement shall be served upon the Commission's Bureau of Investigation and Enforcement, the Bureau of Audits, the Office of Consumer Advocate, and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the supplement.

(C) Indicates Change

RATE R
RESIDENTIAL SERVICE

AVAILABILITY
Available to Customers located on Company's distribution lines and desiring service for household and non-residential uses (where the non-residential use(s) is limited to less than 2 kW) in a single private dwelling, or an individual dwelling unit in a multiple dwelling structure, and its appurtenant detached buildings.

CHARACTER OF SERVICE
Alternating current, 60 cycles, single phase; 120 volts, 2 wire; 120-208 volts, 3 wire; or 120-240 volts, 3 wire.

RATE TABLE

Customer Charge: $9.50 per Month **(I)**

Distribution Charge (all usage): 3.907 ¢/kWh **(I)**

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider C - Universal Service Program Rider
Rider E - Energy Efficiency and Conservation Rider
Rider G- Distribution System and Improvement Charge

MINIMUM MONTHLY CHARGE
The Minimum Monthly Charge shall be the Customer Charge.

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Section 13, Payment Terms, paragraph 13-f.

(I) Indicates Increase (C) Indicates Change

RATE OL
OUTDOOR LIGHTING SERVICE

AVAILABILITY
This Rate is available for outdoor lighting in the entire territory served by the Company, where contracted for by a Customer for private area lighting.

CONTRACT TERM AND BILLING
Standard contracts are on a yearly basis with monthly payments for service.

RATE TABLE
Rates per month for standard construction with monthly payments for service rendered.

Flood Lighting Luminaire – Mercury Vapor

	Residential		Commercial		
	Customer Charge (Per Lamp)	Distribution (¢/kWh)	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
11,000 Lumen	$7.20	3.962	$6.79	4.776	(I)
20,000 Lumen	$8.05	3.962	$7.43	4.776	(I)
60,000 Lumen	$8.24	3.962	$6.69	4.776	(I)

Street Lighting Luminaire – Mercury Vapor

	Residential		Commercial		
	Customer Charge (Per Lamp)	Distribution (¢/kWh)	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
7,000 Lumen	$4.54	3.962	$4.26	4.776	(I)
11,000 Lumen	$7.20	3.962	$6.79	4.776	(I)
20,000 Lumen	$8.05	3.962	$7.43	4.776	(I)
60,000 Lumen	$8.24	3.962	$6.69	4.776	(I)

Low mounted, decorative fixture and pole ....$ 7.46 per month
for underground service, provided that in addition to charge
no trenching and back-filling is required in Rate Tables above

Distribution and Generation Supply rates will be applied to per kilowatt hour of energy used each month. The number of kWh supplied is based upon the average hours' use and size of lamps.

STANDARD CONSTRUCTION
The prices specified in the Rate Table for Standard Construction cover the supply of lamps and equipment to mount floodlighting or street lighting luminaires and photo-electric switch control on Company's existing wood pole or other support approved by the Company and located within one span (150 feet) of existing 120 volt facilities. If Customer requires an additional wood pole, or poles, to be installed, a monthly charge of $5.99 per pole shall be added to the above Rates for standard installation poles. Any additional facilities other than specified herein shall be paid by the Customer in advance.

HOURS OF BURNING
Operation shall be from dusk until dawn, a total of approximately 4,000 hours per year. Credit shall not be allowed for lamp outages.

(I) Indicates Increase

RATE OL - (Continued)
OUTDOOR LIGHTING SERVICE

MAINTENANCE
All facilities shall be owned and maintained by the Company. Lamp renewal service, during normal working hours will be provided upon notice to the Company for lamps burned out or broken. Burned out or broken lamps will be replaced as long as the supply of mercury vapor lighting is available to the Company.

RURAL LINE MINIMUMS
Rural line minimums shall not be applicable to charges under this Rate.

APPROVAL
Customer shall obtain proper approval for lights to be located on public thoroughfares.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E- Energy Efficiency and Conservation Rider
Rider G- Distribution System and Improvement Charge

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Section 13, Payment Terms, paragraph 13-f.

(C) Indicates Change

RATE SOL
SODIUM OUTDOOR LIGHTING SERVICE

AVAILABILITY
This Rate for high pressure sodium outdoor lighting is available in the entire territory served by the Company, where contracted for by a Customer for private area lighting.

CONTRACT TERM
Two years and thereafter in accordance with contract provisions. The contract may be terminated with sixty (60) days' notice prior to expiration period of contract by either party.

NET MONTHLY RATE
Rates per month for standard construction with monthly payments for service rendered.

Floodlighting Luminaire – High Pressure Sodium

	Residential		Commercial		
	Customer Charge (Per Lamp)	Distribution (¢/kWh)	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
16,000 Lumen	$7.96	3.962	$7.65	4.776	(I)
25,000 Lumen	$8.35	3.962	$7.88	4.776	(I)
50,000 Lumen	$10.42	3.962	$9.72	4.776	(I)

Street Lighting Luminaire – High Pressure Sodium

	Residential		Commercial		
	Customer Charge (Per Lamp)	Distribution (¢/kWh)	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
9,500 Lumen	$7.87	3.962	$7.66	4.776	(I)
16,000 Lumen	$7.96	3.962	$7.65	4.776	(I)
25,000 Lumen	$8.35	3.962	$7.88	4.776	(I)
50,000 Lumen	$10.42	3.962	$9.72	4.776	(I)

Low mounted, decorative fixture and pole ....$ 7.46 per month
for underground service, provided that in addition to charge
no trenching and backfiling is required in Rate Table above

Distribution and Generation Supply rates will be applied to per kilowatt hour of energy used each month. The number of kWh supplied is based upon the average hours' use and size of lamps.

GENERAL PROVISIONS

(a) The prices specified in the Rate Table for Standard Overhead Construction cover the supply of lamps and equipment to mount flood lighting or street lighting luminaires and photo-electric switch control on Company's existing wood pole or other support approved by Company and located within 150 feet of existing 120 volt facilities.

(b) If Customer requires an additional wood pole, or poles, to be installed for mounting heights up to 25 feet, a monthly charge of $5.99 per pole shall be added to the above rates.

(c) Any additional facilities other than specified herein shall be paid by the Customer in advance.

(I) Indicates Increase

RATE SOL - (Continued)
SODIUM OUTDOOR LIGHTING SERVICE

(d) Customer shall obtain proper approval for lights to be located on public thoroughfares

(e) Operation shall be from dusk to dawn, a total of approximately 4,000 hours per year. Lamp renewal service, during normal working hours, will be provided upon notice to Company for lamps burned out or broken and no credit for outages allowed. Company will supply, install, operate, and maintain necessary lighting facilities.

REMOVAL OF MERCURY VAPOR
When, at the request of the Customer, a sodium vapor light replaces a fully operational mercury vapor light that has been installed for less than 10 years, the Customer shall pay the Company for the Company's estimated cost of removal and rehabilitation plus the estimated remaining value of the system. When, at the request of the Customer, a sodium vapor light replaces a failed mercury vapor light that can neither be repaired nor replaced, the installation will be completed at no charge to the Customer.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G- Distribution System and Improvement Charge

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Section 13, Payment Terms, paragraph 13-f.

(C) Indicates Change

RATE MHOL
METAL HALIDE OUTDOOR LIGHTING SERVICE

AVAILABILITY
This Rate is available in the entire territory served by the Company, where contracted for by a Customer for private area lighting.

CONTRACT TERM
Two years and thereafter in accordance with contract provisions. The contract may be terminated with sixty (60) days' notice prior to expiration period of contract by either party.

NET MONTHLY RATE

Flood Lighting Luminaire

	Residential		Commercial		
	Customer Charge (Per Lamp)	Distribution (¢/kWh)	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
20,500 Lumen	$9.05	3.962	$8.65	4.776	(I)
36,000 Lumen	$9.20	3.962	$8.57	4.776	(I)
110,000 Lumen	$16.11	3.962	$14.58	4.776	(I)

Street Lighting Luminaire

	Residential		Commercial		
	Customer Charge (Per Lamp)	Distribution (¢/kWh)	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
9,000 Lumen	$8.07	3.962	$7.86	4.776	(I)
12,900 Lumen	$6.83	3.962	$6.57	4.776	(I)
13,000 Lumen	$6.36	3.962	$6.07	4.776	(I)
20,500 Lumen	$9.05	3.962	$8.65	4.776	(I)
36,000 Lumen	$9.20	3.962	$8.57	4.776	(I)

Low mounted, decorative fixture and pole ....$ 7.46 per month
for underground service, provided that in addition to charge
no trenching and backfilling is required in Rate Table above

Distribution and Generation Supply rates will be applied to per kilowatt hour of energy used each month. The number of kWh supplied is based upon the average hours' use and size of lamps. **(C)**

GENERAL PROVISIONS

(a) The prices specified in the Rate Table for Standard Overhead Construction cover the supply of lamps and equipment to mount flood lighting or street lighting luminaries and photo-electric switch control on Company's existing wood pole or other support approved by Company and located within 150 feet of existing 120 volt facilities.

(b) If Customer requires an additional wood pole, or poles, to be installed for mounting heights up to 25 feet, a monthly charge of $5.99 per pole shall be added to the above rates.

(c) Any additional facilities other than specified herein shall be paid by the Customer in advance.

(I) Indicates Increase (C) Indicates Change

RATE MHOL - (Continued)
METAL HALIDE OUTDOOR LIGHTING SERVICE

(d) Customer shall obtain proper approval for lights to be located on public thoroughfares.

(e) Operation shall be from dusk to dawn, a total of approximately 4,000 hours per year. Lamp renewal service, during normal working hours, will be provided upon notice to Company for lamps burned out or broken and no credit for outages allowed. Company will supply, install, operate, and maintain necessary lighting facilities.

REMOVAL OF MERCURY VAPOR & HIGH PRESSURE SODIUM
When, at the request of the Customer, a metal halide light replaces a fully operational mercury vapor or high pressure sodium light that has been installed for less than 1 or 2 years respectively, the Customer shall pay the Company for the Company's estimated cost of removal and rehabilitation plus the estimated remaining value of the system. When, at the request of the Customer, a metal halide light replaces a failed mercury vapor light that can neither be repaired nor replaced, the installation will be completed at no charge to the Customer.

TERMINATION
If Customer terminates outdoor lighting service under this schedule for any reason prior to expiration of the two-year term, Customer shall pay removal cost.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G- Distribution System and Improvement Charge

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Section 13, Payment Terms, paragraph 13-f.

(C) Indicates Change

RATE LED-OL
LIGHT-EMITTING DIODE OUTDOOR LIGHTING SERVICE

AVAILABILITY
This Rate is available in the entire territory served by the Company, where contracted for by a Customer for private area lighting.

CONTRACT TERM
Two years and thereafter in accordance with contract provisions, which shall be consistent with this rate schedule and shall be of a standard form provided by and satisfactory to the Company. The contract may be terminated with sixty (60) days' notice prior to expiration period of contract by either party subject to the termination provision below.

NET MONTHLY RATE

Flood Lighting Luminaire

	Residential		Commercial		
Nominal Lamp Wattage Range	Customer Charge (Per Lamp)	Distribution (¢/kWh)	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
85-100	$15.42	3.962	$15.42	4.776	(I)
170-210	$22.64	3.962	$22.64	4.776	(I)
250-280	$26.08	3.962	$26.08	4.776	(I)

Street Lighting Luminaire

	Residential		Commercial		
Nominal Lamp Wattage Range	Customer Charge (Per Lamp)	Distribution (¢/kWh)	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
50-60	$10.29	3.962	$10.29	4.776	(I)
100-110	$12.16	3.962	$12.16	4.776	(I)
140-160	$14.00	3.962	$14.00	4.776	(I)
250-280	$21.25	3.962	$21.25	4.776	(I)

Distribution and Generation Supply rates will be applied to per kilowatt hour of energy used each month. Service hereunder is unmetered with the number of kWh billed for each size lamp calculated based on the estimated input wattage of the lamp and approximately 4,000 burning hours per year.

GENERAL PROVISIONS

(a) The prices specified in the Rate Table for Customer Charger (Per Lamp) cover the supply of lamps, fixtures, luminaries, and equipment, and installation of flood lighting or street lighting luminaries and photo-electric switch control on Company's existing wood pole or other support approved by Company and located within 150 feet of existing 120 volt facilities. Such charges include normal operation and maintenance.

(I) Indicates Increase

RATE LED-OL (continued)
LIGHT-EMITTING DIODE OUTDOOR LIGHTING SERVICE

(b) If Customer requires an additional wood pole, or poles, to be installed for mounting heights up to 25 feet, a monthly charge of $5.99 per pole shall be added to the above rates.

(c) Any additional facilities other than specified herein and the cost of rearranging facilities required to change mounting height shall be paid by the Customer in advance.

(d) Customer shall obtain proper approval for lights to be located on public thoroughfares.

(e) Operation shall be from dusk to dawn, a total of approximately 4,000 hours per year. Lamp renewal service, during normal working hours, will be provided upon notice to Company for lamps burned out or broken and with no credit for outages. Company will supply, install, operate, and maintain necessary lighting facilities.

REMOVAL OF MERCURY VAPOR, HIGH PRESSURE SODIUM AND METAL HALIDE
When, at the request of the Customer, a LED light replaces a fully operational mercury vapor, high pressure sodium or metal halide light that has been installed for less than the applicable contract term, the Customer shall pay the Company for the Company's estimated cost of removal and rehabilitation plus the estimated remaining value of the system. When, at the request of the Customer, a LED light replaces a failed mercury vapor, high pressure sodium or metal halide light that can neither be repaired nor replaced, the installation will be completed at no charge to the Customer.

TERMINATION
If Customer terminates outdoor lighting service under this schedule for any reason prior to expiration of the two-year term, Customer shall pay removal cost.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G- Distribution System and Improvement Charge

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Section 13, Payment Terms, paragraph 13-f.

(C) Indicates Change

RATE GS-1
GENERAL SERVICE

AVAILABILITY
Available to Customers located on Company's distribution lines desiring electric service for general lighting and/or power service outside the scope of the Residence Service Rate Schedules and whose demand at any time of the year is not in excess of five (5) kilowatts, and any building the primary use of which is public worship.

CHARACTER OF SERVICE
Alternating current, 60 cycles, single phase, 120 volts, 2 wire; or 120-240 volts, 3 wire; and 3 phase, 120-240 volts, 4 wire, except in areas where only 120/208 volts are available.

CONTRACT TERM AND BILLING
Standard contracts are on a yearly basis with monthly payments for service taken.

RATE TABLE

Customer Charge: $13.00 per Month **(I)**

Distribution Charge (all usage): 5.237 ¢/kWh **(I)**

MINIMUM MONTHLY CHARGE
The Minimum Monthly Charge is the Customer Charge.

DETERMINATION OF DEMAND
The demand will be determined at the option of the Company by estimate or by test at the time of maximum use or by demand meter measurement. Demands of Customers with monthly consumption over two thousand (2,000) kilowatt-hours on a recurring basis will be metered unless otherwise shown to be eligible for this rate.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G- Distribution System and Improvement Charge

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Section 13, Payment Terms, paragraph 13-f.

(I) Indicates Increase (C) Indicates Change

RATE GS-4 SERVICE
(5 kW minimum)

AVAILABILITY
Available to Customers located on Company's distribution lines desiring electric service for general lighting and/or power service and whose minimum billing demand is not less than five (5) kilowatts.

CHARACTER OF SERVICE
Alternating current, 60 cycles, 3 phase, 120-240 volts, 4 wire; 120-208 volts, 4 wire; or 240 volts, 3 wire; 480 volts, 3 wire; or 277-480 volts, 4 wire, may be supplied. In addition, alternating current, 60 cycles, single phase, 120-240 volts, 3 wire, and where available 120-208 volts, 3 wire.

CONTRACT TERM AND BILLING
Contracts shall be for a term of not less than one (1) year with monthly payments for service taken. Contracts for a longer term may be required where new investment by Company is necessary.

RATE TABLE

Customer Charge: $15.00 per Month

	Distribution ($/kW)	Distribution (¢/kWh)	
First 20 kW of billing demand	$3.59		
Over 20 kW of billing demand	$2.20		
First 200 hours use of demand		2.882	(I)
Next 300 hours use of demand		1.816	(I)
All over 500 hours use of demand		1.513	(I)

MINIMUM MONTHLY CHARGE
The Minimum Monthly Charge is the charge in the Rate Table for the billing demand. The minimum billing demand will not be less than five (5) kilowatts nor less than the minimum value stated in a contract for service.

DETERMINATION OF DEMAND
The demand shall be the greatest fifteen (15) minute load in kilowatts established during the month, taken for billing purposes to the nearest kilowatt.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider F - Power Factor Surcharge
Rider G- Distribution System and Improvement Charge

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Section 13, Payment Terms, paragraph 13-f.

POWER FACTOR
The Power Factor Charge contained in this Tariff is applied to this Rate

(I) Indicates Increase (C) Indicates Change

RATE GS-5
GENERAL SERVICE
(VOLUNTEER FIRE COMPANY, NON-PROFIT SENIOR CITIZEN CENTER, NON-PROFIT RESCUE SQUAD, AND NON-PROFIT AMBULANCE SERVICE)

AVAILABILITY
Upon application, Pursuant to Act 103 of 1985 and Act 203 of 2002, Volunteer Fire Companies, Non-Profit Senior Citizen Centers, Non-Profit Rescue Squads, and Non-Profit Ambulance Services may elect to have their electric service rendered pursuant to the following charges upon execution of a contract for a minimum term of one year.

For the purpose of this Rate only, the following terms shall have the following meanings indicated for them.

1. "Volunteer Fire Company Service" - A separately metered service location consisting of a building, sirens, a garage for housing vehicular firefighting equipment, or a facility certified by the Pennsylvania Emergency Management Agency (PEMA) for firefighting training. The use of electric service at this service location shall be to support the activities of the volunteer fire company. Any fund raising activities at this service location must be used solely to support volunteer fire fighting operations.
   The customer of record at this service location must be a predominantly volunteer fire company recognized by the local municipality or PEMA as a provider of firefighting services.

2. "Non-Profit Senior Citizen Center Service" - A separately metered service location consisting of a facility for the use of senior citizens coming together as individuals or groups and where access to a wide range of services to senior citizens is provided.
   The customer of record at this service location must be an organization recognized by the Internal Revenue Service (IRS) as non-profit and recognized by the Department of Aging as an operator of a senior citizen center.

3. “Non-Profit Rescue Squad” – A separately metered service location consisting of a building, sirens, a garage for housing vehicular rescue equipment, or a facility that is qualified by the IRS as non-profit and recognized by PEMA and the Department of Health as a provider of rescue services. The use of electric service by the customer of record at this location shall be to support the activities of the non-profit rescue squads.

4. “Non-Profit Ambulance Service” – A separately metered service location consisting of a building, sirens, a garage for housing vehicular ambulance equipment, or a facility that is qualified by the IRS as non-profit and recognized by PEMA and the Department of Health as a provider of ambulance services. The use of electric service by the customer of record at this location shall be to support the activities of the non-profit ambulance service.

CHARACTER OF SERVICE
Alternating current, 60 cycles, single phase, 120 volts, 2 wire; or 120-240 volts, 3 wire; and 3 phase, 120-240 volts, 4 wire, except in areas where only 120/208 volts is available.

CONTRACT TERM AND BILLING
Standard contracts are on a yearly basis with monthly payments for service taken.

RATE GS-5 (continued)
GENERAL SERVICE
(VOLUNTEER FIRE COMPANY, NON-PROFIT SENIOR CITIZEN CENTER, NON-PROFIT RESCUE SQUAD, AND NON-PROFIT AMBULANCE SERVICE)

RATE TABLE

Customer Charge: $9.50 per Month **(I)**

Distribution Charge (all usage): 3.907 ¢/kWh **(I)**

MINIMUM MONTHLY CHARGE
The Minimum Monthly Charge shall be the Customer Charge.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G- Distribution System and Improvement Charge

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Section 13, Payment Terms, paragraph 13-f.

(I) Indicates Increase (C) Indicates Change

RATE LP
LARGE POWER SERVICE

AVAILABILITY
Available to Customers taking general light and power service at each delivery point and whose minimum demand is not less than one hundred (100) kilowatts.

CHARACTER OF SERVICE
Alternating current, 60 cycles, 3 phase, 2,400 volts, 4,160 volts, 8,320 volts, or 13,800 volts, with one (1) transformation to a lower voltage with metering on the primary side of transformers and substation equipment supplied by the Company.

CONTRACT TERM AND BILLING
Contracts shall be for a term of not less than one (1) year with monthly payments for service taken. Contracts for a longer term may be required where new investment by Company is necessary.

RATE TABLE
The Customer's monthly bill shall be the sum of the demand and energy charges.

	Distribution ($/kW)	Distribution (¢/kWh)	
Demand Charge:			
First 100 kW of billing demand	$135.80 *		
Next 400 kW of billing demand	$0.94		
Over 500 kW of billing demand	$0.69		
First 100 hours use of billing demand		2.199	**(I)**
Next 200 hours use of billing demand but not more than 200,000 kWh		1.588	**(I)**
Next 200 hours use of billing demand but not more than 200,000 kWh		1.453	**(I)**
Excess		1.365	**(I)**

* ..... Charge is for the First 100 kW of billing demand or any part thereof.

(I) Indicates Increase

RATE LP - (Continued)
LARGE POWER SERVICE

DETERMINATION OF DEMAND
The demand shall be determined by meters which will, at the option of the Company, either indicate or record the demand. The billing demand shall be the highest fifteen (15) minute demand recorded during the month, provided that the Company reserves the right to use for billing purposes the single maximum demand established during a five (5) minute interval when power installation includes hoists, elevators, welding machines, electric furnaces, or other load having high intermittent peak load requirements. In no event, however, shall the billing demand be less than one hundred (100) kilowatts.

SECONDARY SERVICE
At the Company's option, service may be metered at secondary voltage of transforming equipment. When so metered energy charges will be increased two (2) percent.

POWER FACTOR
The Power Factor Charge contained in this Tariff is applied to this Rate.

MINIMUM MONTHLY CHARGE
The Minimum Monthly Charge shall be an amount equal to the demand charge plus the power factor charge for the month.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider F - Power Factor Surcharge
Rider G- Distribution System and Improvement Charge

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Section 13, Payment Terms, paragraph 13-f.

(C) Indicates Change

RATE HTP
HIGH TENSION POWER SERVICE

AVAILABILITY **(C)**
This rate is available for large general service Customers taking supply from available transmission lines of 66,000 volts or higher.

CHARACTER OF SERVICE
Alternating current, 60 cycles, 3 phase, 66,000 volts (or higher) with metering on the primary side of transformers and substation equipment supplied by the Customer. **(C)**

CONTRACT TERM AND BILLING
Contract shall be for a term of not less than one (1) year with monthly payments for service taken. Contracts for a longer term may be required where new investment by Company is necessary.

RATE TABLE

Customer Charge, Distribution Charge, Demand Charge, and Power Factor Surcharge are all fully negotiated rates. **(C)**

MINIMUM MONTHLY CHARGE
As determined by negotiation between Customer and Company. **(C)**

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge **(C)**
Rider B - Generation Supply Service

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Section 13, Payment Terms, paragraph 13-f.

(C) Indicates Change

RATE SL
STREET LIGHTING SERVICE

AVAILABILITY
This Rate is available for street, bridge, parks and outdoor lighting in the entire territory served by the Company.

CONTRACT TERM
Standard contracts are for the term of five (5) years. Contracts for a longer term may be required where new investment by Company is necessary.

RATE TABLE
Rates per lamp per month for standard construction with monthly payments for service rendered.

Mercury Vapor

	Municipal or Public Authority		
	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
3,750 Lumen	$3.88	4.776	(I)
7,000 Lumen	$4.05	4.776	(I)
11,000 Lumen	$6.37	4.776	(I)
20,000 Lumen	$7.65	4.776	(I)
60,000 Lumen	$6.43	4.776	(I)

Low mounted, decorative fixture and pole for underground service, provided that no trenching and back-filling is required .... $ 7.46 per month in addition to charge in Rate Table above

Additional wood pole installed for the sole purpose of supporting lighting fixtures or circuits .... $ 5.99 per month

The number of kWh supplied is based upon the average hours' use and size of lamps.

Distribution and Generation Supply rates will be applied to per kilowatt hour of energy used each month. The number of kWh supplied is based upon the average hours' use and size of lamps.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G- Distribution System and Improvement Charge

STANDARD CONSTRUCTION
The prices specified in the Rate Table for Standard Construction cover the supply of lamps and equipment to mount lighting fixtures on wood poles and include electric current and maintenance for complete street lighting service when supplied from circuits, mast arms, and fixtures of overhead construction. When Customer desires an underground or ornamental system, or non-standard construction conditions exist, the additional cost shall be borne by Customer; also, if Customer desires to supply equipment such as conductors, conduit, poles and fixtures, a monthly construction credit for such equipment supplied shall be given Customer over the term of the contract.

Other special equipment such as is used for channel lighting on bridges shall be installed and maintained by Customer except lamp bulbs which shall be furnished and renewed by Company.

(I) Indicates Increase (C) Indicates Change

RATE SL - (Continued)
STREET LIGHTING SERVICE

HOURS OF BURNING
All night lamps from one-half (1/2) hour after sunset to one-half (1/2) hour before sunrise, a total of approximately 4,000 hours per year.

LAMP RENEWALS
Free Lamp renewal service is provided upon notice to the Company for lamps burned out, broken or giving less than eighty percent (80%) of initial lumens as rated by the manufacturers. Burned out or broken lamps will be replaced as long as the supply of mercury vapor lighting is available to the Company.

SPACING OF LAMPS
The standard spacing of lamps shall be a distance not to exceed four hundred (400) feet. Non-standard construction costs shall be paid by the customer.

NOTE 1: 3,750 Lumen-Mercury Vapor Lamp Rate restricted to units installed as of July 27, 1994.

ADDITIONAL LAMPS
Additional lamps and fixtures of the type currently being used by the Company may be ordered installed by Customer at any time during the first four (4) years of a standard five (5) year contract. Additional lamps and fixtures ordered installed during last year of standard contract or contracts less than five (5) years may be deferred at Company's option until a new standard contract is executed, unless the Customer is willing to pay the cost of installation, subject to refund by Company when new standard five (5) year contract is executed.

No additional lamps and fixtures are available after July 1, 2007.

RELOCATION OF LAMPS
The cost of any change of location of lamps, from the original location specified by Customer, shall be borne by the Customer and paid to the Company.

CHANGE IN SIZE OF LAMP
In the event that change in size of lamps is desired by the Customer, Company will make such change in accordance with the following requirements:

(1) That no further investment, except lamps, by Company in new fixtures shall be required;

(2) Mercury vapor lamps are available to the Company

(3) Changes of lamp size other than those covered under Clause 1 hereof shall be subject to further agreement between Customer and Company.

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Section 13, Payment Terms, paragraph 13-f.

RATE SSL
SODIUM STREET LIGHTING SERVICE

AVAILABILITY
This Rate schedule for high pressure sodium vapor lighting is available for public roadway, bridge and parks.

CONTRACT TERM
Ten years and thereafter in accordance with contract provisions. The contract may be terminated with sixty (60) days' notice prior to expiration period of contract by either party.

NET MONTHLY RATE

	Municipal or Public Authority		
	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
9,500 Lumen	$7.51	4.776	(I)
16,000 Lumen	$7.58	4.776	(I)
25,000 Lumen	$8.57	4.776	(I)
50,000 Lumen	$9.10	4.776	(I)

Low mounted, decorative fixture and pole ....$ 7.46 per month
for underground service, provided that in addition to charge
no trenching and back-filling is required in Rate Table above

Additional wood pole installed for the sole ....$ 5.99 per month
purpose of supporting lighting fixtures or circuits

The number of kWh supplied is based upon the average hours' use and size of lamp.

Distribution and Generation Supply rates will be applied to per kilowatt hour of energy used each month. The number of kWh supplied is based upon the average hours' use and size of lamps.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G- Distribution System and Improvement Charge

GENERAL PROVISIONS
(a) Necessary street lighting facilities are supplied and installed, operated and maintained by Company and are connected to Company's available general distribution system.

(b) Prices include the standard type luminaire currently being offered at the time service is contracted for and up to 150 circuit feet of overhead secondary extension.

(c) Customer shall pay the cost of any additional facilities required to extend service and the cost of rearranging facilities required to change mounting height.

(d) Company will provide underground and decorative systems of a type being offered by the Company at the time service is contracted for when the additional cost in excess of the estimated cost of a standard overhead system for the same application is paid by Customer. Company shall take title to this system and shall operate and maintain the facilities. At the termination, for any reason, of the useful life of these systems or designated components, a new system or component shall be installed under similar conditions.

(I) Indicates Increase (C) Indicates Change

RATE SSL - (Continued)
SODIUM STREET LIGHTING

SPECIAL CUSTOMER EQUIPMENT
Upon request, the Company may, at its option, operate and maintain special lighting equipment of a type not being offered by Company provided Customer installs equipment and supplies any nonstandard replacement parts at no cost to Company.

REMOVAL OF MERCURY VAPOR
When, at the request of the Customer, a sodium vapor light replaces a fully operational mercury vapor light that has been installed for less than 10 years, the Customer shall pay the Company for the Company's estimated cost of removal and rehabilitation plus the estimated remaining value of the system. When, at the request of the Customer, a sodium vapor light replaces a failed mercury vapor light that can neither be repaired nor replaced, the installation will be completed at no charge to the Customer.

TERMINATION
If Customer terminates street lighting service under this schedule for any reason prior to expiration of any 10-year term, Customer shall pay removal cost plus remaining value of system.

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Section 13, Payment Terms, paragraph 13-f.

RATE MHSL
METAL HALIDE STREET LIGHTING SERVICE

AVAILABILITY
This Rate is available to municipalities or other public authorities for street, bridge, parks and outdoor lighting in the entire territory served by the Company.

CONTRACT TERM
Ten years and thereafter in accordance with contract provisions. The contract may be terminated with sixty (60) days' notice prior to expiration period of contract by either party

NET MONTHLY RATE

	Municipal or Public Authority		
	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
9,000 Lumen	$6.71	4.776	**(I)**
12,900 Lumen	$5.42	4.776	**(I)**
13,000 Lumen	$4.92	4.776	**(I)**
20,500 Lumen	$7.29	4.776	**(I)**
36,000 Lumen	$6.20	4.776	**(I)**

(1) Low mounted, decorative fixture and pole ....$ 7.46 per month
for underground service, provided that — in addition to charge
no trenching and back-filling is required — in Rate Table above

Additional wood pole installed for the sole ....$ 5.99 per month
purpose of supporting lighting fixtures or circuits

The number of kWh supplied is based upon the average hours' use and size of lamp.

Distribution and Generation Supply rates will be applied to per kilowatt hour of energy used each month. The number of kWh supplied is based upon the average hours' use and size of lamps.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G- Distribution System and Improvement Charge

GENERAL PROVISIONS

(a) Necessary street lighting facilities are supplied and installed, operated and maintained by Company and are connected to Company's available general distribution system.
(b) Prices include the standard type luminaries currently being offered at the time service is contracted for and up to 150 circuit feet of overhead secondary extension.
(c) Customer shall pay the cost of any additional facilities required to extend service and the cost of rearranging facilities required to change mounting height.
(d) The cost of any change of location of lamps, from the original location specified by Customer, shall be borne by the Customer and paid to the Company.

(I) Indicates Increase (C) Indicates Change

RATE MHSL - (Continued)
METAL HALIDE STREET LIGHTING SERVICE

(e) Company will provide underground and decorative systems of a type being offered by the Company at the time service is contracted for when the additional cost in excess of the estimated cost of a standard overhead system for the same application is paid by Customer. Company shall take title to this system and shall operate and maintain the facilities. At the termination, for any reason, of the useful life of these systems or designated components, a new system or component shall be installed under similar conditions.

SPECIAL CUSTOMER EQUIPMENT
Upon request, the Company may, at its option, operate and maintain special lighting equipment of a type not being offered by Company provided Customer installs equipment and supplies any nonstandard replacement parts at no cost to Company.

REMOVAL OF MERCURY VAPOR AND HIGH PRESSURE SODIUM
When, at the request of the Customer, a metal halide light replaces a fully operational mercury vapor or high pressure sodium light that has been installed for less than 5 or 10 years respectively, the Customer shall pay the Company for the Company's estimated cost of removal and rehabilitation plus the estimated remaining value of the system. When, at the request of the Customer, a metal halide light replaces a fully operational mercury vapor light that can neither be repaired nor replaced, the installation will be completed at no charge to the customer.

TERMINATION
If Customer terminates street lighting service under this schedule for any reason prior to expiration of any 10-year term, Customer shall pay removal cost plus the estimated remaining value of system.

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Section 13, Payment Terms, paragraph 13-f.

RATE LED-SL
LIGHT-EMITTING DIODE STREET LIGHTING SERVICE

AVAILABILITY
This Rate is available to municipalities or other public authorities for street, bridge, parks and outdoor public lighting in the entire territory served by the Company.

CONTRACT TERM
Ten years and thereafter in accordance with contract provisions, which shall be consistent with this rate schedule and shall be of a standard form provided by and satisfactory to the Company. The contract may be terminated with sixty (60) days' notice prior to expiration period of contract by either party subject to the termination provision below.

NET MONTHLY RATE

	Municipal or Public Authority		
Nominal Lamp Wattage Range	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
50-60	$10.29	4.776	**(I)**
100-110	$12.16	4.776	**(I)**
140-160	$14.00	4.776	**(I)**
250-280	$21.25	4.776	**(I)**

Additional wood pole installed for the sole ....$ 5.99 per month
purpose of supporting lighting fixtures or circuits

Distribution and Generation Supply rates will be applied to per kilowatt hour of energy used each month. Service hereunder is unmetered with the number of kWh billed for each size lamp calculated based on the estimated input wattage of the lamp and approximately 4,000 burning hours per year.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G- Distribution System and Improvement Charge

GENERAL PROVISIONS

(a) Necessary street lighting facilities are supplied and installed, operated and maintained by Company and are connected to Company's available general distribution system.

(b) Prices include the standard type luminaries currently being offered at the time service is contracted for and up to 150 circuit feet of overhead secondary extension. Prices include normal operation and maintenance.

(c) Customer shall pay the cost of any additional facilities required to extend service and the cost of rearranging facilities required to change mounting height.

(d) The cost of any change of location of lamps, from the original location specified by Customer, shall be borne by the Customer and paid to the Company.

(I) Indicates Increase (C) Indicates Change

RATE LED-SL (continued)
LIGHT-EMITTING DIODE STREET LIGHTING SERVICE

(e) Company will provide underground and decorative systems of a type being offered by the Company at the time service is contracted for when the additional cost in excess of the estimated cost of a standard overhead system for the same application is paid by Customer. Company shall take title to this system and shall operate and maintain the facilities. At the termination, for any reason, of the useful life of these systems or designated components, a new system or component shall be installed under similar conditions.

(f) Operation shall be from dusk to dawn, a total of approximately 4,000 hours per year. Lamp renewal service, during normal working hours, will be provided upon notice to Company for lamps burned out or broken and with no credit for outages.

SPECIAL CUSTOMER EQUIPMENT
Upon request, the Company may, at its option, operate and maintain special lighting equipment of a type not being offered by Company provided Customer installs equipment and supplies any nonstandard replacement parts at no cost to Company.

REMOVAL OF MERCURY VAPOR, HIGH PRESSURE SODIUM AND METAL HALIDE
When, at the request of the Customer, a LED light replaces a fully operational mercury vapor, high pressure sodium or metal halide light that has been installed for less than the applicable contract term, the Customer shall pay the Company for the Company's estimated cost of removal and rehabilitation plus the estimated remaining value of the system. When, at the request of the Customer, a LED light replaces a fully operational mercury vapor, high pressure sodium or metal halide light that can neither be repaired nor replaced, the installation will be completed at no charge to the Customer.

TERMINATION
If Customer terminates street lighting service under this schedule for any reason prior to expiration of any 10-year term, Customer shall pay removal cost plus the estimated remaining value of system.

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Section 13, Payment Terms, paragraph 13-f.

RATE LED-CO
CUSTOMER-OWNED LIGHT-EMITTING DIODE STREET LIGHTING SERVICE

AVAILABILITY
This Rate is available to non-residential Customers and municipalities or other public authorities in the entire territory served by the Company for the operation of Light-Emitting Diode (LED) street lighting systems on private or public areas where the Customer wholly owns and installs the street lighting system.

CONTRACT TERM
Ten years and thereafter in accordance with contract provisions, which shall be consistent with this rate schedule and shall be of a standard form provided by and satisfactory to the Company. The contract may be terminated with sixty (60) days' notice prior to expiration period of contract by either party subject to the termination provision below.

NET MONTHLY RATE

Distribution Charge……………..…………………………………………………………………….4.776 (¢/kWh) **(I)**

Customer Charge (Per Lamp)*…..………………………………………………………..………$2.00 per month

* Applicable where, upon Customer election, Company provides operation and maintenance of Customer-owned street lighting system in accordance with the provisions below.

Additional wood pole installed for the sole ....…..$ 5.99 per month
purpose of supporting lighting fixtures or circuits

Distribution and Generation Supply rates will be applied to per kilowatt hour of energy used each month. Service hereunder is unmetered with the number of kWh billed for each size lamp calculated based on the estimated input wattage of the lamp and approximately 4,000 burning hours per year. Rate offering applicable to Customer-owned street lights sized within the standard nominal lamp wattage ranges offered by the Company under Rate Schedule LED-SL, not to exceed 280 nominal lamp wattage. If the Customer-owned street light is of a size outside of the Company's standard size offerings under Rate Schedule LED-SL, but in no event not to exceed 280 nominal lamp wattage, the Customer's kWh billed will be determined based on the next higher nominal lamp wattage range set forth under Rate Schedule LED-SL.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G- Distribution System and Improvement Charge

STANDARD INSTALLATION AND SERVICE
Upon Customer election, the Company shall operate and maintain the Customer-owned street lighting system subject to Customer payment of the monthly Customer charge (per lamp) above.

Customer-owned street lighting equipment shall be installed in accordance with company and industry safety codes and, where installed on Company poles, in accordance with general Company specifications for similar equipment.

Company shall make all connections of Customer's street lighting system to the Company's available general distribution system.

(I) Indicates Increase (C) Indicates Change

RATE LED-CO (continued)
CUSTOMER-OWNED LIGHT-EMITTING DIODE STREET LIGHTING SERVICE

Street Lighting Equipment on Company Wood Pole: The Customer shall own, provide, install, operate and maintain the street lighting luminaire, lamp, control, brackets, ballasts and the wire from the luminaire to the point of connection with the Company's overhead general distribution system. The Company shall provide, install, operate and maintain the wood pole and the overhead secondary wire from Company's general distribution system to the point of connection with Customer's wire. Generally, the Customer will attach its street lighting system to Company's existing poles; but the Company at its option may provide, install, operate and maintain a maximum of one wood pole and one span of secondary conductor to new locations required by the Customer at Customer's expense.

Street Lighting Equipment on Customer Pole or Support: The Customer shall provide, install, operate and maintain the street lighting luminaire, lamp, control, bracket, pole or support, foundation and wire between poles or supports. The Company provides, installs, operates and maintains one span of overhead secondary conductor to a group of street lights, as defined by Company, on Customer-owned poles or supports. The installation by Company in excess of one span of overhead secondary to a group of Customer-owned street lights is at Customer's expense.

Customer-owned street lighting equipment mounted on poles or supports on other utilities with whom Company has joint-use agreements are billed at the rates above.

GENERAL PROVISIONS

(a) Application is limited to Light Emitting Diode (LED) street lights in systems of a minimum of 5 contiguous lamps of one Customer. Customer-owned street lights served hereunder may not be intermixed with street lights served under the Company's other street light rate schedules. The 5 lamp minimum may, at the Company's option, be waived when a Customer desires to take service for its entire street light requirements hereunder and said total requirements is less than the 5 lamp minimum.

(b) The Customer must provide advance written notice to Company at least 90 days for initial systems and 30 days for additions to existing systems of its intentions to install Customer-owned equipment and proposed installation date. In addition, for Customer-owned street lighting proposed for installation on Company's poles the Customer shall provide the construction specifications for Company's approval in advance.

(c) Any non-municipal Customer will be required to demonstrate that it has complied with all municipal requirements pertaining to lighting before being eligible for service under this rate schedule. In addition, before street lighting facilities may be energized, the non-municipal Customer shall provide the Company and the municipality with an inspector's certification that the street lighting facilities are constructed to applicable electrical code requirements and also provide the Company and the municipality with as-built drawings certified by engineering seal of the final placement, configuration, and cut sheets for street light facilities to be energized. The non-municipal Customer shall provide certification to the municipality of continued compliance with the National Electrical Code requirements as required by the municipality.

(d) Written notice of any change in size or type of any components of Customer street lighting system by location is furnished by Customer to Company not more than 14 days after the date of such change. Any rearrangements, replacements or relocations of Company's electric distribution system required solely for the installation, operation or maintenance of Customer's street lighting equipment are at the Customer's expense.

RATE LED-CO (continued)
CUSTOMER-OWNED LIGHT-EMITTING DIODE STREET LIGHTING SERVICE

(e) All luminaires served hereunder are operated at alternating current, 60 hertz, single phase and are controlled by photo control for dusk to dawn operation every night, approximately 4,000 hours per year.

(f) The Attachment Agreement for the Customer-owned lighting system on Company's poles shall include indemnification of Company by Customer and provide for purchase of public liability and property damage insurance by Customer.

REMOVAL OF COMPANY-OWNED LIGHTS
When, at the request of the Customer, a Customer-owned lighting system replaces a fully operational Company-owned mercury vapor, high pressure sodium, metal halide or LED light that has been installed for less than the applicable contract term, the Customer shall pay the Company for the Company's estimated cost of removal and rehabilitation plus the estimated remaining value of the system.

AUDITING
The Company has the right to periodically audit the number and size of lamps of Customer's street lighting system. The Customer agrees to cooperate with Company during such audits.

TERMINATION
If Customer terminates street lighting service under this schedule for any reason prior to expiration of any 10-year term, Customer shall pay removal cost plus the estimated remaining value of system.

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Section 13, Payment Terms, paragraph 13-f.

RATE FCP
FLOOD CONTROL POWER SERVICE

AVAILABILITY
This Rate is available to municipalities and townships in Company's territory requiring power service for the operation of flood pumping stations during periods of public emergency, and for periodic testing of same as hereinafter provided.

CHARACTER OF SERVICE
Alternating current, 60 cycles, three phase, 13,800 volts.

CONTRACT TERM AND BILLING
Term of contract shall be not less than one (1) year, with monthly payments for service taken.

RATE TABLE

	Distribution ($/Month)	Distribution (¢/kWh)	
First 100 kWh or less per month for each electrically driven pump installed	$4.69		
All additional kWh		2.200	**(I)**

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G- Distribution System and Improvement Charge

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Section 13, Payment Terms, paragraph 13-f.

SPECIAL PROVISIONS

(1) The Customer shall own, install, operate and maintain the lines necessary to connect its pumping stations to the Company's existing facilities, and the transforming equipment and auxiliary apparatus necessary to secure voltages less than the supply voltage specified above.
(2) Periodic testing shall be prearranged between the Customer and Company upon at least twenty-four (24) hours' notice to the Company and shall occur on weekdays during the hours between 12 midnight and 6 A.M. unless otherwise justified by load conditions on Company's system, of which conditions the Company's judgment shall be final.
(3) Supply lines at each pumping station shall normally be disconnected and shall be connected only when necessary during periods of public emergency and for periodic testing.

(I) Indicates Increase (C) Indicates Change

RATE BLR
BORDERLINE RESALE SERVICE

AVAILABILITY
Available under reciprocal agreements to neighboring public utilities supplying electric service for resale in territory immediately adjacent to the charter territory of the Company, provided the Company, in its opinion has available capacity over and above that required to meet the demands, present and prospective, for service in its own territory.

CHARACTER OF SERVICE
Alternating current, 60 cycles, single or three phase, 2,400 volts, 4,160 volts, 8,320 volts, or 13,800 volts.

CONTRACT TERM AND BILLING
Standard contracts are for a term of five (5) years with monthly payments for service taken.

RATE TABLE
Service will be provided under the appropriate Company Tariff Rate. The appropriate rate is that under which the Customer would be served if they were located within the Company's franchised service territory.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider F - Power Factor Surcharge
Rider G- Distribution System and Improvement Charge

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Section 13, Payment Terms, paragraph 13-f.

POWER FACTOR
The Power Factor Charge contained in this Tariff is applied to this Rate.

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UGI ELECTRIC EXHIBIT F
CURRENT TARIFF

ELECTRIC GENERATION SUPPLIER
COORDINATION TARIFF - PA P.U.C. NO. 2S

UGI UTILITIES, INC. – ELECTRIC DIVISION

ELECTRIC GENERATION SUPPLIER COORDINATION TARIFF

Issued: November 8, 2021

Effective on and after November 9, 2021; filed in Compliance with the Order of the Pennsylvania Public Utility Commission, entered on October 28, 2021 at Docket No. R-2021-3023618.

Issued by:
Paul J. Szykman
Chief Regulatory Officer
1 UGI Drive
Denver, PA 17517

NOTICE

https://www.ugi.com/tariffs

This tariff makes Changes to existing rules and regulations (see page 2).

LIST OF CHANGES MADE BY THIS TARIFF
(Page Numbers Refer to Official Tariff)

Cover Page
- The issue and effective dates have been updated.
- The supplement number has been updated.

Definition of Terms and Explanation of Abbreviations, Pages 5 and 7.
- Definition of Tariff referenced the incorrect tariff number.
- Definition of Price to Compare ("PTC") has been added.

Rule 3 – Commencement of EDC/EGS Coordination, Pages 10-11.
- Subsection 3.2 language has been updated to address incomplete registrations.
- Subsection 3.7 – Rejection of Registration has been eliminated and included in subsection 3.5.
- The remaining subsections have been renumbered.

Rule 4 – Coordination Obligations, Page 13.
- Subsection 4.11- Communication Requirements has been revised to include the defined term Electronic Data Exchange Working Group ("EDEWG").
- Subsection 4.14(a) has been revised to reference ("EDEWG").

Rule 5 – Direct Access Procedures, Page 18.
- Subsection 5.6(a) has been revised to reference the definition ("PTC").

Rule 11 – Meter Reading and Meter Data, Page 26.
- Subsection 11.1, Meter Read Schedule has been revised to a revolving 22-day work cycle.

Riders:

1 – Individual Coordination Agreement, Pages 39-42.
- Changed title on each page of the Agreement.
- Changes to fax/email instructions.
- Changes to notification contact information.

2 – Scheduling Coordinator Designation Form, Pages 43-46.
- Minor changes to the formatting of the form.

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DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS

Active Load Management - the process for arranging to have firm load become interruptible in accordance with criteria established by the PJM OI.

Appropriate Similar Day - hourly forecasted load comparable based on week day, month, season, and weather.

Bad Credit - an EGS has bad credit if it is insolvent (as evidenced by a credit report prepared by a reputable credit bureau or credit reporting agency or public financial data, liabilities exceeding assets or generally failing to pay debts as they become due) or has failed to pay Company invoices when they became due on two or more occasions within the last twelve billing cycles.

Charge - any fee or charge that is billable by the Company to an EGS under this Tariff, including any Coordination Services Charge.

Competition Act - the Electricity Generation Customer Choice and Competition Act, 66 Pa. C.S. §2801, et seq.

Competitive Energy Supply - unbundled energy and/or capacity provided by an Electric Generation Supplier.

Coordination Activities - all activities related to the provision of Coordination Services.

Coordination Obligations - all obligations identified in Rule 4 of the Tariff, relating to the provision of Coordination Services.

Coordination Services - those services that permit the type of interface and coordination between EGSs and the Company in connection with the delivery of Competitive Energy Supply to serve Customers located within the Company's service territory, including: load forecasting, certain scheduling-related functions and reconciliation

Coordination Services Charges - all Charges stated in this Tariff that are billed by the Company for Coordination Services performed hereunder.

Coordinated Supplier - an Electric Generation Supplier that has appointed a Scheduling Coordinator as its designated agent for the purpose of submitting energy schedules to the PJM OI.

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS (continued)

Creditworthy - a creditworthy EGS pays the Company's charges as and when due and otherwise complies with the Rules and Regulations of this Tariff or the Commission. To determine whether an EGS is creditworthy, the Company will evaluate the EGS's record of paying Company charges and may also take into consideration the EGS's credit.

Customer - any person, partnership, association, or corporation receiving Competitive Energy Supply from an Electric Generation Supplier in accordance with the Competition Act.

Deliver - to "Deliver" a document or other item under this Tariff shall mean to tender by certified mail, hand delivery, or overnight express package delivery service.

Direct Access - "Direct Access" shall have the meaning set forth in the Competition Act.

EDC Tariff - the Company's Electric Service Tariff, denominated Electric Pa. P.U.C. No. 6. **(C)**

Electric Distribution Company or "EDC" - a public utility that owns electric distribution facilities. At times, this term is used to refer to the role of the Company as a deliverer of Competitive Energy Supply in a Direct Access environment as contemplated in the Competition Act.

Electric Generation Supplier or "EGS" - a supplier of electric generation that has been certified or licensed by the Pennsylvania Public Utility Commission to sell electricity to retail customers within the Commonwealth of Pennsylvania in accordance with the Competition Act.

EGS Representative - any officer, director, employee, consultant, contractor, or other agent or representative of an EGS in connection with the EGS's activity solely as an EGS. To the extent an EGS is a division or group of a company, the term EGS Representative does not include any person in that company who is not part of the EGS division.

EDEWG - the Commission's Electronic Data Exchange Working Group.

FERC - the Federal Energy Regulatory Commission.

Hourly or Sub-Hourly Metering Equipment - metering equipment that supplies half-hourly readings of kW and power factor via remote communications, and not metering equipment from which half-hourly or hourly demand readings may be obtained through on-site querying of the metering equipment.

Interest Index - an annual interest rate determined by the average of 1-Year Treasury Bills for September, October and November of the previous year.

(C) Indicates Change

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS (continued)

Kilowatt or kW - unit of measurement of useful power equivalent to 1000 watts.

Load Serving Entity or "LSE" - an entity that has been granted the authority or has an obligation pursuant to State or local law, regulation or franchise to sell electric energy to end-users located within the PJM Control Area.

Locational Marginal Price or "LMP" - the hourly integrated marginal price to serve load at individual locations throughout PJM, calculated by the PJM OI as specified in the PJM Open Access Transmission Tariff.

Megawatt or MW - one thousand kilowatts.

Meter Read Date - the date on which the Company schedules a meter to be read for purposes of producing a customer bill in accordance with the regularly scheduled billing cycles of the Company.

Month - a month under this Tariff means 1/12 of a year, or the period of approximately 30 days between two regular consecutive readings of the Company's meter or meters installed on the customer's premises.

Network Integration Transmission Service Reservation - a reservation under the PJM Tariff of Network Integration Transmission Service, which allows a transmission customer to integrate and economically dispatch generation resources located at one or more points in the PJM Control Area to serve its Network load therein.

Commission - The Pennsylvania Public Utility Commission.

The Company - UGI Utilities, Inc. - Electric Division

PJM - the Pennsylvania-New Jersey-Maryland Interconnection.

PJM Control Area - that certain Control Area encompassing systems in Pennsylvania, New Jersey, Maryland, Delaware and the District of Columbia and which is recognized by the North American Electric Reliability Council as the "PJM Control Area."

PJM InSchedule System - software program administered by the PJM OI through which energy load schedules may be submitted., or any successor system.

PJM OI - the PJM Office of Interconnection, the system operator for the PJM Control Area.

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS (continued)

PJM Tariff - the PJM Open Access Transmission Tariff on file with the FERC and which sets forth the rates, terms and conditions of transmission service over transmission facilities located in the PJM Control Area.

PLR Service - Provider of Last Resort Service.

Price to Compare or "PTC" – the dollar amount charged by the Company, used by customers to compare prices with those offered by Electric Generation Suppliers. **(C)**

Scheduling Coordinator - an entity that performs one or more of an EGS's Coordination Obligations, including the submission of energy schedules to the PJM OI, and that either is (1) a member of the PJM Interconnection, L.L.C. or (2) is the agent, for scheduling purposes, of one or more Electric Generation Suppliers that are members of the PJM Interconnection, L.L.C.

Tariff - this Electric Generation Supplier Coordination Tariff.

(C) Indicates Change

RULES AND REGULATIONS

1. THE TARIFF

1.1 Filing and Posting. A copy of this Tariff, which comprises the Charges, Rules, and Regulations and Riders under which the Company will provide coordination Services to EGSs, is on file with the Commission and is posted and open to inspection at the offices of the Company.

1.2 Revisions. This Tariff may be revised, amended, supplemented, or otherwise changed from time to time in accordance with the Pennsylvania Public Utility Code, and such changes, when effective, shall have the same force as the present Tariff.

1.3 Application. The Tariff provisions apply to all EGSs providing Competitive Energy Supply to Customers located in the Company's service territory including an affiliate or division of the Company that provides Competitive Energy Supply, and with whom the Company has executed an Individual Coordination Agreement as required herein. In addition, the Charges herein shall apply to anyone receiving service unlawfully or to any unauthorized or fraudulent receipt of Coordination Services.

1.4 Rules and Regulations. The Rules and Regulations, filed as part of this Tariff, are a part of every Individual Coordination Agreement entered into by the Company pursuant to this Tariff and govern all Coordination Activities, unless specifically modified by a Charge or Rider provision. The obligation imposed by EGSs in the Rules and Regulations shall apply as well to everyone receiving service unlawfully or to any unauthorized or fraudulent receipt of Coordination Services.

1.5 Use of Riders. The terms governing the supply of Coordination Services under this Tariff or a Charge therein may be modified or amended only by the application of those standard Riders, filed as part of this Tariff.

1.6 Statement by Agents. No Company representative has authority to modify a Tariff rule or provision, or to bind the Company by any promise or representation contrary thereto.

RULES AND REGULATIONS (continued)

2. SCOPE AND PURPOSE OF TARIFF

2.1 Scope And Purpose Of Tariff. This Tariff establishes rules for EGSs seeking to deliver competitive energy supply to Customers using the Company's electric distribution facilities.

2.2 Applicability of Terms to Scheduling Coordinators. As used in this Tariff, the term EGS shall apply equally to a Scheduling Coordinator for an EGS's responsibilities and rights properly assigned to the Scheduling Coordinator by the EGS.

2.3 FERC Jurisdictional Matters. The inclusion of FERC jurisdictional matters within the scope of this Tariff is intended solely for informational purposes and is not intended to accord any jurisdictional authority over such matters to the Commission. Further, to the extent anything stated herein conflicts or is inconsistent with any provision of the Federal Power Act, or any rule, regulation, order or determination of the FERC under the Federal Power Act, then such FERC rule, regulation, order or determination or provision of the Federal Power Act shall control. To the extent required under any provision of the Federal Power Act, or any rule, regulation, order or determination of the FERC under the Federal Power Act, the Company shall secure, from time to time, all orders, approvals and determinations from the FERC necessary to implement this Tariff.

RULES AND REGULATIONS (continued)

3. COMMENCEMENT OF EDC/EGS COORDINATION

3.1 **Registration.** An EGS seeking to deliver competitive energy supply through the Company's electric distribution facilities must provide the Company with the following registration information in addition to signing a confidentiality agreement associated with the customer information available to an EGS through the Company's Internet Web page:

(a) written evidence that the EGS or, to the extent applicable, its Scheduling Coordinator, is a signatory to the Operating Agreement and Reliability Assurance Agreement of the PJM Interconnection, L.L.C., or their successors, if any;

(b) the EGS's Pennsylvania sales tax identification number;

(c) an individual Coordination Agreement, as contained in a Rider hereto, fully executed by an authorized representative of the EGS and Scheduling Coordination Designation form, if applicable; and

(d) the name, mailing address, telephone number, fax number, and e-mail address of the EGS's contact person,

(e) evidence that the EGS is a Pennsylvania Commission licensed supplier; and,

(f) an Electronic Data Interchange (EDI) Trading Partner Agreement, fully executed by an authorized representative of the EGS; and,

(g) a Choice Supplier Profile form and a current W-9; and,

(h) a completed Trading Partner Worksheet; and,

(i) payment of applicable registration fee.

3.2 **Incomplete Registrations.** In the event the EGS submits an incomplete registration, the Company shall provide written notice to the EGS of the registration's deficiencies within ten (10) business days after the date of service, as determined under 52 Pa. Code § 1.56, of the registration. An incomplete registration will not be processed by the Company until it is **(C)** completed by the EGS and provided to the Company.

3.3 **Credit Check.** A registration for Coordination Services shall constitute authorization to the Company to conduct a background credit check on the EGS.

3.4 **Processing of Registrations.** The Company shall complete the processing of each registration within ten (10) business days after the date of service of the registration, as determined under 52 Pa. Code § 1.56. The Company shall approve all completed registrations unless grounds for rejecting the registration, as defined below, exist.

(C) Indicates Change

RULES AND REGULATIONS (continued)

3. COMMENCEMENT OF EDC/EGS COORDINATION

3.5 Rejection of Registrations. The Company may reject any registration for any of the following reasons:

(a) the EGS has undisputed outstanding debts to the Company arising from its previous receipt of services from the Company under this Tariff;

(b) the EGS has failed to submit a corrected registration within thirty (30) calendar days after the date of service of the registration, as determined under 52 Pa. Code § 1.56, of written notice of the registration's deficiency; or

(c) the EGS has not obtained a license from the Commission to provide electric generation services, or such license is suspended or revoked;

(d) the EGS has failed to comply with credit requirements specified in Rule 12 of the Tariff.

Upon rejection of any registration, the Company shall provide the affected EGS with written notice of rejection within ten (10) business days, explaining why the registration was rejected. **(C)**

The Company may also petition the Pa PUC to reject the registration of an EGS with Bad Credit. The Company need not provide Coordination Services to the EGS pending the Pa PUC's review of said Petition unless the EGS has provided security to the Company as provided for in Rule 12.4.

3.6 Offer of Conditional Acceptance of Registration. Where grounds for rejection of a registration exist due to an EGS's outstanding and undisputed debts to the Company arising from its previous receipt of services under this Tariff, the Company may accept a registration conditionally if the EGS pays such debts before it receives service. If the EGS rejects the Company's offer of conditional acceptance under this Rule, then its registration will be deemed rejected.

3.7 Identification Numbers. Upon its approval of a registration, the Company shall assign and provide to the EGS a Supplier ID and Password that will allow the EGS to gain access to pertinent customer information available on the Company's Internet Web Site. **(C)**

3.8 Commencement of Coordination Services. Coordination services shall commence within fifteen (15) days after the Company's acceptance of an EGS's registration for Coordination Services provided that all of the information necessary for the Company to provide Coordination Services has been provided to the Company and any conditions required under Rule 3.6 have been satisfied by the EGS.

(C) Indicates Change

RULES AND REGULATIONS (continued)

4. COORDINATION OBLIGATIONS

4.1 **Provision of Coordination Services.** The Company shall provide all coordination services, as provided herein, necessary for the delivery of an EGS's energy and/or capacity to serve retail access load located within the Company's service territory.

4.2 **Timeliness and Due Diligence.** EGSs shall exercise due diligence in meeting their obligations and deadlines under this Tariff so as to facilitate Direct Access.

4.3 **Duty of Cooperation.** The Company and each EGS shall cooperate in order to ensure delivery of Competitive Energy Supply to Customers as provided for by this Tariff, the EDC Tariff and the Competition Act.

4.4 **State Licensing.** An EGS must have and maintain in good standing a license from the Commission as an authorized EGS.

4.5 **Energy Procurement.** An EGS must make all necessary arrangements for obtaining Competitive Energy Supply in a quantity sufficient to serve its Customers.

4.6 **PJM Services and Obligations.** An EGS is responsible for procuring those services provided by the PJM OI that are necessary for the delivery of Competitive Energy Supply to its Customers. In addition, an EGS must satisfy all obligations which are imposed on LSEs in the PJM Control Area.

4.7 **Energy Scheduling.** An EGS must make all necessary arrangements for scheduling the delivery of energy through the PJM OI.

4.8 **Reliability Requirements.** An EGS shall satisfy those reliability requirements issued by the Commission, or any other governing reliability council with authority over the EGS, that apply to EGSs.

4.9 **Determination of Load and Location.** The Company and EGS shall coordinate with the PJM OI to determine the magnitude and location of the EGS's actual or projected load, as required by the PJM OI, for the purpose of calculating a Network Integration Transmission Service Reservation, an installed capacity obligation, or other requirements under the PJM Tariff.

4.10 **Supply of Data.** An EGS and the Company shall supply to the other all readily available data, materials or other information specified in this Tariff, or otherwise reasonably required by the EGS or Company in connection with the provision of services, in a thorough and timely manner.

RULES AND REGULATIONS (continued)

4. COORDINATION OBLIGATIONS

4.11 Communication Requirements. An EGS must be equipped with the communication capabilities that will allow it to meet the electronic data exchange standards established by the Commission's Electronic Data Exchange Working Group ("EDEWG") in their report entitled "Electronic Data Exchange Standards for Electric Deregulation in the Commonwealth of Pennsylvania" and any subsequent Commission approved revisions to this report or other Commission orders. **(C)**

4.12 Record Retention. An EGS and the Company shall comply with all applicable laws and Pa. PUC rules and regulations for record retention, including but not limited to those Rules of Chapter 56 of the Pa. PUC's regulations.

4.13 Payment Obligation. The Company's provision of service to an EGS is contingent upon the EGS's payment of all charges provided for in this Tariff.

4.14 Data Exchange.

(a) The Company shall make available to an EGS the information regarding that EGS's Customers via EDI transactions. These transactions will conform to specific standards set forth in the Revised Plan. The Revised Plan was developed by the EDEWG that is formally recognized and authorized to maintain such Plan by the Commission. **(C)**

(b) An EGS must notify its Customers that by signing up for competitive energy supply with the EGS, the Customer is consenting to the disclosure by the Company to the EGS of certain basic information about the Customer.

(c) Nothing in this Rule shall prohibit the Company from making available to EGSs other electronic data, in formats chosen by the Company. The Company will not change the file formats of the electronic data made available under this Rule without first providing via Internet electronic mail and posting on its web site at least seven (7) days' notice of such change. The Company will make a good faith effort to provide a greater period of notice when warranted.

(d) If an EGS wishes to obtain from the Company confidential Customer-specific information about a Customer with whom it is discussing the possibility of providing Competitive Energy Supply, the Company will only provide such information if the EGS provides to the Company a copy of written documentation indicating that the Customer has authorized the release of Customer information to the EGS.

(C) Indicates Change

RULES AND REGULATIONS (continued)

4. COORDINATION OBLIGATIONS

4.15 Codes of Conduct. Prior to the Commission's adoption of a generic Code of Conduct the Code of Conduct contained in the Company's Settlement Appendix B are incorporated herein by reference.

4.16 Standards of Conduct and Disclosure for Licensed EGSs. The Commission's Standards of Conduct and Disclosure for Licensees are incorporated herein by reference.

RULES AND REGULATIONS (continued)

5. DIRECT ACCESS PROCEDURES

5.1 Customer Enrollment. The selection of Customers eligible to obtain Competitive Energy Supply shall occur in accordance with the Commission's applicable Orders and Regulations.

(a) Provision of Customer Lists - The Company shall provide to all properly registered EGSs a complete list of all Customer information in electronic format via the Company's website. Said list shall be provided electronically, without charge, to registered EGSs on a monthly basis. Said list shall include, at a minimum, the information outlined in Rule 5.1(b).

(b) Data Exchange

(1) The list of enrolled Customers that the Company provides to all EGSs pursuant to Rule 5.1(a) shall contain, at a minimum, the following information about Customers that have consented to the release of Customer information:

(i) Account number
(ii) Customer Name
(iii) Service Address
(iv) Mailing Address
(v) Telephone Number (if authorized by Customer)
(vi) Meter Reading Cycle
(vii) Rate Code
(viii) Strata - Profile Group (if applicable)
(ix) Registered Peak Demand (if available and authorized by Customer)
(x) 12 Month's Historic Usage Data and the number of months represented by this total (if authorized by Customer)
(xi) Eligibility Date

(2) The list of enrolled Customers that the Company provides to all EGSs pursuant to Rule 5.1(a) above, shall contain the following information about Customers that have restricted the release of load data.

(i) Name, address, and Company Account Number
(ii) Rate Class

(3) Customers who restrict the release of all of their account information shall not be included in the above described Customer list.

RULES AND REGULATIONS (continued)

5. DIRECT ACCESS PROCEDURES

(c) Record of Customer Consent - An EGS that enrolls a Customer in accordance with Rule 5.1(a) of this Tariff must ask the Customer whether the Customer consents to the disclosure, to all EGSs by the Company, of confidential Customer specific information (i.e. telephone number and usage data). The EGS must retain a record indicating that the Customer was made aware of this disclosure. If the record is in an electronic form the EGS must be able to print or otherwise reproduce the record.

5.2 Switching Among EGSs or an Initial Selection of an EGS

(a) If a Customer contacts a new EGS to request a change of EGSs and the new EGS agrees to serve the Customer, the Customer's new EGS shall obtain appropriate authorization from the Customer or person authorized to act on the Customer's behalf indicating the Customer's choice of EGS. The authorization shall include the Customer's acknowledgment that the Customer has received the notice required by Rule 5.1(c). It is the EGS's responsibility to maintain records of the Customer's authorization in the event of a dispute, in order to provide documented evidence of authorization to the Company or the Commission.

(b) The Customer's new EGS shall submit the Customer's information to the Company electronically. This file's form and content shall comply with the data exchange standards established by the EDEWG and approved by the Commission. The Company shall confirm receipt of the file upon receiving it from the EGS. Within one (1) business days of receipt of the electronic file the Company will validate the records contained in the file and will provide an electronic validation including the number of records received and the reasons for any rejections. Such validation shall be prepared in accordance with the data exchange standards established by the EDEWG and approved by the Commission, and shall include appropriate control totals such as the number of records received and the reason(s) for any rejections. Such validation shall also include information an EGS can use to identify rejected records.

(c) The Company will send the Customer a confirmation letter before the end of the next business day after the Company’s receipt of valid notification of a Customer switch from the new EGS notifying the Customer of the switch. The selection will be effective 3 business days after the enrollment request is processed.

RULES AND REGULATIONS (continued)

5. DIRECT ACCESS PROCEDURES

(d) Once the preceding process is complete, the Company will notify the Customer's prior EGS electronically of the discontinuance of service by the Customer and the date of discontinuance of service. Such electronic notification shall be provided in accordance with the data exchange standards established by the EDEWG and approved by the Commission.

5.3 Customer Switching Back to the Company from an EGS

If a Customer contacts the Company to request a change of EGS to the Company's tariffed Energy and Capacity Charges for Default PLR Service, the request will be effective 3 business days after the customer's request is processed and the Company as the Provider-of-Last Resort will become the supplier of record for delivery. The Company will send the Customer a confirmation letter before the end of the next business day confirming the customer's choice to return to Default PLR Service. Once the preceding process is complete, the Company will notify the Customer's prior EGS, via an EDI transaction, of the discontinuance of service to the Customer from that prior EGS.

5.4 Customer Relocations

(a) If a Customer contacts the Company to discontinue electric service at the Customer's then current location, and initiates a request for service at a new location in the Company's service territory, the Company will notify the current EGS, via an EDI transaction, of the Customer's discontinuance of service for the account at the Customer's old location. If relocating within the Company's service territory, the Company will seamlessly move the current EGS to the new location if all qualifications are met in accordance with PUC Order M-2014-2401126.

(b) If a Customer contacts the Company to discontinue electric service and indicates that they will be relocating outside of the Company's service territory the Company will notify the Customer's current EGS of the discontinuance in accordance with the data exchange standards established by the EDEWG and approved by the Commission.

RULES AND REGULATIONS (continued)

5. DIRECT ACCESS PROCEDURES

5.5 Provisions Relating to an EGS's Customers

(a) Arrangements with EGS Customers - EGSs shall be solely responsible for having appropriate contractual or other arrangements with their Customers necessary to implement Direct Access consistent with all applicable laws, Commission requirements, and this Tariff. The Company shall not be responsible for monitoring, reviewing or enforcing such contracts or arrangements.

(b) Transfer of Cost Obligations Between EGSs and Customers - Nothing in this Tariff is intended to prevent an EGS and a Customer from agreeing to reallocate between them any charges that this Tariff imposes on the EGS, provided that any such agreement shall not change in any way the EGS's obligation to pay such charges to the Company, and that any such agreement shall not confer upon the Company any right to seek recourse directly from the EGS's Customer for any charges owed to the Company by the EGS.

5.6 Standard Offer Customer Referral Program (“SO Program”)

(a) Under the Company’s SO Program, participating EGSs agree to offer residential or small commercial customers a 7% discount off of the then current PTC for a twelve (12) month period. **(C)**

(b) The Company shall transfer customers who express an interest in the SO Program to each participating EGS in a fair and impartial manner. Each participating EGS is responsible for enrolling customers who wish to participate in the SO Program. Participating EGSs shall reimburse the Company for the costs to operate the program of $12,000 per month. This charge shall be divided equally based on the number of participating EGSs each month.

(C) Indicates Change

RULES AND REGULATIONS (continued)

6. LOAD FORECASTING

6.1 Customer Load Forecasting. The Company, in conjunction with an EGS, shall perform a Customer load forecasting process for each EGS's load requirements which shall estimate an EGS's anticipated aggregate hourly Customer load. The aggregate hourly load forecast shall define the hourly energy requirements for an EGS. Energy will be delivered to the Company's electric distribution system using the PJM power scheduling policies and procedures.

6.2 Forecasting Methodology.

(a) Customer Forecasts - For each EGS, the Company shall provide hourly load forecasts, for their monthly metered Customers as well as their Customers with Hourly or Sub-Hourly Metering Equipment.

The Company shall develop and maintain, based on load survey data, load forecasting categories corresponding to various Company Customer Groups. The average load curves for these Customer Groups shall be the basis for preparing the aggregate hourly load forecasts for the EGS's monthly metered Customers.

(b) Typical Load Curve Data - The Company will make available to EGSs the average hourly load survey data for each monthly metered survey group. This information will be available on an on-going basis for an EGS to download from the Company's web-site.

(c) Update to Typical Load Curve Data - The Company shall review annually its methodology, algorithms and load forecasting results and shall perform additional load studies to update the load curve data as required.

(d) Daily Forecasting Process

(1) Business Days and Scheduling Window - A daily forecast shall be performed for each business day. A business day is a weekday excepting Company holidays. The daily forecasting process shall be performed for each business day for a scheduling window consisting of all following days through the next business day.

For example, the forecasting process shall be performed for Monday through Thursday (except holidays) for a scheduling window that covers the following day (midnight to midnight). If the following day is a holiday, then the scheduling window shall include the holiday and be extended to

RULES AND REGULATIONS (continued)

6. LOAD FORECASTING

include the first business day following the holiday. Similarly, the forecasting process shall be performed on Friday for a scheduling window consisting of the following Saturday, Sunday, and Monday. If the Monday is a holiday, then the scheduling window shall include the holiday and extend through the first business day following the holiday.

(2) Process Description for Forecasting - The Company will calculate each EGS's load forecast for each monthly metered Customer Group and strata by multiplying the weather-adjusted load curve for the appropriate day type by the number of an EGS's Customers (including Customers of any Coordinated Suppliers that have a designated EGS as their Scheduling Coordinator) in that Customer Group and strata. Added to this total, for each EGS, will be the forecast for each of that EGSs hourly or sub-hourly metered customers. The resulting hourly totals will be adjusted upward by 6.5% to cover line losses. This forecast will be the basis for the Company's daily posting to the PJM InSchedule as described in Rule 7.4.

6.3 Split Load Service

(a) Partial Service by the Company Prohibited - Except as provided in Section 6.3 (b)Customer purchasing Competitive Energy Supply from an EGS may not simultaneously purchase energy or capacity from the Company.

(b) Purchase of Energy and Capacity from More than One EGS

(1) General Rule - Customers may choose to be supplied with Competitive Energy Supply from more than one EGS ("Split Load Service"). Customers or their EGSs will be responsible to the Company for any additional costs the Company incurs that result from a Customer obtaining Split Load Service. When one or more of the EGSs serving the Customer fails to fulfill its obligation to provide Competitive Energy Supply, the Customer shall receive generation and transmission service for such load from the Company. However, in order for the Customer to continue to receive service from the Customer's other supplying EGSs, the Customer must arrange for a replacement for the non-supplying EGSs by the end of the second full billing cycle after the Customer receives notice of the failure to supply. If, by that time, the Customer has not replaced the non-supplying EGSs, the Customer must either discontinue receiving service from the Company or receive service from the Company for all of its load.

RULES AND REGULATIONS (continued)

6. LOAD FORECASTING

(2) Nature of Split Load Service - Split Load Service will be available starting with the first full billing cycle in the year 2000. Only Customers served under Company Rate Schedules LP and HTP shall be eligible for Split Load Service. A Customer who receives Split Load Service must have a lead EGS that will act as a Scheduling Coordinator, as defined herein, for the other EGSs serving the Customer.

RULES AND REGULATIONS (continued)

7. LOAD AND CAPACITY SCHEDULING

7.1 Net Load Schedules. Subject to the provisions of Section 7.2, the net load schedule for an EGS shall be equal to the aggregate forecast value for all of the monthly metered and hourly metered Customers of that EGS and any Coordinated Suppliers that have designated the EGS as their Scheduling Coordinator adjusted by 6.5% to cover line losses.

7.2 Rounding to Whole Megawatts. So long as the PJM OI or its successor requires the scheduling and delivery of power in increments ("Increment") greater than those measured by those used to measure Customer usage, the Company shall round the aggregate forecast value for each hour to the nearest whole Increment a whole MW value for load scheduling purposes.

7.3 Installed Capacity Schedules. The Company shall upload any information required by PJM to calculate the installed capacity obligation of each EGS according to PJM requirements.

7.4 Daily Load Scheduling Process.

(a) Uploading Schedules - The Company shall upload the load schedule for the scheduling window to PJM by 9 AM Eastern Prevailing Time on each business day using the PJM InSchedule System according to PJM requirements. The schedule uploaded by the Company shall serve as the default schedule, and said default schedule shall be binding on that EGS as if it had confirmed it as is.

RULES AND REGULATIONS (continued)

8. MONTHLY SYSTEM SUPPLY/USAGE RECONCILIATION AND BALANCING

8.1 General Description. Reconciliation service accounts for mismatches between an EGS's load schedule (with PJM approved load schedule changes) for serving its Customers and the energy that was actually used by those Customers. This service differs from Energy Imbalance Service - a related service performed exclusively by the PJM OI under the PJM Tariff - in that the latter accounts for differences between an EGS's scheduled energy obligation and the quantity of energy actually delivered by the EGS. The calculation of reconciliation quantities shall occur after the monthly reading of a Customer's meter. The energy is reconciled on a two (2) month lag.

8.2 Billing. The Company and the EGS will rely on PJM to perform calculations to determine the monetary value of reconciliation quantities, and to bill and/or credit EGSs or Scheduling Coordinators at an hourly price through the PJM grid accounting system.

8.3 Company's Role. The Company shall assist PJM in accounting for reconciliation quantities by (1) collecting or calculating all hourly customer usage data for those Customers being served by an EGS; (2) determining hourly aggregate reconciliation quantities for each EGS or Scheduling Coordinator; and (3) submitting the reconciliation quantities to PJM OI.

8.4 Monthly Reconciliation. The reconciliation calculations shall be completed and filed with PJM by the 60th day after a calendar month.

The reconciliation calculation will be performed as follows:

Step 1: On the completion of the meter reads for the month, a monthly metered Customer's actual usage for the month shall be used to adjust the Customer's corresponding load profile curve to reflect the Customer's monthly kWh metered usage. Each hour's consumption shall then be increased by a loss factor of 6.5%, to determine the Customer's gross usage by hour for the calendar month. Each hourly metered Customer's data shall also be multiplied by a 6.5% loss factor to determine gross hourly usage.

Step 2: The Company will gross usage up at the EGS level.

Step 3: The hourly reconciliation quantity shall then be determined by subtracting the EGS's total hourly load from the scheduled hourly load from the PJM InSchedule.

Step 4: The results shall then be submitted to PJM for billing.

RULES AND REGULATIONS (continued)

9. UTILIZATION OF SCHEDULING COORDINATORS

9.1 Participation Through a Scheduling Coordinator. If an EGS chooses not to interact directly with PJM for scheduling purposes, an EGS may become a Coordinated Supplier by entering into a business arrangement with another EGS or other person that shall act as a Scheduling Coordinator. A Coordinated Supplier may enter into this business arrangement with a Scheduling Coordinator(s) for an individual service such as load scheduling, or for a variety of services encompassing installed capacity, import capability, load scheduling, and reconciliation rights and responsibilities. To the extent it is responsible for the following activities, the Scheduling Coordinator's transmission service obligation, installed capacity obligation, import capability, load scheduling and reconciliation rights and responsibilities shall include its own Customers and the Customers of its Coordinated Suppliers. All actions of the Scheduling Coordinator that relate to one of its Coordinated Suppliers are binding on, and attributable to, said Coordinated Supplier.

9.2 Designation of a Scheduling Coordinator. To designate a Scheduling Coordinator, an EGS must provide the Company with a completed Scheduling Coordinator Designation Form, included as a Rider hereto, executed fully by both the EGS and the Scheduling Coordinator. The Scheduling Coordinator Designation Form is not intended to supplement or replace any agency contract between an EGS and a Scheduling Coordinator.

9.3 Change in or Termination of Scheduling Coordinator. To change a Scheduling Coordinator, or cease using a Scheduling Coordinator, an EGS shall notify the Company in writing, and said notice shall specify the effective month of the change or termination. The effective day of the change or termination shall be the first day of the month indicated in the notification letter unless notification is received by the Company less than ten business days before the first day of that month, in which case the effective day of the change shall be the first day of the subsequent month. In the event an EGS ceases using a Scheduling Coordinator, an EGS shall immediately resume the direct performance of all EGS obligations under this Tariff.

9.4 Load Scheduling through a Scheduling Coordinator. Coordinated Suppliers cannot submit individual load schedules to the PJM OI, nor can Coordinated Suppliers propose scheduling changes on an individual basis. Rather, the Scheduling Coordinator is responsible for submitting all schedules and changes thereto on behalf of itself as well as its Coordinated Suppliers.

9.5 Primary Obligations of a Coordinated Supplier. Notwithstanding their designations of Scheduling Coordinators, each and every EGS remains primarily responsible for fully satisfying the requirements of this Tariff.

RULES AND REGULATIONS (continued)

10. METER INSTALLATION

10.1 Meters Supplied by Company. The Company shall furnish, install, maintain and own the meter, transformer or transformers, required for measurement of the service supplied.

10.2 Capacity of Company's Meters. The meters, transformers, service connections and equipment supplied by the Company for each Customer have a definite load capacity and no additions to the equipment or load connected thereto will be allowed except by the consent of the Company.

10.3 Right to Remove Company's Equipment. All meters, transformers or other equipment supplied by the Company shall remain its exclusive property. The Company shall have the right to remove all its property from the premises of the Customer at any time after the termination of service, whatever may have been the reason for such termination.

RULES AND REGULATIONS (continued)

11. METER READING AND METERING DATA

11.1 Meter Reading Schedule. The Company's annual meter reading schedule shall be posted to its web site. The Company currently provides that each electric meter in the Company's service territory shall be read by a Company meter reader on a revolving 22-day work cycle. **(C)**

11.2 Estimated Meter Readings. Nothing in Rule 11.1 prohibits the Company from estimating a Customer's monthly electric consumption. Such estimates are calculated using historic customer usage data along with applicable weather information when appropriate.

11.3 EGS Requested Meter Readings. An EGS may request that the Company obtain an actual meter reading when the Company has estimated a Customer's monthly electric consumption. An EGS may also request the Company re-read a Customer's meter to verify a previously provided meter reading. Requests to obtain an actual meter reading or to re-read a Customer's meter will be scheduled, as time permits, by the Company. The EGS will be assessed a charge of $28 per meter reading attempt if the reading(s) is obtained during normal working hours. Normal working hours are defined as 8 AM through 5:00 PM Monday through Friday, excluding Company holidays. If the EGS requests the Company to obtain this meter reading outside of normal working hours, the EGS shall be assessed a charge of $108 per meter reading attempt.

11.4 Customer Usage Information/Load Data. The Company shall fulfill, with Customer consent only, a request for Customer usage information or load data that is readily available on its customer information system once per year at no charge. The information provided will be limited to the most recent 12-month period. The Company will, however, provide additional available Customer load data, with the Customer's consent, at a charge of $3.58 per customer per month of data provided.

(C) Indicates Change

RULES AND REGULATIONS (continued)

12. PAYMENT AND BILLING

12.1 Customer Billing by the Company. All EGS charges to Customers, billed by the Company, shall be billed in accordance with applicable Commission Orders including, the Commission's Final Rulemaking Order at Docket No. L-00970126 (Customer Information Disclosure for Electricity Providers), and the following provisions:

(a) Company Billing for the EGS - The Company shall offer billing service to those EGSs who provide the Company with their rate plans. EGSs opting not to provide their rate information to the Company shall bill their Customers directly for the services they provide.

The Company shall bill rate plans offered by the EGS which are based on fixed and variable charges similar to those the Company employs for billing distribution service and default provider of last resort services. The Company shall have the sole discretion over whether or not it can bill an EGS rate plan.

(b) Billing Files - In those cases where the Company is billing for an EGS, it shall electronically transmit to the EGS the Customer's meter reading and billing information, once the account has been billed. This transmittal will be formatted and contain data in accordance with the data exchange standards established by the EDEWG, and approved by the Commission. If the Company is not billing for an EGS it shall electronically transmit to the EGS the meter indexes and related information of its Customers on a schedule consistent with the Company's normal Customer meter reading and billing process schedule.

(c) Sales Tax Exemption - The EGS for whom the Company is billing must provide the applicable sales tax exemption percentage to the Company via EDI. The Company shall use the sales tax exemption percentage provided by the EGS for billing the EGS's charges. The EGS is responsible for holding appropriate exemption certificates and is liable for the collection and remittance of sales tax on the EGS's charges.

RULES AND REGULATIONS (continued)

12. PAYMENT AND BILLING

12.2 Application of Customer Payments Received by the Company when the Company is Billing for EGS Services.

(a) Customer had an Unpaid Balance with the Company Prior to Taking Competitive Energy Supply - The Company shall apply payments made by such Customers in the following manner: (1) outstanding amount or the installment amount for a payment agreement on the outstanding amount; (2) competitive transition charge; (3) distribution charges; (4) EGS charges (generation and transmission); and, (5) non-basic service charges.

If a Customer's account develops a further unpaid balance after they begin taking Competitive Energy Supply, the Company shall first apply partial payments to the unpaid balance the Customer had with the Company prior to taking Competitive Energy Supply, before they are applied to the new unpaid balance. Any such payments shall be applied to the prior unpaid balance in accordance with the terms of any applicable payment agreement.

(b) Customer had No Unpaid Balance Prior to Taking Competitive Energy Supply but Develops an Arrearage After They Started Taking Such Service - The Company shall apply payments made by these Customers in the following manner : (1) balance due for prior competitive transition charge as well as distribution charges; (2) current period competitive transition charges; (3) current period distribution charges; (4) balance due for prior EGS charges (generation and transmission); (5) current period EGS charges (generation and transmission); and, (6) non-basic service charges.

RULES AND REGULATIONS (continued)

12. PAYMENT AND BILLING

12.3 EGS Payment of Obligations to the Company. An EGS shall pay all Coordination Services Charges or any other Charges it incurs hereunder in accordance with the following provisions:

(a) Billing Procedure - Each month, the Company shall submit an invoice to the EGS for all Coordination Services Charges provided under this Tariff. The invoice may be transmitted to the EGS by any reasonable method requested by the EGS. An EGS shall make payment for Charges incurred on or before the due date shown on the bill. The due date shall be determined by the Company and shall not be less than fifteen (15) days from the date of transmittal of the bill.

(b) Manner of Payment - The EGS may make payments of funds payable to the Company by wire transfer to a bank designated by the Company. The Company may require that an EGS that is not creditworthy tender payment by means of a certified, cashier's, teller's, or bank check, or by wire transfer, or other immediately available funds. If disputes arise regarding an EGS bill, the EGS must pay the undisputed portion of disputed bills under investigation.

(c) Late Fee for Unpaid Balances - If payment is made to the Company after the due date shown on the bill, a late fee will be added to the unpaid balance until the entire bill is paid. This late fee will be 2% per month on the unpaid balance.

(d) Billing Dispute - In the event of a billing dispute between the Company and the EGS, the Company shall continue to provide service pursuant to the Individual Coordination Agreement and the Tariff as long as the EGS continues to make all payments not in dispute.

12.4 Billing for Supplier Obligations to Other Parties. The Company shall assume no responsibility for billing between an EGS and PJM, an EGS and any energy source, or a Scheduling Coordinator and any Coordinated Suppliers.

12.5 Guarantee of Payments. Before the Company will render service or continue to render service, the Company may require an applicant for Coordination Service or an EGS currently receiving such service that has Bad Credit to provide a cash deposit, letter of credit, surety bond, or other guarantee, satisfactory to the Company. The Company shall hold the deposit as security for the payment of final bills and compliance with the Company's Rules and Regulations. In addition, the Company may require an EGS to post a deposit at any time if the Company determines that the EGS is no longer creditworthy or has Bad Credit.

RULES AND REGULATIONS (continued)

12. PAYMENT AND BILLING

12.6 Amount of Deposits. The deposit shall be equal to the value of Coordination Services Charges the Company projects the EGS will incur during the next two billing periods based on that EGS's forecasted load obligation.

12.7 Return of Deposits. Deposits secured from an EGS shall either be applied with interest to the EGS's account or returned to the EGS with interest when the EGS becomes creditworthy. In cases of discontinuance or termination of service, deposits shall be returned with accrued interest upon payment of all service charges and guarantees or with deduction of unpaid accounts.

12.8 Interest on Deposits. Simple interest on cash deposits shall be calculated at the lower of the Interest Index or six (6) percent. Deposits shall cease to bear interest upon discontinuance of service (or, if earlier, when the Company closes the account).

RULES AND REGULATIONS (continued)

13. CONFIDENTIALITY OF INFORMATION

13.1 Generally. All confidential or proprietary information made available by the Company to an EGS in connection with the provision of Coordination Services, including but not limited to load curve data, and information regarding the business processes of the Company and the computer and communication systems owned or leased by the Company, shall be used only for purposes of receiving Coordination Services and/or providing Competitive Energy Supply to Customers in the Company's service territory.

13.2 Customer Information. The EGS shall keep all Customer-specific information supplied by the Company confidential unless the EGS has the Customer's written authorization to do otherwise.

RULES AND REGULATIONS (continued)

14. WITHDRAWAL BY EGS FROM RETAIL SERVICE

14.1 Notice of Withdrawal to the Company. An EGS shall provide notice to the Company, in a form specified by the Company, of withdrawal by the EGS from retail service in a manner consistent with the Commission's Rulings at Docket No. 00960890F.0013, and any subsequent applicable Commission rulings.

14.2 Notice to Customers. An EGS shall provide notice to its Customers of withdrawal by the EGS from retail service in accordance with the Commission's Rulings at Docket No. 00960890F.0013, and any subsequent applicable Commission rulings.

14.3 Costs of Noncompliance. An EGS that withdrawals from retail service and fails to provide at least ninety (90) days written notice of said withdrawal shall reimburse the Company for any of the following costs associated with the withdrawal:

(a) mailings by the Company to the EGS's Customers to inform them of the withdrawal and their options;

(b) non-standard/manual bill calculation and production performed by the Company;

(c) EGS data transfer responsibilities that must be performed by the Company; and,

(d) charges or penalties imposed on the Company by PJM or other third parties resulting from EGS non-performance.

RULES AND REGULATIONS (continued)

15. EGS's DISCONTINUANCE OF CUSTOMERS

15.1 Notice of Discontinuance to the Company. An EGS shall provide electronic notice to the Company of all intended discontinuances of service to Customers in a manner consistent with the data exchange standards established by the EDEWG and approved by the Commission.

15.2 Notice to Customers. An EGS shall provide a minimum of thirty (30) days advance notice to any customer it intends to stop serving in a manner consistent with the Commission's Rulings at Docket No. 00960890F.0013, and any subsequent applicable Commission rulings. It will be the EGS's responsibility to provide notice to the Customer of its intention to discontinue service in accordance with the EGS's contractual obligation with the Customer.

15.3 Effective Date of Discontinuance. Any discontinuance will be effective on a meter read date and in accordance with the EGS switching rules in this Tariff and the Company's EDC Tariff.

RULES AND REGULATIONS (continued)

16. LIABILITY

16.1 General Limitation on Liability. The Company shall have no duty or liability with respect to electric energy or capacity before it is delivered by an EGS to a point of delivery on the Company's distribution system. After its receipt of electric energy and capacity at the point of delivery, the Company shall have the same duty and liability for distribution service to customers receiving Competitive Energy Supply as to those receiving electric energy and capacity from the Company.

16.2 Limitation On Liability For Service Interruptions And Variations. The Company does not guarantee continuous, regular and uninterrupted supply of service. The Company may, without liability, interrupt or limit the supply of service for the purpose of making repairs, changes, or improvements in any part of its system for the general good of the service or the safety of the public or for the purpose of preventing or limiting any actual or threatened instability or disturbance of the system. The Company is also not liable for any damages due to accident, strike, storm, riot, fire, flood, legal process, state or municipal interference, or any other cause beyond the Company's control.

16.3 Additional Limitations On Liability In Connection With Direct Access. Other than its duty to deliver electric energy and capacity, the Company shall have no duty or liability to an EGS providing Competitive Energy Supply arising out of or related to a contract or other relationship between an EGS and a Customer of the EGS.

The Company shall implement Customer selection of an EGS consistent with applicable rules of the Commission and shall have no liability to an EGS providing Competitive Energy Supply arising out of or related to switching EGSs, unless the Company is negligent in switching or failing to switch a customer.

16.4 Company's Indemnification of EGS. Subject to Rule 16.2, in the event the Company is not able to render continuous, regular, and uninterrupted supply of service due to interruption or service limitations not caused by the EGS, the Company shall hold the EGS harmless for any penalties, fines, or other costs that the Company may incur.

RULES AND REGULATIONS (continued)

17. BREACH OF COORDINATION OBLIGATIONS

17.1 Breach of Obligations. The Company or an EGS shall be deemed to be in breach of its Coordination Obligations under the Individual Coordination Agreement and this Tariff upon its failure to observe any material term or condition of this Tariff, including any rule and regulation, charge or rider thereof.

17.2 Events of Breach. A material breach of Coordination Obligations hereunder, as described in Rule 17.1, shall include, but is not limited to, the following:

(a) a breach of any rule or regulation of the Tariff;

(b) an EGS's failure to maintain license or certification as an electric generation supplier or electricity supplier from the Commission;

(c) the involuntary bankruptcy/insolvency of the EGS, including but not limited to, the appointment of a receiver, liquidator or trustee of the EGS, or a decree by such a court adjudging the EGS bankrupt or insolvent or sequestering any substantial part of its property, or a petition to declare bankruptcy so as to reorganize the EGS; or,

(d) an EGS's filing of a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law, or its consent to the filing of any bankruptcy or reorganization petition against it under any similar law; or without limiting the generality of the foregoing, an EGS admits in writing its inability to pay its debts generally as they become due or consents to the appointment of a receiver, trustee or liquidator of it or of all or any part of its property.

17.3 Cure and Default. If either the Company or an EGS materially breaches any of its Coordination Obligations (hereinafter the "Breaching Party"), the other party (hereinafter the "Non-Breaching Party") shall provide the Breaching Party a written notice describing such breach in reasonable detail and demanding its cure. The Breaching Party shall be deemed to be in default ("Default") of its obligations under this Tariff and the Individual Coordination Agreement if: (I) it fails to cure its breach within thirty (30) days after its receipt of such notice; or (ii) the breach cannot be cured within such period and the Breaching Party does not commence action to cure the breach within said period and thereafter diligently pursues such action to completion.

17.4 Rights Upon Default. Notwithstanding anything stated herein, upon the occurrence of any Default, the party not in Default shall be entitled to (I) commence an action to require the party in Default to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, and (ii) exercise such other rights and remedies as it may have in equity or at law.

RULES AND REGULATIONS (continued)

18. TERMINATION OF INDIVIDUAL COORDINATION AGREEMENT

18.1 Termination. An Individual Coordination Agreement shall or may be terminated as follows:

(a) Withdrawal of the EGS from Retail Service - In the event the EGS ceases to participate in or otherwise withdraws the provision of Competitive Energy Supply to Customers in the Company's service territory, the Individual Coordination Agreement between the EGS and the Company shall terminate thirty (30) days following the date on which the EGS has no more active Customers.

(b) The Company's Termination Rights Upon Default by EGS - In the event of a Default by the EGS, the Company may terminate the Individual Coordination Agreement between the EGS and the Company by providing written notice to the EGS in Default, without prejudice to any remedies at law or in equity available to the party not in Default by reason of the Default.

18.2 Effect of Termination. Termination of Individual Coordination Agreements will have the same effect on an EGS's Customers as the EGS's discontinuance of supply to such Customers described in Rule 14 of the Company's Tariff. If a Customer of a terminated EGS has not switched to another EGS prior to termination, said Customer will receive service from a provider of last resort pending its selection of another EGS.

18.3 Survival of Obligations. Termination of an Individual Coordination Agreement for any reason shall not relieve the Company or an EGS of any obligation accrued or accruing prior to such termination.

RULES AND REGULATIONS (continued)

19. MISCELLANEOUS

19.1 Notices. Unless otherwise stated herein, any notice contemplated by this Tariff shall be in writing and shall be given to the other party at the addresses stated in the notice section of the Individual Coordination Agreement. If given by electronic transmission (including fax or E-mail), notice shall be deemed given on the date sent and shall be confirmed by a written copy sent by first class mail. If sent in writing by first class mail, notice shall be deemed given on the fifth business day following deposit in the United States mail (as noted by the postmark), properly addressed, with postage prepaid. If sent by same-day or overnight delivery service, notice shall be deemed given on the day of delivery. The Company and an EGS may change their representative for receiving notices contemplated by this Tariff by delivering written notice of their new representatives to the other.

19.2 No Prejudice of Rights. The failure by either the Company or the EGS to enforce any of the terms of this Tariff or any Individual Coordination Agreement shall not be deemed a waiver of the right of either to do so.

19.3 Gratuities to Employees. The Company's employees are strictly forbidden to demand or accept any personal compensation, or gifts, for service rendered by them while working for the Company on the Company's time.

19.4 Assignment.

(a) An Individual Coordination Agreement hereunder may not be assigned by either the Company or the EGS without (a) any necessary regulatory approval and (b) the consent of the other party, which consent shall not be unreasonably withheld.

(b) Any assignment occurring in accordance with Rule 19.4(a) hereunder shall be binding upon, and oblige and inure to the benefit of, the successors and assigns of the parties to the Individual Coordination Agreement.

19.5 Governing Law. To the extent not subject to the exclusive jurisdiction of FERC, the formation, validity, interpretation, execution, amendment and termination of this Tariff or any Individual Coordination Agreement shall be governed by the laws of the Commonwealth of Pennsylvania.

The Tariff or any Individual Coordination Agreement, and the performance of the parties' obligations thereunder, is subject to and contingent upon (i) present and future local, state and federal laws, and (ii) present and future regulations or orders of any local, state or federal regulating authority having jurisdiction over the matter set forth herein.

RULES AND REGULATIONS (continued)

19. MISCELLANEOUS

If at any time during the term of the Tariff or any Individual Coordination Agreement, FERC, the Commission or a court of competent jurisdiction issues an order under which a party hereto believes that its rights, interests and/or expectations under the Agreement are materially affected by said order, the party so affected shall within thirty (30) days of said final order provide the other party with notice setting forth in reasonable detail how said order has materially affected its rights, interests and/or expectations in the Agreement. Within thirty (30) days from the receiving party's receipt of said notice the parties agree to attempt through good faith negotiations to resolve the issue. If the parties are unable to resolve the issue within thirty (30) days from the commencement of negotiations, either party may at the close of said thirty (30) day period terminate the Agreement, subject to any applicable regulatory requirements, following an additional thirty (30) days prior written notice to the other party without any liability or responsibility whatsoever except for obligations arising prior to the date of service termination.

RIDERS

INDIVIDUAL COORDINATION AGREEMENT **(C)**

1.0 This Individual Coordination Agreement ("Agreement"), dated as of ________________ ________________________ is entered into, by and between UGI Utilities, Inc. - Electric Division (the "Company") and ____ ("EGS").

2.0. The Company agrees to supply, and the EGS agrees to have the Company supply, all "Coordination Services" specified in the Electric Generation Supplier Coordination Tariff ("EGS Coordination Tariff"), including but not limited to load forecasting, load scheduling, and reconciliation services. Both Parties agree that such services are necessary to coordinate the delivery of Competitive Energy Supply to Customers located within the Company's service territory.

3.0 Representations and Warranties.

(a) The EGS hereby represents, warrants and covenants as follows:

(i) The EGS is in compliance, and will continue to comply, with all obligations, rules and regulations, as established and interpreted by the PJM OI, that are applicable to LSEs serving Customers located in the PJM Control Area; and

(ii) The EGS is licensed by the Commission to provide Competitive Energy Supply to Customers in Pennsylvania and has and will continue to satisfy all other Commission requirements applicable to EGSs.

(C) Indicates Change

RIDERS (continued)

INDIVIDUAL COORDINATION AGREEMENT **(C)**

(b) The Company and the EGS, individually referred to hereafter as the "Party," each represents, warrants and covenants as follows:

(i) Each Party's performance of its obligations hereunder has been duly authorized by all necessary action on the part of the Party and does not and will not conflict with or result in a breach of the Party's charter documents or bylaws or any indenture, mortgage, other agreement or instrument, or any statute or rule, regulation, order, judgment, or decree of any judicial or administrative body to which the Party is a party or by which the Party or any of its properties is bound or subject.

(ii) This Agreement is a valid and binding obligation of the Party, enforceable in accordance with its terms, except as such enforceability may be limited by applicable bankruptcy, insolvency or similar laws from time to time in effect that affect creditors' rights generally or by general principles of equity.

4.0 The EGS shall provide notice to the Company via E-mail, with a copy delivered pursuant to overnight mail, at such time that the EGS learns that any of the representations, warranties, or covenants in Section 3.0 of this Agreement have been violated.

5.0 As consideration for Coordination Services provided by the Company, the EGS shall pay the Company those Coordination Services Charges billed to the EGS in accordance with the terms and conditions of the EGS Coordination Tariff.

(C) Indicates Change

RIDERS (continued)

INDIVIDUAL COORDINATION AGREEMENT **(C)**

6.0 Coordination Services between the Company and the EGS will commence on __________ ________________________.

7.0 Any notice or request made to or by either Party regarding this Agreement shall be made to the representative of the other Party as indicated below.

UGI Utilities, Inc. - Electric Division
1 UGI Drive
Denver, PA 17517

Attention: Rates Department, Choice Administrator

E-Mail: EDI-ELECTRIC@UGI.COM

To the EGS:

____

____

____

Attention:___________________________

Title:_______________________________

Telephone: __________________________

E-Mail: _____________________________

(C) Indicates Change

RIDERS (continued)

INDIVIDUAL COORDINATION AGREEMENT **(C)**

8.0 The EGS Coordination Tariff is incorporated herein by reference and made a part hereof. All terms used in this Agreement that are not otherwise defined shall have the meaning provided in the EGS Coordination Tariff.

IN WITNESS WHEREOF, and intending to be legally bound thereby, UGI Utilities, Inc. - Electric Division and the EGS identified above have caused this Coordination Agreement to be executed by their respective authorized officials.

ATTEST: **UGI UTILITIES, INC. – ELECTRIC DIVISION**

____________________ BY: ____________________
(Signature)

____
(Print Name)

____
(Title)

ATTEST: **ELECTRIC GENERATION SUPPLIER**

____________________ BY: ____________________
(Signature)

____
(Print Name)

____
(Title)

(C) Indicates Change

RIDERS (continued)

SCHEDULING COORDINATOR DESIGNATION FORM **(C)**

1.0 This Scheduling Coordinator Designation Form, dated ____________________ , is being submitted to UGI Utilities, Inc. - Electric Division (the "Company") by the following Electric Generation Supplier ("EGS"): __________________.

2.0 By submitting this form, the EGS hereby notifies the Company that it has appointed the following entity to act as its Scheduling Coordinator in accordance with Rule 9 of the Company's Electric Generation Supplier Coordination Tariff (the "EGS Coordination Tariff"): __________________________.

3.0. The EGS further notifies the Company that it is designating the person identified in the preceding paragraph as its Scheduling Coordinator for the specific purpose(s) (please check and/or fill in):

_____ Load Scheduling
_____ Installed Capacity Obligations
_____ Import Capability
_____ Reconciliation Rights and Responsibilities
_____ Other: ____________________________

4.0. The Company may utilize the Scheduling Coordinator as the sole point of contact with the EGS in connection with the Company's provision of Coordination Services to the EGS. Likewise, the Scheduling Coordinator appointed by the EGS shall be responsible for the performance of all Coordination Obligations of the EGS that are specifically delegated to said Scheduling Coordinator in this Form.

(C) Indicates Change

RIDERS (continued)

SCHEDULING COORDINATOR DESIGNATION FORM **(C)**

5.0 The EGS agrees that the Company may bill the Scheduling Coordinator directly for all Coordination Services Charges attributable to the EGS and that the Scheduling Coordinator will pay the Company such charges on behalf of the EGS in accordance with the terms and conditions in the EGS Coordination Tariff.

6.0 The EGS and its appointed Scheduling Coordinator shall comply with all terms and conditions of the EGS Coordination Tariff, including those pertaining to Scheduling Coordinators and to payment and billing.

7.0 All inquiries, communications or notices relating to the EGS's use of the Scheduling Coordinator designated above may be directed to the following representatives:

To the EGS:

Attention:_________________________

Title:_____________________________

Telephone: ________________________

Email: ____________________________

(C) Indicates Change

RIDERS (continued)

SCHEDULING COORDINATOR DESIGNATION FORM **(C)**

To the Scheduling Coordinator:

Attention: ________________________

Title:____________________________

Telephone:_______________________

Email: ___________________________

8.0 The EGS Coordination Tariff is incorporated herein by reference and made a part hereof. All capitalized terms used, but not defined, in this designation form shall have the meaning stated in the EGS Coordination Tariff.

9.0 The EGS has executed this designation form below by its duly authorized representative as follows:

Signature:_________________________________

Name:____________________________________

Title:_____________________________________

Date: ___________________________________

(C) Indicates Change

RIDERS (continued)

SCHEDULING COORDINATOR DESIGNATION FORM **(C)**

10.0 The EGS has obtained the following Acknowledgment and Consent to this designation, which is executed below by the duly authorized representative of the Scheduling Coordinator:

Acknowledgment and Consent

Intending to be legally bound thereby, the duly authorized representative of above-designated Scheduling Coordinator has executed this document below to acknowledge and consent to its appointment as a Scheduling Coordinator, and to further state its agreement to abide by the terms and conditions of its designation set forth above in the Scheduling Coordinator Designation Form prepared by the EGS, including the terms and conditions of the EGS Coordination Tariff which is incorporated therein by reference.

Signature: ___________________________________

Name: ______________________________________

Title: _______________________________________

Date: ____________________________________

(C) Indicates Change

BOOK V

UGI UTILITIES, INC. – ELECTRIC DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI ELECTRIC EXHIBIT C
(FULLY PROJECTED FUTURE)
2024 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF SEPTEMBER 30, 2024

Witness: John F. Wiedmayer
Prepared by: Gannett Fleming
Valuation and Rate Consultants, LLC

UGI UTILITIES, INC. – ELECTRIC DIVISION
PA P.U.C. NO. 6, SUPPLEMENT NO. 51
PA P.U.C. NO. 2S, SUPPLEMENT NO. 7

DOCKET NO. R-2022-3037368

Issued: January 27, 2023 **Effective: March 28, 2023**

UGI Electric C (Fully Projected)
Witness: J. F. Wiedmayer

UGI UTILITIES, INC. - ELECTRIC DIVISION

DOCKET NO. R-2022-3037368

2024 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO ELECTRIC PLANT
AT SEPTEMBER 30, 2024

Prepared by:

GANNETT FLEMING

Excellence Delivered As Promised

UGI UTILITIES, INC. - ELECTRIC DIVISION

Docket No. R-2022-3037368

2024 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AT SEPTEMBER 30, 2024

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

Valley Forge, Pennsylvania

Gannett Fleming
Valuation and Rate Consultants, LLC

Corporate Headquarters
207 Senate Avenue
Camp Hill, PA 17011
P 717.763.7211 | **F** 717.763.8150

gannettfleming.com

January 17, 2023

Mr. Christopher R. Brown
Vice President and General Manager, Rates and Supply
UGI Utilities, Inc. - Electric Division
1 UGI Drive
Denver, PA 17517

Ladies and Gentlemen:

Pursuant to your request, we have determined the annual depreciation accruals applicable to electric plant at September 30, 2024. Summaries of the original cost, annual accruals and the book depreciation reserve are presented in Tables 1 through 4 of the attached report.

A description of the methods and procedures upon which the study was based is set forth in a companion report, UGI Electric Exhibit C (Future), "2023 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant at September 30, 2023".

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

John F. Wiedmayer

JOHN F. WIEDMAYER
Project Manager – Depreciation Studies

JFW:mle

073630.100

TABLE OF CONTENTS

PART I. INTRODUCTION

UGI UTILITIES, INC. - ELECTRIC DIVISION
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for UGI Utilities, Inc. - Electric Division to determine the annual depreciation accrual rates and amounts for ratemaking purposes applicable to the original cost of electric plant at September 30, 2024.

BASIS

Depreciation

The annual depreciation accruals and accrued depreciation were calculated using the straight-line method, the remaining life basis, the average service life (ASL) procedure for plant installed prior to 1982 and the equal life group procedure (ELG) for 1982 and subsequent vintages. The calculations were based on the attained ages and estimated service life characteristics for each depreciable group of electric property.

Service Life Estimates

The service life and survivor curve estimates used for the calculation of depreciation at September 30, 2024, are set forth in Table 1 and are based on company data through 2021. The company is not proposing any changes to the service life estimates. The service life estimates are the same estimates as submitted to the Pennsylvania Public Utility Commission (PA PUC) in the company's most recent service life study report in May 2022.

Remaining Life Annual Accruals

For the purpose of calculating remaining life accruals at September 30, 2024, the book reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation for the average service life procedure are presented in Exhibit C (Future). The detailed calculations at September 30, 2024, are set forth in Part III of this report.

Amortization of Net Salvage

In accordance with Pennsylvania rate regulation practice, under which experienced costs of negative net salvage are amortized after their occurrence, no adjustments for expected net salvage were made to either the annual depreciation accrual or the calculated accrued depreciation for the individual accounts. The annual provision for recovering negative net salvage is based on the amortization of experienced net salvage over a five-year period.

PART II. RESULTS OF STUDY

PART II. RESULTS OF STUDY

DESCRIPTION OF SUMMARY TABULATIONS

Tables 1 through 4 presented on pages II-3 through II-11 summarize the results of the depreciation study at September 30, 2024. Table 1 sets forth, by depreciable group, the estimated survivor curve, original cost, book depreciation reserve at September 30, 2024, future book accruals, calculated annual accrual amount and rate, and composite remaining life for plant in service. Table 2 presents the bringforward of the book reserve to September 30, 2024. Table 3 sets forth the calculation of the depreciation accruals for the twelve months ended September 30, 2024. Table 4 presents the annual amortization of experienced and estimated net salvage based on the period 2020 through 2024.

DETAILED TABULATIONS OF DEPRECIATION CALCULATIONS

Supporting data for the original cost depreciation calculations in account sequence are presented in Part III of this report. The tables indicate the estimated survivor curves used in the calculations and set forth, for each installation year, the original cost, calculated accrued depreciation, allocated book reserve, future book accruals, remaining life, and calculated remaining life accrual.

Detailed tabulations setting forth the experienced and estimated cost of removal and salvage amounts by year and account are presented in Part IV of this report. The net salvage amounts are carried forward to Table 4 which presents the five-year amortization.

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND
CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF SEPTEMBER 30, 2024

ACCOUNT	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
ELECTRIC PLANT							
DISTRIBUTION PLANT							
361 STRUCTURES AND IMPROVEMENTS		50 - R3	627,496	67,339	560,157	2.37	14,856
362 STATION EQUIPMENT		40 - S1	11,568,188	1,555,321	10,012,867	3.20	370,323
364 POLES, TOWERS AND FIXTURES		59 - R2.5	56,561,695	18,154,021	38,407,674	1.82	1,029,131
365 OVERHEAD CONDUCTORS AND DEVICES		58 - R1.5	83,518,448	14,475,964	69,042,484	2.40	2,000,748
365.7 REG AFUDC		40 - SQ	(711,827)	(115,649)	(596,178)	2.29	(16,334)
366 UNDERGROUND CONDUIT		65 - R3	8,779,918	2,692,439	6,087,479	1.56	136,759
367 UNDERGROUND CONDUCTORS AND DEVICES		42 - R1.5	15,566,131	4,927,497	10,638,634	2.78	432,991
368.1 TRANSFORMERS		45 - S1	19,861,657	8,266,630	11,595,027	2.15	427,778
368.2 TRANSFORMER INSTALLATIONS		39 - R2	11,239,609	6,688,323	4,551,286	1.84	206,924
369 SERVICES		53 - R2	16,710,606	8,069,605	8,641,001	1.67	279,667
370.1 METERS		34 - R1	3,093,268	1,938,784	1,154,484	2.13	65,979
370.2 METER INSTALLATIONS		75 - R4	1,988,715	825,222	1,163,493	1.26	25,015
370.3 ELECTRONIC METERS		20 - S3	5,037,891	4,274,497	763,394	2.28	114,671
371 INSTALLATIONS ON CUSTOMER PREMISES		30 - O1	2,219,114	1,087,883	1,131,231	3.33	73,861
371.5 INSTALLATIONS ON CUSTOMER PREMISES - DUSK TO DAWN LIGHTS		23 - R1	347,706	337,722	9,984	0.36	1,260
373 STREET LIGHTING AND SIGNAL SYSTEMS		28 - L0	2,614,126	1,138,619	1,475,507	4.24	110,861
TOTAL DISTRIBUTION PLANT			**239,022,741**	**74,384,217**	**164,638,524**	**2.21**	**5,274,490**
GENERAL PLANT							
390.1 STRUCTURES AND IMPROVEMENTS							
FORTY FORT	06-2032	* 100 - L0	4,677,729	1,141,047	3,536,682	10.03	469,231
PLYMOUTH		FULLY ACCRUED	15,111	15,111	0	-	0
IDETOWN	06-2046	* 100 - L0	49,926	13,389	36,537	3.78	1,885
NANTICOKE		FULLY ACCRUED	76,179	76,179	0	-	0
EMPIRE YARD		FULLY ACCRUED	19,895	19,895	0	-	0
SYSTEM CONTROL CENTER	07-2056	* 100 - L0	1,891,888	387,545	1,504,343	2.99	56,589
SUBTOTAL ACCOUNT 390.1			*6,730,728*	*1,653,166*	*5,077,562*	*7.84*	*527,705*
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	66,068	24,980	41,088	7.48	4,943
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	9,824	(613)	10,437	42.50	4,175
391.9 OFFICE FURNITURE AND EQUIPMENT - OUTAGE MANAGEMENT SOFTWARE		5 - SQ	3,496,035	1,490,702	2,005,333	22.68	792,861
393 STORES EQUIPMENT		10 - SQ	14,618	7,651	6,967	10.69	1,562
394 TOOLS, SHOP AND GARAGE EQUIPMENT		20 - SQ	1,522,715	669,762	852,953	5.01	76,247
395 LABORATORY EQUIPMENT		10 - SQ	37,739	28,138	9,601	8.28	3,126
397 COMMUNICATION EQUIPMENT		10 - SQ	877,809	368,166	509,643	11.47	100,692
398 MISCELLANEOUS EQUIPMENT		10 - SQ	757,799	210,964	546,835	10.84	82,154
TOTAL GENERAL PLANT			**13,513,335**	**4,452,916**	**9,060,419**	**11.79**	**1,593,465**
SPECIAL DEPRECIABLE PLANT							
392.1 TRANSPORTATION EQUIPMENT - CARS		7 - L3	370,097	213,285	156,812	12.72	47,058
392.2 TRANSPORTATION EQUIPMENT - LIGHT TRUCKS		11 - L3	2,786,671	487,745	2,298,926	10.87	302,797
392.4 TRANSPORTATION EQUIPMENT - HEAVY TRUCKS		14 - S3	490,636	115,114	375,522	8.06	39,534
396 POWER OPERATED EQUIPMENT		20 - S0	1,071,351	117,248	954,103	7.31	78,325
TOTAL SPECIAL DEPRECIABLE PLANT			**4,718,755**	**933,392**	**3,785,363**	**9.91**	**467,714**
TOTAL DEPRECIABLE PLANT			**257,254,831**	**79,770,525**	**177,484,306**	**2.85**	**7,335,669**

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND
CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF SEPTEMBER 30, 2024

ACCOUNT (1)	PROBABLE RETIREMENT YEAR (2)	SURVIVOR CURVE (3)	ORIGINAL COST (4)	BOOK RESERVE (5)	FUTURE BOOK ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL RATE (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)
NONDEPRECIABLE PLANT							
301.1 ORGANIZATION			1,602				
302.1 FRANCHISES AND CONSENTS - PERPETUAL			6,436				
360.1 LAND AND LAND RIGHTS - LAND			299,162				
360.2 LAND AND LAND RIGHTS - LAND RIGHTS			14,336				
389.1 LAND AND LAND RIGHTS - LAND			202,584	14,257			
TOTAL NONDEPRECIABLE PLANT			**524,120**	**14,257**			
TOTAL ELECTRIC PLANT			**257,778,951**	**14,257**			
LESS GENERAL AND INTANGIBLE PLANT ALLOCATED TO TRANSMISSION - 25.6247%			4,725,890	1,383,879	3,291,693		528,171
TOTAL ELECTRIC PLANT RELATED TO DISTRIBUTION OPERATIONS			**253,053,061**	**78,400,903**	**174,192,613**		**6,807,498**
OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION							
COMMON PLANT							
301 ORGANIZATION (NONDEPRECIABLE)			138,964				
389.1 LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)			6,947,108				
390.1 STRUCTURES AND IMPROVEMENTS	01-2069 *	SQUARE	35,947,826	5,076,206	30,871,620	2.68	964,749
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	5,230,878	1,549,592	3,681,286	5.27	275,805
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	1,076,385	727,143	349,242	21.63	232,828
392.1 TRANSPORTATION EQUIPMENT - CARS		FULLY ACCRUED	71,637	71,637	0	-	0
398 MISCELLANEOUS EQUIPMENT		10 - SQ	27,967	7,572	20,395	13.26	3,708
TOTAL COMMON PLANT			**49,440,765**	**7,432,150**	**34,922,543**	**3.00**	**1,477,090**
TOTAL COMMON PLANT ALLOCATED TO ELECTRIC DIVISION - 9.83%			**4,860,027**	**730,580**	**3,432,886**		**145,198**
INFORMATION SERVICES (IS)							
390 STRUCTURES AND IMPROVEMENTS - NEW READING DATA CENTER	11-2073	80 - R1.5	20,329,983	494,527	19,835,456	2.98	606,218
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	2,319	1,598	721	5.18	120
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	5,249,785	3,507,489	1,742,296	17.34	910,442
391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE							
SUCCESS FACTORS	09-2024 **	SQUARE	2,803,866	2,803,866	0	-	0
UNITE ERP	09-2034 ***	SQUARE	10,695,816	3,150,333	7,545,483	7.05	754,548
TOTAL OFFICE FURNITURE AND EQUIPMENT - SOFTWARE			13,499,682	5,954,199	7,545,483		754,548
391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS		10 - SQ	71,171,098	19,812,785	51,358,313	10.20	7,262,526
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS		15 - SQ	134,231,132	58,010,414	76,220,718	6.71	9,003,180
TOTAL INFORMATION SERVICES (EXCLUDING 100% ALLOCATION AMOUNT)			**244,483,999**	**87,781,012**	**156,702,987**	**7.58**	**18,537,034**
TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION - 9.08%			**22,199,147**	**7,970,516**	**14,228,631**		**1,683,163**
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV.COSTS - 15 YEARS		15 - SQ	246,470	17,006	229,464	6.90	16,997
TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION - 100.00%			**246,470**	**17,006**	**229,464**		**16,997**
TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION			**22,445,617**	**7,987,522**	**14,458,095**		**1,700,160**

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND
CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF SEPTEMBER 30, 2024

ACCOUNT	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
EMPIRE YARD BUILDING							
390.1 STRUCTURES AND IMPROVEMENTS	12-2047 *	80 - R1.5	16,870,342	8,845,824	8,024,518	2.29	385,936
TOTAL EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%			**2,204,954**	**1,156,149**	**1,048,805**		**50,442**
TOTAL OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION			**29,510,598**	**9,874,251**	**18,939,786**		**1,895,800**
LESS OTHER UTILITY PLANT ALLOCATED TO ELECTRIC TRANSMISSION - 25.6247%			7,562,002	2,530,247	4,853,263		485,793
TOTAL OTHER PLANT ALLOCATED TO ELECTRIC RELATED TO DISTRIBUTION OPERATIONS			**21,948,596**	**7,344,004**	**14,086,523**		**1,410,007**
TOTAL PLANT IN SERVICE RELATED TO DISTRIBUTION OPERATIONS			**275,001,657**	**85,744,907**	**188,279,136**		**8,217,505**
AMORTIZATION OF NEGATIVE NET SALVAGE							*857,038*
GRAND TOTAL			**275,001,657**	**85,744,907**	**188,279,136**		**9,074,543**

* SURVIVOR CURVES FOR ACCOUNT 390 ARE INTERIM SURVIVOR CURVES. INDIVIDUAL BUILDINGS ARE LIFE SPANNED.
** REGULATORY ASSET DEPRECIATED OVER FOUR YEARS. ZERO YEARS REMAINING.
*** REGULATORY ASSET DEPRECIATED OVER FOURTEEN YEARS. TEN YEARS REMAINING

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 2. BOOK RESERVE AT SEPTEMBER 30, 2023 PROJECTED TO SEPTEMBER 30, 2024

ACCOUNT		BOOK RESERVE AT BEGINNING OF YEAR	ANNUAL ACCRUAL	AMORTIZATION OF NET SALVAGE	RETIREMENTS	GROSS SALVAGE	COST OF REMOVAL	TRANSFERS AND ADJUSTMENTS	BOOK RESERVE AT END OF YEAR	BOOK RESERVE AS A PERCENT OF ORIGINAL COST
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
ELECTRIC PLANT										
DISTRIBUTION PLANT										
361	STRUCTURES AND IMPROVEMENTS	51,995	15,123	221	0	0	0	0	67,339	10.73
362	STATION EQUIPMENT	1,177,222	371,828	9,213	(2,866)	211	(287)	0	1,555,321	13.44
364	POLES, TOWERS AND FIXTURES	16,932,371	1,024,283	404,575	(82,883)	0	(124,325)	0	18,154,021	32.10
365	OVERHEAD CONDUCTORS AND DEVICES	13,966,110	1,723,959	255,499	(734,802)	0	(734,802)	0	14,475,964	17.33
365.7	REG AFUDC	(99,348)	(16,301)	0	0	0	0	0	(115,649)	16.25
366	UNDERGROUND CONDUIT	2,551,835	137,845	2,759	0	0	0	0	2,692,439	30.67
367	UNDERGROUND CONDUCTORS AND DEVICES	4,511,139	434,336	12,252	(25,188)	0	(5,042)	0	4,927,497	31.66
368.1	TRANSFORMERS	8,139,253	381,335	6,081	(245,644)	0	(14,395)	0	8,266,630	41.62
368.2	TRANSFORMER INSTALLATIONS	6,450,987	213,291	27,318	(2,182)	0	(1,091)	0	6,688,323	59.51
369	SERVICES	7,799,373	275,473	65,052	(25,561)	0	(44,732)	0	8,069,605	48.29
370.1	METERS	2,054,528	55,618	(48,676)	(282,297)	159,611	0	0	1,938,784	62.68
370.2	METER INSTALLATIONS	801,991	24,990	3,774	(3,460)	0	(2,073)	0	825,222	41.50
370.3	ELECTRONIC METERS	4,148,090	125,947	460	0	0	0	0	4,274,497	84.85
371	INSTALLATIONS ON CUSTOMER PREMISES	987,794	83,883	16,206	0	0	0	0	1,087,883	49.02
371.5	INSTALLATIONS ON CUSTOMER PREMISES - DUSK TO DAWN LIGHTS	336,331	1,391	0	0	0	0	0	337,722	97.13
373	STREET LIGHTING AND SIGNAL SYSTEMS	1,058,359	108,934	16,934	(30,468)	0	(15,140)	0	1,138,619	43.56
TOTAL DISTRIBUTION PLANT		**70,868,030**	**4,961,935**	**771,668**	**(1,435,351)**	**159,822**	**(941,887)**	**0**	**74,384,217**	**31.12**
GENERAL PLANT										
390.1	STRUCTURES AND IMPROVEMENTS	1,275,204	463,526	35	(85,599)	0	0	0	1,653,166	24.56
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	20,137	4,843	0	0	0	0	0	24,980	37.81
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	285,540	73,239	0	(359,392)	0	0	0	(613)	-6.24
391.9	OFFICE FURNITURE AND EQUIPMENT - OUTAGE MANAGEMENT SOFTWARE	697,801	792,901	0	0	0	0	0	1,490,702	42.64
392.1	TRANSPORTATION EQUIPMENT - CARS	167,889	45,396	0	0	0	0	0	213,285	57.63
392.2	TRANSPORTATION EQUIPMENT - LIGHT TRUCKS	307,336	182,950	(2,541)	0	0	0	0	487,745	17.50
392.4	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	75,520	39,594	0	0	0	0	0	115,114	23.46
393	STORES EQUIPMENT	5,885	1,766	0	0	0	0	0	7,651	52.34
394	TOOLS, SHOP AND GARAGE EQUIPMENT	622,707	79,650	0	(32,595)	0	0	0	669,762	43.98
395	LABORATORY EQUIPMENT	62,234	2,136	0	(36,232)	0	0	0	28,138	74.56
396	POWER OPERATED EQUIPMENT	45,151	72,097	0	0	0	0	0	117,248	10.94
397	COMMUNICATION EQUIPMENT	297,890	123,609	14	(53,344)	0	(3)	0	368,166	41.94
398	MISCELLANEOUS EQUIPMENT	126,923	76,151	7,890	0	0	0	0	210,964	27.84
TOTAL GENERAL PLANT		**3,990,217**	**1,957,858**	**5,398**	**(567,162)**	**0**	**(3)**	**0**	**5,386,308**	**29.54**
TOTAL DEPRECIABLE PLANT		**74,858,247**	**6,919,793**	**777,066**	**(2,002,513)**	**159,822**	**(941,890)**	**0**	**79,770,525**	**31.01**
NONDEPRECIABLE PLANT										
301.1	ORGANIZATION	0	0	0	0	0	0	0	0	0.00
302.1	FRANCHISES AND CONSENTS - PERPETUAL	0	0	0	0	0	0	0	0	0.00
360.1	LAND AND LAND RIGHTS - LAND	0	0	0	0	0	0	0	0	0.00
360.2	LAND AND LAND RIGHTS - LAND RIGHTS	0	0	0	0	0	0	0	0	0.00
389.1	LAND AND LAND RIGHTS - LAND	14,257	0	0	0	0	0	0	14,257	7.04
TOTAL NONDEPRECIABLE PLANT		**14,257**	**0**	**0**	**0**	**0**	**0**	**0**	**14,257**	
TOTAL ELECTRIC PLANT		**74,872,504**	**6,919,793**	**777,066**	**(2,002,513)**	**159,822**	**(941,890)**	**0**	**79,784,782**	
LESS GENERAL PLANT ALLOCATED TO TRANSMISSION - 25.6247%		1,026,134	501,695	1,383	(145,334)	0	(1)	0	1,383,879	
TOTAL DEPRECIABLE PLANT RELATED TO DISTRIBUTION OPERATIONS		**73,846,370**	**6,418,098**	**775,683**	**(1,857,179)**	**159,822**	**(941,889)**	**0**	**78,400,903**	

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 2. BOOK RESERVE AT SEPTEMBER 30, 2023 PROJECTED TO SEPTEMBER 30, 2024

ACCOUNT (1)	BOOK RESERVE AT BEGINNING OF YEAR (2)	ANNUAL ACCRUAL (3)	AMORTIZATION OF NET SALVAGE (4)	RETIREMENTS (5)	GROSS SALVAGE (6)	COST OF REMOVAL (7)	TRANSFERS AND ADJUSTMENTS (8)	BOOK RESERVE AT END OF YEAR (9)	BOOK RESERVE AS A PERCENT OF ORIGINAL COST (10)
OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION									
COMMON PLANT									
390.1 STRUCTURES AND IMPROVEMENTS	4,076,856	999,350	0	0	0	0	0	5,076,206	14.12
390.2 STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	0	0	0	0	0	0	0	0	0.00
391.0 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,282,392	279,096	0	(11,896)	0	0	0	1,549,592	29.62
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	664,008	340,331	0	(277,196)	0	0	0	727,143	67.55
392.1 TRANSPORTATION EQUIPMENT - CARS	71,637	0	0	0	0	0	0	71,637	100.00
398 MISCELLANEOUS EQUIPMENT	3,864	3,708	0	0	0	0	0	7,572	27.07
TOTAL COMMON PLANT	**6,098,757**	**1,622,485**	**0**	**(289,092)**	**0**	**0**	**0**	**7,432,150**	**15.03**
TOTAL COMMON PLANT ALLOCATED TO ELECTRIC DIVISION - 9.83%	**599,508**	**159,490**	**0**	**(28,418)**	**0**	**0**	**0**	**730,580**	
INFORMATION SERVICES (IS)									
390.1 STRUCTURES AND IMPROVEMENTS - NEW READING DATA CENTER	0	494,527	0	0	0	0	0	494,527	2.43
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	7,045	252	0	(5,699)	0	0	0	1,598	68.91
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	11,091,382	1,923,378	0	(9,507,271)	0	0	0	3,507,489	66.81
391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE									
SUCCESS FACTORS	2,046,868	756,998	0	0	0	0	0	2,803,866	100.00
UNITE ERP	2,395,208	755,125	0	0	0	0	0	3,150,333	29.45
TOTAL OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	4,442,076	1,512,123	0	0	0	0	0	5,954,199	
391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	14,683,389	6,064,627	0	(935,231)	0	0	0	19,812,785	27.84
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	49,003,505	9,006,909	0	0	0	0	0	58,010,414	43.22
TOTAL INFORMATION SERVICES (EXCLUDING 100% ALLOCATION AMOUNT)	**79,227,397**	**19,001,816**	**0**	**(10,448,201)**	**0**	**0**	**0**	**87,781,012**	**35.90**
TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION - 9.08%	**7,193,848**	**1,725,365**	**0**	**(948,697)**	**0**	**0**	**0**	**7,970,516**	
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV.COSTS - 15 YEARS	0	17,006	0	0	0	0	0	17,006	6.90
TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION - 100.00%	**0**	**17,006**	**0**	**0**	**0**	**0**	**0**	**17,006**	
TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION	**7,193,848**	**1,742,371**	**0**	**(948,697)**	**0**	**0**	**0**	**7,987,522**	
EMPIRE YARD BUILDING									
390.1 STRUCTURES AND IMPROVEMENTS	8,781,870	281,419	0	(217,465)	0	0	0	8,845,824	52.43
TOTAL EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%	**1,147,790**	**36,781**	**0**	**(28,423)**	**0**	**0**	**0**	**1,156,149**	
TOTAL OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION	**8,941,146**	**1,938,642**	**0**	**(1,005,538)**	**0**	**0**	**0**	**9,874,251**	
LESS OTHER UTILITY PLANT ALLOCATED TO ELECTRIC TRANSMISSION - 25.6247%	2,291,142	496,771	0	(257,666)	0	0	0	2,530,247	
TOTAL OTHER PLANT ALLOCATED TO ELECTRIC RELATED TO DISTRIBUTION OPERATIONS	**6,650,004**	**1,441,871**	**0**	**(747,872)**	**0**	**0**	**0**	**7,344,004**	
TOTAL DEPRECIABLE PLANT IN SERVICE RELATED TO DISTRIBUTION OPERATIONS	**80,496,374**	**7,859,969**	**775,683**	**(2,605,051)**	**159,822**	**(941,889)**	**0**	**85,744,907**	

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 3. CALCULATION OF DEPRECIATION ACCRUALS FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2024

ACCOUNT	BEGINNING OF YEAR BALANCE	ADDITIONS	RETIREMENTS	TRANSFERS AND ADJUSTMENTS	END OF YEAR BALANCE	AVERAGE BALANCE	ANNUAL ACCRUAL RATE	ANNUAL ACCRUAL AMOUNT*
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
ELECTRIC PLANT								
DISTRIBUTION PLANT								
361 STRUCTURES AND IMPROVEMENTS	627,496	0	0	0	627,496	627,496	2.41	15,123
362 STATION EQUIPMENT	11,263,245	307,809	(2,866)	0	11,568,188	11,415,717	3.26	371,828
364 POLES, TOWERS AND FIXTURES	55,047,300	1,597,278	(82,883)	0	56,561,695	55,804,498	1.85	1,024,283
365 OVERHEAD CONDUCTORS AND DEVICES	69,557,228	14,696,022	(734,802)	0	83,518,448	76,537,838	2.34	1,723,959
365.7 REG AFUDC	(711,827)	0	0	0	(711,827)	(711,827)	2.29	(16,301)
366 UNDERGROUND CONDUIT	8,779,918	0	0	0	8,779,918	8,779,918	1.57	137,845
367 UNDERGROUND CONDUCTORS AND DEVICES	15,051,435	539,884	(25,188)	0	15,566,131	15,308,783	2.85	434,336
368.1 TRANSFORMERS	18,263,782	1,843,519	(245,644)	0	19,861,657	19,062,720	2.08	381,335
368.2 TRANSFORMER INSTALLATIONS	11,218,276	23,515	(2,182)	0	11,239,609	11,228,943	1.90	213,291
369 SERVICES	16,224,921	511,246	(25,561)	0	16,710,606	16,467,764	1.68	275,473
370.1 METERS	2,977,856	397,709	(282,297)	0	3,093,268	3,035,562	1.85	55,618
370.2 METER INSTALLATIONS	1,980,373	11,802	(3,460)	0	1,988,715	1,984,544	1.26	24,990
370.3 ELECTRONIC METERS	5,037,891	0	0	0	5,037,891	5,037,891	2.50	125,947
371 INSTALLATIONS ON CUSTOMER PREMISES	2,219,114	0	0	0	2,219,114	2,219,114	3.78	83,883
371.5 INSTALLATIONS ON CUSTOMER PREMISES - DUSK TO DAWN LIGHTS	347,706	0	0	0	347,706	347,706	0.40	1,391
373 STREET LIGHTING AND SIGNAL SYSTEMS	2,470,771	173,823	(30,468)	0	2,614,126	2,542,449	4.32	108,934
TOTAL DISTRIBUTION PLANT	**220,355,485**	**20,102,607**	**(1,435,351)**	**0**	**239,022,741**	**229,689,113**		**4,961,935**
GENERAL PLANT								
390.1 STRUCTURES AND IMPROVEMENTS	6,245,672	570,655	(85,599)	0	6,730,728	6,488,200	7.14	463,526
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	66,068	0	0	0	66,068	66,068	7.33	4,843
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	369,215	0	(359,392)	0	9,824	189,520	41.96	73,239
391.9 OFFICE FURNITURE AND EQUIPMENT - OUTAGE MANAGEMENT SOFTWARE	3,496,035	0	0	0	3,496,035	3,496,035	22.71	792,901
392.1 TRANSPORTATION EQUIPMENT - CARS	336,097	34,000	0	0	370,097	353,097	13.45	45,396
392.2 TRANSPORTATION EQUIPMENT - TRUCKS	1,620,671	1,166,000	0	0	2,786,671	2,203,671	10.96	182,950
392.4 TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	490,636	0	0	0	490,636	490,636	8.07	39,594
393 STORES EQUIPMENT	14,618	0	0	0	14,618	14,618	12.08	1,766
394 TOOLS, SHOP AND GARAGE EQUIPMENT	1,555,310	0	(32,595)	0	1,522,715	1,539,013	5.18	79,650
395 LABORATORY EQUIPMENT	73,971	0	(36,232)	0	37,739	55,855	3.93	2,136
396 POWER OPERATED EQUIPMENT	804,018	267,333	0	0	1,071,351	937,685	7.74	72,097
397 COMMUNICATION EQUIPMENT	931,152	0	(53,344)	0	877,809	904,481	13.70	123,609
398 MISCELLANEOUS EQUIPMENT	591,542	166,257	0	0	757,799	674,671	11.66	76,151
TOTAL GENERAL PLANT	**16,595,005**	**2,204,245**	**(567,161)**	**0**	**18,232,090**	**17,413,548**		**1,957,858**
TOTAL DEPRECIABLE PLANT	**236,950,490**	**22,306,852**	**(2,002,512)**	**0**	**257,254,831**	**247,102,661**		**6,919,793**
NONDEPRECIABLE PLANT								
301.1 ORGANIZATION	1,602	0	0	0	1,602	1,602		
302.1 FRANCHISES AND CONSENTS - PERPETUAL	6,436	0	0	0	6,436	6,436		
360.1 LAND AND LAND RIGHTS - LAND	299,162	0	0	0	299,162	299,162		
360.2 LAND AND LAND RIGHTS - LAND RIGHTS	14,336	0	0	0	14,336	14,336		
389.1 LAND AND LAND RIGHTS - LAND	202,584	0	0	0	202,584	202,584		
TOTAL NONDEPRECIABLE PLANT	**524,120**	**0**	**0**	**0**	**524,120**	**524,120**		
TOTAL ELECTRIC PLANT	**237,474,610**	**22,306,852**	**(2,002,512)**	**0**	**257,778,951**	**247,626,781**		
LESS GENERAL AND INTANGIBLE PLANT ALLOCATED TO TRANSMISSION - 25.6247%	4,306,392	564,831	(145,333)	0	4,725,890	4,516,141		501,695
TOTAL ELECTRIC PLANT RELATED TO DISTRIBUTION OPERATIONS	**233,168,218**	**21,742,021**	**(1,857,179)**	**0**	**253,053,061**	**243,110,640**		**6,418,098**

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 3. CALCULATION OF DEPRECIATION ACCRUALS FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2024

ACCOUNT (1)	BEGINNING OF YEAR BALANCE (2)	ADDITIONS (3)	RETIREMENTS (4)	TRANSFERS AND ADJUSTMENTS (5)	END OF YEAR BALANCE (6)	AVERAGE BALANCE (7)	ANNUAL ACCRUAL RATE (8)	ANNUAL ACCRUAL AMOUNT* (9)
OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION								
COMMON PLANT								
301 ORGANIZATION (NONDEPRECIABLE)	138,964	0	0	0	138,964	138,964		
389.1 LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)	6,947,108	0	0	0	6,947,108	6,947,108		
390.1 STRUCTURES AND IMPROVEMENTS	35,947,826	0	-	0	35,947,826	35,947,826	2.78	999,350
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	5,242,774	0	(11,896)	0	5,230,878	5,236,826	5.33	279,096
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	1,353,581	0	(277,196)	0	1,076,385	1,214,983	28.28	340,331
392.1 TRANSPORTATION EQUIPMENT - CARS	71,637	0	0	0	71,637	71,637	-	0
398 MISCELLANEOUS EQUIPMENT	27,967	0	0	0	27,967	27,967	13.26	3,708
TOTAL COMMON PLANT	**49,729,857**	**0**	**(289,092)**	**0**	**49,440,765**	**49,585,311**		**1,622,485**
TOTAL COMMON PLANT ALLOCATED TO ELECTRIC DIVISION - 9.83%	**4,888,445**	**0**	**(28,418)**	**0**	**4,860,027**	**4,874,236**		**159,490**
INFORMATION SERVICES (IS)								
390 STRUCTURES AND IMPROVEMENTS - NEW READING DATA CENTER	0	20,329,983	0	0	20,329,983	10,164,992	2.78	494,527
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	8,017	0	(5,699)	0	2,319	5,168	5.11	252
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	14,757,055	0	(9,507,271)	0	5,249,785	10,003,420	20.02	1,923,378
391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE					0			
SUCCESS FACTORS	2,803,866	0	0	0	2,803,866	2,803,866	27.00	756,998
UNITE ERP	10,695,816	0	0	0	10,695,816	10,695,816	7.06	755,125
TOTAL OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	13,499,682	0	0	0	13,499,682	13,499,682		1,512,123
391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	52,284,361	19,821,968	(935,231)	0	71,171,098	61,727,730	10.39	6,064,627
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	134,231,132	0	0	0	134,231,132	134,231,132	6.71	9,006,909
TOTAL INFORMATION SERVICES (EXCLUDING 100% ALLOCATION AMOUNT)	**214,780,247**	**40,151,951**	**(10,448,200)**	**0**	**244,483,999**	**229,632,123**		**19,001,816**
TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION - 9.08%	**19,502,046**	**3,645,797**	**(948,697)**	**0**	**22,199,147**	**20,850,597**		**1,725,365**
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV.COSTS - 15 YEARS	246,470	0	0	0	246,470	246,470	6.90	17,006
TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION - 100.00%	**246,470**	**0**	**0**	**0**	**246,470**	**246,470**		**17,006**
TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION	**19,748,516**	**3,645,797**	**(948,697)**	**0**	**22,445,617**	**21,097,067**		**1,742,371**
EMPIRE YARD BUILDING								
390.1 STRUCTURES AND IMPROVEMENTS	14,913,154	2,174,653	(217,465)	0	16,870,341	15,891,748	1.87	281,419
TOTAL EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%	**1,949,149**	**284,227**	**(28,423)**	**0**	**2,204,954**	**2,077,051**		**36,781**
TOTAL OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION	**26,586,110**	**3,930,024**	**(1,005,538)**	**0**	**29,510,598**	**28,048,354**		**1,938,642**
LESS OTHER UTILITY PLANT ALLOCATED TO ELECTRIC TRANSMISSION - 25.6247%	6,812,611	1,007,057	(257,666)	0	7,562,002	7,187,307		496,771
TOTAL OTHER PLANT ALLOCATED TO ELECTRIC RELATED TO DISTRIBUTION OPERATIONS	**19,773,499**	**2,922,967**	**(747,872)**	**0**	**21,948,596**	**20,861,047**		**1,441,871**
TOTAL PLANT IN SERVICE RELATED TO DISTRIBUTION OPERATIONS	**252,941,717**	**24,664,988**	**(2,605,051)**	**0**	**275,001,657**	**263,971,687**		**7,859,969**

* TOTAL ACCRUALS SHOWN ARE BASED ON AVERAGE MONTHLY BALANCES

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 4. AMORTIZATION OF EXPERIENCED AND ESTIMATED NET SALVAGE

ACCOUNT	2020 GROSS SALVAGE	2020 COST OF REMOVAL	2021 GROSS SALVAGE	2021 COST OF REMOVAL	2022 GROSS SALVAGE	2022 COST OF REMOVAL	2023 GROSS SALVAGE	2023 COST OF REMOVAL	2024 GROSS SALVAGE	2024 COST OF REMOVAL	FIVE YEAR NET SALVAGE TOTAL	NET SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=(12)/5
ELECTRIC PLANT												
DISTRIBUTION PLANT												
361	0	0	0	0	0	1,103	0	0	0	0	1,103	221
362	0	24,880	0	5,721	0	9,451	(195)	265	(211)	287	40,198	8,040
364	0	695,428	0	628,085	0	441,244	0	79,641	0	124,325	1,968,723	393,745
365	0	121,069	0	175,874	0	138,834	0	787,454	0	734,802	1,958,033	391,607
366	0	9,269	0	49	0	500	0	0	0	0	9,818	1,964
367	0	14,036	0	23,539	0	16,452	0	2,950	0	5,042	62,019	12,404
368.1	0	3,020	0	4,895	0	7,807	0	14,447	0	14,395	44,564	8,913
368.2	0	58,648	0	25,689	0	33,600	0	1,060	0	1,091	120,088	24,018
369	0	81,584	0	72,000	0	39,522	0	43,432	0	44,732	281,270	56,254
370.1	(59,469)	0	0	(76,928)	0	(68,289)	(38,693)	0	(159,611)	0	(402,990)	(80,598)
370.2	0	3,781	0	3,263	0	3,331	0	2,005	0	2,073	14,453	2,891
370.3	0	0	0	0	0	2,299	0	0	0	0	2,299	460
371	0	9,609	0	30,601	0	32,911	0	0	0	0	73,121	14,624
371.5	0	0	0	0	0	0	0	0	0	0	-	0
373	0	19,433	0	14,719	0	28,409	0	14,699	0	15,140	92,400	18,480
TOTAL	**(59,469)**	**1,040,757**	**0**	**907,507**	**0**	**687,174**	**(38,888)**	**945,953**	**(159,822)**	**941,887**	**4,265,099**	**853,023**
GENERAL PLANT												
390.1	0	0	0	0	0	174	0	0	0	0	174	35
390.2	0	0	0	0	0	0	0	0	0	0	0	0
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
391.92	0	0	0	0	0	0	0	0	0	0	0	0
392.1	0	0	0	0	0	0	0	0	0	0	0	0
392.2	(13,693)	0	0	(112)	0	1,099	0	0	0	0	(12,706)	(2,541)
392.4	0	0	0	0	0	0	0	0	0	0	0	0
393	0	0	0	0	0	0	0	0	0	0	0	0
394	0	0	0	0	0	0	0	0	0	0	0	0
395	0	0	0	0	0	0	0	0	0	0	0	0
396	0	0	0	0	0	0	0	0	0	0	0	0
397	0	0	0	63	0	0	0	5	0	3	71	14
398	0	419	0	8,277	0	30,752	0	0	0	0	39,448	7,890
TOTAL	**(13,693)**	**419**	**0**	**8,228**	**0**	**32,025**	**0**	**5**	**0**	**3**	**26,987**	**5,398**
TOTAL ELECTRIC	**(73,162)**	**1,041,176**	**0**	**915,735**	**0**	**719,199**	**(38,888)**	**945,958**	**(159,822)**	**941,890**	**4,292,086**	**858,421**
LESS GENERAL PLANT ALLOCATED TO TRANSMISSION - 25.6247%	(3,509)	107	0	2,108	0	8,206	0	1	0	1	6,915	1,383
TOTAL	**(69,653)**	**1,041,069**	**0**	**913,627**	**0**	**710,993**	**(38,888)**	**945,957**	**(159,822)**	**941,889**	**4,285,171**	**857,038**

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 4. AMORTIZATION OF EXPERIENCED AND ESTIMATED NET SALVAGE

	2020		2021		2022		2023		2024			
ACCOUNT	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	FIVE YEAR NET SALVAGE TOTAL	NET SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=(12)/5
OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION												
COMMON PLANT												
390.2	0	0	0	0	0	0	0	0	0	0	0	0
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
392.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
INFORMATION SERVICES												
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
391.3	0	0	0	0	0	0	0	0	0	0	0	0
391.4	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
GRAND TOTAL	**(69,653)**	**1,041,069**	**0**	**913,627**	**0**	**710,993**	**(38,888)**	**945,957**	**(159,822)**	**941,889**	**4,285,171**	**857,038**

PART III. DETAILED DEPRECIATION CALCULATIONS

CUMULATIVE DEPRECIATED ORIGINAL COST

ELECTRIC PLANT

UGI UTILITIES, INC. - ELECTRIC DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1917	7,383	7,358	25	25	0.0
1918	8	7	1	26	0.0
1919	6,970	6,896	74	100	0.0
1920	5,305	5,281	24	124	0.0
1921	433	392	41	165	0.0
1922	45	45		165	0.0
1923	12,656	12,548	108	273	0.0
1924	4,274	4,264	10	283	0.0
1925	6,077	6,029	48	331	0.0
1926	11,072	11,071	1	332	0.0
1927	4,768	4,683	85	417	0.0
1928	3,006	2,953	53	470	0.0
1929	23,621	23,618	3	473	0.0
1930	5,932	5,616	316	789	0.0
1931	832	817	15	804	0.0
1932	3,620	3,562	58	862	0.0
1933	7,587	7,424	163	1,025	0.0
1934	7,130	6,926	204	1,229	0.0
1935	13,413	12,982	431	1,660	0.0
1936	21,753	20,252	1,501	3,161	0.0
1937	10,377	9,917	460	3,621	0.0
1938	9,022	8,283	739	4,360	0.0
1939	15,770	14,147	1,623	5,983	0.0
1940	15,839	14,342	1,497	7,480	0.0
1941	23,002	21,354	1,648	9,128	0.0
1942	16,706	15,844	862	9,990	0.0
1943	18,875	17,275	1,600	11,590	0.0
1944	17,709	16,410	1,299	12,889	0.0
1945	22,028	19,850	2,178	15,067	0.0
1946	38,277	33,727	4,550	19,617	0.0
1947	41,975	36,135	5,840	25,457	0.0
1948	61,692	54,657	7,035	32,492	0.0
1949	66,305	57,614	8,691	41,183	0.0
1950	61,154	51,507	9,647	50,830	0.0
1951	74,437	63,708	10,729	61,559	0.0
1952	70,369	59,671	10,698	72,257	0.0
1953	49,851	41,891	7,960	80,217	0.0
1954	69,233	58,346	10,887	91,104	0.1
1955	124,246	105,848	18,398	109,502	0.1
1956	85,548	68,861	16,687	126,189	0.1
1957	110,919	92,583	18,336	144,525	0.1
1958	161,893	141,121	20,772	165,297	0.1
1959	127,045	106,042	21,003	186,300	0.1
1960	94,604	77,985	16,619	202,919	0.1
1961	134,896	108,373	26,523	229,442	0.1
1962	141,915	111,742	30,173	259,615	0.1

UGI UTILITIES, INC. - ELECTRIC DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1963	174,600	137,474	37,126	296,741	0.2
1964	225,815	177,203	48,612	345,353	0.2
1965	279,723	214,884	64,839	410,192	0.2
1966	257,632	202,529	55,103	465,295	0.3
1967	332,710	266,971	65,739	531,034	0.3
1968	403,002	324,559	78,443	609,477	0.3
1969	624,777	486,710	138,067	747,544	0.4
1970	693,658	552,217	141,441	888,985	0.5
1971	774,149	604,356	169,793	1,058,778	0.6
1972	779,311	634,782	144,529	1,203,307	0.7
1973	918,587	718,793	199,794	1,403,101	0.8
1974	1,007,861	751,341	256,520	1,659,621	0.9
1975	1,147,973	860,381	287,592	1,947,213	1.1
1976	933,894	694,676	239,218	2,186,431	1.2
1977	1,109,311	786,656	322,655	2,509,086	1.4
1978	1,056,280	751,894	304,386	2,813,472	1.6
1979	1,219,060	873,986	345,074	3,158,546	1.8
1980	1,049,965	751,002	298,963	3,457,509	1.9
1981	962,524	657,452	305,072	3,762,581	2.1
1982	1,108,712	865,471	243,241	4,005,822	2.3
1983	1,022,498	789,944	232,554	4,238,376	2.4
1984	988,229	758,772	229,457	4,467,833	2.5
1985	1,125,926	872,796	253,130	4,720,963	2.7
1986	1,253,915	939,263	314,652	5,035,615	2.8
1987	1,380,132	1,015,932	364,200	5,399,815	3.0
1988	1,677,263	1,198,454	478,809	5,878,624	3.3
1989	2,137,053	1,485,092	651,961	6,530,585	3.7
1990	2,206,908	1,510,557	696,351	7,226,936	4.1
1991	2,466,915	1,640,853	826,062	8,052,998	4.5
1992	2,978,370	1,945,710	1,032,660	9,085,658	5.1
1993	2,188,747	1,411,166	777,581	9,863,239	5.6
1994	2,751,034	1,726,070	1,024,964	10,888,203	6.1
1995	3,791,459	2,292,661	1,498,798	12,387,001	7.0
1996	3,662,272	2,181,521	1,480,751	13,867,752	7.8
1997	3,572,880	2,135,360	1,437,520	15,305,272	8.6
1998	3,294,936	1,907,302	1,387,634	16,692,906	9.4
1999	3,018,703	1,772,693	1,246,010	17,938,916	10.1
2000	2,695,986	1,520,803	1,175,183	19,114,099	10.8
2001	3,207,176	1,677,163	1,530,013	20,644,112	11.6
2002	2,797,824	1,395,647	1,402,177	22,046,289	12.4
2003	2,986,931	1,457,912	1,529,019	23,575,308	13.3
2004	3,350,995	1,617,472	1,733,523	25,308,831	14.3
2005	4,483,640	2,072,517	2,411,123	27,719,954	15.6
2006	3,323,527	1,480,730	1,842,797	29,562,751	16.7
2007	6,122,392	3,613,470	2,508,922	32,071,673	18.1
2008	5,226,690	2,093,425	3,133,265	35,204,938	19.8

UGI UTILITIES, INC. - ELECTRIC DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2009	3,496,944	1,235,464	2,261,480	37,466,418	21.1
2010	3,093,435	1,055,459	2,037,976	39,504,394	22.3
2011	3,517,432	1,207,278	2,310,154	41,814,548	23.6
2012	3,543,049	1,071,312	2,471,737	44,286,285	25.0
2013	4,904,881	1,352,951	3,551,930	47,838,215	27.0
2014	4,944,257	1,230,279	3,713,978	51,552,193	29.0
2015	5,627,806	1,367,882	4,259,924	55,812,117	31.4
2016	8,530,650	1,959,332	6,571,318	62,383,435	35.1
2017	9,510,146	1,793,511	7,716,635	70,100,070	39.5
2018	8,426,609	1,582,845	6,843,764	76,943,834	43.4
2019	16,212,607	2,257,982	13,954,625	90,898,459	51.2
2020	14,865,412	2,154,326	12,711,086	103,609,545	58.4
2021	12,074,133	1,313,066	10,761,067	114,370,612	64.4
2022	22,813,537	3,147,265	19,666,272	134,036,884	75.5
2023	22,805,561	1,242,140	21,563,421	155,600,305	87.7
2024	22,306,852	422,855	21,883,997	177,484,302	100.0
TOTAL	257,254,828	79,770,526	177,484,302		

COMMON PLANT

UGI UTILITIES, INC. - COMMON PLANT

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1952					0.0
1953					0.0
2004	26,876	26,876			0.0
2005	39,966	36,182	3,784	3,784	0.0
2006	2,469	2,121	348	4,132	0.0
2007	878	713	165	4,297	0.0
2008	23,109	22,974	135	4,432	0.0
2009	4,753	3,421	1,332	5,764	0.0
2010	747,319	503,078	244,241	250,005	0.7
2014	22,225	22,225		250,005	0.7
2017				250,005	0.7
2019	33,513,297	5,405,399	28,107,898	28,357,903	81.2
2020	1,945,898	254,455	1,691,443	30,049,346	86.0
2021	1,730,955	794,861	936,094	30,985,440	88.7
2022	4,030,382	344,488	3,685,894	34,671,334	99.3
2023	266,566	15,357	251,209	34,922,543	100.0
SUBTOTAL	42,354,693	7,432,150	34,922,543		
NONDEPRECIABLE	7,086,071		7,086,071		
TOTAL	49,440,764	7,432,150	42,008,614		

INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2007	1,760	1,529	231	231	0.0
2011	425,873	380,536	45,337	45,568	0.0
2012	401,290	332,008	69,282	114,850	0.1
2013	142,365	108,364	34,001	148,851	0.1
2014	495,556	344,401	151,155	300,006	0.2
2015	732,103	669,229	62,874	362,880	0.2
2016	2,349,695	1,559,478	790,217	1,153,097	0.7
2017	77,621,819	38,836,535	38,785,284	39,938,381	25.4
2018	1,545,759	933,231	612,528	40,550,909	25.8
2019	64,669,854	25,822,628	38,847,226	79,398,135	50.6
2020	14,501,914	7,164,850	7,337,064	86,735,199	55.3
2021	15,645,524	4,823,772	10,821,752	97,556,951	62.2
2022	13,473,468	3,652,184	9,821,284	107,378,235	68.4
2023	12,571,538	1,721,083	10,850,455	118,228,690	75.3
2024	40,151,951	1,448,191	38,703,760	156,932,450	100.0
TOTAL	244,730,469	87,798,019	156,932,450		

EMPIRE YARD

UGI UTILITIES, INC. - ELECTRIC DIVISION - EMPIRE YARD

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1960	116,516	96,495	20,021	20,021	0.2
1961	79,506	61,885	17,621	37,642	0.5
1962	137,654	108,409	29,245	66,887	0.8
1963	8,527	6,521	2,006	68,893	0.9
1964	3,547	2,750	797	69,690	0.9
1965	915	809	106	69,796	0.9
1966	271	205	66	69,862	0.9
1967	788	590	198	70,060	0.9
1968	3,285	2,448	837	70,897	0.9
1969	611	453	158	71,055	0.9
1970	2,156	1,589	567	71,622	0.9
1971	69,645	51,033	18,612	90,234	1.1
1972	9,777	8,438	1,339	91,573	1.1
1973	64,832	63,315	1,517	93,090	1.2
1974	1,013	728	285	93,375	1.2
1975	18,968	13,555	5,413	98,788	1.2
1976	93,752	66,734	27,018	125,806	1.6
1977	258,152	184,665	73,487	199,293	2.5
1978	38,263	34,019	4,244	203,537	2.5
1979	30,409	21,285	9,124	212,661	2.7
1980	56,776	41,843	14,933	227,594	2.8
1981	99,359	84,519	14,840	242,434	3.0
1982	37,757	33,417	4,340	246,774	3.1
1983	15,324	10,970	4,354	251,128	3.1
1984	57,338	43,895	13,443	264,571	3.3
1985	66,445	46,674	19,771	284,342	3.5
1986	244,500	179,844	64,656	348,998	4.3
1987	104,210	75,140	29,070	378,068	4.7
1988	92,462	67,950	24,512	402,580	5.0
1989	138,869	96,315	42,554	445,134	5.5
1990	95,774	95,293	481	445,615	5.6
1991	12,447	8,174	4,273	449,888	5.6
1992	111,846	74,936	36,910	486,798	6.1
1993	235,368	151,483	83,885	570,683	7.1
1994	47,897	44,558	3,339	574,022	7.2
1995	135,077	85,834	49,243	623,265	7.8
1996	77,703	48,274	29,429	652,694	8.1
1997	4,543,724	2,744,816	1,798,908	2,451,602	30.6
1998	279,363	167,156	112,207	2,563,809	31.9
1999	83,509	48,596	34,913	2,598,722	32.4
2000	88,369	50,563	37,806	2,636,528	32.9
2001	721,375	407,821	313,554	2,950,082	36.8
2002	50,366	31,592	18,774	2,968,856	37.0
2003	205,361	122,718	82,643	3,051,499	38.0
2004	407,020	338,138	68,882	3,120,381	38.9
2005	193,206	112,309	80,897	3,201,278	39.9

UGI UTILITIES, INC. - ELECTRIC DIVISION - EMPIRE YARD

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2006	138,396	68,571	69,825	3,271,103	40.8
2007	867,450	416,321	451,129	3,722,232	46.4
2008	107,763	65,782	41,981	3,764,213	46.9
2009	53,582	24,023	29,559	3,793,772	47.3
2010	383,687	272,959	110,728	3,904,500	48.7
2011	529,451	346,039	183,412	4,087,912	50.9
2012	48,979	19,283	29,696	4,117,608	51.3
2013	121,627	45,396	76,231	4,193,839	52.3
2014	182,328	76,773	105,555	4,299,394	53.6
2015	94,154	30,855	63,299	4,362,693	54.4
2016	640,488	219,565	420,923	4,783,616	59.6
2017	100,744	58,986	41,758	4,825,374	60.1
2018	129,795	76,294	53,501	4,878,875	60.8
2019	845,684	840,458	5,226	4,884,101	60.9
2020	45,380	8,488	36,892	4,920,993	61.3
2021	220,112	33,508	186,604	5,107,597	63.6
2022	778,043	226,528	551,515	5,659,112	70.5
2023	267,994	19,465	248,529	5,907,641	73.6
2024	2,174,653	57,776	2,116,877	8,024,518	100.0
TOTAL	16,870,342	8,845,824	8,024,518		

UTILITY PLANT IN SERVICE

ELECTRIC PLANT

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. 0						
1925	4,675.49	4,675	4,675			
1926	1,561.20	1,561	1,561			
1943	642.32	632	501	141	0.78	141
1971	7,177.62	5,934	4,701	2,477	8.66	286
1975	12,539.90	9,919	7,859	4,681	10.45	448
1977	485.00	374	296	189	11.45	17
2018	50,277.08	7,351	5,824	44,453	37.95	1,171
2019	240,869.72	29,940	23,721	217,149	38.75	5,604
2020	34,409.01	3,517	2,786	31,623	39.55	800
2021	163,744.75	13,067	10,353	153,392	40.36	3,801
2022	111,114.35	6,389	5,062	106,052	40.98	2,588
	627,496.44	83,359	67,339	560,157		14,856

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.7 2.37

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 362 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-S1						
NET SALVAGE PERCENT.. 0						
1924	2,652.88	2,653	2,653			
1925	868.15	868	868			
1926	6,164.75	6,165	6,165			
1927	817.53	818	818			
1929	15,708.26	15,708	15,708			
1937	394.38	394	394			
1938	219.32	219	219			
1939	206.93	207	207			
1941	647.02	647	647			
1942	4,215.01	4,215	4,215			
1944	1,636.11	1,636	1,636			
1945	166.88	166	147	20	0.23	20
1948	2,536.91	2,473	2,193	344	1.00	344
1949	918.08	889	789	129	1.27	102
1950	9,481.38	9,116	8,086	1,395	1.54	906
1951	6,799.99	6,492	5,758	1,042	1.81	576
1952	19,683.43	18,655	16,546	3,137	2.09	1,501
1955	3,940.46	3,652	3,239	701	2.93	239
1956	4,258.30	3,917	3,474	784	3.21	244
1957	933.58	852	756	178	3.50	51
1958	31,489.97	28,506	25,284	6,206	3.79	1,637
1959	11,147.96	10,008	8,877	2,271	4.09	555
1960	4,891.08	4,356	3,864	1,027	4.38	234
1961	9,025.21	7,969	7,068	1,957	4.68	418
1962	31,751.21	27,790	24,649	7,102	4.99	1,423
1963	5,544.58	4,811	4,267	1,278	5.29	242
1964	6,017.82	5,175	4,590	1,428	5.60	255
1965	4,444.40	3,787	3,359	1,085	5.92	183
1966	3,351.16	2,829	2,509	842	6.23	135
1967	25,292.48	21,151	18,760	6,532	6.55	997
1968	3,051.25	2,526	2,240	811	6.88	118
1969	39,803.05	32,629	28,941	10,862	7.21	1,507
1970	1,813.19	1,471	1,305	508	7.54	67
1971	730.20	586	520	210	7.88	27
1972	24,280.09	19,291	17,110	7,170	8.22	872
1973	2,748.83	2,161	1,917	832	8.56	97
1974	2,803.34	2,178	1,932	871	8.92	98
1975	5,673.90	4,359	3,866	1,808	9.27	195
1976	1,021.22	775	687	334	9.63	35
1977	7,237.57	5,428	4,814	2,424	10.00	242
1978	514.53	381	338	177	10.37	17
1982	3,011.35	2,405	2,133	878	10.66	82
1984	2,654.15	2,072	1,838	816	11.30	72

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 362 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

SURVIVOR CURVE.. IOWA 40-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1991	20,647.39	14,622	12,969	7,678	13.70	560
1997	24,223.22	15,321	13,589	10,634	15.98	665
2008	8,572.27	3,819	3,387	5,185	20.54	252
2011	2,253.62	855	758	1,496	22.09	68
2015	60,424.03	16,991	15,070	45,354	24.28	1,868
2016	16,188.09	4,115	3,650	12,538	24.94	503
2017	1,267,430.91	287,960	255,411	1,012,020	25.50	39,687
2018	226,482.39	45,047	39,955	186,527	26.18	7,125
2019	2,526,597.05	429,521	380,971	2,145,626	26.86	79,882
2020	1,493,942.86	209,152	185,511	1,308,432	27.65	47,321
2021	1,118,807.12	122,957	109,059	1,009,748	28.35	35,617
2022	3,899,603.42	308,069	273,246	3,626,357	29.15	124,403
2023	284,659.13	13,550	12,018	272,641	30.04	9,076
2024	307,808.51	4,894	4,341	303,468	30.95	9,805
	11,568,187.90	1,749,259	1,555,321	10,012,867		370,323

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.0   3.20

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 364 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 59-R2.5						
NET SALVAGE PERCENT.. 0						
1919	6,251.65	6,134	6,252			
1920	5,086.33	4,968	5,086			
1921	60.81	59	61			
1922	44.98	44	45			
1923	195.60	188	196			
1924	120.62	116	121			
1926	1,450.44	1,377	1,450			
1927	1,140.67	1,077	1,141			
1928	1,294.28	1,217	1,294			
1929	826.25	773	823	3	3.77	1
1930	2,938.75	2,739	2,915	24	4.01	6
1931	360.95	335	356	5	4.24	1
1932	2,857.72	2,641	2,810	48	4.47	11
1933	6,784.26	6,245	6,645	139	4.69	30
1934	5,849.96	5,363	5,707	143	4.91	29
1935	12,116.85	11,065	11,774	343	5.12	67
1936	14,500.26	13,188	14,033	467	5.34	87
1937	6,853.95	6,208	6,606	248	5.56	45
1938	3,558.20	3,210	3,416	142	5.78	25
1939	5,388.77	4,841	5,151	238	6.00	40
1940	7,325.64	6,552	6,972	354	6.23	57
1941	15,111.71	13,457	14,320	792	6.46	123
1942	10,488.23	9,299	9,895	593	6.69	89
1943	14,575.21	12,863	13,688	887	6.93	128
1944	13,104.17	11,514	12,252	852	7.16	119
1945	15,400.12	13,469	14,332	1,068	7.40	144
1946	21,274.84	18,516	19,703	1,572	7.65	205
1947	15,680.94	13,581	14,452	1,229	7.90	156
1948	24,077.06	20,751	22,081	1,996	8.15	245
1949	18,629.35	15,974	16,998	1,631	8.41	194
1950	17,252.65	14,714	15,657	1,596	8.68	184
1951	33,443.47	28,365	30,183	3,260	8.96	364
1952	24,603.46	20,750	22,080	2,523	9.24	273
1953	22,199.69	18,614	19,807	2,393	9.53	251
1954	26,405.56	22,006	23,417	2,989	9.83	304
1955	41,316.98	34,209	36,402	4,915	10.15	484
1956	28,394.63	23,356	24,853	3,542	10.47	338
1957	26,129.12	21,342	22,710	3,419	10.81	316
1958	44,633.94	36,199	38,520	6,114	11.15	548
1959	45,133.14	36,321	38,650	6,483	11.52	563
1960	36,755.37	29,348	31,229	5,526	11.89	465
1961	52,315.75	41,427	44,083	8,233	12.28	670
1962	44,285.09	34,767	36,996	7,289	12.68	575

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 364 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 59-R2.5						
NET SALVAGE PERCENT.. 0						
1963	60,494.90	47,063	50,080	10,415	13.10	795
1964	61,998.59	47,771	50,834	11,165	13.54	825
1965	100,952.95	77,032	81,971	18,982	13.98	1,358
1966	77,317.82	58,381	62,124	15,194	14.45	1,051
1967	58,077.41	43,391	46,173	11,904	14.92	798
1968	90,560.87	66,892	71,180	19,381	15.42	1,257
1969	132,856.61	97,008	103,227	29,630	15.92	1,861
1970	159,969.64	115,396	122,794	37,176	16.44	2,261
1971	215,739.44	153,650	163,500	52,239	16.98	3,077
1972	157,325.19	110,581	117,670	39,655	17.53	2,262
1973	236,625.50	164,074	174,593	62,032	18.09	3,429
1974	313,368.24	214,206	227,939	85,429	18.67	4,576
1975	246,311.11	165,905	176,541	69,770	19.26	3,623
1976	263,931.92	175,090	186,315	77,617	19.86	3,908
1977	288,195.87	188,206	200,272	87,924	20.47	4,295
1978	316,237.91	203,142	216,165	100,073	21.10	4,743
1979	382,162.24	241,408	256,885	125,277	21.73	5,765
1980	274,983.95	170,677	181,619	93,365	22.38	4,172
1981	265,616.24	161,890	172,269	93,347	23.04	4,052
1982	280,365.09	187,172	199,172	81,193	21.04	3,859
1983	313,840.41	205,848	219,045	94,795	21.64	4,381
1984	326,359.09	210,175	223,649	102,710	22.25	4,616
1985	305,157.94	192,829	205,191	99,967	22.86	4,373
1986	371,905.71	230,433	245,206	126,700	23.48	5,396
1987	444,290.13	269,773	287,068	157,222	24.10	6,524
1988	464,835.00	276,344	294,060	170,775	24.73	6,906
1989	690,648.85	401,681	427,433	263,216	25.36	10,379
1990	660,485.41	375,552	399,629	260,856	25.99	10,037
1991	728,214.55	406,781	432,860	295,355	26.27	11,243
1992	973,816.49	530,730	564,755	409,061	26.92	15,195
1993	748,416.76	398,457	424,002	324,415	27.67	11,724
1994	959,131.89	497,310	529,192	429,940	28.32	15,181
1995	1,299,670.50	659,453	701,730	597,940	28.64	20,878
1996	1,257,894.65	620,142	659,899	597,996	29.31	20,402
1997	953,393.05	456,199	485,446	467,947	29.97	15,614
1998	925,421.26	429,210	456,727	468,694	30.64	15,297
1999	774,329.40	347,519	369,798	404,531	31.32	12,916
2000	703,233.77	304,922	324,471	378,763	32.00	11,836
2001	947,646.11	396,400	421,813	525,833	32.68	16,090
2002	815,377.33	328,434	349,490	465,887	33.36	13,965
2003	971,930.90	376,137	400,251	571,680	34.06	16,784
2004	1,101,060.22	408,493	434,681	666,379	34.75	19,176
2005	1,118,939.65	399,238	424,833	694,107	35.15	19,747

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 364 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

SURVIVOR CURVE.. IOWA 59-R2.5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
2006	1,078,008.49	366,954	390,479	687,529	35.85	19,178
2007	880,538.86	285,118	303,397	577,142	36.55	15,790
2008	1,073,965.50	329,600	350,731	723,234	37.26	19,410
2009	1,066,885.65	309,183	329,005	737,881	37.98	19,428
2010	1,012,124.71	275,905	293,593	718,532	38.69	18,572
2011	1,374,712.23	352,614	375,220	999,492	39.13	25,543
2012	865,724.75	206,735	219,989	645,736	39.85	16,204
2013	1,185,709.99	261,805	278,589	907,121	40.58	22,354
2014	1,689,992.55	344,251	366,321	1,323,672	41.05	32,245
2015	1,560,035.64	288,919	307,442	1,252,594	41.78	29,981
2016	1,803,807.04	301,957	321,315	1,482,492	42.26	35,080
2017	2,228,138.45	332,438	353,750	1,874,388	42.75	43,845
2018	1,675,323.81	217,792	231,755	1,443,569	43.50	33,185
2019	4,178,635.02	464,246	494,009	3,684,626	44.00	83,742
2020	2,963,945.65	273,276	290,796	2,673,150	44.28	60,369
2021	2,989,694.17	217,650	231,603	2,758,091	44.58	61,868
2022	3,799,295.20	200,603	213,463	3,585,832	44.89	79,880
2023	1,022,571.41	33,336	35,473	987,098	44.58	22,142
2024	1,597,277.51	18,209	19,377	1,577,901	43.17	36,551
	56,561,694.61	17,060,768	18,154,021	38,407,674		1,029,131

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.3   1.82

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 58-R1.5						
NET SALVAGE PERCENT.. 0						
1937	644.33	554	548	96	8.16	12
1938	3,475.92	2,970	2,940	536	8.44	64
1939	8,412.27	7,146	7,074	1,338	8.73	153
1940	6,390.24	5,396	5,341	1,049	9.02	116
1941	4,839.52	4,063	4,022	818	9.31	88
1942	1,322.09	1,103	1,092	230	9.61	24
1943	3,104.88	2,574	2,548	557	9.91	56
1944	2,306.16	1,900	1,881	425	10.21	42
1945	5,529.32	4,526	4,480	1,049	10.52	100
1946	14,775.75	12,014	11,893	2,883	10.84	266
1947	21,772.83	17,584	17,406	4,367	11.16	391
1948	19,084.37	15,307	15,152	3,932	11.48	343
1949	29,512.49	23,503	23,265	6,247	11.81	529
1950	25,802.64	20,398	20,192	5,611	12.15	462
1951	24,491.24	19,217	19,023	5,468	12.49	438
1952	16,355.89	12,738	12,609	3,747	12.83	292
1953	16,607.42	12,831	12,701	3,906	13.19	296
1954	27,806.82	21,311	21,096	6,711	13.55	495
1955	45,022.47	34,217	33,871	11,151	13.92	801
1956	27,965.50	21,071	20,858	7,108	14.30	497
1957	41,803.76	31,223	30,907	10,897	14.68	742
1958	20,919.77	15,484	15,327	5,593	15.07	371
1959	27,914.13	20,464	20,257	7,657	15.48	495
1960	29,680.48	21,549	21,331	8,349	15.89	525
1961	47,687.00	34,286	33,939	13,748	16.30	843
1962	46,396.76	33,014	32,680	13,717	16.73	820
1963	69,264.09	48,760	48,267	20,997	17.17	1,223
1964	98,652.69	68,700	68,006	30,647	17.61	1,740
1965	82,932.00	57,095	56,518	26,414	18.07	1,462
1966	48,391.84	32,932	32,599	15,793	18.53	852
1967	56,389.20	37,917	37,534	18,855	19.00	992
1968	88,593.78	58,839	58,244	30,350	19.48	1,558
1969	190,572.20	124,956	123,693	66,879	19.97	3,349
1970	162,768.79	105,323	104,258	58,511	20.47	2,858
1971	189,403.67	120,893	119,671	69,733	20.98	3,324
1972	115,854.19	72,928	72,191	43,663	21.49	2,032
1973	152,023.04	94,306	93,353	58,670	22.02	2,664
1974	244,240.04	149,238	147,729	96,511	22.56	4,278
1975	262,112.59	157,718	156,124	105,989	23.10	4,588
1976	204,487.71	121,106	119,882	84,606	23.65	3,577
1977	317,286.00	184,848	182,979	134,307	24.21	5,548
1978	236,474.76	135,443	134,074	102,401	24.78	4,132
1979	208,955.35	117,592	116,403	92,552	25.36	3,650

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

SURVIVOR CURVE.. IOWA 58-R1.5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1980	152,792.24	84,457	83,603	69,189	25.94	2,667
1981	191,917.42	104,098	103,046	88,871	26.54	3,349
1982	200,944.88	129,047	127,743	73,202	23.54	3,110
1983	114,046.60	71,975	71,247	42,800	24.11	1,775
1984	92,989.46	58,016	57,430	35,559	24.26	1,466
1985	113,318.72	69,385	68,684	44,635	24.85	1,796
1986	151,042.25	90,701	89,784	61,258	25.45	2,407
1987	133,763.69	78,733	77,937	55,827	26.04	2,144
1988	242,677.61	140,753	139,330	103,348	26.25	3,937
1989	287,578.15	163,201	161,551	126,027	26.86	4,692
1990	313,664.61	174,021	172,262	141,403	27.48	5,146
1991	497,760.93	271,429	268,685	229,076	27.73	8,261
1992	621,934.40	330,931	327,586	294,348	28.36	10,379
1993	374,049.15	195,590	193,613	180,436	28.74	6,278
1994	518,747.36	265,806	263,119	255,628	29.02	8,809
1995	824,634.73	411,163	407,007	417,628	29.67	14,076
1996	802,617.72	388,868	384,937	417,681	30.32	13,776
1997	664,681.86	314,395	311,217	353,465	30.64	11,536
1998	675,329.62	311,394	308,246	367,084	30.97	11,853
1999	527,523.93	235,381	233,002	294,522	31.65	9,306
2000	423,447.07	183,607	181,751	241,696	32.00	7,553
2001	645,021.59	269,813	267,086	377,936	32.68	11,565
2002	445,299.90	180,346	178,523	266,777	33.06	8,069
2003	606,710.98	237,406	235,006	371,705	33.45	11,112
2004	594,425.12	224,217	221,951	372,474	33.85	11,004
2005	1,033,536.87	374,864	371,075	662,462	34.26	19,336
2006	706,347.27	245,668	243,185	463,162	34.69	13,351
2007	1,163,857.98	386,983	383,071	780,787	35.13	22,226
2008	1,203,921.02	381,402	377,547	826,374	35.58	23,226
2009	1,149,559.55	345,673	342,179	807,381	36.05	22,396
2010	841,746.41	240,403	237,973	603,773	36.26	16,651
2011	815,828.11	219,131	216,916	598,912	36.75	16,297
2012	1,279,774.54	323,143	319,876	959,899	37.00	25,943
2013	1,824,593.00	430,239	425,890	1,398,703	37.28	37,519
2014	1,738,930.97	379,783	375,944	1,362,987	37.58	36,269
2015	2,070,930.78	415,015	410,820	1,660,111	37.90	43,802
2016	2,360,065.90	431,420	427,059	1,933,007	38.01	50,855
2017	2,747,281.34	451,104	446,544	2,300,737	38.16	60,292
2018	2,005,906.26	292,060	289,108	1,716,798	38.14	45,013
2019	4,199,052.48	529,081	523,733	3,675,319	38.17	96,288
2020	5,554,369.51	589,874	583,911	4,970,459	37.87	131,251
2021	3,747,454.90	320,033	316,798	3,430,657	37.48	91,533

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 58-R1.5						
NET SALVAGE PERCENT.. 0						
2022	5,229,820.83	332,094	328,737	4,901,084	36.87	132,929
2023	15,684,502.16	636,791	630,354	15,054,148	35.40	425,258
2024	14,696,022.49	229,258	226,940	14,469,082	31.65	457,159
	83,518,448.35	14,623,789	14,475,964	69,042,484		2,000,748

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 34.5   2.40

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 365.7 REG AFUDC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	711,827.21-	62,285-	115,649-	596,178-		16,334-
	711,827.21-	62,285-	115,649-	596,178-		16,334-

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 36.5 2.29

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 366 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. 0						
1923	11,558.71	11,194	11,559			
1925	37.18	36	37			
1928	977.05	927	977			
1955	321.43	266	313	8	11.25	1
1957	1,089.51	887	1,043	47	12.09	4
1966	171.19	127	149	22	16.62	1
1967	2,233.28	1,643	1,932	301	17.19	18
1968	5,305.30	3,854	4,533	772	17.78	43
1969	482.65	346	407	76	18.38	4
1970	3,078.47	2,179	2,563	515	18.99	27
1971	3,756.90	2,623	3,085	672	19.62	34
1972	7,229.66	4,976	5,852	1,378	20.26	68
1973	9,574.39	6,494	7,638	1,936	20.91	93
1974	12,540.35	8,379	9,855	2,685	21.57	124
1975	9,522.75	6,263	7,366	2,157	22.25	97
1976	14,345.28	9,285	10,920	3,425	22.93	149
1977	17,590.28	11,196	13,168	4,422	23.63	187
1978	25,021.43	15,656	18,413	6,608	24.33	272
1979	43,579.82	26,785	31,502	12,078	25.05	482
1980	7,270.58	4,387	5,160	2,111	25.78	82
1981	11,294.79	6,688	7,866	3,429	26.51	129
1982	11,192.02	7,094	8,343	2,849	24.41	117
1983	14,496.16	9,030	10,620	3,876	24.97	155
1984	5,717.07	3,475	4,087	1,630	25.97	63
1985	15,585.87	9,299	10,937	4,649	26.54	175
1986	48,278.74	28,253	33,229	15,050	27.11	555
1987	29,523.06	16,934	19,916	9,607	27.69	347
1988	76,661.56	42,792	50,328	26,334	28.69	918
1989	113,372.28	61,947	72,856	40,516	29.26	1,385
1990	144,531.37	77,223	90,822	53,709	29.85	1,799
1991	53,431.24	27,891	32,803	20,628	30.45	677
1992	99,809.99	50,534	59,433	40,377	31.45	1,284
1993	36,156.76	17,995	21,164	14,993	31.79	472
1994	118,794.48	57,615	67,761	51,033	32.39	1,576
1995	150,384.17	70,530	82,951	67,433	33.40	2,019
1996	91,378.94	41,669	49,007	42,372	34.00	1,246
1997	233,401.22	103,350	121,551	111,850	34.61	3,232
1998	151,590.70	65,078	76,539	75,052	35.23	2,130
1999	192,024.40	79,325	93,295	98,729	36.23	2,725
2000	160,172.66	63,973	75,239	84,934	36.85	2,305
2001	227,349.82	87,621	103,052	124,298	37.48	3,316
2002	321,940.17	118,796	139,717	182,223	38.48	4,736
2003	161,435.90	57,277	67,364	94,072	39.10	2,406

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 366 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

SURVIVOR CURVE.. IOWA 65-R3
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
2004	172,849.36	58,458	68,753	104,096	40.11	2,595
2005	430,305.70	139,290	163,820	266,486	40.74	6,541
2006	313,210.56	96,782	113,826	199,385	41.38	4,818
2007	95,642.88	27,947	32,869	62,774	42.38	1,481
2008	693,812.85	192,325	226,194	467,619	43.02	10,870
2009	66,961.89	17,544	20,634	46,328	43.67	1,061
2010	173,900.46	42,606	50,109	123,791	44.67	2,771
2011	38,275.92	8,784	10,331	27,945	45.32	617
2012	105,122.31	22,338	26,272	78,850	46.32	1,702
2013	153,776.20	30,232	35,556	118,220	46.98	2,516
2014	138,890.11	25,084	29,501	109,389	47.64	2,296
2015	90,029.54	14,711	17,302	72,728	48.64	1,495
2016	421,879.54	62,016	72,937	348,943	49.31	7,077
2017	544,253.07	70,644	83,085	461,168	50.30	9,168
2018	751,950.64	85,046	100,023	651,928	50.97	12,790
2019	1,561,494.51	150,216	176,669	1,384,826	51.65	26,812
2020	200,300.10	15,864	18,658	181,642	52.32	3,472
2021	46,993.55	2,914	3,427	43,567	52.99	822
2022	136,059.64	6,055	7,121	128,939	53.68	2,402
	8,779,918.41	2,290,748	2,692,439	6,087,479		136,759

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 44.5 1.56

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

SURVIVOR CURVE.. IOWA 42-R1.5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1957	20,627.49	18,260	18,489	2,138	4.82	444
1966	125.20	103	104	21	7.35	3
1967	11,774.06	9,627	9,748	2,026	7.66	264
1968	5,892.27	4,773	4,833	1,059	7.98	133
1969	6,593.65	5,291	5,357	1,237	8.30	149
1970	10,445.11	8,299	8,403	2,042	8.63	237
1971	10,426.34	8,200	8,303	2,123	8.97	237
1972	40,901.18	31,825	32,225	8,676	9.32	931
1973	34,371.06	26,457	26,789	7,582	9.67	784
1974	70,554.39	53,688	54,363	16,191	10.04	1,613
1975	100,419.69	75,506	76,455	23,965	10.42	2,300
1976	44,861.76	33,315	33,734	11,128	10.81	1,029
1977	84,417.56	61,887	62,665	21,753	11.21	1,940
1978	51,208.16	37,040	37,505	13,703	11.62	1,179
1979	60,597.67	43,226	43,769	16,829	12.04	1,398
1980	31,146.68	21,892	22,167	8,980	12.48	720
1981	36,147.19	25,028	25,343	10,804	12.92	836
1982	26,941.84	20,945	21,208	5,734	12.10	474
1983	57,676.92	44,250	44,806	12,871	12.52	1,028
1984	25,374.93	19,201	19,442	5,933	12.94	459
1985	32,795.58	24,587	24,896	7,900	13.10	603
1986	74,691.07	55,137	55,830	18,861	13.56	1,391
1987	56,717.39	41,200	41,718	14,999	14.03	1,069
1988	119,545.84	85,368	86,441	33,105	14.51	2,282
1989	169,717.53	119,057	120,553	49,165	15.00	3,278
1990	127,887.90	88,473	89,585	38,303	15.26	2,510
1991	206,241.78	139,894	141,652	64,590	15.77	4,096
1992	118,074.09	78,448	79,434	38,640	16.29	2,372
1993	143,325.78	93,907	95,087	48,239	16.58	2,909
1994	139,642.13	89,441	90,565	49,077	17.12	2,867
1995	217,759.11	136,840	138,560	79,199	17.45	4,539
1996	313,046.69	191,835	194,246	118,801	18.01	6,596
1997	346,722.43	206,924	209,524	137,198	18.58	7,384
1998	270,535.58	157,722	159,704	110,832	18.95	5,849
1999	194,935.05	110,353	111,740	83,195	19.55	4,255
2000	203,626.89	112,239	113,649	89,978	19.95	4,510
2001	429,375.57	230,059	232,950	196,426	20.36	9,648
2002	159,586.14	82,586	83,624	75,962	20.98	3,621
2003	40,572.59	20,327	20,582	19,991	21.42	933
2004	101,728.79	49,216	49,834	51,895	21.87	2,373
2005	296,149.29	138,006	139,740	156,409	22.34	7,001
2006	195,144.15	87,366	88,464	106,680	22.82	4,675
2007	130,067.60	55,773	56,474	73,594	23.31	3,157

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

SURVIVOR CURVE.. IOWA 42-R1.5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
2008	559,268.90	228,853	231,729	327,540	23.82	13,751
2009	106,129.39	41,284	41,803	64,326	24.34	2,643
2010	238,413.35	88,165	89,273	149,140	24.71	6,036
2011	196,108.31	68,559	69,421	126,687	25.11	5,045
2012	95,466.53	31,389	31,783	63,684	25.52	2,495
2013	436,024.00	133,859	135,541	300,483	25.96	11,575
2014	360,233.83	102,523	103,811	256,423	26.40	9,713
2015	136,275.83	35,732	36,181	100,095	26.73	3,745
2016	183,762.22	44,048	44,602	139,160	26.96	5,162
2017	1,079,568.15	233,187	236,117	843,451	27.22	30,986
2018	1,136,910.63	217,264	219,994	916,917	27.51	33,330
2019	1,248,080.94	207,306	209,911	1,038,170	27.61	37,601
2020	1,427,107.54	199,795	202,306	1,224,802	27.65	44,297
2021	1,254,372.93	141,744	143,525	1,110,848	27.46	40,453
2022	1,434,754.43	120,806	122,325	1,312,429	27.18	48,287
2023	315,377.44	17,030	17,244	298,133	26.28	11,344
2024	539,884.70	11,230	11,371	528,514	23.54	22,452
	15,566,131.24	4,866,345	4,927,497	10,638,634		432,991

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 24.6 2.78

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 368.1 TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S1						
NET SALVAGE PERCENT.. 0						
1941	872.49	837	872			
1948	6,484.68	5,941	6,485			
1949	9,672.27	8,800	9,672			
1952	403.39	359	403			
1953	537.73	475	538			
1954	5,212.94	4,571	5,213			
1955	17,747.81	15,441	17,748			
1956	2,027.59	1,750	2,012	16	6.16	3
1957	10,091.62	8,641	9,933	159	6.47	25
1958	44,521.84	37,814	43,467	1,055	6.78	156
1959	21,935.09	18,474	21,236	699	7.10	98
1960	14,264.71	11,913	13,694	571	7.42	77
1961	13,677.31	11,322	13,015	662	7.75	85
1962	4,765.19	3,910	4,495	270	8.08	33
1963	5,943.37	4,833	5,556	387	8.41	46
1964	18,969.01	15,285	17,570	1,399	8.74	160
1965	13,827.75	11,038	12,688	1,140	9.08	126
1966	34,369.17	27,167	31,229	3,140	9.43	333
1967	59,602.50	46,649	53,623	5,980	9.78	611
1968	78,289.39	60,666	69,736	8,553	10.13	844
1969	55,449.85	42,524	48,881	6,569	10.49	626
1970	79,302.15	60,182	69,179	10,123	10.85	933
1971	63,060.54	47,352	54,431	8,630	11.21	770
1972	82,972.04	61,602	70,812	12,160	11.59	1,049
1973	108,599.99	79,736	91,657	16,943	11.96	1,417
1974	130,864.43	94,950	109,145	21,719	12.35	1,759
1975	185,224.11	132,826	152,684	32,540	12.73	2,556
1976	131,545.65	93,163	107,091	24,455	13.13	1,863
1977	150,336.96	105,135	120,853	29,484	13.53	2,179
1978	153,528.71	106,002	121,849	31,680	13.93	2,274
1979	150,874.44	102,795	118,163	32,711	14.34	2,281
1980	173,014.30	116,266	133,648	39,366	14.76	2,667
1981	99,611.76	65,987	75,852	23,760	15.19	1,564
1982	210,108.64	158,002	181,624	28,485	13.93	2,045
1983	158,142.85	117,421	134,976	23,167	14.31	1,619
1984	158,276.86	116,587	134,017	24,260	14.39	1,686
1985	220,860.34	160,367	184,342	36,518	14.81	2,466
1986	157,044.86	112,334	129,128	27,917	15.22	1,834
1987	235,670.62	165,912	190,716	44,955	15.66	2,871
1988	228,340.15	158,925	182,685	45,655	15.83	2,884
1989	276,391.47	188,996	217,251	59,140	16.30	3,628
1990	311,141.93	208,870	240,096	71,046	16.77	4,236
1991	288,190.61	190,696	219,205	68,986	17.00	4,058

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 368.1 TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

SURVIVOR CURVE.. IOWA 45-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1992	352,830.71	228,705	262,897	89,934	17.50	5,139
1993	207,657.78	132,776	152,626	55,032	17.76	3,099
1994	257,648.70	161,881	186,083	71,566	18.04	3,967
1995	316,952.66	195,433	224,651	92,302	18.34	5,033
1996	335,640.43	201,854	232,032	103,608	18.89	5,485
1997	321,634.81	189,282	217,580	104,055	19.23	5,411
1998	375,000.95	215,626	247,862	127,139	19.59	6,490
1999	384,033.59	214,444	246,504	137,530	20.16	6,822
2000	409,267.35	222,601	255,880	153,387	20.55	7,464
2001	249,003.85	131,673	151,358	97,646	20.94	4,663
2002	331,680.97	170,152	195,590	136,091	21.36	6,371
2003	175,881.30	87,343	100,401	75,480	21.79	3,464
2004	270,196.15	129,613	148,990	121,206	22.24	5,450
2005	267,604.53	123,687	142,178	125,427	22.69	5,528
2006	111,012.59	49,290	56,659	54,354	23.17	2,346
2007	434,849.00	184,898	212,541	222,308	23.65	9,400
2008	497,615.36	201,982	232,179	265,436	24.15	10,991
2009	414,924.20	160,161	184,105	230,819	24.66	9,360
2010	110,807.37	40,489	46,542	64,265	25.18	2,552
2011	315,229.01	108,502	124,723	190,506	25.72	7,407
2012	413,698.99	133,418	153,364	260,335	26.26	9,914
2013	310,049.53	93,077	106,992	203,058	26.81	7,574
2014	189,679.51	52,389	60,221	129,459	27.52	4,704
2015	324,204.24	81,926	94,174	230,030	28.09	8,189
2016	236,194.17	53,994	62,066	174,128	28.68	6,071
2017	498,214.88	101,237	116,372	381,843	29.40	12,988
2018	568,028.82	101,166	116,291	451,738	30.00	15,058
2019	505,672.39	76,761	88,237	417,435	30.73	13,584
2020	563,465.60	70,490	81,029	482,437	31.47	15,330
2021	1,176,890.49	115,335	132,578	1,044,312	32.21	32,422
2022	1,070,783.02	75,169	86,407	984,376	33.09	29,748
2023	1,850,016.41	78,256	89,956	1,760,060	33.96	51,827
2024	1,843,518.69	26,178	30,092	1,813,427	34.83	52,065
	19,861,657.16	7,192,304	8,266,630	11,595,027		427,778

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.1   2.15

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 368.2 TRANSFORMER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

SURVIVOR CURVE.. IOWA 39-R2
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1966	1,929.05	1,736	1,929			
1967	2,171.52	1,938	2,172			
1968	531.87	471	532			
1970	1,338.80	1,164	1,339			
1971	5,193.89	4,476	5,194			
1972	19,389.76	16,556	19,390			
1973	36,534.42	30,904	36,534			
1974	25,830.70	21,632	25,831			
1975	77,222.77	64,015	77,223			
1976	53,862.54	44,181	53,863			
1977	19,827.62	16,086	19,828			
1978	15,484.66	12,415	15,316	169	7.73	22
1979	83,875.10	66,433	81,957	1,918	8.11	236
1980	59,278.94	46,359	57,192	2,087	8.50	246
1981	55,816.14	43,078	53,145	2,671	8.90	300
1982	68,532.57	57,040	68,533			
1983	64,528.69	52,972	64,529			
1984	62,113.98	50,499	62,114			
1985	107,195.38	85,831	105,938	1,257	9.77	129
1986	132,903.73	105,233	129,885	3,019	10.06	300
1987	112,966.03	87,944	108,546	4,420	10.60	417
1988	142,398.69	109,433	135,069	7,330	10.92	671
1989	171,799.36	129,605	159,967	11,832	11.48	1,031
1990	170,667.36	126,840	156,554	14,113	11.83	1,193
1991	224,798.59	163,698	202,047	22,752	12.41	1,833
1992	347,636.46	248,908	307,219	40,417	12.79	3,160
1993	235,547.05	166,202	205,137	30,410	13.14	2,314
1994	330,013.78	228,502	282,032	47,982	13.55	3,541
1995	416,071.68	281,098	346,950	69,122	14.17	4,878
1996	340,140.08	224,901	277,588	62,552	14.60	4,284
1997	395,465.23	255,550	315,417	80,048	15.06	5,315
1998	306,285.24	192,347	237,407	68,878	15.70	4,387
1999	274,195.58	167,808	207,120	67,076	16.17	4,148
2000	220,040.19	131,012	161,704	58,336	16.65	3,504
2001	244,261.31	140,646	173,594	70,667	17.31	4,082
2002	274,461.19	153,149	189,026	85,435	17.82	4,794
2003	457,142.11	246,674	304,461	152,681	18.34	8,325
2004	313,458.73	163,218	201,454	112,005	18.87	5,936
2005	282,705.27	141,692	174,886	107,819	19.41	5,555
2006	312,876.74	150,494	185,750	127,127	19.96	6,369
2007	341,351.24	157,090	193,891	147,460	20.52	7,186
2008	241,221.99	105,872	130,674	110,548	21.09	5,242
2009	227,989.20	95,071	117,343	110,646	21.67	5,106

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 368.2 TRANSFORMER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 39-R2						
NET SALVAGE PERCENT.. 0						
2010	170,797.08	67,362	83,143	87,654	22.26	3,938
2011	99,169.83	36,812	45,436	53,734	22.87	2,350
2012	204,623.09	71,373	88,093	116,530	23.34	4,993
2013	275,807.21	89,444	110,398	165,409	23.96	6,904
2014	153,812.87	46,190	57,011	96,802	24.47	3,956
2015	204,738.46	56,405	69,619	135,119	24.98	5,409
2016	280,837.77	70,181	86,622	194,216	25.51	7,613
2017	373,270.95	83,687	103,292	269,979	25.95	10,404
2018	94,317.45	18,637	23,003	71,314	26.39	2,702
2019	1,038,937.24	176,619	217,994	820,943	26.86	30,564
2020	384,436.80	54,513	67,283	317,154	27.24	11,643
2021	350,077.32	39,559	48,826	301,251	27.46	10,971
2022	285,379.12	23,744	29,306	256,073	27.53	9,302
2023	22,833.49	1,187	1,465	21,368	27.32	782
2024	23,514.75	447	552	22,963	25.82	889
	11,239,608.66	5,426,933	6,688,323	4,551,286		206,924

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 22.0 1.84

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 369 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 53-R2						
NET SALVAGE PERCENT.. 0						
1947	65.90	59	66			
1954	117.33	100	117			
1955	330.16	278	330			
1956	127.83	107	128			
1958	215.48	178	215			
1959	635.70	520	634	2	9.64	
1960	1,276.62	1,036	1,263	14	9.99	1
1961	474.56	382	466	9	10.36	1
1962	5,102.56	4,070	4,962	141	10.73	13
1963	13,831.34	10,932	13,329	502	11.11	45
1964	20,502.27	16,054	19,573	929	11.50	81
1965	23,106.41	17,914	21,841	1,265	11.91	106
1966	27,517.45	21,121	25,751	1,766	12.32	143
1967	55,603.10	42,237	51,496	4,107	12.74	322
1968	85,919.95	64,570	78,725	7,195	13.17	546
1969	162,950.65	121,076	147,619	15,332	13.62	1,126
1970	233,307.95	171,327	208,886	24,422	14.08	1,735
1971	229,457.13	166,508	203,011	26,446	14.54	1,819
1972	198,708.19	142,394	173,610	25,098	15.02	1,671
1973	268,271.51	189,765	231,366	36,906	15.51	2,379
1974	151,535.35	105,760	128,945	22,590	16.01	1,411
1975	141,731.72	97,554	118,940	22,792	16.52	1,380
1976	154,532.15	104,819	127,798	26,734	17.05	1,568
1977	154,199.67	103,052	125,644	28,556	17.58	1,624
1978	167,700.24	110,333	134,521	33,179	18.13	1,830
1979	197,900.61	128,151	156,245	41,656	18.68	2,230
1980	146,781.63	93,469	113,960	32,822	19.25	1,705
1981	189,400.31	118,536	144,522	44,878	19.83	2,263
1982	162,232.55	113,790	138,736	23,497	17.99	1,306
1983	177,736.48	122,443	149,286	28,450	18.63	1,527
1984	202,493.21	136,926	166,944	35,549	19.27	1,845
1985	174,492.97	116,422	141,945	32,548	19.58	1,662
1986	211,135.25	138,104	168,380	42,755	20.23	2,113
1987	239,430.19	154,289	188,113	51,317	20.55	2,497
1988	248,878.36	156,992	191,409	57,469	21.22	2,708
1989	261,865.52	162,461	198,077	63,789	21.57	2,957
1990	275,611.31	167,076	203,703	71,908	22.25	3,232
1991	261,549.87	155,674	189,802	71,748	22.61	3,173
1992	252,274.48	146,445	178,549	73,725	23.31	3,163
1993	188,255.37	107,343	130,875	57,380	23.75	2,416
1994	162,832.21	90,893	110,819	52,013	24.14	2,155
1995	314,235.49	170,567	207,960	106,275	24.85	4,277
1996	289,086.88	153,245	186,840	102,247	25.26	4,048

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 369 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

SURVIVOR CURVE.. IOWA 53-R2
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1997	336,695.60	173,129	211,083	125,613	25.98	4,835
1998	292,342.41	146,405	178,501	113,841	26.41	4,311
1999	326,069.17	157,981	192,614	133,455	27.13	4,919
2000	175,980.98	82,781	100,929	75,052	27.58	2,721
2001	196,589.08	89,625	109,273	87,316	28.05	3,113
2002	236,529.77	103,789	126,542	109,988	28.78	3,822
2003	221,072.51	93,646	114,176	106,897	29.26	3,653
2004	283,739.03	115,766	141,145	142,594	29.75	4,793
2005	419,286.98	164,360	200,392	218,895	30.25	7,236
2006	147,723.75	55,204	67,306	80,418	31.00	2,594
2007	593,279.74	211,801	258,233	335,047	31.52	10,630
2008	486,862.59	165,485	201,763	285,100	32.04	8,898
2009	339,770.78	109,542	133,556	206,215	32.58	6,329
2010	354,979.45	108,091	131,787	223,192	33.12	6,739
2011	241,011.80	68,978	84,100	156,912	33.67	4,660
2012	383,277.64	102,527	125,003	258,275	34.23	7,545
2013	478,401.55	119,409	145,586	332,816	34.58	9,625
2014	439,944.24	101,187	123,370	316,574	35.16	9,004
2015	420,012.14	88,581	108,000	312,012	35.55	8,777
2016	501,756.63	95,534	116,478	385,279	36.14	10,661
2017	414,726.55	70,586	86,060	328,667	36.56	8,990
2018	388,775.47	58,394	71,195	317,580	36.79	8,632
2019	434,636.99	55,938	68,201	366,436	37.24	9,840
2020	410,419.63	44,161	53,842	356,578	37.34	9,549
2021	591,235.29	50,491	61,560	529,675	37.48	14,132
2022	534,863.65	33,589	40,953	493,911	37.34	13,227
2023	495,962.21	19,442	23,704	472,258	36.81	12,830
2024	511,246.56	7,260	8,852	502,395	34.59	14,524
	16,710,606.10	6,618,654	8,069,605	8,641,001		279,667

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 30.9 1.67

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.1 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 34-R1						
NET SALVAGE PERCENT.. 0						
1968	1,693.27	1,503	1,693			
1969	4,358.34	3,829	4,358			
1970	6,452.23	5,608	6,452			
1971	18,341.56	15,768	18,342			
1972	105,411.30	89,600	105,411			
1973	20,721.16	17,406	20,721			
1974	12,665.48	10,512	12,665			
1975	18,420.60	15,100	18,421			
1976	30,505.10	24,682	30,251	254	6.49	39
1977	26,799.02	21,392	26,218	581	6.86	85
1978	46,748.48	36,807	45,111	1,637	7.23	226
1979	27,977.31	21,715	26,614	1,363	7.61	179
1980	35,063.23	26,813	32,863	2,200	8.00	275
1981	18,311.10	13,793	16,905	1,406	8.39	168
1982	36,595.67	30,616	36,596			
1983	25,104.59	20,814	25,105			
1984	26,713.73	21,935	26,714			
1985	35,016.01	28,314	34,737	279	9.29	30
1986	50,643.94	40,485	49,670	974	9.60	101
1987	44,740.75	35,332	43,348	1,393	9.92	140
1988	52,111.72	40,616	49,830	2,282	10.26	222
1989	59,826.93	45,971	56,400	3,427	10.62	323
1990	80,597.89	61,005	74,845	5,753	11.00	523
1991	67,308.35	50,131	61,504	5,804	11.39	510
1992	115,794.30	84,773	104,005	11,789	11.80	999
1993	86,787.96	62,609	76,813	9,975	12.17	820
1994	104,046.31	73,623	90,325	13,721	12.60	1,089
1995	99,467.74	68,951	84,594	14,874	13.06	1,139
1996	76,078.26	51,825	63,582	12,496	13.34	937
1997	64,161.37	42,699	52,386	11,775	13.82	852
1998	153,038.87	99,766	122,399	30,640	14.15	2,165
1999	74,425.90	47,260	57,982	16,444	14.66	1,122
2000	194,996.70	120,859	148,278	46,719	15.03	3,108
2001	17,793.38	10,747	13,185	4,608	15.41	299
2002	5,700.27	3,335	4,092	1,608	15.96	101
2003	39,746.12	22,560	27,678	12,068	16.38	737
2004	104,367.62	57,548	70,603	33,765	16.68	2,024
2005	3,351.19	1,784	2,189	1,162	17.13	68
2006	17,529.30	8,982	11,020	6,509	17.60	370
2017	90,327.04	23,648	29,013	61,314	21.15	2,899
2018	359,804.49	84,194	103,294	256,510	21.28	12,054

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.1 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 34-R1						
NET SALVAGE PERCENT.. 0						
2020	140,586.56	24,603	30,184	110,403	21.21	5,205
2023	95,427.47	6,794	8,335	87,092	19.55	4,455
2024	397,708.91	11,454	14,053	383,656	16.89	22,715
	3,093,267.52	1,587,761	1,938,784	1,154,484		65,979

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.5 2.13

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.2 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1924	1,421.46	1,363	1,421			
1925	125.62	120	126			
1926	1,253.21	1,193	1,253			
1927	2,187.12	2,076	2,187			
1928	358.40	339	358			
1929	1,765.64	1,663	1,766			
1930	1,049.49	985	1,049			
1931	404.60	378	405			
1932	700.72	653	701			
1933	660.39	613	660			
1934	913.27	844	913			
1935	781.77	720	782			
1936	1,416.72	1,299	1,417			
1937	1,848.05	1,687	1,848			
1938	1,475.06	1,341	1,469	6	6.83	1
1939	1,592.88	1,441	1,578	15	7.13	2
1940	1,551.36	1,397	1,530	21	7.44	3
1941	1,177.48	1,056	1,157	20	7.76	3
1942	551.10	492	539	12	8.10	1
1943	553.04	491	538	15	8.44	2
1944	662.56	585	641	22	8.80	2
1945	873.36	766	839	34	9.18	4
1946	1,894.37	1,653	1,810	84	9.57	9
1947	4,349.99	3,771	4,130	220	9.98	22
1948	6,356.43	5,474	5,996	360	10.41	35
1949	6,090.31	5,208	5,704	386	10.86	36
1950	6,099.12	5,178	5,671	428	11.33	38
1951	7,056.44	5,944	6,510	546	11.82	46
1952	6,258.97	5,229	5,727	532	12.34	43
1953	6,480.11	5,368	5,879	601	12.87	47
1954	5,684.36	4,666	5,111	573	13.43	43
1955	6,889.11	5,602	6,136	753	14.01	54
1956	6,921.42	5,573	6,104	817	14.61	56
1957	6,387.28	5,090	5,575	812	15.23	53
1958	10,243.28	8,077	8,847	1,396	15.86	88
1959	6,094.29	4,753	5,206	888	16.51	54
1960	5,129.76	3,955	4,332	798	17.17	46
1961	6,070.76	4,627	5,068	1,003	17.84	56
1962	4,769.73	3,592	3,934	836	18.52	45
1963	6,676.00	4,966	5,439	1,237	19.21	64
1964	5,839.81	4,290	4,699	1,141	19.91	57
1965	9,040.22	6,555	7,180	1,860	20.62	90
1966	8,145.36	5,829	6,384	1,761	21.33	83

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.2 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1967	10,900.69	7,694	8,427	2,474	22.06	112
1968	10,005.64	6,964	7,628	2,378	22.80	104
1969	12,474.31	8,557	9,372	3,102	23.55	132
1970	11,830.73	7,998	8,760	3,071	24.30	126
1971	13,436.83	8,945	9,797	3,640	25.07	145
1972	13,285.39	8,706	9,535	3,750	25.85	145
1973	17,821.90	11,494	12,589	5,233	26.63	197
1974	13,751.23	8,722	9,553	4,198	27.43	153
1975	11,476.52	7,155	7,837	3,640	28.24	129
1976	10,117.05	6,197	6,787	3,330	29.06	115
1977	17,895.34	10,766	11,792	6,103	29.88	204
1978	15,983.55	9,437	10,336	5,648	30.72	184
1979	28,611.00	16,568	18,147	10,464	31.57	331
1980	21,300.04	12,093	13,245	8,055	32.42	248
1981	45,377.13	25,242	27,647	17,730	33.28	533
1982	27,226.74	15,644	17,135	10,092	31.28	323
1983	18,810.84	10,553	11,558	7,253	32.28	225
1984	23,934.21	13,102	14,350	9,584	33.28	288
1985	32,413.19	17,429	19,090	13,323	33.74	395
1986	32,185.22	16,865	18,472	13,713	34.74	395
1987	34,826.35	17,772	19,465	15,361	35.74	430
1988	33,808.48	16,911	18,522	15,286	36.22	422
1989	34,342.72	16,704	18,296	16,047	37.22	431
1990	31,720.12	14,991	16,419	15,301	38.22	400
1991	29,667.92	13,612	14,909	14,759	39.22	376
1992	34,199.85	15,332	16,793	17,407	39.69	439
1993	27,575.11	12,072	13,222	14,353	40.45	355
1994	31,637.95	13,414	14,692	16,946	41.44	409
1995	35,503.63	14,556	15,943	19,561	42.45	461
1996	27,256.43	10,799	11,828	15,428	43.44	355
1997	35,331.50	13,603	14,899	20,432	43.93	465
1998	18,201.92	6,753	7,396	10,806	44.93	241
2000	32,315.96	11,084	12,140	20,176	46.93	430
2001	3,046.87	1,002	1,097	1,950	47.93	41
2002	57,978.76	18,263	20,003	37,976	48.93	776
2003	120,547.24	36,285	39,742	80,805	49.93	1,618
2004	123,337.75	35,645	39,041	84,297	50.43	1,672
2005	164,376.01	45,203	49,510	114,866	51.42	2,234
2006	21,252.23	5,543	6,071	15,181	52.43	290
2007	22,555.90	5,567	6,098	16,458	53.42	308
2008	43,899.29	10,211	11,184	32,715	54.43	601
2009	30,700.07	6,711	7,350	23,350	55.42	421
2010	20,822.01	4,256	4,662	16,160	56.43	286

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.2 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
2011	12,947.84	2,465	2,700	10,248	57.42	178
2012	32,808.73	5,781	6,332	26,477	58.43	453
2013	43,327.96	7,028	7,698	35,630	59.42	600
2014	48,191.57	7,132	7,812	40,380	60.43	668
2015	116,511.49	15,613	17,100	99,411	61.42	1,619
2016	24,226.87	2,902	3,179	21,048	62.43	337
2017	27,101.86	2,886	3,161	23,941	62.92	380
2018	17,054.23	1,574	1,724	15,330	63.92	240
2019	27,034.81	2,111	2,312	24,723	64.92	381
2020	11,436.72	731	801	10,636	65.92	161
2021	20,943.92	1,041	1,140	19,804	66.92	296
2022	24,369.69	865	947	23,423	67.92	345
2023	11,414.86	243	266	11,149	68.92	162
2024	11,801.91	84	92	11,710	69.92	167
	1,988,714.50	753,778	825,222	1,163,492		25,015

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.5 1.26

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.3 ELECTRONIC METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-S3						
NET SALVAGE PERCENT.. 0						
1995	280.36	268	280			
1996	68,883.81	65,371	68,884			
1997	102,737.04	96,624	102,737			
1998	28,763.57	26,831	28,764			
1999	188,041.11	173,581	188,041			
2000	79,287.63	72,263	79,288			
2001	138,189.12	124,370	138,189			
2002	53,297.66	47,248	53,295	3	2.88	1
2003	91,737.08	80,077	90,325	1,412	3.13	451
2004	199,255.57	170,324	192,121	7,135	3.48	2,050
2005	296,348.56	247,925	279,653	16,696	3.81	4,382
2006	207,413.16	169,208	190,862	16,551	4.18	3,960
2007	2,301,040.99	1,824,265	2,057,723	243,318	4.57	53,242
2008	303,024.99	232,481	262,233	40,792	5.01	8,142
2010	88,994.13	62,972	71,031	17,963	5.99	2,999
2011	231,480.17	155,624	175,540	55,940	6.58	8,502
2012	101,602.74	64,396	72,637	28,966	7.22	4,012
2013	64,307.89	38,083	42,957	21,351	7.92	2,696
2014	85,443.25	46,737	52,718	32,725	8.69	3,766
2015	44,174.73	22,114	24,944	19,231	9.48	2,029
2016	129,029.77	58,244	65,697	63,333	10.33	6,131
2018	4,662.78	1,622	1,830	2,833	12.19	232
2022	229,894.69	30,806	34,748	195,147	16.16	12,076
	5,037,890.80	3,811,434	4,274,497	763,394		114,671

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.7   2.28

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-O1						
NET SALVAGE PERCENT.. 0						
1926	642.41	642	642			
1929	5,321.34	5,321	5,321			
1940	197.92	198	198			
1941	263.93	264	264			
1945	32.62	33	33			
1946	283.36	283	283			
1948	1,451.21	1,451	1,451			
1949	253.79	254	254			
1950	17.14	17	17			
1951	453.74	454	454			
1952	127.16	127	127			
1954	1,722.53	1,723	1,723			
1955	5,517.30	5,517	5,517			
1956	70.84	71	71			
1957	1,458.37	1,458	1,458			
1958	8,469.70	8,470	8,470			
1959	4,103.33	4,103	4,103			
1960	1,507.24	1,507	1,507			
1961	2,700.54	2,701	2,701			
1962	2,255.35	2,255	2,255			
1963	5,671.86	5,672	5,672			
1964	8,035.28	8,035	8,035			
1965	3,704.69	3,658	3,565	140	0.38	140
1966	9,174.56	8,908	8,682	493	0.87	493
1967	13,870.71	13,233	12,897	974	1.38	706
1968	14,200.92	13,311	12,973	1,228	1.88	653
1969	9,906.37	9,124	8,892	1,014	2.37	428
1970	14,122.73	12,767	12,443	1,680	2.88	583
1971	5,824.84	5,169	5,038	787	3.38	233
1972	9,178.06	7,994	7,791	1,387	3.87	358
1973	8,790.25	7,507	7,317	1,473	4.38	336
1974	13,190.14	11,044	10,764	2,426	4.88	497
1975	4,362.97	3,582	3,491	872	5.37	162
1976	3,177.16	2,554	2,489	688	5.88	117
1977	8,577.39	6,753	6,582	1,995	6.38	313
1978	2,737.09	2,110	2,056	681	6.87	99
1979	1,616.62	1,219	1,188	429	7.38	58
1980	11,925.65	8,793	8,570	3,356	7.88	426
1981	16,141.57	11,638	11,343	4,799	8.37	573
1982	18,883.68	15,798	15,397	3,487	8.25	423
1983	16,411.21	13,539	13,195	3,216	8.75	368
1984	22,000.61	17,886	17,432	4,569	9.26	493
1985	18,787.13	15,116	14,732	4,055	9.53	425

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-O1						
NET SALVAGE PERCENT.. 0						
1986	9,922.73	7,857	7,658	2,265	10.06	225
1987	16,483.16	12,893	12,566	3,917	10.37	378
1988	23,966.98	18,419	17,952	6,015	10.92	551
1989	33,211.86	25,171	24,532	8,680	11.26	771
1990	35,050.72	26,169	25,505	9,546	11.62	822
1991	24,596.13	18,073	17,614	6,982	12.00	582
1992	35,762.34	25,835	25,179	10,583	12.39	854
1993	11,592.34	8,253	8,044	3,548	12.75	278
1994	42,356.58	29,582	28,831	13,526	13.17	1,027
1995	59,961.02	41,217	40,171	19,790	13.42	1,475
1996	12,276.38	8,257	8,047	4,229	13.87	305
1997	31,396.73	20,722	20,196	11,201	14.17	790
1998	28,411.16	18,371	17,905	10,506	14.48	726
1999	15,625.56	9,882	9,631	5,995	14.82	405
2000	34,452.28	21,271	20,731	13,721	15.18	904
2001	43,335.86	26,175	25,511	17,825	15.41	1,157
2002	72,442.64	42,705	41,621	30,822	15.67	1,967
2003	29,016.52	16,655	16,232	12,785	15.96	801
2004	23,409.96	13,053	12,722	10,688	16.26	657
2005	12,053.15	6,534	6,368	5,685	16.47	345
2006	122,072.81	64,137	62,510	59,563	16.71	3,565
2007	69,471.83	35,257	34,362	35,110	16.98	2,068
2008	56,319.94	27,597	26,897	29,423	17.17	1,714
2009	33,569.02	15,818	15,417	18,152	17.39	1,044
2010	20,156.51	9,119	8,888	11,269	17.55	642
2011	91,834.61	39,801	38,791	53,044	17.65	3,005
2012	25,438.26	10,493	10,227	15,211	17.80	855
2013	61,860.47	24,262	23,646	38,214	17.82	2,144
2014	40,611.98	15,010	14,629	25,983	17.91	1,451
2015	189,149.16	65,597	63,933	125,216	17.90	6,995
2016	201,370.11	65,043	63,393	137,977	17.82	7,743
2017	130,859.86	38,865	37,879	92,981	17.75	5,238
2018	105,309.30	28,476	27,753	77,556	17.54	4,422
2019	49,677.75	11,992	11,688	37,990	17.28	2,198
2020	34,301.17	7,210	7,027	27,274	16.91	1,613
2021	25,224.02	4,450	4,337	20,887	16.34	1,278
2022	89,421.39	12,412	12,097	77,324	15.52	4,982
	2,219,113.60	1,114,892	1,087,883	1,131,231		73,861

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.3 3.33

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 371.5 INSTALLATIONS ON CUSTOMERS PREMISES - DUSK TO DAWN LIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 23-R1						
NET SALVAGE PERCENT.. 0						
1973	1,435.43	1,435	1,435			
1974	6,471.13	6,471	6,471			
1975	3,583.76	3,584	3,584			
1976	4,402.59	4,403	4,403			
1977	4,697.22	4,697	4,697			
1978	4,229.73	4,230	4,230			
1979	5,985.23	5,902	5,985			
1980	4,861.55	4,724	4,862			
1981	2,917.37	2,792	2,917			
1982	1,561.73	1,518	1,562			
1983	2,231.26	2,154	2,231			
1984	2,149.66	2,059	2,150			
1985	2,342.27	2,225	2,342			
1986	990.28	932	990			
1987	1,925.20	1,793	1,925			
1988	2,301.67	2,128	2,302			
1989	1,493.31	1,363	1,493			
1990	4,328.13	3,913	4,328			
1991	2,572.95	2,301	2,573			
1992	4,859.73	4,294	4,860			
1993	2,315.34	2,028	2,315			
1994	8,619.58	7,440	8,620			
1995	9,663.67	8,210	9,664			
1996	37,963.03	31,809	37,963			
1997	53,663.03	44,272	53,584	79	5.83	14
1998	61,778.99	49,930	60,431	1,348	6.29	214
1999	61,882.53	49,073	59,395	2,488	6.66	374
2000	30,918.71	24,089	29,155	1,764	6.95	254
2008	14,410.22	8,893	10,764	3,646	10.24	356
2017	1,150.61	406	491	660	13.73	48
	347,705.91	289,068	337,722	9,984		1,260

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.9   0.36

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 28-L0						
NET SALVAGE PERCENT.. 0						
1917	255.59	238	231	25	1.88	13
1918	7.89	7	7	1	2.01	
1919	718.11	664	644	74	2.12	35
1920	218.81	201	195	24	2.24	11
1921	372.29	341	331	41	2.36	17
1923	902.04	818	793	109	2.60	42
1924	78.85	71	69	10	2.72	4
1925	370.36	333	323	47	2.84	17
1927	623.08	554	537	86	3.09	28
1928	376.73	334	324	53	3.21	17
1930	1,943.88	1,703	1,652	292	3.47	84
1931	66.18	58	56	10	3.59	3
1932	61.29	53	51	10	3.72	3
1933	142.50	123	119	24	3.85	6
1934	366.66	315	306	61	3.98	15
1935	514.37	439	426	88	4.12	21
1936	5,836.39	4,950	4,802	1,034	4.25	243
1937	636.31	537	521	115	4.38	26
1938	293.22	246	239	54	4.52	12
1939	169.11	141	137	32	4.66	7
1940	374.17	310	301	73	4.80	15
1941	90.12	74	72	18	4.94	4
1942	129.75	106	103	27	5.08	5
1945	25.34	20	19	6	5.51	1
1946	48.26	39	38	10	5.66	2
1947	104.97	83	81	24	5.81	4
1948	1,701.47	1,339	1,299	402	5.96	67
1949	1,228.90	961	932	297	6.11	49
1950	2,501.19	1,942	1,884	617	6.26	99
1951	1,636.01	1,261	1,223	413	6.42	64
1952	2,936.51	2,246	2,179	758	6.58	115
1953	4,025.67	3,058	2,966	1,060	6.73	158
1954	2,283.67	1,721	1,669	615	6.90	89
1955	3,160.13	2,363	2,292	868	7.06	123
1956	15,781.41	11,712	11,361	4,420	7.22	612
1957	2,398.09	1,765	1,712	686	7.39	93
1958	1,399.49	1,022	991	408	7.56	54
1959	10,081.76	7,298	7,079	3,003	7.73	388
1960	1,098.79	789	765	334	7.90	42
1961	2,944.42	2,096	2,033	911	8.07	113
1962	2,589.12	1,826	1,771	818	8.25	99
1963	7,174.25	5,014	4,864	2,310	8.43	274
1964	5,799.04	4,016	3,896	1,903	8.61	221

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 28-L0						
NET SALVAGE PERCENT.. 0						
1965	41,714.26	28,619	27,762	13,952	8.79	1,587
1966	47,078.10	31,980	31,022	16,056	8.98	1,788
1967	34,875.50	23,454	22,751	12,124	9.17	1,322
1968	18,957.37	12,620	12,242	6,715	9.36	717
1969	9,328.93	6,147	5,963	3,366	9.55	352
1970	9,228.59	6,015	5,835	3,394	9.75	348
1971	7,570.86	4,880	4,734	2,837	9.95	285
1972	3,045.94	1,942	1,884	1,162	10.15	114
1973	21,069.78	13,282	12,884	8,186	10.35	791
1974	9,493.91	5,913	5,736	3,758	10.56	356
1975	47,627.30	29,308	28,430	19,197	10.77	1,782
1976	16,201.25	9,848	9,553	6,648	10.98	605
1977	11,765.08	7,059	6,848	4,917	11.20	439
1978	18,865.13	11,171	10,836	8,029	11.42	703
1979	15,099.26	8,822	8,558	6,541	11.64	562
1980	15,204.14	8,759	8,497	6,707	11.87	565
1981	29,555.65	16,794	16,291	13,265	12.09	1,097
1982	59,350.10	47,391	45,971	13,379	10.66	1,255
1983	45,661.97	36,164	35,081	10,581	10.83	977
1984	29,429.93	23,100	22,408	7,022	11.03	637
1985	16,889.65	13,127	12,734	4,156	11.25	369
1986	7,345.08	5,647	5,478	1,867	11.50	162
1987	15,581.52	11,898	11,542	4,040	11.53	350
1988	41,736.47	31,469	30,526	11,210	11.83	948
1989	31,598.96	23,614	22,907	8,692	11.92	729
1990	29,503.47	21,827	21,173	8,330	12.05	691
1991	20,440.69	14,952	14,504	5,937	12.20	487
1992	20,060.24	14,492	14,058	6,002	12.39	484
1993	118,349.77	84,620	82,085	36,265	12.56	2,887
1994	36,077.33	25,528	24,763	11,314	12.60	898
1995	25,240.46	17,572	17,046	8,194	12.87	637
1996	10,008.95	6,874	6,668	3,341	13.00	257
1997	9,372.82	6,341	6,151	3,222	13.15	245
1998	5,546.32	3,689	3,578	1,968	13.34	148
1999	5,616.98	3,681	3,571	2,046	13.41	153
2000	28,245.82	18,131	17,588	10,658	13.67	780
2001	65,563.28	41,292	40,055	25,508	13.81	1,847
2002	23,529.67	14,560	14,124	9,406	13.86	679
2003	71,138.02	42,982	41,694	29,444	14.09	2,090
2004	63,166.97	37,294	36,177	26,990	14.22	1,898
2005	72,014.84	41,567	40,322	31,693	14.28	2,219
2008	28,480.49	15,083	14,631	13,849	14.65	945
2009	8,392.13	4,293	4,164	4,228	14.80	286

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 28-L0						
NET SALVAGE PERCENT.. 0						
2010	21,206.41	10,455	10,142	11,064	14.91	742
2011	1,690.50	801	777	914	14.99	61
2012	23,695.25	10,753	10,431	13,264	15.05	881
2013	1,972.77	853	827	1,146	15.10	76
2014	7,775.45	3,184	3,089	4,686	15.14	310
2015	28,083.74	10,832	10,507	17,577	15.13	1,162
2016	14,782.29	5,316	5,157	9,625	15.14	636
2017	31,287.03	10,372	10,061	21,226	15.12	1,404
2018	370,175.56	111,645	108,300	261,876	15.05	17,400
2019	13,693.56	3,675	3,565	10,129	14.99	676
2020	219,259.36	51,000	49,472	169,787	14.84	11,441
2021	84,028.10	16,201	15,716	68,312	14.65	4,663
2022	125,934.15	18,701	18,141	107,793	14.34	7,517
2023	168,229.62	16,453	15,960	152,270	13.84	11,002
2024	173,823.01	6,553	6,356	167,467	12.76	13,124
	2,614,125.97	1,173,782	1,138,619	1,475,507		110,861

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.3   4.24

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

FORTY FORT WAREHOUSE
INTERIM SURVIVOR CURVE.. IOWA 100-L0
PROBABLE RETIREMENT YEAR.. 6-2032
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1966	61.57	53	47	15	7.48	2
1967	1,919.41	1,658	1,458	461	7.49	62
1972	1,729.64	1,479	1,301	429	7.50	57
1974	551.90	470	413	139	7.50	19
1975	720.12	611	537	183	7.50	24
1978	1,546.04	1,301	1,144	402	7.51	54
1979	10,894.76	9,144	8,042	2,853	7.51	380
1980	116,341.79	97,351	85,616	30,726	7.51	4,091
1981	417.29	348	306	111	7.51	15
1982	1,765.11	1,499	1,318	447	7.50	60
1983	199.97	169	149	51	7.53	7
1984	7,012.84	5,899	5,188	1,825	7.60	240
1985	14,706.53	12,353	10,864	3,843	7.48	514
1986	1,037.59	869	764	273	7.41	37
1987	4,239.52	3,522	3,097	1,142	7.59	150
1989	5,206.49	4,294	3,776	1,430	7.49	191
1990	21,718.26	17,779	15,636	6,082	7.59	801
1991	41,494.19	33,801	29,726	11,768	7.57	1,555
1992	1,317.36	1,071	942	375	7.43	50
1993	8,717.34	7,030	6,183	2,535	7.56	335
1994	41,486.05	33,280	29,268	12,218	7.52	1,625
1995	21,633.35	17,231	15,154	6,479	7.54	859
1998	2,689.80	2,096	1,843	846	7.51	113
2005	19,157.92	13,822	12,156	7,002	7.53	930
2006	64,108.89	45,543	40,053	24,056	7.54	3,190
2011	20,461.97	13,120	11,538	8,924	7.55	1,182
2014	8,543.23	4,970	4,371	4,172	7.55	553
2015	283,270.24	157,697	138,687	144,583	7.56	19,125
2016	119,440.71	63,256	55,631	63,810	7.55	8,452
2018	47,492.75	21,951	19,305	28,188	7.56	3,729
2020	32,266.22	12,035	10,584	21,682	7.56	2,868
2021	230,400.78	72,899	64,111	166,290	7.56	21,996
2022	1,322,726.44	329,094	289,423	1,033,304	7.55	136,861
2023	1,651,798.05	274,033	240,999	1,410,799	7.54	187,109
2024	570,655.28	35,723	31,417	539,239	7.49	71,995
	4,677,729.40	1,297,451	1,141,047	3,536,682		469,231

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PLYMOUTH STOREROOM (BRICK STRUCTURE)						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1917	7,127.10	7,127	7,127			
1951	556.54	557	557			
1976	902.76	903	903			
1984	1,008.80	1,009	1,009			
2008	5,516.25	5,516	5,516			
	15,111.45	15,112	15,111			
IDETOWN						
INTERIM SURVIVOR CURVE.. IOWA 100-L0						
PROBABLE RETIREMENT YEAR.. 6-2046						
NET SALVAGE PERCENT.. 0						
1979	930.87	603	528	402	19.86	20
1983	13,610.31	9,263	8,117	5,494	19.36	284
2021	35,384.32	5,414	4,744	30,640	19.38	1,581
	49,925.50	15,280	13,389	36,536		1,885
NANTICOKE SERVICE CENTER						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1971	4,029.19	4,029	4,029			
1975	21,022.88	21,023	21,023			
1985	36,364.35	36,364	36,364			
1986	4,788.36	4,788	4,788			
1987	9,974.00	9,974	9,974			
	76,178.78	76,178	76,179			
EMPIRE YARD						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
2014	19,894.79	19,895	19,895			
	19,894.79	19,895	19,895			

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SYSTEM CONTROL CENTER INTERIM SURVIVOR CURVE.. IOWA 100-L0 PROBABLE RETIREMENT YEAR.. 7-2056 NET SALVAGE PERCENT.. 0						
2016	1,875,841.31	454,329	386,252	1,489,589	26.59	56,021
2021	3,575.00	423	360	3,215	26.09	123
2022	12,471.61	1,098	933	11,538	25.91	445
	1,891,887.92	455,850	387,545	1,504,343		56,589
	6,730,727.84	1,879,766	1,653,166	5,077,561		527,705

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.6 7.84

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2007	13,833.00	12,104	9,120	4,713	2.50	1,885
2015	15,627.39	7,423	5,593	10,034	10.50	956
2016	17,280.62	7,344	5,534	11,747	11.50	1,021
2018	19,327.09	6,281	4,733	14,594	13.50	1,081
	66,068.10	33,152	24,980	41,088		4,943

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.3   7.48

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	9,823.55	4,912	613-	10,437	2.50	4,175
	9,823.55	4,912	613-	10,437		4,175

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.5 42.50

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 391.92 OFFICE FURNITURE AND EQUIPMENT - OUTAGE MANAGEMENT SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	20,008.56	14,006	12,103	7,906	1.50	5,271
2022	3,341,592.33	1,670,796	1,443,749	1,897,843	2.50	759,137
2023	134,434.40	40,330	34,850	99,584	3.50	28,453
	3,496,035.29	1,725,132	1,490,702	2,005,333		792,861

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.5   22.68

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - CARS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 7-L3						
NET SALVAGE PERCENT.. 0						
2020	209,034.47	135,078	150,958	58,076	2.46	23,608
2021	59,173.85	31,457	35,155	24,019	3.08	7,798
2022	33,888.94	13,352	14,921	18,968	3.85	4,927
2023	34,000.00	8,208	9,173	24,827	4.71	5,271
2024	34,000.00	2,754	3,078	30,922	5.67	5,454
	370,097.26	190,849	213,285	156,812		47,058

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.3 12.72

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 392.2 TRANSPORTATION EQUIPMENT - LIGHT TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 11-L3						
NET SALVAGE PERCENT.. 0						
2020	709,058.60	316,524	253,242	455,817	5.58	81,688
2021	232,833.23	82,307	65,852	166,981	6.40	26,091
2022	453,079.46	115,898	92,727	360,352	7.27	49,567
2023	225,700.00	34,848	27,881	197,819	8.22	24,066
2024	1,166,000.00	60,049	48,043	1,117,957	9.21	121,385
	2,786,671.29	609,626	487,745	2,298,926		302,797

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.6 10.87

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 392.4 TRANSPORTATION EQUIPMENT - HEAVY TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 14-S3						
NET SALVAGE PERCENT.. 0						
2020	136,684.28	46,992	40,538	96,146	8.59	11,193
2021	243,704.15	65,337	56,364	187,340	9.55	19,617
2022	110,248.00	21,112	18,212	92,036	10.55	8,724
	490,636.43	133,441	115,114	375,522		39,534

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.5   8.06

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 393 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	3,216.82	3,056	2,856	361	0.50	361
2020	11,401.12	5,131	4,795	6,606	5.50	1,201
	14,617.94	8,187	7,651	6,967		1,562

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.5 10.69

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2005	67,810.09	66,115	65,395	2,415	0.50	2,415
2006	26,827.51	24,815	24,545	2,283	1.50	1,522
2007	75,903.01	66,415	65,691	10,212	2.50	4,085
2008	9,798.31	8,084	7,996	1,802	3.50	515
2009	52,062.46	40,348	39,908	12,154	4.50	2,701
2010	39,487.40	28,628	28,316	11,171	5.50	2,031
2011	76,427.62	51,589	51,027	25,401	6.50	3,908
2012	11,816.07	7,385	7,305	4,511	7.50	601
2013	69,050.65	39,704	39,271	29,780	8.50	3,504
2014	22,312.31	11,714	11,586	10,726	9.50	1,129
2015	64,165.13	30,478	30,146	34,019	10.50	3,240
2016	79,880.35	33,949	33,579	46,301	11.50	4,026
2017	64,019.56	24,007	23,745	40,275	12.50	3,222
2018	515,650.14	167,586	165,760	349,890	13.50	25,918
2019	162,882.48	44,793	44,305	118,577	14.50	8,178
2020	37,646.28	8,470	8,378	29,268	15.50	1,888
2021	93,757.93	16,408	16,229	77,529	16.50	4,699
2022	53,217.59	6,652	6,580	46,638	17.50	2,665
	1,522,714.89	677,140	669,762	852,953		76,247

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.2 5.01

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 395 LABORATORY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	8,105.79	7,701	7,803	303	0.50	303
2016	16,836.39	14,311	14,500	2,336	1.50	1,557
2020	12,796.72	5,759	5,835	6,962	5.50	1,266
	37,738.90	27,771	28,138	9,601		3,126

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.1 8.28

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 396 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-S0						
NET SALVAGE PERCENT.. 0						
2020	59,262.02	16,451	16,669	42,593	11.71	3,637
2022	117,369.54	20,094	20,360	97,010	12.10	8,017
2023	627,385.98	68,636	69,546	557,840	12.22	45,650
2024	267,333.53	10,533	10,673	256,661	12.21	21,021
	1,071,351.07	115,714	117,248	954,103		78,325

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.2 7.31

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 397 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2016	166,321.59	141,373	128,468	37,854	1.50	25,236
2017	12,516.18	9,387	8,530	3,986	2.50	1,594
2018	22,527.08	14,643	13,306	9,221	3.50	2,635
2019	25,342.02	13,938	12,666	12,676	4.50	2,817
2020	204,414.03	91,986	83,589	120,825	5.50	21,968
2021	221,515.29	77,530	70,453	151,062	6.50	23,240
2022	225,172.48	56,293	51,154	174,018	7.50	23,202
	877,808.67	405,150	368,166	509,643		100,692

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.1   11.47

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	8,850.87	8,408	7,705	1,146	0.50	1,146
2016	81,148.36	68,976	63,213	17,935	1.50	11,957
2018	66,633.01	43,311	39,692	26,941	3.50	7,697
2020	14,868.03	6,691	6,132	8,736	5.50	1,588
2021	76,140.46	26,649	24,422	51,718	6.50	7,957
2022	162,653.03	40,663	37,266	125,387	7.50	16,718
2023	181,248.28	27,187	24,916	156,332	8.50	18,392
2024	166,256.63	8,313	7,618	158,639	9.50	16,699
	757,798.67	230,198	210,964	546,835		82,154

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.7   10.84

COMMON PLANT

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 301 ORGANIZATION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NONDEPRECIABLE						
1952	96,447.19					
1953	42,516.33					
	138,963.52					

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 389.1 LAND AND LAND RIGHTS - LAND

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NONDEPRECIABLE						
2017	6,947,107.66					
	6,947,107.66					

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

UGI HEADQUARTERS BUILDING
INTERIM SURVIVOR CURVE.. IOWA 70-R1
PROBABLE RETIREMENT YEAR.. 1-2069
NET SALVAGE PERCENT.. 0

2019	29,987,923.48	4,372,239	4,505,219	25,482,704	32.23	790,652
2020	1,890,627.83	234,060	241,179	1,649,449	31.86	51,772
2021	654,570.06	65,719	67,718	586,852	31.34	18,725
2022	3,248,137.93	246,209	253,697	2,994,441	30.50	98,178
2023	166,566.49	8,145	8,393	158,174	29.17	5,422
	35,947,825.79	4,926,372	5,076,206	30,871,620		964,749

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 32.0   2.68

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2005	39,965.68	38,967	36,182	3,784	0.50	3,784
2006	2,468.81	2,284	2,121	348	1.50	232
2007	878.14	768	713	165	2.50	66
2008	572.40	472	438	134	3.50	38
2009	4,753.12	3,684	3,421	1,332	4.50	296
2010	747,318.56	541,806	503,078	244,241	5.50	44,407
2019	3,525,373.71	969,478	900,180	2,625,194	14.50	181,048
2020	27,303.10	6,143	5,704	21,599	15.50	1,393
2022	782,244.07	97,781	90,791	691,453	17.50	39,512
2023	100,000.00	7,500	6,964	93,036	18.50	5,029
	5,230,877.59	1,668,883	1,549,592	3,681,286		275,805

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.3   5.27

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	1,076,384.85	753,469	727,143	349,242	1.50	232,828
	1,076,384.85	753,469	727,143	349,242		232,828

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.5 21.63

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 392 TRANSPORTATION EQUIPMENT - CARS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 7-L2.5						
NET SALVAGE PERCENT.. 0						
2004	26,875.84	26,876	26,876			
2008	22,536.44	21,939	22,536			
2014	22,224.80	19,531	22,225			
	71,637.08	68,346	71,637			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE NET SALVAGE PERCENT.. 0						
2020	27,967.27	12,585	7,572	20,395	5.50	3,708
	27,967.27	12,585	7,572	20,395		3,708

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.5 13.26

INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NEW READING DATA CENTER INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 11-2073 NET SALVAGE PERCENT.. 0						
2024	20,329,982.50	304,950	494,527	19,835,456	32.72	606,218
	20,329,982.50	304,950	494,527	19,835,456		606,218

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 32.7   2.98

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2007	1,760.05	1,540	1,529	231	2.50	92
2022	558.68	70	69	490	17.50	28
	2,318.73	1,610	1,598	721		120

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.0 5.18

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2020	1,979,935.89	1,781,942	1,742,793	237,143	0.50	237,143
2021	847,064.50	592,945	579,918	267,146	1.50	178,097
2022	2,422,784.11	1,211,392	1,184,778	1,238,006	2.50	495,202
	5,249,784.50	3,586,279	3,507,489	1,742,296		910,442

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.9 17.34

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SUCCESS FACTORS INTERIM SURVIVOR CURVE.. SQUARE PROBABLE RETIREMENT YEAR.. 9-2024 NET SALVAGE PERCENT.. 0						
2019	2,803,866.07	2,803,866	2,803,866			
	2,803,866.07	2,803,866	2,803,866			
UNITE ERP INTERIM SURVIVOR CURVE.. SQUARE PROBABLE RETIREMENT YEAR.. 9-2034 NET SALVAGE PERCENT.. 0						
2019	10,695,816.43	3,565,236	3,150,333	7,545,483	10.00	754,548
	10,695,816.43	3,565,236	3,150,333	7,545,483		754,548
	13,499,682.50	6,369,102	5,954,199	7,545,483		754,548

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.0   5.59

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.3 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE - SYSTEM DEV. COSTS - 10 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	732,102.69	695,498	669,229	62,874	0.50	62,874
2016	930,430.13	790,866	760,995	169,436	1.50	112,957
2017	1,349,992.48	1,012,494	974,251	375,741	2.50	150,296
2018	1,373,844.01	892,999	859,270	514,574	3.50	147,021
2019	7,509,579.44	4,130,269	3,974,266	3,535,313	4.50	785,625
2020	12,521,978.02	5,634,890	5,422,057	7,099,921	5.50	1,290,895
2021	7,759,405.05	2,715,792	2,613,215	5,146,190	6.50	791,722
2022	8,508,252.60	2,127,063	2,046,723	6,461,530	7.50	861,537
2023	10,663,545.78	1,599,532	1,539,117	9,124,429	8.50	1,073,462
2024	19,821,968.05	991,098	953,664	18,868,304	9.50	1,986,137
	71,171,098.25	20,590,501	19,812,785	51,358,313		7,262,526

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.1   10.20

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.4 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE - SYSTEM DEV. COSTS - 15 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

SURVIVOR CURVE.. 15-SQUARE
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
2011	425,873.07	383,286	380,536	45,337	1.50	30,225
2012	401,290.13	334,407	332,008	69,282	2.50	27,713
2013	142,364.69	109,147	108,364	34,001	3.50	9,715
2014	495,556.48	346,890	344,401	151,155	4.50	33,590
2016	1,419,264.44	804,255	798,484	620,780	6.50	95,505
2017	76,271,826.62	38,135,913	37,862,284	38,409,543	7.50	5,121,272
2018	171,914.66	74,496	73,961	97,954	8.50	11,524
2019	43,660,591.71	16,009,029	15,894,163	27,766,429	9.50	2,922,782
2021	7,039,054.95	1,642,423	1,630,639	5,408,416	11.50	470,297
2022	2,541,873.11	423,654	420,614	2,121,259	12.50	169,701
2023	1,661,521.87	166,152	164,960	1,496,562	13.50	110,856
	134,231,131.73	58,429,652	58,010,414	76,220,718		9,003,180

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.5 6.71

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.4 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE - SYSTEM DEV. COSTS - 15 YRS - 100% ELECTRIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2023	246,470.00	24,647	17,006	229,464	13.50	16,997
	246,470.00	24,647	17,006	229,464		16,997

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.5   6.90

EMPIRE YARD

UGI UTILITIES, INC. - ELECTRIC DIVISION - EMPIRE YARD

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MAJOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2047						
NET SALVAGE PERCENT.. 0						
1960	89,140.58	64,521	69,120	20,020	19.35	1,035
1961	77,255.71	55,667	59,635	17,620	19.45	906
1962	126,258.88	90,558	97,014	29,245	19.55	1,496
1963	8,526.99	6,087	6,521	2,006	19.65	102
1964	3,334.42	2,369	2,538	797	19.75	40
1965	435.05	307	329	106	19.85	5
1966	271.32	191	205	67	19.94	3
1967	788.29	551	590	198	20.03	10
1968	3,284.98	2,285	2,448	837	20.12	42
1969	610.82	423	453	158	20.20	8
1970	2,155.82	1,483	1,589	567	20.29	28
1971	69,645.14	47,637	51,033	18,612	20.37	914
1972	4,930.52	3,352	3,591	1,340	20.45	66
1973	5,494.44	3,712	3,977	1,518	20.53	74
1974	1,013.05	680	728	285	20.60	14
1975	18,967.77	12,653	13,555	5,413	20.67	262
1976	93,077.07	61,663	66,059	27,018	20.75	1,302
1977	249,037.72	163,869	175,551	73,487	20.81	3,531
1978	14,138.52	9,236	9,894	4,244	20.88	203
1979	29,868.49	19,364	20,744	9,124	20.95	436
1980	48,049.56	30,913	33,117	14,933	21.01	711
1981	46,928.14	29,953	32,088	14,840	21.07	704
1982	15,463.69	10,384	11,124	4,339	20.79	209
1983	15,324.39	10,240	10,970	4,354	20.61	211
1984	45,920.51	30,317	32,478	13,442	20.85	645
1985	66,444.57	43,568	46,674	19,771	20.74	953
1986	213,369.42	138,818	148,714	64,656	20.67	3,128
1987	92,847.20	59,534	63,778	29,069	20.98	1,386
1988	76,689.12	48,705	52,177	24,512	20.97	1,169
1989	130,214.67	81,827	87,660	42,555	20.99	2,027
1990	1,436.70	892	956	481	21.06	23
1991	12,446.70	7,630	8,174	4,273	21.15	202
1992	105,796.19	64,303	68,887	36,909	20.97	1,760
1993	233,769.82	139,911	149,885	83,885	21.13	3,970
1994	9,037.19	5,319	5,698	3,339	21.32	157
1995	130,490.57	75,841	81,247	49,243	21.26	2,316
1996	76,171.05	43,631	46,741	29,430	21.25	1,385
1997	4,542,593.65	2,561,114	2,743,686	1,798,907	21.28	84,535
1998	275,879.79	152,782	163,673	112,207	21.35	5,256
1999	83,508.85	45,362	48,596	34,913	21.45	1,628
2000	88,369.48	47,198	50,563	37,807	21.37	1,769

UGI UTILITIES, INC. - ELECTRIC DIVISION - EMPIRE YARD

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MAJOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2047						
NET SALVAGE PERCENT.. 0						
2001	714,823.67	374,568	401,270	313,554	21.35	14,686
2002	41,680.68	21,382	22,906	18,774	21.36	879
2003	178,385.00	89,371	95,742	82,643	21.42	3,858
2004	144,311.55	70,410	75,429	68,882	21.52	3,201
2005	165,003.38	78,509	84,106	80,898	21.48	3,766
2006	138,396.33	64,008	68,571	69,825	21.50	3,248
2007	867,450.16	388,618	416,321	451,129	21.56	20,924
2008	78,460.18	34,052	36,479	41,981	21.52	1,951
2009	53,581.69	22,424	24,023	29,559	21.54	1,372
2010	194,337.59	78,046	83,610	110,728	21.60	5,126
2011	312,046.16	120,075	128,635	183,411	21.59	8,495
2012	48,978.96	18,000	19,283	29,696	21.51	1,381
2013	121,627.16	42,375	45,396	76,231	21.50	3,546
2014	162,630.88	53,278	57,076	105,555	21.55	4,898
2015	94,153.61	28,802	30,855	63,298	21.56	2,936
2016	604,058.49	170,949	183,135	420,923	21.53	19,551
2017	57,776.48	14,953	16,019	41,758	21.48	1,944
2018	71,266.79	16,584	17,766	53,501	21.43	2,497
2019	6,693.57	1,370	1,468	5,226	21.38	244
2020	45,379.59	7,923	8,488	36,892	21.27	1,734
2021	220,112.28	31,278	33,508	186,605	21.13	8,831
2022	622,542.32	66,301	71,027	551,515	20.97	26,300
2023	267,993.65	18,170	19,465	248,528	20.62	12,053
2024	2,174,652.68	53,931	57,776	2,116,877	19.62	107,894
	14,495,329.69	6,040,227	6,470,812	8,024,518		385,936
PNG - EMPIRE YARD - MINOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2022						
NET SALVAGE PERCENT.. 0						
1960	27,374.98	27,375	27,375			
1961	2,250.14	2,250	2,250			
1962	11,395.40	11,395	11,395			
1964	212.41	212	212			
1965	479.69	480	480			
1972	4,846.95	4,847	4,847			
1973	59,338.04	59,338	59,338			
1976	674.99	675	675			

UGI UTILITIES, INC. - ELECTRIC DIVISION - EMPIRE YARD

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2024

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MINOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2022						
NET SALVAGE PERCENT.. 0						
1977	9,114.69	9,115	9,115			
1978	24,124.85	24,125	24,125			
1979	540.75	541	541			
1980	8,726.53	8,727	8,727			
1981	52,430.77	52,431	52,431			
1982	22,292.87	22,293	22,293			
1984	11,417.15	11,417	11,417			
1986	31,130.64	31,131	31,131			
1987	11,362.33	11,362	11,362			
1988	15,773.37	15,773	15,773			
1989	8,654.63	8,655	8,655			
1990	94,337.02	94,337	94,337			
1992	6,049.58	6,050	6,050			
1993	1,598.34	1,598	1,598			
1994	38,859.45	38,859	38,859			
1995	4,586.75	4,587	4,587			
1996	1,532.27	1,532	1,532			
1997	1,129.92	1,130	1,130			
1998	3,483.10	3,483	3,483			
2001	6,551.41	6,551	6,551			
2002	8,685.69	8,686	8,686			
2003	26,975.97	26,976	26,976			
2004	262,708.52	262,709	262,709			
2005	28,203.02	28,203	28,203			
2008	29,302.79	29,303	29,303			
2010	189,349.18	189,349	189,349			
2011	217,404.63	217,405	217,405			
2014	19,697.18	19,697	19,697			
2016	36,430.01	36,430	36,430			
2017	42,967.09	42,967	42,967			
2018	58,528.05	58,528	58,528			
2019	838,990.00	838,990	838,990			
2022	155,500.81	155,501	155,501			
	2,375,011.96	2,375,013	2,375,012			
	16,870,341.65	8,415,240	8,845,824	8,024,518		385,936

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.8 2.29

PART IV. EXPERIENCED AND ESTIMATED NET SALVAGE

UGI UTILITIES, INC. - ELECTRIC DIVISION

EXPERIENCED AND ESTIMATED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2020 TRANSACTION YEAR				
362.00		24,880.00		24,880.00-
364.00	28,014.00	695,428.00		695,428.00-
365.00		121,069.00		121,069.00-
366.00		9,269.00		9,269.00-
367.00		14,036.00		14,036.00-
368.10		3,020.00		3,020.00-
368.20		58,648.00		58,648.00-
369.00		81,584.00		81,584.00-
370.10	222,832.00		59,469.00	59,469.00
370.20		3,781.00		3,781.00-
371.00		9,609.00		9,609.00-
373.00		19,433.00		19,433.00-
391.00	538.00			
391.10	10,122.00			
392.20			13,693.00	13,693.00
394.00	26,726.00			
397.00	337,961.00			
398.00	19,983.00	419.00		419.00-
	646,176.00	1,041,176.00	73,162.00	968,014.00-
2021 TRANSACTION YEAR				
362.00		5,721.00		5,721.00-
364.00	210,322.00	628,085.00		628,085.00-
365.00	135,947.00	175,874.00		175,874.00-
366.00	3,158.00	49.00		49.00-
367.00	7,219.00	23,539.00		23,539.00-
368.10	259.00	4,895.00		4,895.00-
368.20	83,839.00	25,689.00		25,689.00-
369.00	26,812.00	72,000.00		72,000.00-
370.10	36,917.00	76,928.00-		76,928.00
370.20	26,564.00	3,263.00		3,263.00-
370.30	67,438.00			
371.00	141,173.00	30,601.00		30,601.00-
373.00	36,544.00	14,719.00		14,719.00-
391.10	7,084.00			
392.20		112.00-		112.00
395.00	55,959.00			
397.00	15,410.00	63.00		63.00-
398.00		8,277.00		8,277.00-
	854,645.00	915,735.00		915,735.00-

UGI UTILITIES, INC. - ELECTRIC DIVISION

EXPERIENCED AND ESTIMATED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2022 TRANSACTION YEAR				
361.00		1,103.00		1,103.00-
362.00		9,451.00		9,451.00-
364.00	276,581.00	441,244.00		441,244.00-
365.00	133,125.00	138,834.00		138,834.00-
366.00	2,024.00	500.00		500.00-
367.00	25,277.00	16,452.00		16,452.00-
368.10	524,628.00	7,807.00		7,807.00-
368.20	95,304.00	33,600.00		33,600.00-
369.00	2,405.00	39,522.00		39,522.00-
370.10	28,484.00	68,289.00-		68,289.00
370.20	3,088.00	3,331.00		3,331.00-
370.30	21,404.00	2,299.00		2,299.00-
371.00	42,122.00	32,911.00		32,911.00-
373.00	70,453.00	28,409.00		28,409.00-
390.10		174.00		174.00-
391.00	2,580.00			
391.10	6,904.00			
392.20		1,099.00		1,099.00-
394.00	1,033.00			
395.00	17,678.00			
397.00	182,759.00			
398.00		30,752.00		30,752.00-
	1,435,849.00	719,199.00		719,199.00-
2023 TRANSACTION YEAR				
362.00	2,651.00	265.00	195.00	70.00-
364.00	53,094.00	79,641.00		79,641.00-
365.00	787,454.00	787,454.00		787,454.00-
367.00	14,734.00	2,950.00		2,950.00-
368.10	246,521.00	14,447.00		14,447.00-
368.20	2,119.00	1,060.00		1,060.00-
369.00	24,818.00	43,432.00		43,432.00-
370.10	68,379.00		38,693.00	38,693.00
370.20	3,346.00	2,005.00		2,005.00-
373.00	29,580.00	14,699.00		14,699.00-
390.10	250,394.00			
391.92	662,056.00			
394.00	78,913.00			
395.00	23,859.00			
397.00	92,135.00	5.00		5.00-
	2,340,053.00	945,958.00	38,888.00	907,070.00-

UGI UTILITIES, INC. - ELECTRIC DIVISION

EXPERIENCED AND ESTIMATED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2024 TRANSACTION YEAR				
362.00	2,866.00	287.00	211.00	76.00-
364.00	82,883.00	124,325.00		124,325.00-
365.00	734,802.00	734,802.00		734,802.00-
367.00	25,188.00	5,042.00		5,042.00-
368.10	245,644.00	14,395.00		14,395.00-
368.20	2,182.00	1,091.00		1,091.00-
369.00	25,561.00	44,732.00		44,732.00-
370.10	282,297.00		159,611.00	159,611.00
370.20	3,460.00	2,073.00		2,073.00-
373.00	30,468.00	15,140.00		15,140.00-
390.10	85,599.00			
391.10	359,392.00			
394.00	32,595.00			
395.00	36,232.00			
397.00	53,344.00	3.00		3.00-
	2,002,513.00	941,890.00	159,822.00	782,068.00-
TOTAL	7,279,236.00	4,563,958.00	271,872.00	4,292,086.00-

BOOK VI

UGI UTILITIES, INC. – ELECTRIC DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI ELECTRIC EXHIBIT C
(FUTURE)
2023 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO ELECTRIC PLANT
AS OF SEPTEMBER 30, 2023

Witness: John F. Wiedmayer
Prepared by: Gannett Fleming
Valuation and Rate Consultants, LLC

UGI UTILITIES, INC. – ELECTRIC DIVISION
PA P.U.C. NO. 6, SUPPLEMENT NO. 51
PA P.U.C. NO. 2S, SUPPLEMENT NO. 7

DOCKET NO. R-2022-3037368

Issued: January 27, 2023   Effective: March 28, 2023

UGI Electric Exhibit C (Future)
Witness: J. F. Wiedmayer

UGI UTILITIES, INC. - ELECTRIC DIVISION

DOCKET NO. R-2022-3037368

2023 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO ELECTRIC PLANT
AT SEPTEMBER 30, 2023

Prepared by:

GANNETT FLEMING

Excellence Delivered As Promised

UGI UTILITIES, INC. - ELECTRIC DIVISION

Docket No. R-2022-3037368

2023 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT
AT SEPTEMBER 30, 2023

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC
Valley Forge, Pennsylvania

Gannett Fleming
Valuation and Rate Consultants, LLC

Corporate Headquarters
207 Senate Avenue
Camp Hill, PA 17011
P 717.763.7211 | **F** 717.763.8150

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January 17, 2023

Mr. Christopher R. Brown
Vice President and General Manager, Rates and Supply
UGI Utilities, Inc. – Electric Division
1 UGI Drive
Denver, PA 17518

Ladies and Gentlemen:

Pursuant to your request, we have determined the annual depreciation accruals applicable to electric plant in service for each of the three respective test year periods. The results of our study for the future test year period ending at September 30, 2023 are presented in the attached report labeled as UGI Electric Exhibit C (Future).

The results of our study for the historic test year period ending at September 30, 2022 are presented in our report titled "2022 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant at September 30, 2022". This report is identified for purposes of this filing as Exhibit C (Historic). The results of our study for the fully projected future test year period ending at September 30, 2024 are presented in our report titled "2024 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant at September 30, 2024". This report is identified for purposes of this filing as Exhibit C (Fully Projected). The same methods, procedures and estimates are used in all three studies. The results for each respective test year are set forth in three, separately bound reports.

The attached report sets forth a description of the methods and procedures upon which the studies were based, the estimates of survivor curves and the calculated annual depreciation rates at September 30, 2023.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

John F. Wiedmayer

JOHN F. WIEDMAYER, C.D.P.
Project Manager, Depreciation Studies

JFW:mle

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PART I. INTRODUCTION

UGI UTILITIES, INC. - ELECTRIC DIVISION
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study conducted for UGI Utilities, Inc. – Electric Division to determine the annual depreciation accrual rates and amounts for ratemaking purposes applicable to the original cost of electric plant at September 30, 2023.

The depreciation accrual rates and amounts presented herein are based on estimated survivor curves and on methods and procedures set forth in previous orders approved by the Pennsylvania Public Utility Commission. The estimated survivor curves presented herein were based on the results of a service life study incorporating statistical analyses of data through 2021.

BASIS OF STUDY

Depreciation and Amortization

Depreciation, as defined in the Uniform System of Accounts, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital procedures. These subjects are discussed in the sections which follow.

For most plant accounts, depreciation accruals and accrued depreciation were calculated using the straight line method, the remaining life basis, the costs over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight line method of depreciation.

The calculation of annual and accrued depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation average service life (ASL) procedure for plant installed prior to 1982 and the equal life group (ELG) procedure for 1982 and subsequent vintages. The calculations were based on the attained ages and estimated service life characteristics for each depreciable group of electric property. For certain general plant accounts, the amortization amounts, annual and accrued, were based on the age of the vintage and the selected amortization period.

Survivor curves were used to reflect the expected dispersion of retirements, thus providing a consistent method of estimating service lives and depreciation for mass property. Iowa type curves were used to depict the estimated survivor curves. For life span groups, the estimate of life characteristics is consistent because the calculated lives of the units within a group are obtained by employing a single probable retirement date for the entire group.

Service Life Estimates

The method of estimating service life consisted of compiling the service life history of the plant accounts, subaccounts or depreciable groups, reducing this history to trends through the use of acceptable actuarial techniques, and forecasting the trend of survivors for each depreciable group on the basis of interpretations of past trends and consideration of Company plans for the future. The combination of the historical trend and the estimated future trend yielded a complete pattern of life characteristics from which the average service life was derived.

The Company's service life estimates used in the depreciation calculation incorporated historical data compiled through 2021 from the property records of the Company. Such data included plant additions, retirements, transfers and other activity. Generally, retirement data for the years 1960 through 2021 were used in the actuarial life table computations which were the primary statistical support of the service life estimates.

A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirement was obtained through field trips conducted during the course of the service life study. Discussions with operating and management personnel also provided information regarding plans for the future which was incorporated in the interpretation and extrapolation of the statistical analyses.

AMORTIZATION OF NET SALVAGE

Inasmuch as this report relates primarily to Pennsylvania rate regulation practices, under which experienced costs of negative net salvage are amortized after their occurrence, no adjustments for expected salvage were made to either the annual depreciation accrual or the calculated accrued depreciation for the individual accounts.

The annual provision for recovering negative net salvage is based on the amortization of experienced and estimated net salvage recorded October 1, 2018 through September 30, 2023 over a five-year period.

PART II. ESTIMATION OF SURVIVOR CURVES

PART II. ESTIMATION OF SURVIVOR CURVES

The calculation of annual depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. The estimation of survivor curves is discussed below and the development of net salvage is discussed in later sections of this report.

SURVIVOR CURVES

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units or by constructing a survivor curve by plotting the number of units which survive at successive ages.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

This study has incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of survivor curves and of the development of survivor curves using the retirement rate method is presented below.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements (or the portion of the frequency curve with the highest level of retirements) in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family. A higher number designates a higher mode curve.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.

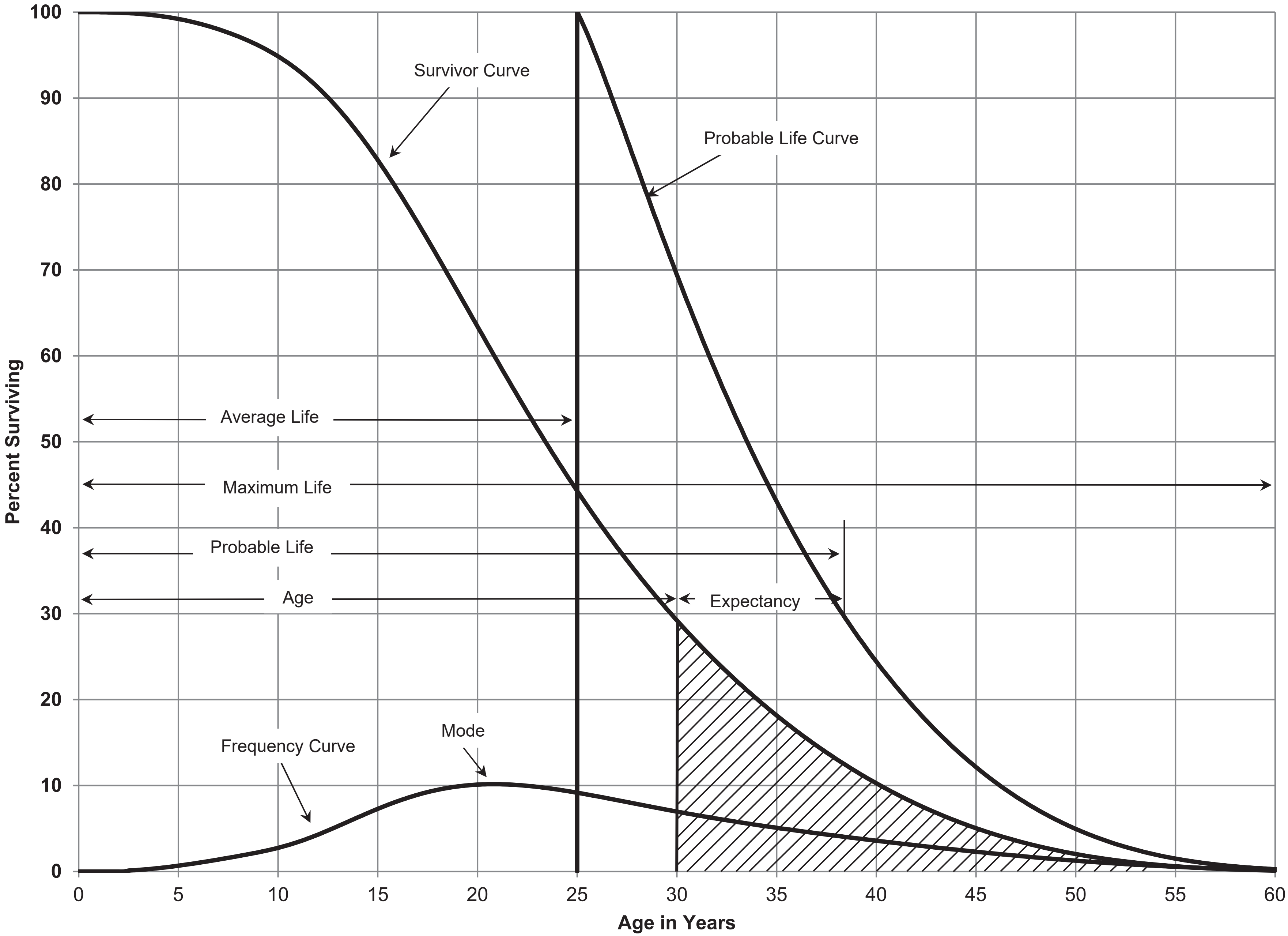


FIGURE 1. TYPICAL SURVIVOR CURVE AND DERIVED CURVES

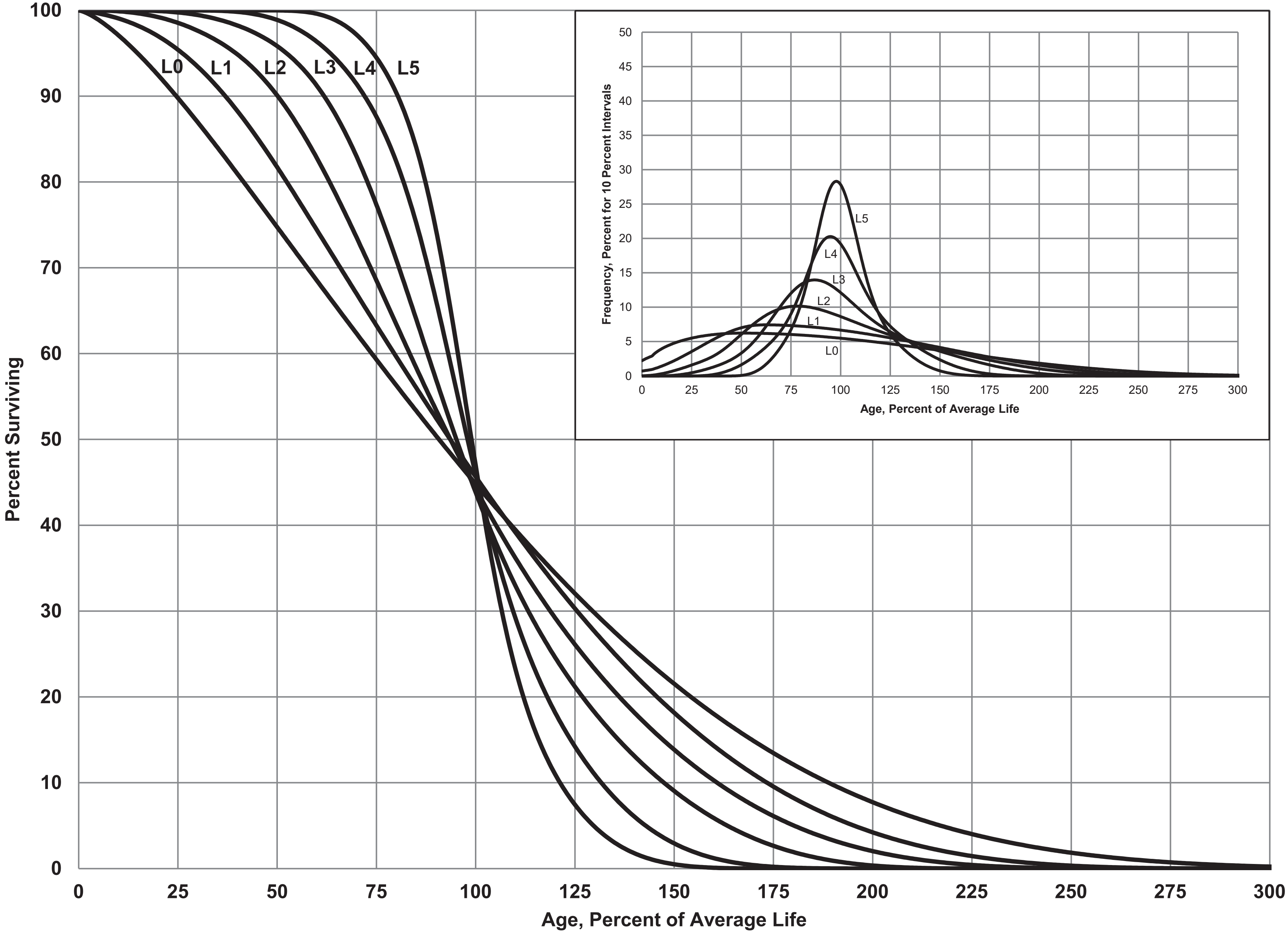


FIGURE 2. LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

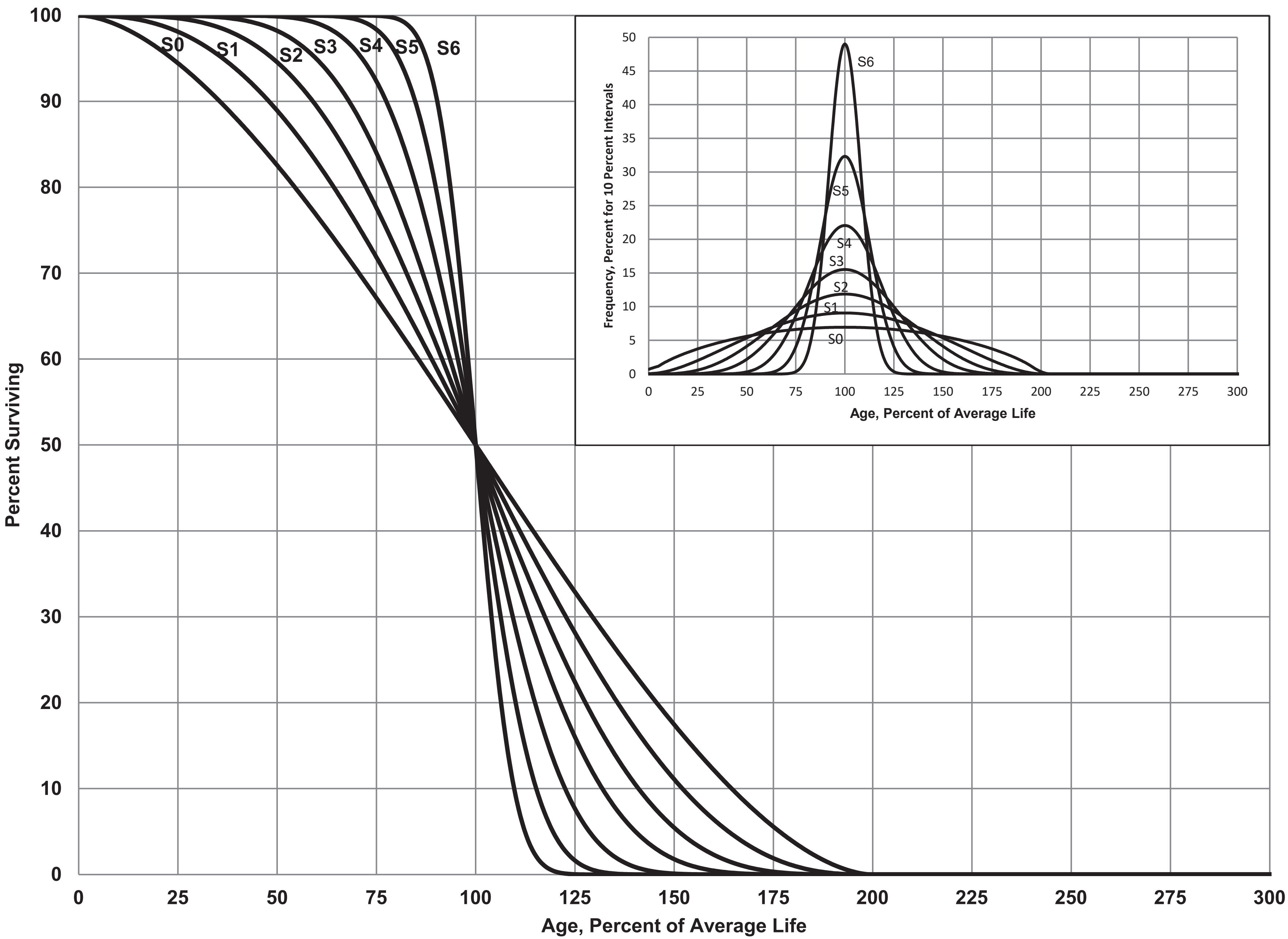


FIGURE 3. SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

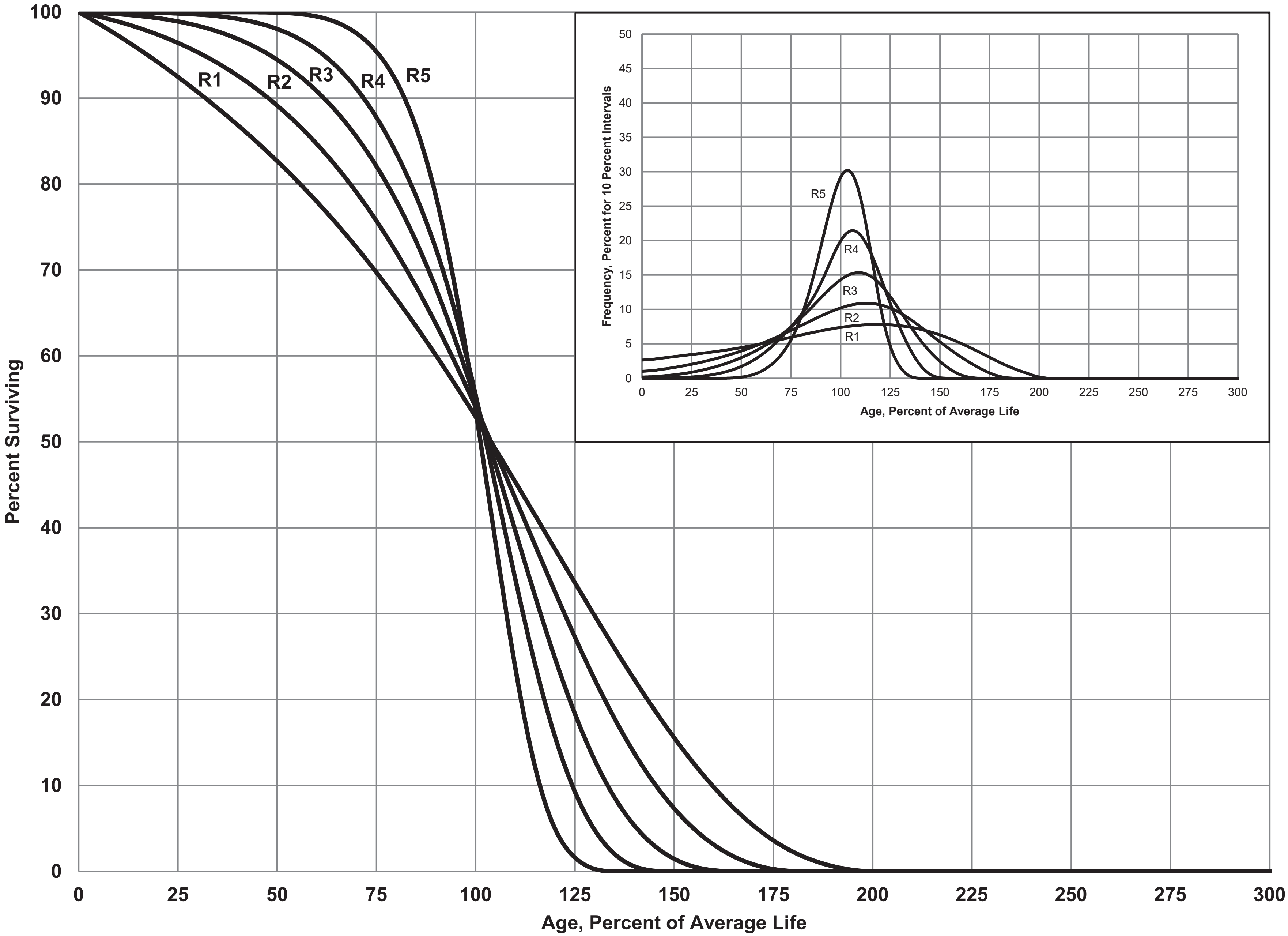


FIGURE 4. RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

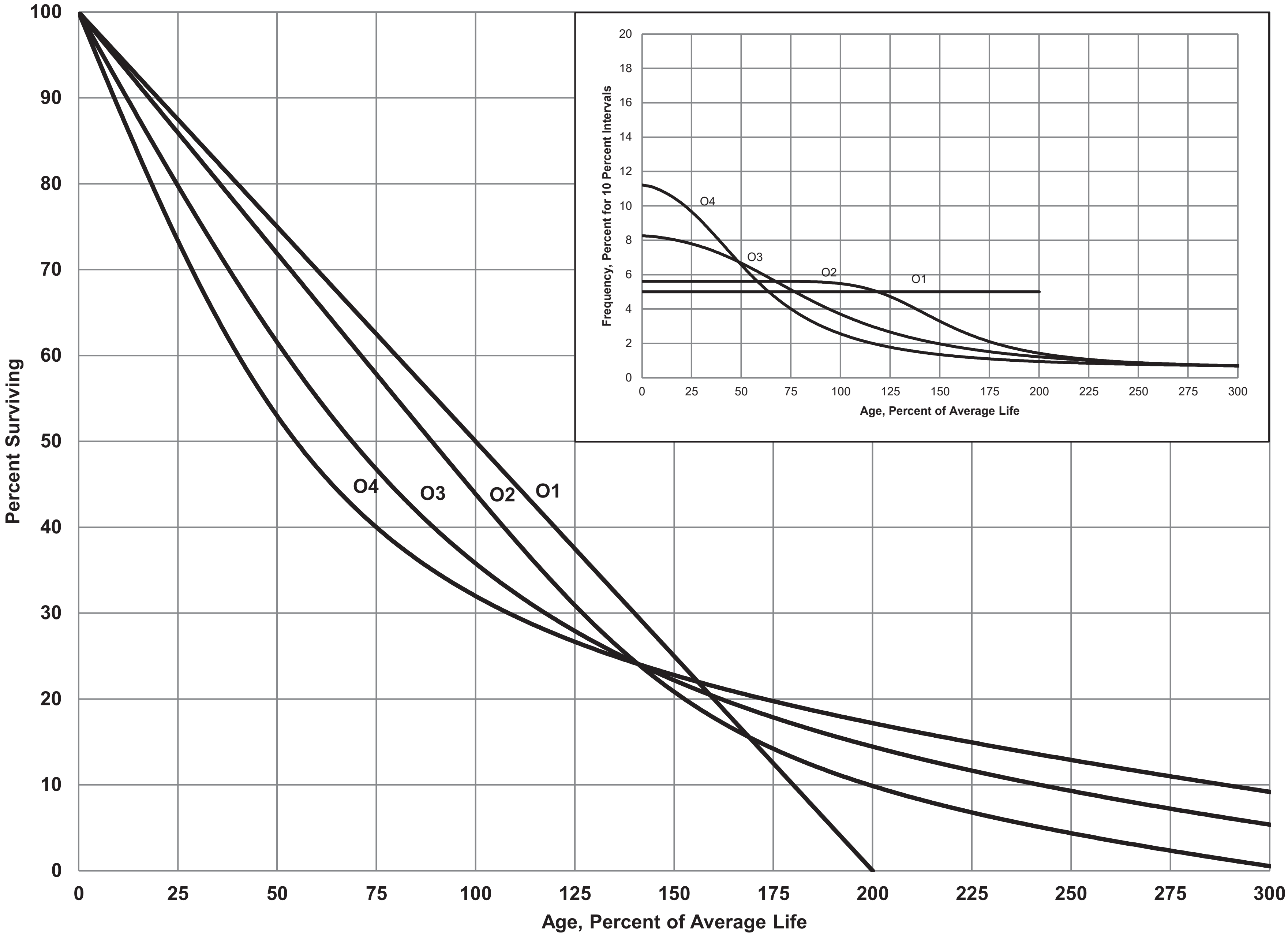


FIGURE 5. ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES

These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[1] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text and is also explained in several publications including "Statistical Analyses of Industrial Property Retirements,"[2] "Engineering Valuation and Depreciation,"[3] and "Depreciation Systems."[4]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band. The band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

---

[1]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[2]Winfrey, Robley, Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

[3]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 1.

[4]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2014-2023 for which there were placements during the years 2009-2023. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on pages II-11 and II-12. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2009 were retired in 2014. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2014 retirements of 2009 installations and ending with the 2023 retirements of the 2018 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2014-2023
SUMMARIZED BY AGE INTERVAL

Experience Band 2014-2023 | Placement Band 2009-2023

Year Placed (1)	2014 (2)	2015 (3)	2016 (4)	2017 (5)	2018 (6)	2019 (7)	2020 (8)	2021 (9)	2022 (10)	2023 (11)	Total During Age Interval (12)	Age Interval (13)
	Retirements, Thousands of Dollars During Year											
2009	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2010	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2011	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2012	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2013	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2014	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2015		5	11	12	13	14	15	16	18	20	113	7½-8½
2016			6	12	13	15	16	17	19	19	124	6½-7½
2017				6	13	15	16	17	19	19	131	5½-6½
2018					7	14	16	17	19	20	143	4½-5½
2019						8	18	20	22	23	146	3½-4½
2020							9	20	22	25	150	2½-3½
2021								11	23	25	151	1½-2½
2022									11	24	153	½-1½
2023										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2014-2023
SUMMARIZED BY AGE INTERVAL

Experience Band 2014-2023

Placement Band 2009-2023

Year Placed (1)	2014 (2)	2015 (3)	2016 (4)	2017 (5)	2018 (6)	2019 (7)	2020 (8)	2021 (9)	2022 (10)	2023 (11)	Total During Age Interval (12)	Age Interval (13)
	Acquisitions, Transfers and Sales, Thousands of Dollars During Year											
2009	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2010	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2011	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2012	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2013	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2014	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2015		-	-	-	-	-	-	-	-	-	6	7½-8½
2016			-	-	-	-	-	-	-	-	-	6½-7½
2017				-	-	-	-	(12)[b]	-	-	-	5½-6½
2018					-	-	-	-	22[a]	-	-	4½-5½
2019						-	-	(19)[b]	-	-	10	3½-4½
2020							-	-	-	-	-	2½-3½
2021								-	-	(102)[c]	(121)	1½-2½
2022									-	-	-	½-1½
2023											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses Denote Credit Amount.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on page II-14. The surviving plant at the beginning of each year from 2014 through 2023 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2019 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2014-2023
SUMMARIZED BY AGE INTERVAL

Experience Band 2014-2023 | Placement Band 2009-2023

	Exposures, Thousands of Dollars										Total at	
Year	Annual Survivors at the Beginning of the Year										Beginning of	Age
Placed	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Age Interval	Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2009	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2010	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2011	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2012	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2013	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2014	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2015		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2016			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2017				580[a]	574	561	546	530	501	482	3,057	5½-6½
2018					660[a]	653	639	623	628	609	3,789	4½-5½
2019						750[a]	742	724	685	663	4,332	3½-4½
2020							850[a]	841	821	799	4,955	2½-3½
2021								960[a]	949	926	5,719	1½-2½
2022									1,080[a]	1,069	6,579	½-1½
2023										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a]Additions during the year

For the entire experience band 2014-2023, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on page II-16, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

SCHEDULE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2014-2023 Placement Band 2009-2023

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Beginning of Age Interval
(1)	(2)	(3)	(4)	(5)	(6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 as of the Preceding Age Interval.

The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE

ORIGINAL AND SMOOTH SURVIVOR CURVES

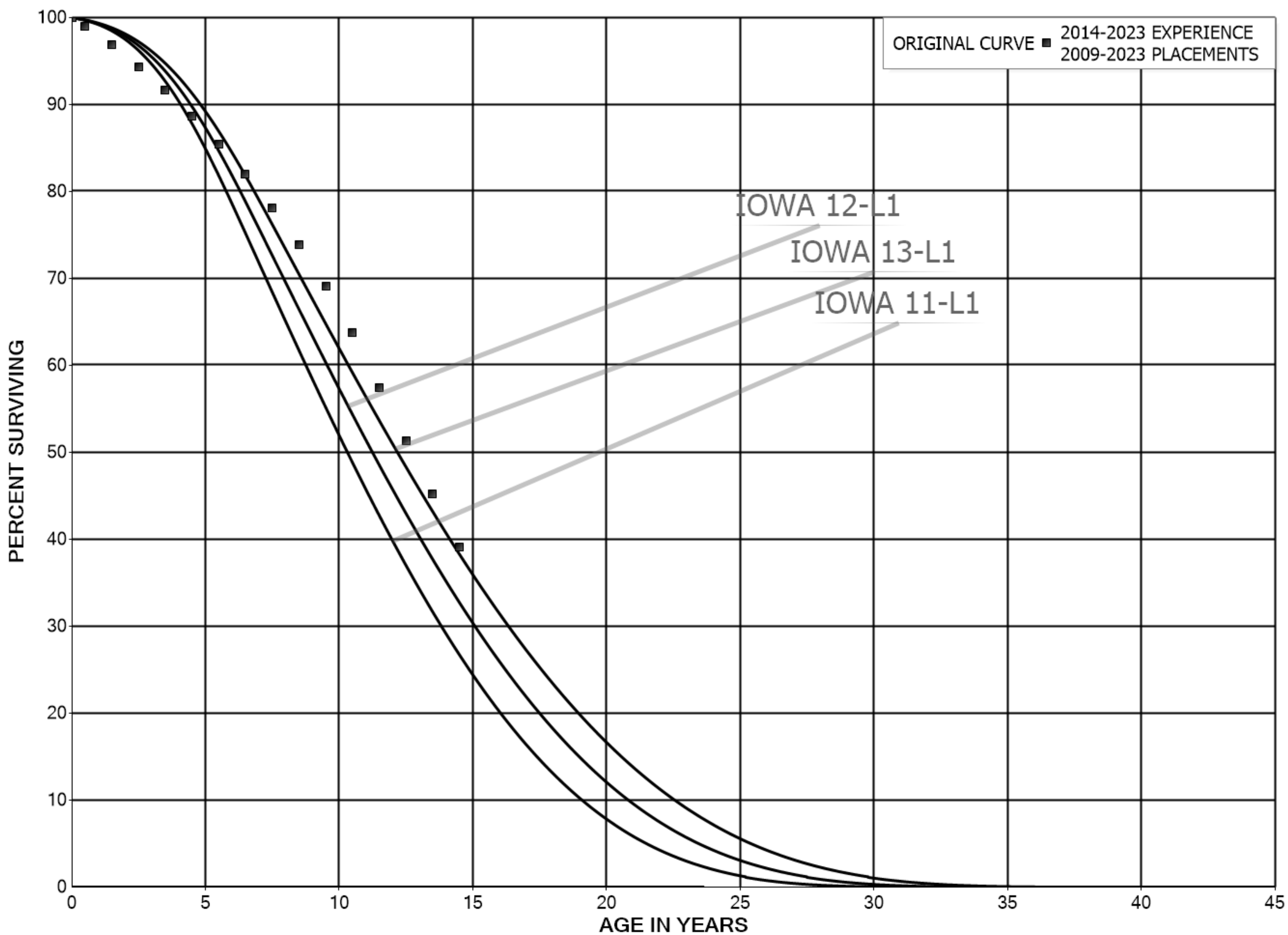


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

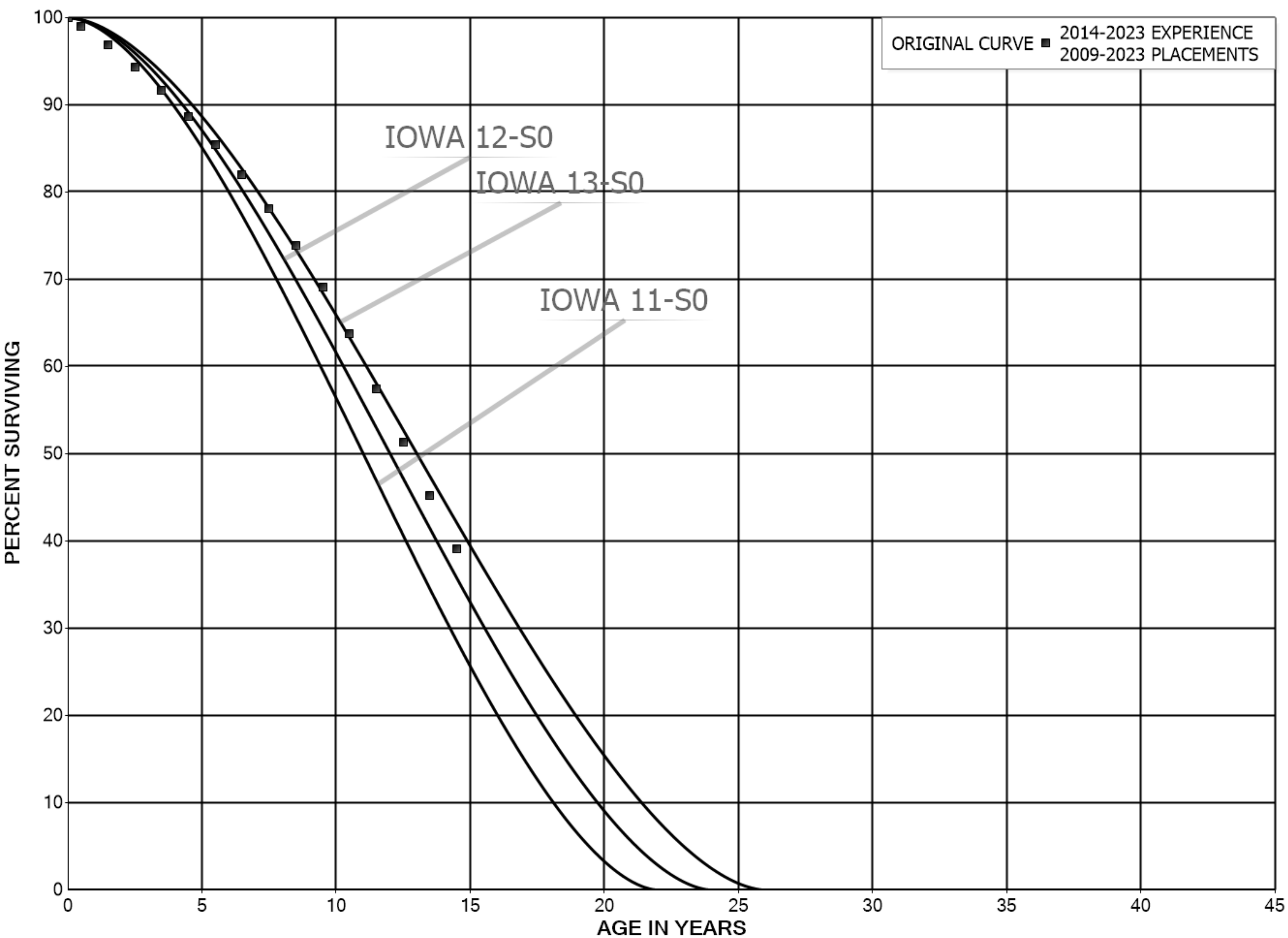


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE

ORIGINAL AND SMOOTH SURVIVOR CURVES

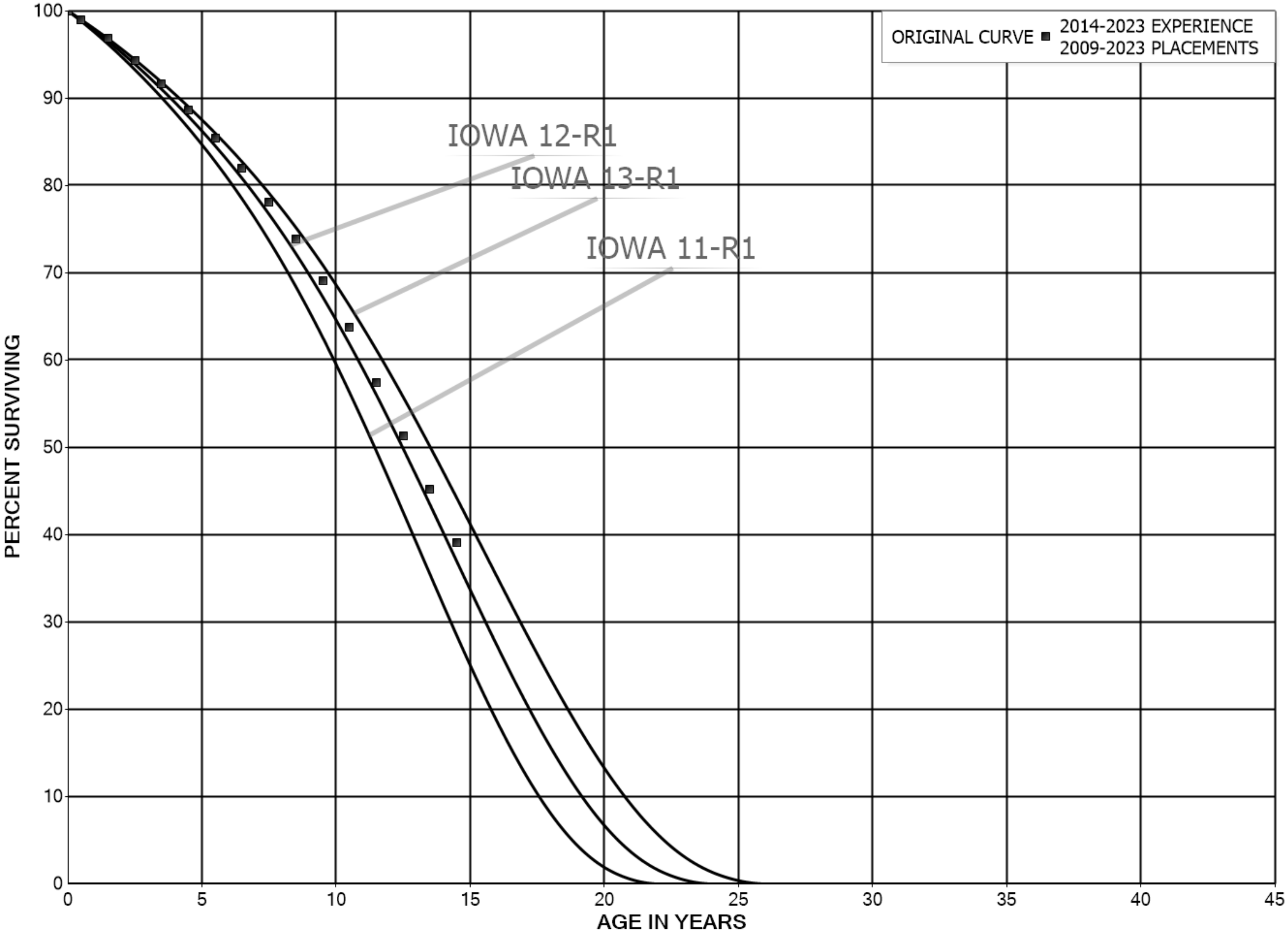
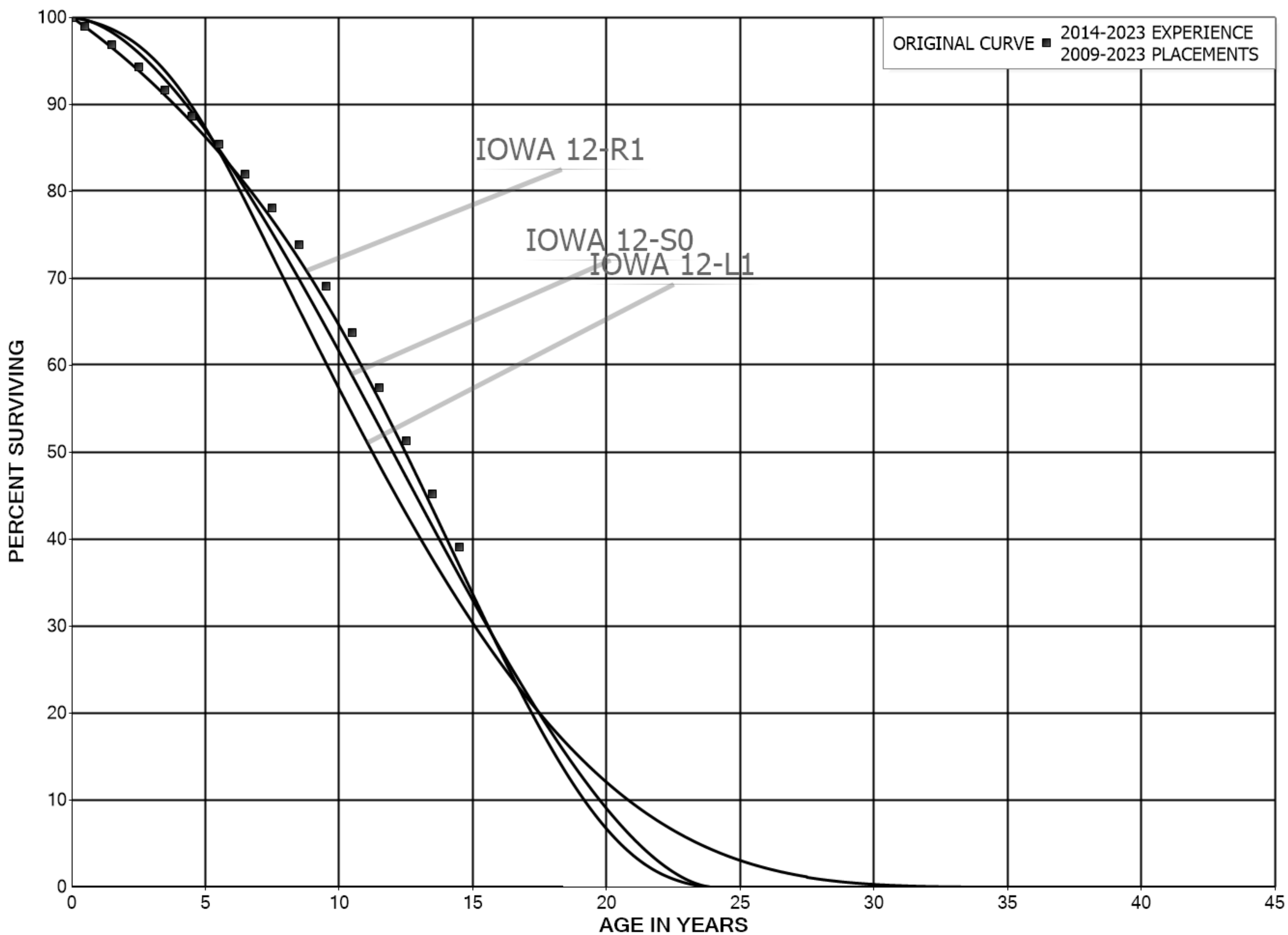


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

Field Trips

In order to be familiar with the operation of the Company and observe representative portions of the plant, field trips have been conducted periodically. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements are obtained during these field trips. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

The following is a list of the locations visited during the most recent trips:

December 9, 2021
- Empire Administrative Office Building
- Hanover Industrial Park Transmission Substation
- Loomis Substation
- Transmission Tower No. 89
- Mountain Transmission Substation
- Forty Fort Warehouse

January 27, 2017
- Empire Administrative Office Building
- Hunlock Transmission Substation
- Huntsville Transmission Substation
- Mountain Transmission Substation
- Power Control Center

December 14, 2011
- Empire Office
- Hanover Industrial Park Office
- Hanover Industrial Park Transmission Substation
- Mountain Transmission Substation
- Hunlock Transmission Substation
- Plymouth Transmission Substation
- Swoyersville Transmission Substation
- Kingston Transmission Substation
- Courtdale Transmission Substation
- Lincoln Street Transmission Substation
- Nanticoke Service Center
- Forty Fort Warehouse

May 14, 2007

- Hanover Industrial Park Transmission Substation
- Hanover Industrial Park Office
- Hunlock Transmission Substation
- Mountain Transmission Substation
- Swoyersville Transmission Substation
- Forty Fort Warehouse
- Courtdale Transmission Substation
- Plymouth Storeroom

May 8, 2002

- Hunlock Transmission Substation
- Nanticoke Transmission Substation
- Nanticoke Service Center
- Plymouth Transmission Substation
- Kingston Transmission and Distribution Substation
- Mountain Transmission Substation
- Huntsville Transmission Substation
- Kunkle Transmission Substation
- Dallas Transmission Substation
- Glenview Substation
- Swoyersville Transmission Substation
- Forty Fort Warehouse
- Courtdale Transmission Substation
- Plymouth Storeroom

October 16, 1996

- Hunlock Generating and Transmission Substation
- Hanover Industrial Park Transmission Substation
- Nanticoke Transmission Substation
- Nanticoke Service Center
- Plymouth Transmission Substation
- Kingston Transmission and Distribution Substation
- Mountain Transmission Substation
- Huntsville Transmission Substation
- Idetown Distribution Substation
- Alderson Distribution Substation
- Kunkle Transmission Substation
- Dallas Transmission Substation
- Glenview Substation
- Swoyersville Transmission Substation
- Koonsville Transmission Substation
- Forty Fort Warehouse
- Courtdale Transmission Substation
- Plymouth Storeroom

Judgment.

The survivor curve estimates were based on judgment which considered a number of factors. The primary factors were the statistical analyses of data; current Company policies and outlook as determined during the field trips and other conversations with management; and the survivor curve estimates from previous studies of this company and other electric companies.

The current service life study is based on data through 2021. For a majority of the mass plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses resulted in reasonable indications of the survivor patterns experienced. Generally, the information external to the statistics led to no significant departure from the indicated survivor curves for the following accounts:

Account Number and Title	
364	Poles, Towers & Fixtures
365	Overhead Conductors and Devices
367	Underground Conductors & Devices
368.1	Transformers
368.2	Transformer Installations
369	Services
370.1	Meters
371.5	Installations on Customers' Premises - Dusk to Dawn Lights
373	Street Lighting and Signal Systems

Account 368.1, Transformers, is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Aged retirement and other plant accounting data were compiled for the years 1960 through 2021. These data were coded in the course of the Company's normal recordkeeping according to plant account or property group, type of transaction, year in which the transaction took place, and year in which the electric plant was placed in service. The data were analyzed by the retirement rate method of life analysis. The survivor curve chart for the account is presented on

page VI-17 and the life table for the experience band plotted on the chart follows it.

The rates of retirements of transformers have been consistent throughout the experience band. Retirements of transformers are primarily caused by storm damage, deterioration, fire or third-party damage, capacity or loading issues, etc. Most of the pre-1983 line transformers that contained PCB's have been removed. Discussions with operating and management personnel indicated that the life characteristics of transformers will be similar in the future as they have been in the past. Typical service lives for line transformers of other electric companies range from 30 to 45 years. The Iowa 45-S1 survivor curve reflects the outlook of management, is within the range of service life estimates used by other electric companies and is a reasonable interpretation of the significant portion of the stub survivor curve through age 54.

For Account 365, Overhead Conductors and Devices, the estimate of survivor characteristics is based on the 1960-2021 experience band. Most retirements have been due to deterioration, inadequacy and voltage conversions. Typical service lives for overhead conductors and devices range from 45 to 60 years. The Iowa 58-R1.5 survivor curve is within the range of other estimates, is a reasonable interpretation of a significant portion of the survivor curve through age 61 and reflects the outlook of management.

The estimate for Account 367, the 42-R1.5, is based on management's expectation of a relatively short life for the direct buried conductor which represents a significant portion of the pre-1986 vintage conductor in this account. Other electric companies have experienced significant levels of early retirements; thus, management's service life outlook for direct buried conductor is much less than overhead conductor. Improvements in the insulating material for conductors installed subsequent to 1985 have greatly reduced early retirements for this account.

Similar studies were performed for the remaining significant mass plant accounts. The results of the statistical analyses are presented in account sequence in this report, beginning on page VI-2.

The survivor curve estimates for Accounts 361, 362, 366, 370.2, 370.3, 390.1 and 396 were based on engineering judgment giving consideration to the nature of the property units in each account and the low rates of retirements experienced to date.

The life span technique was used for Account 390.1, Structures and Improvements. A life span was estimated for each structure based on individual circumstances such as size, condition, type of construction, location, and management's plans. An interim survivor curve was estimated for the Forty Fort warehouse complex, inasmuch as interim retirements are normal for such structures and, in fact, have been experienced.

The major structures in Account 390.1, Structures and Improvements include two primary locations, Forty Fort warehouse and the Nanticoke (a.k.a., Dundee) Service Center. A third facility at Empire housing most of the electric division's offices is included with UGI PNG's gas operations for accounting purposes. The Empire facility, located in Wilkes, Barre, PA, was previously owned by PG Energy before being acquired by UGI. Shortly after PG Energy was acquired in 2006 by UGI, the electric division personnel relocated to Empire from their leased office building in Hanover Industrial Park. For ratemaking purposes, the cost of the buildings at Empire are allocated to each respective division, i.e., Gas and the Electric Division, based on their square footage utilization. The structures within Account 390.1 consists of structures or complexes of significant size and nature that the life span procedure is appropriate. The life spans assigned to the major structures were typically 40 to 60 years from the date of original construction or major refurbishment and varied within this range based on individual circumstances, such as size, condition, type of construction, location, age and management's plans. Long-term continued use is planned for most of the major structures.

The Iowa 100-L0 interim survivor curve was judged appropriate for the Forty Fort warehouse. The statistical analysis for major structures was based on the 1960-2021 interim retirement experience and a review of the interim survivor curves derived for similar structures of other utility companies. The interim survivor curve for Account 390.1, Structures and Improvements describes the survivor characteristics of the property units that will be replaced during the life of the facility such as roofs, windows, doors, flooring, HVAC, plumbing and electrical systems, etc.

Amortization accounting is being used for certain General Plant accounts. The accounts for which amortization accounting is being used comprises a relatively minor percent of the total depreciable electric plant in service.

Generally, the survivor curve estimates for the remainder of the accounts were based on judgments which considered the nature of the plant and equipment, reviews of available historical retirement data, and a general knowledge of the service lives for similar equipment in other electric companies.

PART IV. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART IV. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

Group Depreciation Procedures

A group procedure for depreciation is appropriate when considering more than a single item of property. Normally, the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group.

In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the equal life group procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. This procedure eliminates the need to base depreciation on average lives, inasmuch as each group is equivalent to a unit having a single life. The full costs of short-lived units are accrued during their lives, leaving no deferral of accruals required to be added to the annual costs associated with long-lived units. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life group.

Remaining Life Annual Accruals

For the purpose of calculating remaining life accrual rates at September 30, 2023, the estimated book depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation for the vintages calculated by the average service life procedure and for the vintages calculated by the equal life group procedure follow. The detailed calculations are set forth in the Results of Study section of the report.

Average Service Life Procedure

In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future whole life depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account, based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$Ratio = 1 - \frac{Average\ Remaining\ Life\ Expectancy}{Average\ Service\ Life}.$$

Equal Life Group Procedure

In the equal life group procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the composite remaining life for the surviving original cost of that vintage. The composite remaining life is derived by compositing the individual equal life group remaining lives in accordance with the following equation:

$$\textit{Composite Remaining Life} \ - \ \frac{(\frac{\textit{Book Cost}}{\textit{Life}} \, x \ \textit{Remaining Life})}{\frac{\textit{Book Cost}}{\textit{Life}}}$$

The book costs and lives of the several equal life groups which are summed in the foregoing equation are defined by the estimated future survivor curve.

Inasmuch as book cost divided by life equals the whole life annual accrual, the foregoing equation reduces to the following form:

$$\textit{Composite Remaining LIfe} \ = \ \frac{\sum \textit{Whole Life Future Accruals}}{\sum \textit{Whole Life Annual Accruals}}$$

or

$$\textit{Composite Remaining Life} \ = \ \frac{\sum \textit{Book Cost} \ - \ \textit{Calc. Reserve}}{\sum \textit{Whole Life Annual Accrual}}.$$

The annual accrual rate for each account is equal to the sum of the remaining life annual accruals for all vintages divided by the account's total original cost. The account's "composite remaining life" is calculated by dividing the sum of the future book accruals for all vintages by the sum of the remaining life annual accruals for all vintages.

The calculated accrued depreciation in the equal life group procedure also represents that portion of depreciable cost which will not be allocated to expense through future accruals. However, the calculation is based at the equal life group level rather than the vintage group level, and does not require the use of averages. The equal life group accrued depreciation ratio is calculated as follows:

$$Ratio = 1 - \frac{Remaining\ Life}{Average\ Service\ Life}.$$

Inasmuch as service life minus remaining life equals age, when averages are not employed, the foregoing equation reduces to:

$$Ratio = \frac{Age}{Service\ Life}.$$

The table on the following page illustrates the procedure for calculating straight line equal life group accrued depreciation, using an Iowa 20-S0 survivor curve and a September 30, 2023 calculation date.

In the table, each equal life group is defined by the age interval shown in columns 1 and 2, which identify the ages at which the first and last retirement of each group occur. The group's designated life, shown in column 3, is the midpoint of the interval. In the calculation, the equal life groups of each vintage are arranged such that the midpoint of each one-year age interval coincides with the calculation date, e.g., September 30 in this case. This enables the calculation of annual accruals which are centered on, or as of, the same date as the calculation of accrued depreciation.

The retirement during each age interval, shown in column 4, is the size of each equal life group. It is derived from the Iowa 20-S0 survivor curve and is the difference between the percents surviving (not shown) at the beginning and end of the age interval.

DETAILED COMPUTATION OF ANNUAL AND ACCRUED FACTORS USING THE EQUAL LIFE GROUP PROCEDURE

INPUT PARAMETERS:
CALCULATION DATE.. 9-30-2023
SURVIVOR CURVE.... 20-S0
IN-SERVICE MONTH.. 3.00

AGE INTERVAL BEG (1)	END (2)	LIFE (3)	RETIREMENTS DURING INTERVAL (4)	GROUP ANNUAL ACCRUAL (5)=(4)/(3)	YEAR INST (6)	SUMMATION OF ANNUAL ACCRUALS (7)	AVERAGE PERCENT SURVIVING (8)	ANNUAL FACTOR (9)	ACCRUED FACTOR (10)
0.000	1.000	0.500	0.35012	0.35012000000	2023	7.85656929733	99.868498	0.0787	0.0394
1.000	2.000	1.500	0.81284	0.54189333333	2022	7.23550263066	99.243460	0.0729	0.1094
2.000	3.000	2.500	1.17125	0.46850000000	2021	6.73030596400	98.251415	0.0685	0.1713
3.000	4.000	3.500	1.47766	0.42218857143	2020	6.28496167828	96.926960	0.0648	0.2268
4.000	5.000	4.500	1.74739	0.38830888889	2019	5.87971294812	95.314435	0.0617	0.2777
5.000	6.000	5.500	1.98798	0.36145090909	2018	5.50483304913	93.446750	0.0589	0.3240
6.000	7.000	6.500	2.20398	0.33907384615	2017	5.15457067151	91.350770	0.0564	0.3666
7.000	8.000	7.500	2.39831	0.31977466667	2016	4.82514641510	89.049625	0.0542	0.4065
8.000	9.000	8.500	2.57310	0.30271764706	2015	4.51390025824	86.563920	0.0521	0.4429
9.000	10.000	9.500	2.72988	0.28735578947	2014	4.21886353997	83.912430	0.0503	0.4779
10.000	11.000	10.500	2.86981	0.27331523810	2013	3.93852802619	81.112585	0.0486	0.5103
11.000	12.000	11.500	2.99382	0.26033217391	2012	3.67170432018	78.180770	0.0470	0.5405
12.000	13.000	12.500	3.10262	0.24820960000	2011	3.41743343323	75.132550	0.0455	0.5688
13.000	14.000	13.500	3.19677	0.23679777778	2010	3.17492974434	71.982855	0.0441	0.5954
14.000	15.000	14.500	3.27673	0.22598137931	2009	2.94354016579	68.746105	0.0428	0.6206
15.000	16.000	15.500	3.34287	0.21566903226	2008	2.72271496001	65.436305	0.0416	0.6448
16.000	17.000	16.500	3.39546	0.20578545455	2007	2.51198771660	62.067140	0.0405	0.6683
17.000	18.000	17.500	3.43473	0.19627028571	2006	2.31095984647	58.652045	0.0394	0.6895
18.000	19.000	18.500	3.46083	0.18707189189	2005	2.11928875767	55.204265	0.0384	0.7104
19.000	20.000	19.500	3.47385	0.17814615385	2004	1.93667973480	51.736925	0.0374	0.7293
20.000	21.000	20.500	3.47385	0.16945609756	2003	1.76287860910	48.263075	0.0365	0.7483
21.000	22.000	21.500	3.46083	0.16096883721	2002	1.59766614171	44.795735	0.0357	0.7676
22.000	23.000	22.500	3.43473	0.15265466667	2001	1.44085438977	41.347955	0.0348	0.7830
23.000	24.000	23.500	3.39546	0.14448765957	2000	1.29228322665	37.932860	0.0341	0.8014
24.000	25.000	24.500	3.34287	0.13644367347	1999	1.15181756013	34.563695	0.0333	0.8159
25.000	26.000	25.500	3.27673	0.12849921569	1998	1.01934611555	31.253895	0.0326	0.8313
26.000	27.000	26.500	3.19677	0.12063283019	1997	0.89478009261	28.017145	0.0319	0.8454
27.000	28.000	27.500	3.10261	0.11282218182	1996	0.77805258661	24.867455	0.0313	0.8608
28.000	29.000	28.500	2.99383	0.10504666667	1995	0.66911816236	21.819235	0.0307	0.8750
29.000	30.000	29.500	2.86981	0.09728169492	1994	0.56795398157	18.887415	0.0301	0.8880
30.000	31.000	30.500	2.72988	0.08950426230	1993	0.47456100296	16.087570	0.0295	0.8998
31.000	32.000	31.500	2.57310	0.08168571429	1992	0.38896601466	13.436080	0.0289	0.9104
32.000	33.000	32.500	2.39831	0.07379415385	1991	0.31122608059	10.950375	0.0284	0.9230
33.000	34.000	33.500	2.20398	0.06579044776	1990	0.24143377979	8.649230	0.0279	0.9347
34.000	35.000	34.500	1.98798	0.05762260870	1989	0.17972725156	6.553250	0.0274	0.9453
35.000	36.000	35.500	1.74739	0.04922225352	1988	0.12630482045	4.685565	0.0270	0.9585
36.000	37.000	36.500	1.47766	0.04048383562	1987	0.08145177588	3.073040	0.0265	0.9673
37.000	38.000	37.500	1.17125	0.03123333333	1986	0.04559319140	1.748585	0.0261	0.9788
38.000	39.000	38.500	0.81284	0.02111272727	1985	0.01942016110	0.756540	0.0257	0.9895
39.000	40.000	39.500	0.35012	0.00886379747	1984	0.00443189874	0.175060	0.0253	1.0000
TOTAL			100.00000						

Each equal life group's whole life annual accrual, shown in column 5, equals the group's size (column 4) divided by its life (column 3), except that for the first age interval, the annual accrual is set equal to the group's size.

Columns 6 through 10 show the derivation of the whole life annual factor and accrued factor for each vintage based on the data developed in the first five columns. The year installed is shown in column 6. For all vintages other than the first and last year (2023 and 1984), the summation of annual accruals for each year installed, shown in column 7, is calculated by adding one-half of the group annual accrual (column 5) for that vintage's current age interval plus the group annual accruals for all succeeding age intervals. For example, the figure 7.23550263066 for 2022 equals one-half of 0.54189333333 plus all of the succeeding figures in column 5. Only one-half of the annual accrual for the vintage's current age interval group is included in the summation because the equal life group for that interval expires at the midpoint of the current year.

The summation of annual accruals (column 7) for installations during 2023 is calculated on the basis of a mid-year in-service date. Consequentially, the accrual for 2023 installation represents only one-half of one year. The first figure in column 7, for vintage 2023, equals all of the group annual accrual for the first equal life group (2023) plus all of the accruals for all of the subsequent equal life groups. For vintage 1984, the attained age at the beginning of the year is 39.00 years leaving only 0.500 year remaining. Thus, the accrual in 1984 is .500 times the normal annual accrual in column 5.

The average percent surviving, derived from the Iowa 20-S0 survivor curve, is shown in column 8 for each age interval. The annual factor, shown in column 9, is the result of dividing the summation of annual accruals (column 7) by the average percent surviving (column 8).

The accrued depreciation factor, shown in column 10, equals the annual factor multiplied by the age of the group at September 30, 2023.

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization, as defined in the Uniform System of Accounts, is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization periods and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is appropriate for certain General Plant accounts that represent numerous units of property, but a very small portion of depreciable electric plant in service. The accounts and their amortization periods are as follows:

Account	Amortization Period, Years
ELECTRIC DIVISION	
391, Office Furniture and Equipment	
Furniture	20
Equipment	5
Outage Management Software	5
393, Stores Equipment	10
394, Tools, Shop and Garage Equipment	20
395, Laboratory Equipment	10
397, Communication Equipment	10
398, Miscellaneous Equipment	10

COMMON PLANT		
391,	Office Furniture and Equipment	
	Furniture	20
	Equipment	5
398,	Miscellaneous Equipment	10
INFORMATION SERVICES		
391,	Office Furniture and Equipment	
	Furniture	20
	Equipment	5
	Software -System Development Costs	10
	Software - System Development Costs - Major	15

For the purpose of calculating annual amortization amounts at September 30, 2023, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

AMORTIZATION OF NET SALVAGE

Experienced salvage is incorporated in the results of the study, as it was reported on the Company's books and records for the period October 1, 2018 through September 30, 2022, and as estimated for the twelve months ended September 30, 2023. The five-year amortization calculations are shown in Table 4.

Net salvage experienced during the five-year period is presented in this manner to determine the amount of negative net salvage to be amortized for book purposes. In developing the amount to be amortized, the data for the accounts which experienced positive net salvage have been netted with those for accounts which experienced negative net salvage.

In order to be consistent with this manner of recognizing salvage, no adjustments for salvage were made to the annual accruals and accrued depreciation calculated for each individual account. Also, there were no exclusions from the 2019 through 2023 experienced and estimated net salvage amounts that were used to determine the five-year net salvage amortization amount for each account.

PART V. RESULTS OF STUDY

PART V. RESULTS OF STUDY

DESCRIPTION OF SUMMARY TABULATIONS

Tables 1 through 4 presented on pages V-4 through V-12 summarize the results of the depreciation study at September 30, 2023. Table 1 sets forth, by depreciable group, the estimated survivor curve, original cost, book depreciation reserve at September 30, 2023, future book accruals, calculated annual accrual amount and rate, and composite remaining life for plant in service. Table 2 presents the bringforward of the book reserve to September 30, 2023. Table 3 sets forth the calculation of the depreciation accruals for the twelve months ended September 30, 2023. Table 4 presents the annual amortization of experienced and estimated net salvage based on the period 2019 through 2023.

DESCRIPTION OF DETAILED TABULATIONS

Supporting statistical data for the estimates of average service lives and survivor curves, the annual depreciation calculations, and salvage and cost of removal for the years 2019-2023 are presented in three sections.

The section beginning on page VI-2 sets forth, for each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table(s) plotted on the chart. A cumulative summary, by year installed, for electric plant and the supporting data for the original cost depreciation calculations are presented in the section beginning on page VII-2. The tabulations of experienced and estimated net salvage by year by account for the five-year period, 2019-2023, are presented in the section beginning on page VIII-2.

In Part VI, the survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the type curve designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. In cases where only a segment of the estimated curve is used in the depreciation calculation, the numeral used for identification purposes is not a designation of the average life of the group. The titles of the charts indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which were plotted. The experience band indicates the range of years for which the retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The tables of the calculated annual depreciation related to original cost are presented in Part VII and indicate the estimated average survivor curves used in the calculations. The tables set forth, for each installation year, the original cost, calculated accrued depreciation, allocated book reserve, future book accruals, remaining life expectancy and the calculated annual accrual.

Detailed tabulations setting forth the cost of removal and salvage amounts, by plant account for each year, are presented beginning on page VIII-2. The total salvage and removal costs, by year, were used to calculate the five-year net salvage amortization presented in Table 4 in Part V on pages V-11 and V-12.

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND
CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF SEPTEMBER 30, 2023

ACCOUNT		PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
ELECTRIC PLANT								
DISTRIBUTION PLANT								
361	STRUCTURES AND IMPROVEMENTS		50 - R3	627,496	51,995	575,501	2.41	15,093
362	STATION EQUIPMENT		40 - S1	11,263,245	1,177,222	10,086,023	3.25	366,341
364	POLES, TOWERS AND FIXTURES		59 - R2.5	55,047,300	16,932,371	38,114,929	1.85	1,018,082
365	OVERHEAD CONDUCTORS AND DEVICES		58 - R1.5	69,557,228	13,966,110	55,591,118	2.34	1,625,571
365.7	REG AFUDC		40 SQ	(711,827)	(99,348)	(612,479)	2.29	(16,333)
366	UNDERGROUND CONDUIT		65 - R3	8,779,918	2,551,835	6,228,083	1.57	137,656
367	UNDERGROUND CONDUCTORS AND DEVICES		42 - R1.5	15,051,435	4,511,139	10,540,296	2.85	428,554
368.1	TRANSFORMERS		45 - S1	18,263,782	8,139,253	10,124,529	2.08	379,659
368.2	TRANSFORMER INSTALLATIONS		39 - R2	11,218,276	6,450,987	4,767,289	1.90	213,344
369	SERVICES		53 - R2	16,224,921	7,799,373	8,425,548	1.68	271,960
370.1	METERS		34 - R1	2,977,856	2,054,528	923,328	1.85	55,146
370.2	METER INSTALLATIONS		75 - R4	1,980,373	801,991	1,178,382	1.26	24,969
370.3	ELECTRONIC METERS		20 - S3	5,037,891	4,148,090	889,801	2.50	126,120
371	INSTALLATIONS ON CUSTOMER PREMISES		30 - O1	2,219,114	987,794	1,231,320	3.73	82,731
371.5	INSTALLATIONS ON CUSTOMER PREMISES - DUSK TO DAWN LIGHTS		23 - R1	347,706	336,331	11,375	0.40	1,391
373	STREET LIGHTING AND SIGNAL SYSTEMS		28 - L0	2,470,771	1,058,359	1,412,412	4.32	106,847
TOTAL DISTRIBUTION PLANT				**220,355,485**	**70,868,030**	**149,487,455**	**2.20**	**4,837,131**
GENERAL PLANT								
390.1	STRUCTURES AND IMPROVEMENTS							
	FORTY FORT	06-2032	* 100 - L0	4,192,673	809,231	3,383,442	9.57	401,046
	PLYMOUTH		FULLY ACCRUED	15,111	15,111	0	-	0
	IDETOWN	06-2046	* 100 - L0	49,926	11,815	38,111	3.80	1,898
	NANTICOKE		FULLY ACCRUED	76,179	76,179	0	-	0
	EMPIRE YARD		FULLY ACCRUED	19,895	19,895	0	-	0
	SYSTEM CONTROL CENTER	07-2056	* 100 - L0	1,891,888	342,973	1,548,915	3.02	57,176
	SUBTOTAL ACCOUNT 390.1			*6,245,672*	*1,275,204*	*4,970,468*	*7.37*	*460,120*
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	66,068	20,137	45,931	7.33	4,841
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	369,215	285,540	83,675	21.26	78,500
391.92	OFFICE FURNITURE AND EQUIPMENT - OUTAGE MANAGEMENT SOFTWARE		5 - SQ	3,496,035	697,801	2,798,234	22.68	793,049
393	STORES EQUIPMENT		10 - SQ	14,618	5,885	8,733	12.08	1,766
394	TOOLS, SHOP AND GARAGE EQUIPMENT		20 - SQ	1,555,310	622,707	932,603	5.10	79,266
395	LABORATORY EQUIPMENT		10 - SQ	73,971	62,234	11,737	3.93	2,910
397	COMMUNICATION EQUIPMENT		10 - SQ	931,152	297,890	633,262	12.38	115,248
398	MISCELLANEOUS EQUIPMENT		10 - SQ	591,542	126,923	464,619	11.66	68,984
TOTAL GENERAL PLANT				**13,343,583**	**3,394,321**	**9,949,262**	**12.03**	**1,604,684**

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND
CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF SEPTEMBER 30, 2023

ACCOUNT	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
SPECIAL DEPRECIABLE PLANT							
392.1 TRANSPORTATION EQUIPMENT - CARS		7 - L3	336,097	167,889	168,208	13.45	45,201
392.2 TRANSPORTATION EQUIPMENT - LIGHT TRUCKS		11 - L3	1,620,671	307,336	1,313,335	10.96	177,627
392.4 TRANSPORTATION EQUIPMENT - HEAVY TRUCKS		14 - S3	490,636	75,520	415,116	8.07	39,603
396 POWER OPERATED EQUIPMENT		20 - S0	804,018	45,151	758,867	7.74	62,236
TOTAL SPECIAL DEPRECIABLE PLANT			**3,251,422**	**595,896**	**2,655,526**	**9.99**	**324,667**
TOTAL DEPRECIABLE PLANT			**236,950,490**	**74,858,247**	**162,092,243**	**2.86**	**6,766,482**
NONDEPRECIABLE PLANT							
301.1 ORGANIZATION			1,602				
302.1 FRANCHISES AND CONSENTS - PERPETUAL			6,436				
360.1 LAND AND LAND RIGHTS - LAND			299,162				
360.2 LAND AND LAND RIGHTS - LAND RIGHTS			14,336				
389.1 LAND AND LAND RIGHTS - LAND			202,584	14,257			
TOTAL NONDEPRECIABLE PLANT			**524,120**	**14,257**			
TOTAL ELECTRIC PLANT			**237,474,610**	**14,257**			
LESS GENERAL AND INTANGIBLE PLANT ALLOCATED TO TRANSMISSION - 25.6247%			4,306,392	1,026,134	3,229,939		494,390
TOTAL ELECTRIC PLANT RELATED TO DISTRIBUTION OPERATIONS			**233,168,218**	**73,846,370**	**158,862,304**		**6,272,092**
OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION							
COMMON PLANT							
301 ORGANIZATION (NONDEPRECIABLE)			138,964				
389.1 LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)			6,947,108				
390.1 STRUCTURES AND IMPROVEMENTS	01-2069	* SQUARE	35,947,826	4,076,856	31,870,970	2.78	999,640
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	5,242,774	1,282,392	3,960,382	5.31	278,239
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	1,353,581	664,008	689,573	23.34	315,961
392.1 TRANSPORTATION EQUIPMENT - CARS		FULLY ACCRUED	71,637	71,637	0	-	0
398 MISCELLANEOUS EQUIPMENT		10 - SQ	27,967	3,864	24,103	13.26	3,708
TOTAL COMMON PLANT			**49,729,857**	**6,098,757**	**36,545,028**	**3.22**	**1,597,548**
TOTAL COMMON PLANT ALLOCATED TO ELECTRIC DIVISION - 9.83%			**4,888,445**	**599,508**	**3,592,376**		**157,039**

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND
CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF SEPTEMBER 30, 2023

ACCOUNT (1)	PROBABLE RETIREMENT YEAR (2)	SURVIVOR CURVE (3)	ORIGINAL COST (4)	BOOK RESERVE (5)	FUTURE BOOK ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL RATE (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)
INFORMATION SERVICES (IS)							
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	8,017	7,045	972	3.28	263
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	14,757,055	11,091,382	3,665,673	13.57	2,002,004
391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE							
SUCCESS FACTORS	09-2024 **	SQUARE	2,803,866	2,046,868	756,998	27.00	756,998
UNITE ERP	09-2034 ***	SQUARE	10,695,816	2,395,208	8,300,608	7.06	754,601
TOTAL OFFICE FURNITURE AND EQUIPMENT - SOFTWARE			13,499,682	4,442,076	9,057,606		1,511,599
391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS		10 - SQ	52,284,361	14,683,389	37,600,972	10.22	5,345,423
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS		15 - SQ	134,231,132	49,003,505	85,227,627	6.71	9,003,362
TOTAL INFORMATION SERVICES (EXCLUDING 100% ALLOCATION AMOUNT)			**214,780,247**	**79,227,397**	**135,552,850**	**8.32**	**17,862,651**
TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION - 9.08%			**19,502,046**	**7,193,848**	**12,308,199**		**1,621,929**
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV.COSTS - 15 YEARS		15 - SQ	246,470	0	246,470	6.90	16,998
TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION - 100.00%			**246,470**	**0**	**246,470**		**16,998**
TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION			**19,748,516**	**7,193,848**	**12,554,669**		**1,638,927**
EMPIRE YARD BUILDING							
390.1 STRUCTURES AND IMPROVEMENTS	12-2047 *	80 - R1.5	14,913,154	8,781,870	6,131,284	1.87	279,560
TOTAL EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%			**1,949,149**	**1,147,790**	**801,359**		**36,538**
TOTAL OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION			**26,586,110**	**8,941,146**	**16,948,404**		**1,832,504**
LESS OTHER UTILITY PLANT ALLOCATED TO ELECTRIC TRANSMISSION - 25.6247%			6,812,611	2,291,142	4,342,978		469,574
TOTAL OTHER PLANT ALLOCATED TO ELECTRIC RELATED TO DISTRIBUTION OPERATIONS			**19,773,499**	**6,650,004**	**12,605,426**		**1,362,930**
TOTAL PLANT IN SERVICE RELATED TO DISTRIBUTION OPERATIONS			**252,941,717**	**80,496,374**	**171,467,730**		**7,635,022**
AMORTIZATION OF NEGATIVE NET SALVAGE							*775,683*
GRAND TOTAL			**252,941,717**	**80,496,374**	**171,467,730**		**8,410,705**

* SURVIVOR CURVES FOR ACCOUNT 390 ARE INTERIM SURVIVOR CURVES. INDIVIDUAL BUILDINGS ARE LIFE SPANNED.
** REGULATORY ASSET DEPRECIATED OVER FOUR YEARS. ONE YEAR REMAINING.
*** REGULATORY ASSET DEPRECIATED OVER FOURTEEN YEARS. ELEVEN YEARS REMAINING

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 2. BOOK RESERVE AT SEPTEMBER 30, 2022 PROJECTED TO SEPTEMBER 30, 2023

ACCOUNT	BOOK RESERVE AT BEGINNING OF YEAR	ANNUAL ACCRUAL	AMORTIZATION OF NET SALVAGE	RETIREMENTS	GROSS SALVAGE	COST OF REMOVAL	TRANSFERS AND ADJUSTMENTS	BOOK RESERVE AT END OF YEAR	BOOK RESERVE AS A PERCENT OF ORIGINAL COST
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
ELECTRIC PLANT									
DISTRIBUTION PLANT									
361 STRUCTURES AND IMPROVEMENTS	36,400	15,374	221	0	0	0	0	51,995	8.29
362 STATION EQUIPMENT	796,511	369,258	14,174	(2,651)	195	(265)	0	1,177,222	10.45
364 POLES, TOWERS AND FIXTURES	15,594,836	1,036,683	433,587	(53,094)	0	(79,641)	0	16,932,371	30.76
365 OVERHEAD CONDUCTORS AND DEVICES	14,111,095	1,322,228	107,695	(787,454)	0	(787,454)	0	13,966,110	20.08
365.7 REG AFUDC	(83,047)	(16,301)	0	0	0	0	0	(99,348)	13.96
366 UNDERGROUND CONDUIT	2,409,512	138,723	3,600	0	0	0	0	2,551,835	29.06
367 UNDERGROUND CONDUCTORS AND DEVICES	4,071,859	444,047	12,917	(14,734)	0	(2,950)	0	4,511,139	29.97
368.1 TRANSFORMERS	8,046,476	347,494	6,251	(246,521)	0	(14,447)	0	8,139,253	44.56
368.2 TRANSFORMER INSTALLATIONS	6,195,958	221,917	36,291	(2,119)	0	(1,060)	0	6,450,987	57.50
369 SERVICES	7,527,834	268,618	71,171	(24,818)	0	(43,432)	0	7,799,373	48.07
370.1 METERS	2,073,283	51,868	(40,937)	(68,379)	38,693	0	0	2,054,528	68.99
370.2 METER INSTALLATIONS	778,252	24,902	4,188	(3,346)	0	(2,005)	0	801,991	40.50
370.3 ELECTRONIC METERS	4,010,096	137,534	460	0	0	0	0	4,148,090	82.34
371 INSTALLATIONS ON CUSTOMER PREMISES	873,689	95,866	18,239	0	0	0	0	987,794	44.51
371.5 INSTALLATIONS ON CUSTOMER PREMISES - DUSK TO DAWN LIGHTS	334,801	1,530	0	0	0	0	0	336,331	96.73
373 STREET LIGHTING AND SIGNAL SYSTEMS	980,610	105,892	16,136	(29,580)	0	(14,699)	0	1,058,359	42.84
TOTAL DISTRIBUTION PLANT	**67,758,165**	**4,565,633**	**683,993**	**(1,232,696)**	**38,888**	**(945,953)**	**0**	**70,868,030**	**32.16**
GENERAL PLANT									
390.1 STRUCTURES AND IMPROVEMENTS	1,193,834	331,729	35	(250,394)	0	0	0	1,275,204	20.42
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	15,334	4,803	0	0	0	0	0	20,137	30.48
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	130,617	154,923	0	0	0	0	0	285,540	77.34
391.9 OFFICE FURNITURE AND EQUIPMENT - OUTAGE MANAGEMENT SOFTWARE	660,150	699,707	0	(662,056)	0	0	0	697,801	19.96
392.1 TRANSPORTATION EQUIPMENT - CARS	123,694	44,195	0	0	0	0	0	167,889	49.95
392.2 TRANSPORTATION EQUIPMENT - LIGHT TRUCKS	140,850	169,027	(2,541)	0	0	0	0	307,336	18.96
392.4 TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	35,877	39,643	0	0	0	0	0	75,520	15.39
393 STORES EQUIPMENT	4,135	1,750	0	0	0	0	0	5,885	40.26
394 TOOLS, SHOP AND GARAGE EQUIPMENT	615,343	86,277	0	(78,913)	0	0	0	622,707	40.04
395 LABORATORY EQUIPMENT	83,568	2,525	0	(23,859)	0	0	0	62,234	84.13
396 POWER OPERATED EQUIPMENT	6,317	38,834	0	0	0	0	0	45,151	5.62
397 COMMUNICATION EQUIPMENT	152,259	237,758	13	(92,135)	0	(5)	0	297,890	31.99
398 MISCELLANEOUS EQUIPMENT	51,910	67,123	7,890	0	0	0	0	126,923	21.46
TOTAL GENERAL PLANT	**3,213,888**	**1,878,294**	**5,397**	**(1,107,357)**	**0**	**(5)**	**0**	**3,990,217**	**24.04**
TOTAL DEPRECIABLE PLANT	**70,972,053**	**6,443,927**	**689,390**	**(2,340,053)**	**38,888**	**(945,958)**	**0**	**74,858,247**	**31.49**
NONDEPRECIABLE PLANT									
301.1 ORGANIZATION	0	0	0	0	0	0	0	0	0.00
302.1 FRANCHISES AND CONSENTS - PERPETUAL	0	0	0	0	0	0	0	0	0.00
360.1 LAND AND LAND RIGHTS - LAND	0	0	0	0	0	0	0	0	0.00
360.2 LAND AND LAND RIGHTS - LAND RIGHTS	0	0	0	0	0	0	0	0	0.00
389.1 LAND AND LAND RIGHTS - LAND	14,257	0	0	0	0	0	0	14,257	7.04
TOTAL NONDEPRECIABLE PLANT	**14,257**	**0**	**0**	**0**	**0**	**0**	**0**	**14,257**	
TOTAL ELECTRIC PLANT	**70,986,310**	**6,443,927**	**689,390**	**(2,340,053)**	**38,888**	**(945,958)**	**0**	**74,872,504**	
LESS GENERAL PLANT ALLOCATED TO TRANSMISSION - 25.6247%	827,202	481,307	1,383	(283,757)	0	(1)	0	1,026,134	
TOTAL DEPRECIABLE PLANT RELATED TO DISTRIBUTION OPERATIONS	**70,159,108**	**5,962,620**	**688,007**	**(2,056,296)**	**38,888**	**(945,957)**	**0**	**73,846,370**	

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 2. BOOK RESERVE AT SEPTEMBER 30, 2022 PROJECTED TO SEPTEMBER 30, 2023

ACCOUNT (1)	BOOK RESERVE AT BEGINNING OF YEAR (2)	ANNUAL ACCRUAL (3)	AMORTIZATION OF NET SALVAGE (4)	RETIREMENTS (5)	GROSS SALVAGE (6)	COST OF REMOVAL (7)	TRANSFERS AND ADJUSTMENTS (8)	BOOK RESERVE AT END OF YEAR (9)	BOOK RESERVE AS A PERCENT OF ORIGINAL COST (10)
OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION									
COMMON PLANT									
390.1 STRUCTURES AND IMPROVEMENTS	3,018,983	1,047,245	0	0	0	0	10,628	4,076,856	11.34
390.2 STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	10,628	0	0	0	0	0	(10,628)	0	0.00
391.0 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,011,569	278,006	0	(7,183)	0	0	0	1,282,392	24.46
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	272,031	480,595	0	(88,618)	0	0	0	664,008	49.06
392.1 TRANSPORTATION EQUIPMENT - CARS	71,637	0	0	0	0	0	0	71,637	100.00
398 MISCELLANEOUS EQUIPMENT	0	0	0	0	0	0	3,864	3,864	13.82
TOTAL COMMON PLANT	**4,384,848**	**1,805,846**	**0**	**(95,801)**	**0**	**0**	**3,864**	**6,098,757**	**12.26**
TOTAL COMMON PLANT ALLOCATED TO ELECTRIC DIVISION - 9.83%	**431,031**	**177,515**	**0**	**(9,417)**	**0**	**0**	**380**	**599,508**	
INFORMATION SERVICES (IS)									
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	28,853	877	0	(22,685)	0	0	0	7,045	87.88
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	13,083,477	3,592,336	0	(5,584,431)	0	0	0	11,091,382	75.16
391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE									
SUCCESS FACTORS	1,289,824	757,044	0	0	0	0	0	2,046,868	73.00
UNITE ERP	1,640,083	755,125	0	0	0	0	0	2,395,208	22.39
TOTAL OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	2,929,907	1,512,169	0	0	0	0	0	4,442,076	
391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	22,617,829	4,747,149	0	(12,681,589)	0	0	0	14,683,389	28.08
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	48,592,264	8,891,579	0	(8,480,338)	0	0	0	49,003,505	36.51
TOTAL INFORMATION SERVICES (EXCLUDING 100% ALLOCATION AMOUNT)	**87,252,330**	**18,744,110**	**0**	**(26,769,043)**	**0**	**0**	**0**	**79,227,397**	**36.89**
TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION - 9.08%	**7,922,512**	**1,701,965**	**0**	**(2,430,629)**	**0**	**0**	**0**	**7,193,848**	
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV.COSTS - 15 YEARS	0	0	0	0	0	0	0	0	0.00
TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION - 100.00%	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION	**7,922,512**	**1,701,965**	**0**	**(2,430,629)**	**0**	**0**	**0**	**7,193,848**	
EMPIRE YARD BUILDING									
390.1 STRUCTURES AND IMPROVEMENTS	8,535,610	273,175	0	(26,915)	0	0	0	8,781,870	58.89
TOTAL EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%	**1,115,604**	**35,704**	**0**	**(3,518)**	**0**	**0**	**0**	**1,147,790**	
TOTAL OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION	**9,469,147**	**1,915,184**	**0**	**(2,443,564)**	**0**	**0**	**380**	**8,941,146**	
LESS OTHER UTILITY PLANT ALLOCATED TO ELECTRIC TRANSMISSION - 25.6247%	2,426,441	490,760	0	(626,156)	0	0	97	2,291,142	
TOTAL OTHER PLANT ALLOCATED TO ELECTRIC RELATED TO DISTRIBUTION OPERATIONS	**7,042,706**	**1,424,424**	**0**	**(1,817,408)**	**0**	**0**	**283**	**6,650,004**	
TOTAL DEPRECIABLE PLANT IN SERVICE RELATED TO DISTRIBUTION OPERATIONS	**77,201,814**	**7,387,044**	**688,007**	**(3,873,704)**	**38,888**	**(945,957)**	**283**	**80,496,374**	

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 3. CALCULATION OF DEPRECIATION ACCRUALS FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

ACCOUNT (1)	BEGINNING OF YEAR BALANCE (2)	ADDITIONS (3)	RETIREMENTS (4)	TRANSFERS AND ADJUSTMENTS (5)	END OF YEAR BALANCE (6)	AVERAGE BALANCE (7)	ANNUAL ACCRUAL RATE (8)	ANNUAL ACCRUAL AMOUNT (9)=(7)*(8)
ELECTRIC PLANT								
DISTRIBUTION PLANT								
361 STRUCTURES AND IMPROVEMENTS	627,496	0	0	0	627,496	627,496	2.45	15,374
362 STATION EQUIPMENT	10,981,236	284,660	(2,651)	0	11,263,245	11,122,241	3.32	369,258
364 POLES, TOWERS AND FIXTURES	54,077,226	1,023,168	(53,094)	0	55,047,300	54,562,263	1.90	1,036,683
365 OVERHEAD CONDUCTORS AND DEVICES	54,595,611	15,749,071	(787,454)	0	69,557,228	62,076,420	2.13	1,322,228
365.7 REG AFUDC	(711,827)	0	0	0	(711,827)	(711,827)	2.29	(16,301)
366 UNDERGROUND CONDUIT	8,779,918	0	0	0	8,779,918	8,779,918	1.58	138,723
367 UNDERGROUND CONDUCTORS AND DEVICES	14,750,367	315,802	(14,734)	0	15,051,435	14,900,901	2.98	444,047
368.1 TRANSFORMERS	16,660,208	1,850,095	(246,521)	0	18,263,782	17,461,995	1.99	347,494
368.2 TRANSFORMER INSTALLATIONS	11,197,561	22,834	(2,119)	0	11,218,276	11,207,919	1.98	221,917
369 SERVICES	15,753,385	496,354	(24,818)	0	16,224,921	15,989,153	1.68	268,618
370.1 METERS	2,949,899	96,336	(68,379)	0	2,977,856	2,963,878	1.75	51,868
370.2 METER INSTALLATIONS	1,972,304	11,415	(3,346)	0	1,980,373	1,976,339	1.26	24,902
370.3 ELECTRONIC METERS	5,037,891	0	0	0	5,037,891	5,037,891	2.73	137,534
371 INSTALLATIONS ON CUSTOMER PREMISES	2,219,114	0	0	0	2,219,114	2,219,114	4.32	95,866
371.5 INSTALLATIONS ON CUSTOMER PREMISES - DUSK TO DAWN LIGHTS	347,706	0	0	0	347,706	347,706	0.44	1,530
373 STREET LIGHTING AND SIGNAL SYSTEMS	2,331,583	168,768	(29,580)	0	2,470,771	2,401,177	4.41	105,892
TOTAL DISTRIBUTION PLANT	**201,569,678**	**20,018,503**	**(1,232,696)**	**0**	**220,355,485**	**210,962,582**		**4,565,633**
GENERAL PLANT								
390.1 STRUCTURES AND IMPROVEMENTS	4,826,771	1,669,295	(250,394)	0	6,245,672	5,536,222	5.99	331,729
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	66,068	0	0	0	66,068	66,068	7.27	4,803
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	369,215	0	0	0	369,215	369,215	41.96	154,923
391.9 OFFICE FURNITURE AND EQUIPMENT - OUTAGE MANAGEMENT SOFTWARE	4,023,657	134,434	(662,056)	0	3,496,035	3,759,846	18.61	699,707
392.1 TRANSPORTATION EQUIPMENT - CARS	302,097	34,000	0	0	336,097	319,097	13.85	44,195
392.2 TRANSPORTATION EQUIPMENT - TRUCKS	1,394,971	225,700	0	0	1,620,671	1,507,821	11.21	169,027
392.4 TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	490,636	0	0	0	490,636	490,636	8.08	39,643
393 STORES EQUIPMENT	14,618	0	0	0	14,618	14,618	11.97	1,750
394 TOOLS, SHOP AND GARAGE EQUIPMENT	1,634,223	0	(78,913)	0	1,555,310	1,594,767	5.41	86,277
395 LABORATORY EQUIPMENT	97,830	0	(23,859)	0	73,971	85,901	2.94	2,525
396 POWER OPERATED EQUIPMENT	176,632	627,386	0	0	804,018	490,325	7.92	38,834
397 COMMUNICATION EQUIPMENT	1,023,287	0	(92,135)	0	931,152	977,220	24.33	237,758
398 MISCELLANEOUS EQUIPMENT	410,294	181,248	0	0	591,542	500,918	13.40	67,123
TOTAL GENERAL PLANT	**14,830,299**	**2,872,063**	**(1,107,357)**	**0**	**16,595,005**	**15,712,652**		**1,878,294**
TOTAL DEPRECIABLE PLANT	**216,399,977**	**22,890,566**	**(2,340,053)**	**0**	**236,950,490**	**226,675,234**		**6,443,927**
NONDEPRECIABLE PLANT								
301.1 ORGANIZATION	1,602	0	0	0	1,602	1,602		
302.1 FRANCHISES AND CONSENTS - PERPETUAL	6,436	0	0	0	6,436	6,436		
360.1 LAND AND LAND RIGHTS - LAND	294,162	5,000	0	0	299,162	296,662		
360.2 LAND AND LAND RIGHTS - LAND RIGHTS	14,336	0	0	0	14,336	14,336		
389.1 LAND AND LAND RIGHTS - LAND	202,584	0	0	0	202,584	202,584		
TOTAL NONDEPRECIABLE PLANT	**519,120**	**5,000**	**0**	**0**	**524,120**	**521,620**		
TOTAL ELECTRIC PLANT	**216,919,097**	**22,895,566**	**(2,340,053)**	**0**	**237,474,610**	**227,196,854**		
LESS GENERAL AND INTANGIBLE PLANT ALLOCATED TO TRANSMISSION - 25.6247%	3,854,191	735,958	(283,757)	0	4,306,392	4,080,291		481,307
TOTAL ELECTRIC PLANT RELATED TO DISTRIBUTION OPERATIONS	**213,064,906**	**22,159,608**	**(2,056,296)**	**0**	**233,168,218**	**223,116,563**		**5,962,620**

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 3. CALCULATION OF DEPRECIATION ACCRUALS FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

ACCOUNT (1)	BEGINNING OF YEAR BALANCE (2)	ADDITIONS (3)	RETIREMENTS (4)	TRANSFERS AND ADJUSTMENTS (5)	END OF YEAR BALANCE (6)	AVERAGE BALANCE (7)	ANNUAL ACCRUAL RATE (8)	ANNUAL ACCRUAL AMOUNT (9)=(7)*(8)
OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION								
COMMON PLANT								
301 ORGANIZATION (NONDEPRECIABLE)	138,964	0	0	0	138,964	138,964		
389.1 LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)	6,947,108	0	0	0	6,947,108	6,947,108		
390.1 STRUCTURES AND IMPROVEMENTS	35,781,259	166,567	-	0	35,947,826	35,864,543	2.92	1,047,245
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	5,149,957	100,000	(7,183)	0	5,242,774	5,196,366	5.35	278,006
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	1,442,199	0	(88,618)	0	1,353,581	1,397,890	34.38	480,595
392.1 TRANSPORTATION EQUIPMENT - CARS	71,637	0	0	0	71,637	71,637	-	0
398 MISCELLANEOUS EQUIPMENT	-	0	0	27,967	27,967	13,984	-	0
TOTAL COMMON PLANT	**49,531,124**	**266,567**	**(95,801)**	**27,967**	**49,729,857**	**49,630,491**		**1,805,846**
TOTAL COMMON PLANT ALLOCATED TO ELECTRIC DIVISION - 9.83%	**4,868,909**	**26,204**	**(9,417)**	**2,749**	**4,888,445**	**4,878,677**		**177,515**
INFORMATION SERVICES (IS)								
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	30,702	0	(22,685)	0	8,017	19,360	4.53	877
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	20,341,486	0	(5,584,431)	0	14,757,055	17,549,271	20.47	3,592,336
391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE								
SUCCESS FACTORS	2,803,866	0	0	0	2,803,866	2,803,866	27.00	757,044
UNITE ERP	10,695,816	0	0	0	10,695,816	10,695,816	7.06	755,125
TOTAL OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	13,499,682	0	0	0	13,499,682	13,499,682		1,512,169
391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	54,302,404	10,663,545	(12,681,589)	0	52,284,361	53,293,383	8.08	4,747,149
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	141,049,948	1,661,522	(8,480,338)	0	134,231,132	137,640,540	6.46	8,891,579
TOTAL INFORMATION SERVICES (EXCLUDING 100% ALLOCATION AMOUNT)	**229,224,222**	**12,325,067**	**(26,769,043)**	**0**	**214,780,247**	**222,002,235**		**18,744,110**
TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION - 9.08%	**20,813,559**	**1,119,116**	**(2,430,629)**	**0**	**19,502,046**	**20,157,803**		**1,701,965**
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV.COSTS - 15 YEARS	0	246,470	0	0	246,470	123,235	-	0
TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION - 100.00%	**0**	**246,470**	**0**	**0**	**246,470**	**123,235**		**0**
TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION	**20,813,559**	**1,365,586**	**(2,430,629)**	**0**	**19,748,516**	**20,281,038**		**1,701,965**
EMPIRE YARD BUILDING								
390.1 STRUCTURES AND IMPROVEMENTS	14,670,918	269,151	(26,915)	0	14,913,154	14,792,036	1.84	273,175
TOTAL EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%	**1,917,489**	**35,178**	**(3,518)**	**0**	**1,949,149**	**1,933,319**		**35,704**
TOTAL OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION	**27,599,957**	**1,426,968**	**(2,443,564)**	**2,749**	**26,586,110**	**27,093,034**		**1,915,184**
LESS OTHER UTILITY PLANT ALLOCATED TO ELECTRIC TRANSMISSION - 25.6247%	7,072,406	365,656	(626,156)	704	6,812,611	6,942,509		490,760
TOTAL OTHER PLANT ALLOCATED TO ELECTRIC RELATED TO DISTRIBUTION OPERATIONS	**20,527,551**	**1,061,312**	**(1,817,408)**	**2,045**	**19,773,499**	**20,150,525**		**1,424,424**
TOTAL PLANT IN SERVICE RELATED TO DISTRIBUTION OPERATIONS	**233,592,457**	**23,220,920**	**(3,873,704)**	**2,045**	**252,941,717**	**243,267,088**		**7,387,044**

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 4. AMORTIZATION OF EXPERIENCED AND ESTIMATED NET SALVAGE

ACCOUNT	2019		2020		2021		2022		2023		FIVE YEAR NET SALVAGE TOTAL	NET SALVAGE ACCRUAL
	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=(12)/5
ELECTRIC PLANT												
DISTRIBUTION PLANT												
361	0	0	0	0	0	0	0	1,103	0	0	1,103	221
362	0	5,944	0	24,880	0	5,721	0	9,451	(195)	265	46,066	9,213
364	0	178,476	0	695,428	0	628,085	0	441,244	0	79,641	2,022,874	404,575
365	0	54,263	0	121,069	0	175,874	0	138,834	0	787,454	1,277,494	255,499
366	0	3,977	0	9,269	0	49	0	500	0	0	13,795	2,759
367	0	4,285	0	14,036	0	23,539	0	16,452	0	2,950	61,262	12,252
368.1	0	235	0	3,020	0	4,895	0	7,807	0	14,447	30,404	6,081
368.2	0	17,595	0	58,648	0	25,689	0	33,600	0	1,060	136,592	27,318
369	0	88,722	0	81,584	0	72,000	0	39,522	0	43,432	325,260	65,052
370.1	0	0	(59,469)	0	0	(76,928)	0	(68,289)	(38,693)	0	(243,379)	(48,676)
370.2	0	6,489	0	3,781	0	3,263	0	3,331	0	2,005	18,869	3,774
370.3	0	0	0	0	0	0	0	2,299	0	0	2,299	460
371	0	7,910	0	9,609	0	30,601	0	32,911	0	0	81,031	16,206
371.5	0	0	0	0	0	0	0	0	0	0	-	0
373	0	7,411	0	19,433	0	14,719	0	28,409	0	14,699	84,671	16,934
TOTAL	**0**	**375,307**	**(59,469)**	**1,040,757**	**0**	**907,507**	**0**	**687,174**	**(38,888)**	**945,953**	**3,858,341**	**771,668**
GENERAL PLANT												
390.1	0	0	0	0	0	0	0	174	0	0	174	35
390.2	0	0	0	0	0	0	0	0	0	0	0	0
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
391.92	0	0	0	0	0	0	0	0	0	0	0	0
392.1	0	0	0	0	0	0	0	0	0	0	0	0
392.2	0	0	(13,693)	0	0	(112)	0	1,099	0	0	(12,706)	(2,541)
392.4	0	0	0	0	0	0	0	0	0	0	0	0
393	0	0	0	0	0	0	0	0	0	0	0	0
394	0	0	0	0	0	0	0	0	0	0	0	0
395	0	0	0	0	0	0	0	0	0	0	0	0
396	0	0	0	0	0	0	0	0	0	0	0	0
397	0	0	0	0	0	63	0	0	0	5	68	14
398	0	0	0	419	0	8,277	0	30,752	0	0	39,448	7,890
TOTAL	**0**	**0**	**(13,693)**	**419**	**0**	**8,228**	**0**	**32,025**	**0**	**5**	**26,984**	**5,398**
TOTAL ELECTRIC	**0**	**375,307**	**(73,162)**	**1,041,176**	**0**	**915,735**	**0**	**719,199**	**(38,888)**	**945,958**	**3,885,325**	**777,066**
LESS GENERAL PLANT ALLOCATED TO TRANSMISSION - 25.6247%	0	0	(3,509)	107	0	2,108	0	8,206	0	1	6,915	1,383
TOTAL	**0**	**375,307**	**(69,653)**	**1,041,069**	**0**	**913,627**	**0**	**710,993**	**(38,888)**	**945,957**	**3,878,410**	**775,683**

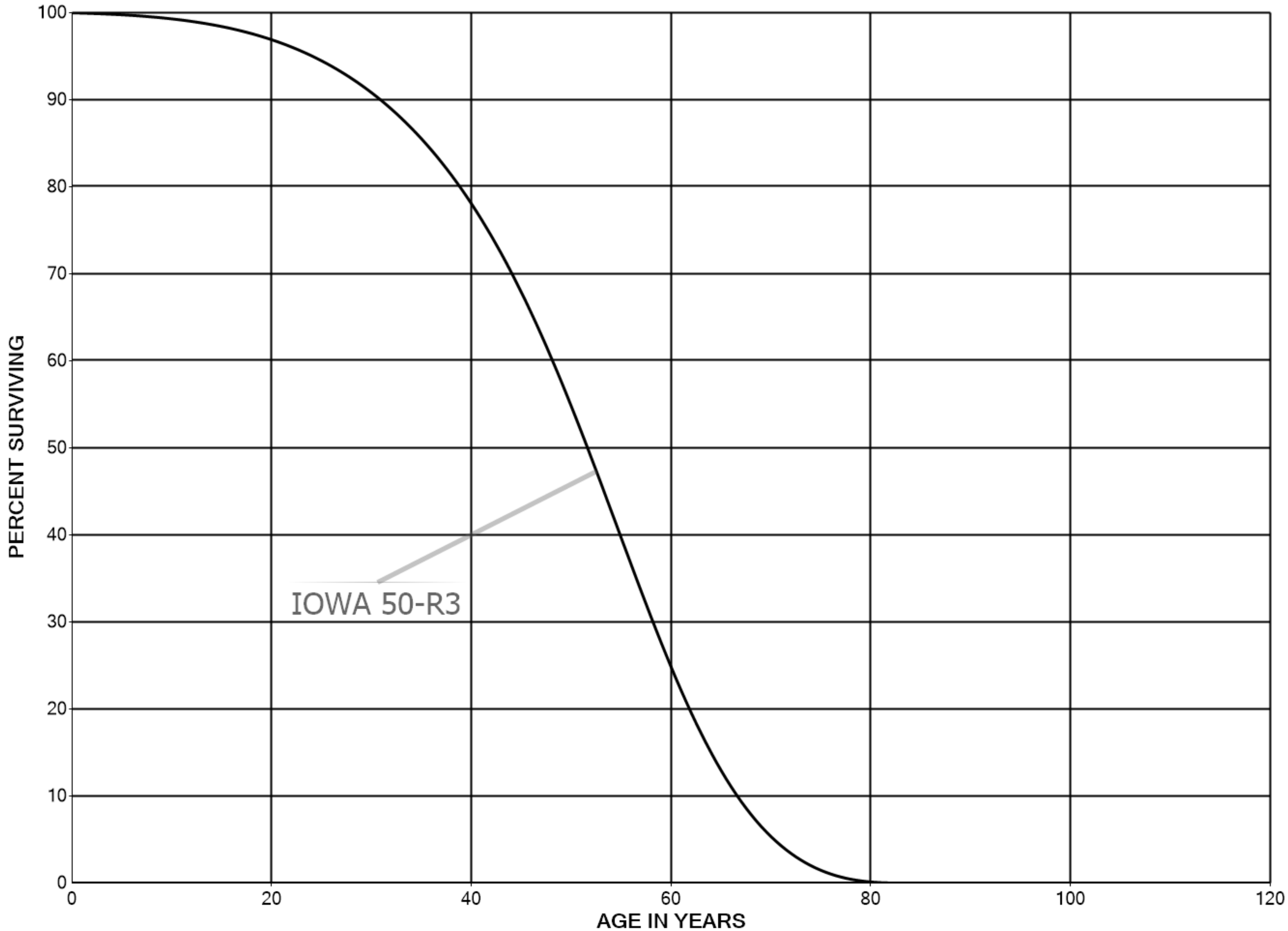
UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 4. AMORTIZATION OF EXPERIENCED AND ESTIMATED NET SALVAGE

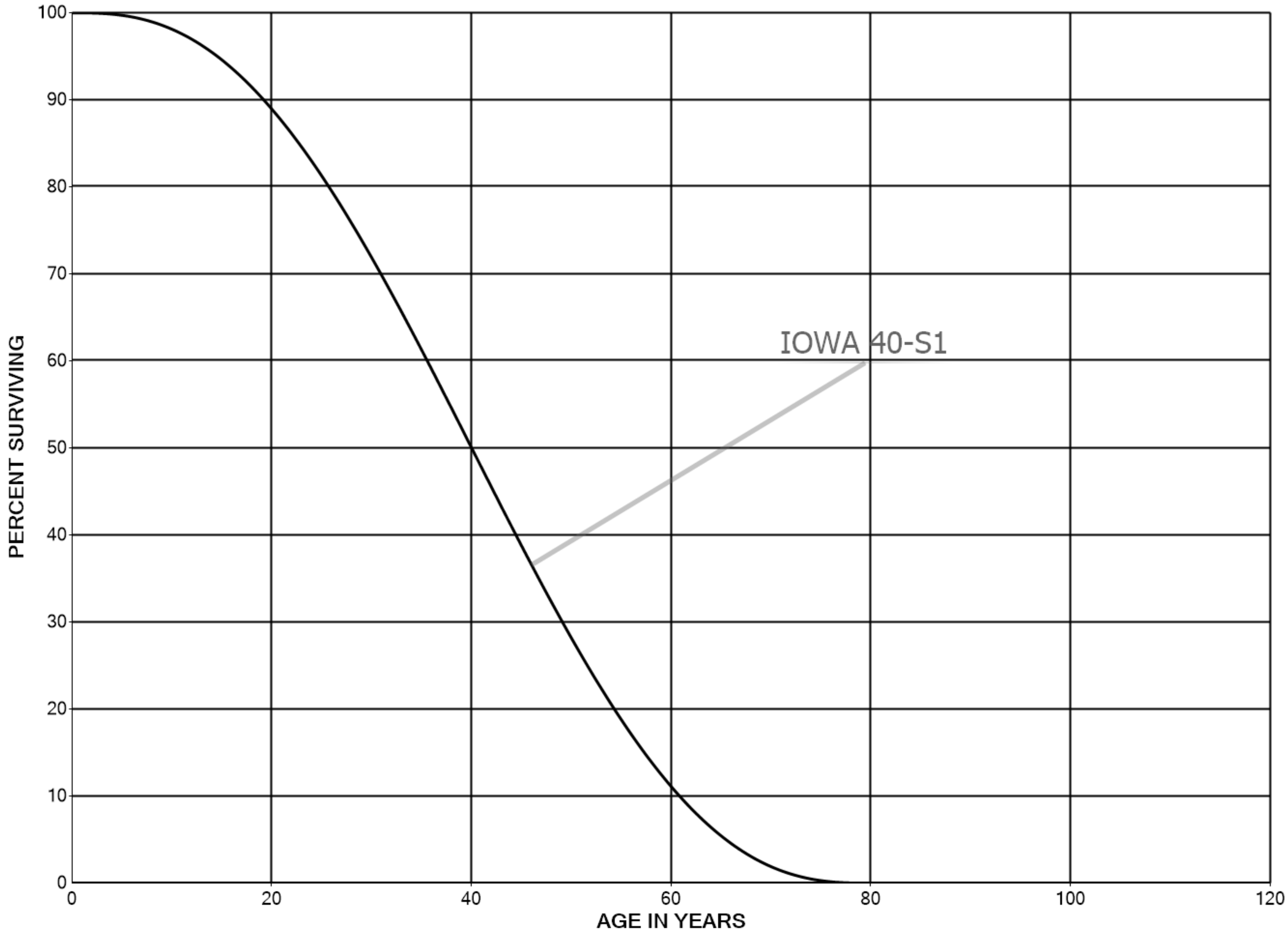
ACCOUNT	2019 GROSS SALVAGE	2019 COST OF REMOVAL	2020 GROSS SALVAGE	2020 COST OF REMOVAL	2021 GROSS SALVAGE	2021 COST OF REMOVAL	2022 GROSS SALVAGE	2022 COST OF REMOVAL	2023 GROSS SALVAGE	2023 COST OF REMOVAL	FIVE YEAR NET SALVAGE TOTAL	NET SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=(12)/5
OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION												
COMMON PLANT												
390.2	0	0	0	0	0	0	0	0	0	0	0	0
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
392.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
INFORMATION SERVICES												
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
391.3	0	0	0	0	0	0	0	0	0	0	0	0
391.4	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
GRAND TOTAL	**0**	**375,307**	**(69,653)**	**1,041,069**	**0**	**913,627**	**0**	**710,993**	**(38,888)**	**945,957**	**3,878,410**	**775,683**

PART VI. SERVICE LIFE STATISTICS

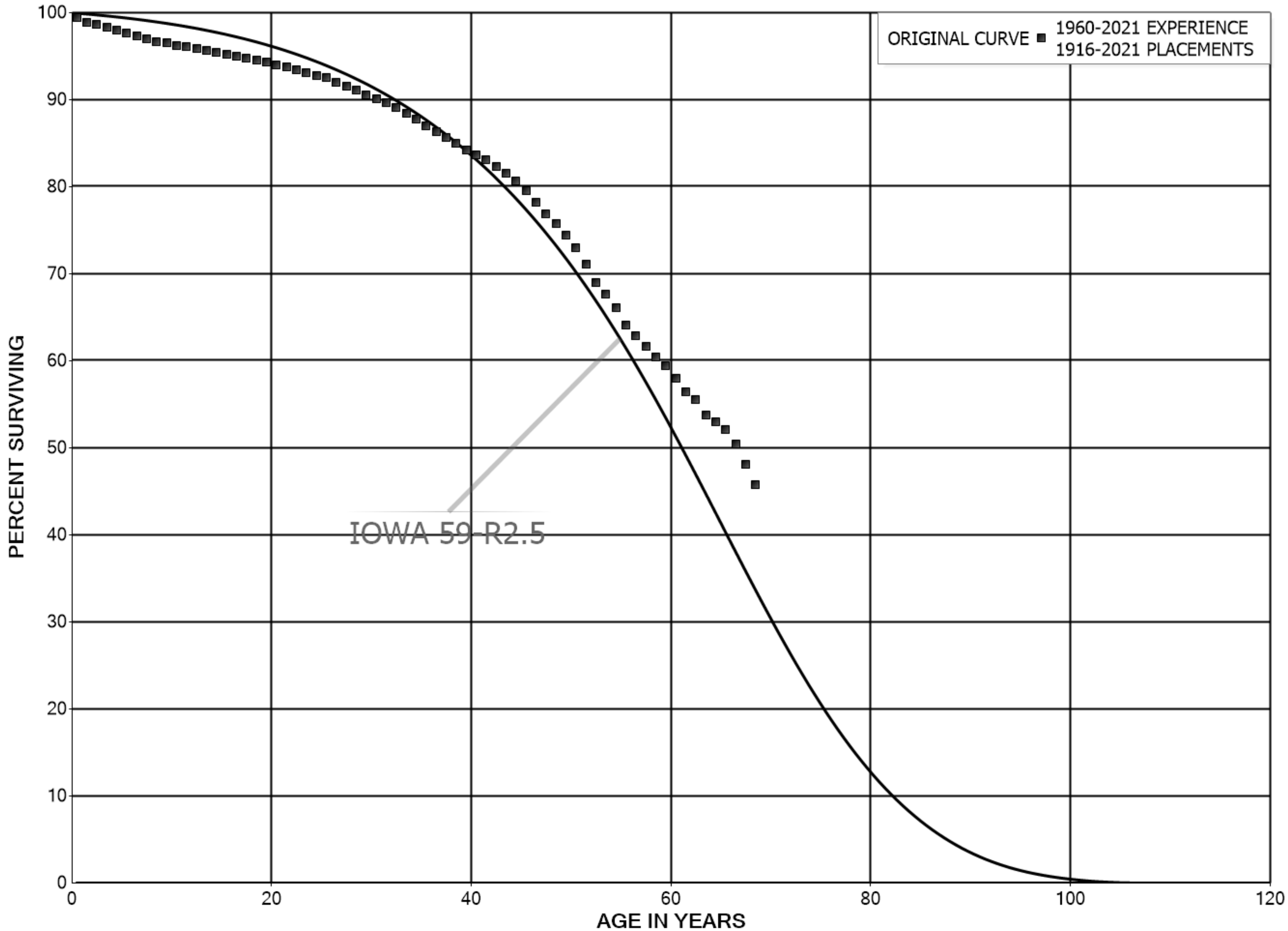
UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 361 - STRUCTURES AND IMPROVEMENTS
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 362 - STATION EQUIPMENT
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 364 - POLES, TOWERS AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 364 - POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1916-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	52,450,850	290,038	0.0055	0.9945	100.00
0.5	49,110,906	298,393	0.0061	0.9939	99.45
1.5	46,037,195	113,341	0.0025	0.9975	98.84
2.5	41,810,941	153,407	0.0037	0.9963	98.60
3.5	40,096,410	127,411	0.0032	0.9968	98.24
4.5	37,845,330	118,991	0.0031	0.9969	97.93
5.5	35,979,986	108,050	0.0030	0.9970	97.62
6.5	34,383,423	136,649	0.0040	0.9960	97.32
7.5	32,645,715	94,119	0.0029	0.9971	96.94
8.5	31,423,253	65,404	0.0021	0.9979	96.66
9.5	30,555,405	72,713	0.0024	0.9976	96.46
10.5	29,141,165	53,128	0.0018	0.9982	96.23
11.5	28,145,876	58,891	0.0021	0.9979	96.05
12.5	27,074,451	58,403	0.0022	0.9978	95.85
13.5	26,017,677	79,483	0.0031	0.9969	95.64
14.5	25,118,801	47,967	0.0019	0.9981	95.35
15.5	24,044,207	49,360	0.0021	0.9979	95.17
16.5	22,932,153	52,140	0.0023	0.9977	94.97
17.5	21,789,870	57,796	0.0027	0.9973	94.76
18.5	20,792,852	56,582	0.0027	0.9973	94.51
19.5	19,959,721	64,275	0.0032	0.9968	94.25
20.5	19,005,265	53,754	0.0028	0.9972	93.95
21.5	18,315,764	60,867	0.0033	0.9967	93.68
22.5	17,532,919	56,955	0.0032	0.9968	93.37
23.5	16,596,273	54,981	0.0033	0.9967	93.07
24.5	15,637,708	49,608	0.0032	0.9968	92.76
25.5	14,392,444	74,255	0.0052	0.9948	92.46
26.5	13,085,592	67,905	0.0052	0.9948	91.99
27.5	12,085,915	65,920	0.0055	0.9945	91.51
28.5	11,287,838	66,103	0.0059	0.9941	91.01
29.5	10,287,350	48,282	0.0047	0.9953	90.48
30.5	9,537,612	46,208	0.0048	0.9952	90.05
31.5	8,872,527	57,889	0.0065	0.9935	89.62
32.5	8,158,328	58,825	0.0072	0.9928	89.03
33.5	7,662,194	53,794	0.0070	0.9930	88.39
34.5	7,194,537	69,255	0.0096	0.9904	87.77
35.5	6,784,542	45,958	0.0068	0.9932	86.92
36.5	6,482,953	51,262	0.0079	0.9921	86.34
37.5	6,103,917	53,223	0.0087	0.9913	85.65
38.5	5,736,972	46,580	0.0081	0.9919	84.91

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 364 - POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1916-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	5,415,058	41,056	0.0076	0.9924	84.22
40.5	5,119,321	32,807	0.0064	0.9936	83.58
41.5	4,811,736	42,605	0.0089	0.9911	83.04
42.5	4,398,316	43,445	0.0099	0.9901	82.31
43.5	4,042,066	43,698	0.0108	0.9892	81.49
44.5	3,721,262	50,921	0.0137	0.9863	80.61
45.5	3,409,438	57,328	0.0168	0.9832	79.51
46.5	3,104,987	52,841	0.0170	0.9830	78.17
47.5	2,735,988	38,750	0.0142	0.9858	76.84
48.5	2,457,969	44,857	0.0182	0.9818	75.75
49.5	2,261,321	41,778	0.0185	0.9815	74.37
50.5	2,002,083	51,531	0.0257	0.9743	73.00
51.5	1,793,701	54,087	0.0302	0.9698	71.12
52.5	1,617,643	33,000	0.0204	0.9796	68.97
53.5	1,495,975	33,267	0.0222	0.9778	67.57
54.5	1,403,639	42,071	0.0300	0.9700	66.06
55.5	1,281,841	25,377	0.0198	0.9802	64.08
56.5	1,154,042	23,047	0.0200	0.9800	62.82
57.5	1,067,950	19,325	0.0181	0.9819	61.56
58.5	986,610	17,636	0.0179	0.9821	60.45
59.5	923,663	21,334	0.0231	0.9769	59.37
60.5	849,183	24,103	0.0284	0.9716	58.00
61.5	787,772	12,286	0.0156	0.9844	56.35
62.5	729,716	23,009	0.0315	0.9685	55.47
63.5	661,515	8,957	0.0135	0.9865	53.72
64.5	626,042	10,423	0.0166	0.9834	52.99
65.5	586,198	19,413	0.0331	0.9669	52.11
66.5	525,214	24,199	0.0461	0.9539	50.39
67.5	474,156	23,452	0.0495	0.9505	48.06
68.5	428,073	9,923	0.0232	0.9768	45.69
69.5	393,084	12,140	0.0309	0.9691	44.63
70.5	346,590	11,266	0.0325	0.9675	43.25
71.5	317,595	10,230	0.0322	0.9678	41.84
72.5	285,477	7,684	0.0269	0.9731	40.50
73.5	253,195	10,586	0.0418	0.9582	39.41
74.5	226,660	4,049	0.0179	0.9821	37.76
75.5	200,396	4,161	0.0208	0.9792	37.08
76.5	180,552	4,760	0.0264	0.9736	36.31
77.5	162,388	2,499	0.0154	0.9846	35.36
78.5	145,002	1,304	0.0090	0.9910	34.81

UGI UTILITIES, INC. - ELECTRIC DIVISION

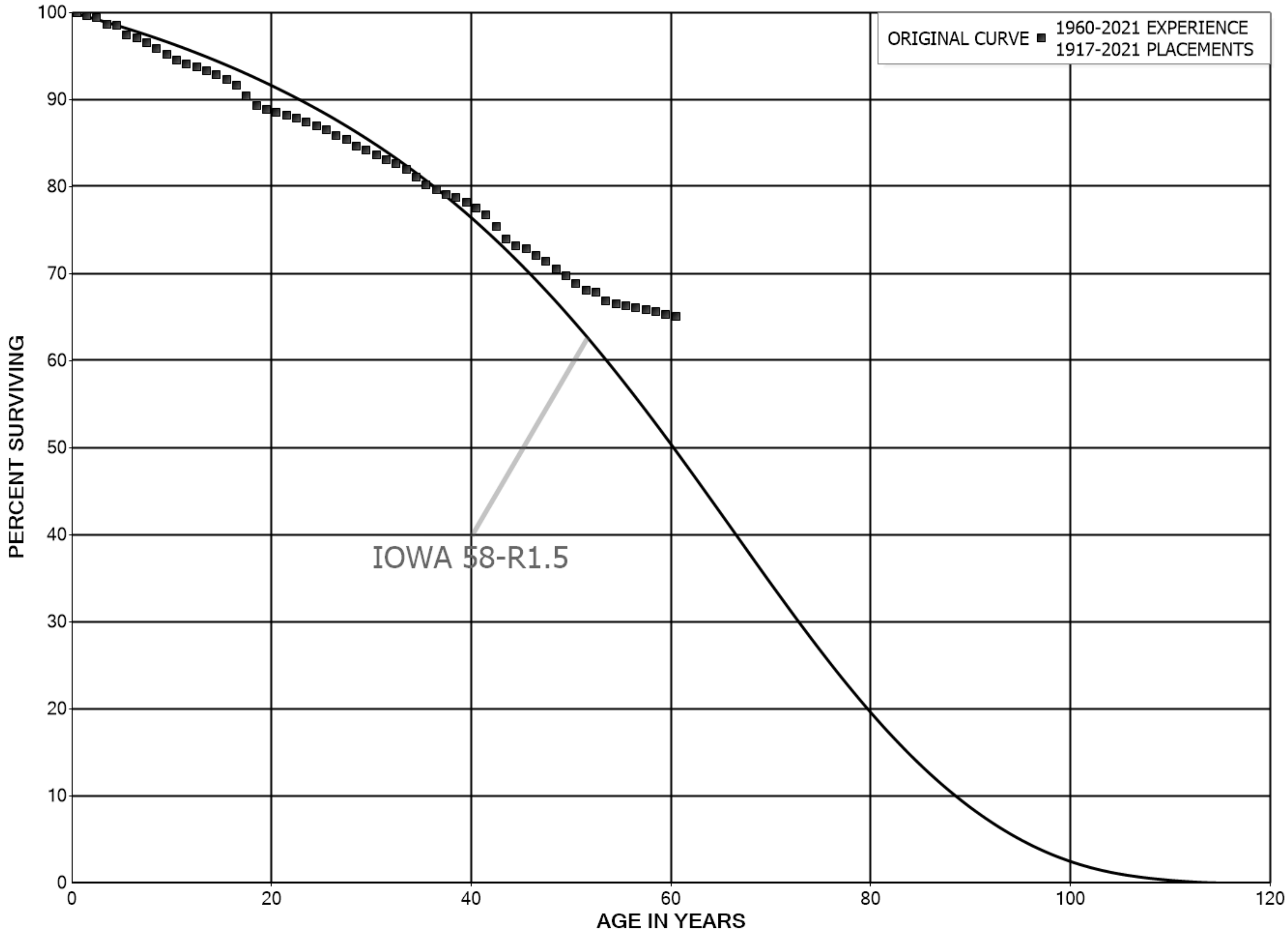
ACCOUNT 364 - POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1916-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	132,776	981	0.0074	0.9926	34.50
80.5	116,275	1,451	0.0125	0.9875	34.25
81.5	107,337	801	0.0075	0.9925	33.82
82.5	101,034	8,873	0.0878	0.9122	33.57
83.5	88,518	2,628	0.0297	0.9703	30.62
84.5	78,868	4,414	0.0560	0.9440	29.71
85.5	59,584	3,509	0.0589	0.9411	28.05
86.5	43,637	1,176	0.0269	0.9731	26.39
87.5	36,451	1,032	0.0283	0.9717	25.68
88.5	28,008	354	0.0126	0.9874	24.96
89.5	24,545	260	0.0106	0.9894	24.64
90.5	23,913	77	0.0032	0.9968	24.38
91.5	20,803	3,377	0.1623	0.8377	24.30
92.5	16,573	162	0.0098	0.9902	20.36
93.5	15,073		0.0000	1.0000	20.16
94.5	13,892		0.0000	1.0000	20.16
95.5	12,388	77	0.0062	0.9938	20.16
96.5	12,311		0.0000	1.0000	20.03
97.5	12,185		0.0000	1.0000	20.03
98.5	11,982		0.0000	1.0000	20.03
99.5	11,935		0.0000	1.0000	20.03
100.5	11,871		0.0000	1.0000	20.03
101.5	6,555		0.0000	1.0000	20.03
102.5					20.03

UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 365 - OVERHEAD CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 365 - OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1917-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	50,923,394	18,009	0.0004	0.9996	100.00
0.5	47,568,094	143,251	0.0030	0.9970	99.96
1.5	42,050,076	124,322	0.0030	0.9970	99.66
2.5	37,805,272	267,256	0.0071	0.9929	99.37
3.5	35,745,254	75,794	0.0021	0.9979	98.67
4.5	33,075,831	348,913	0.0105	0.9895	98.46
5.5	30,415,157	118,153	0.0039	0.9961	97.42
6.5	28,288,915	154,754	0.0055	0.9945	97.04
7.5	26,497,432	182,760	0.0069	0.9931	96.51
8.5	24,627,636	161,004	0.0065	0.9935	95.84
9.5	23,317,686	171,688	0.0074	0.9926	95.22
10.5	22,421,644	113,304	0.0051	0.9949	94.52
11.5	21,550,536	69,490	0.0032	0.9968	94.04
12.5	20,378,033	94,561	0.0046	0.9954	93.74
13.5	19,075,769	100,976	0.0053	0.9947	93.30
14.5	17,806,770	100,458	0.0056	0.9944	92.81
15.5	17,005,179	132,179	0.0078	0.9922	92.28
16.5	15,842,248	204,098	0.0129	0.9871	91.57
17.5	15,059,244	182,310	0.0121	0.9879	90.39
18.5	14,279,528	76,246	0.0053	0.9947	89.29
19.5	13,773,329	44,799	0.0033	0.9967	88.81
20.5	13,105,092	50,498	0.0039	0.9961	88.53
21.5	12,654,689	56,391	0.0045	0.9955	88.18
22.5	12,100,255	47,655	0.0039	0.9961	87.79
23.5	11,384,703	64,886	0.0057	0.9943	87.45
24.5	10,661,050	49,095	0.0046	0.9954	86.95
25.5	9,818,419	77,631	0.0079	0.9921	86.55
26.5	8,932,625	45,343	0.0051	0.9949	85.86
27.5	8,375,489	74,973	0.0090	0.9910	85.43
28.5	7,930,251	50,311	0.0063	0.9937	84.66
29.5	7,285,728	44,872	0.0062	0.9938	84.13
30.5	6,766,498	41,449	0.0061	0.9939	83.61
31.5	6,461,164	40,494	0.0063	0.9937	83.10
32.5	6,181,757	45,584	0.0074	0.9926	82.57
33.5	5,965,021	62,643	0.0105	0.9895	81.97
34.5	5,803,115	64,078	0.0110	0.9890	81.10
35.5	5,596,746	44,738	0.0080	0.9920	80.21
36.5	5,438,677	32,772	0.0060	0.9940	79.57
37.5	5,303,210	26,365	0.0050	0.9950	79.09
38.5	5,159,781	32,273	0.0063	0.9937	78.70

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 365 - OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1917-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,925,445	44,107	0.0090	0.9910	78.20
40.5	4,680,009	45,237	0.0097	0.9903	77.50
41.5	4,466,200	79,609	0.0178	0.9822	76.75
42.5	4,171,933	80,241	0.0192	0.9808	75.39
43.5	3,860,013	38,152	0.0099	0.9901	73.94
44.5	3,486,350	19,559	0.0056	0.9944	73.20
45.5	3,248,210	32,321	0.0100	0.9900	72.79
46.5	2,932,078	28,832	0.0098	0.9902	72.07
47.5	2,642,571	32,784	0.0124	0.9876	71.36
48.5	2,450,269	25,764	0.0105	0.9895	70.48
49.5	2,321,756	29,149	0.0126	0.9874	69.73
50.5	2,082,585	22,492	0.0108	0.9892	68.86
51.5	1,877,960	8,558	0.0046	0.9954	68.12
52.5	1,655,512	24,963	0.0151	0.9849	67.81
53.5	1,531,898	6,819	0.0045	0.9955	66.78
54.5	1,464,879	4,512	0.0031	0.9969	66.49
55.5	1,408,728	5,536	0.0039	0.9961	66.28
56.5	1,307,054	2,881	0.0022	0.9978	66.02
57.5	1,189,491	5,311	0.0045	0.9955	65.87
58.5	1,102,692	4,876	0.0044	0.9956	65.58
59.5	1,042,805	4,290	0.0041	0.9959	65.29
60.5	981,505	6,714	0.0068	0.9932	65.02
61.5	938,996	16,199	0.0173	0.9827	64.58
62.5	888,817	14,144	0.0159	0.9841	63.46
63.5	849,122	6,407	0.0075	0.9925	62.45
64.5	790,794	10,080	0.0127	0.9873	61.98
65.5	745,578	3,100	0.0042	0.9958	61.19
66.5	685,213	2,733	0.0040	0.9960	60.94
67.5	646,643	3,601	0.0056	0.9944	60.69
68.5	621,326	5,694	0.0092	0.9908	60.36
69.5	593,897	3,977	0.0067	0.9933	59.80
70.5	556,476	6,218	0.0112	0.9888	59.40
71.5	514,253	9,940	0.0193	0.9807	58.74
72.5	462,827	2,899	0.0063	0.9937	57.60
73.5	432,519	1,218	0.0028	0.9972	57.24
74.5	399,350	6,663	0.0167	0.9833	57.08
75.5	370,484	7,719	0.0208	0.9792	56.13
76.5	353,550	8,408	0.0238	0.9762	54.96
77.5	341,270	12,747	0.0374	0.9626	53.65
78.5	323,138	5,396	0.0167	0.9833	51.65

UGI UTILITIES, INC. - ELECTRIC DIVISION

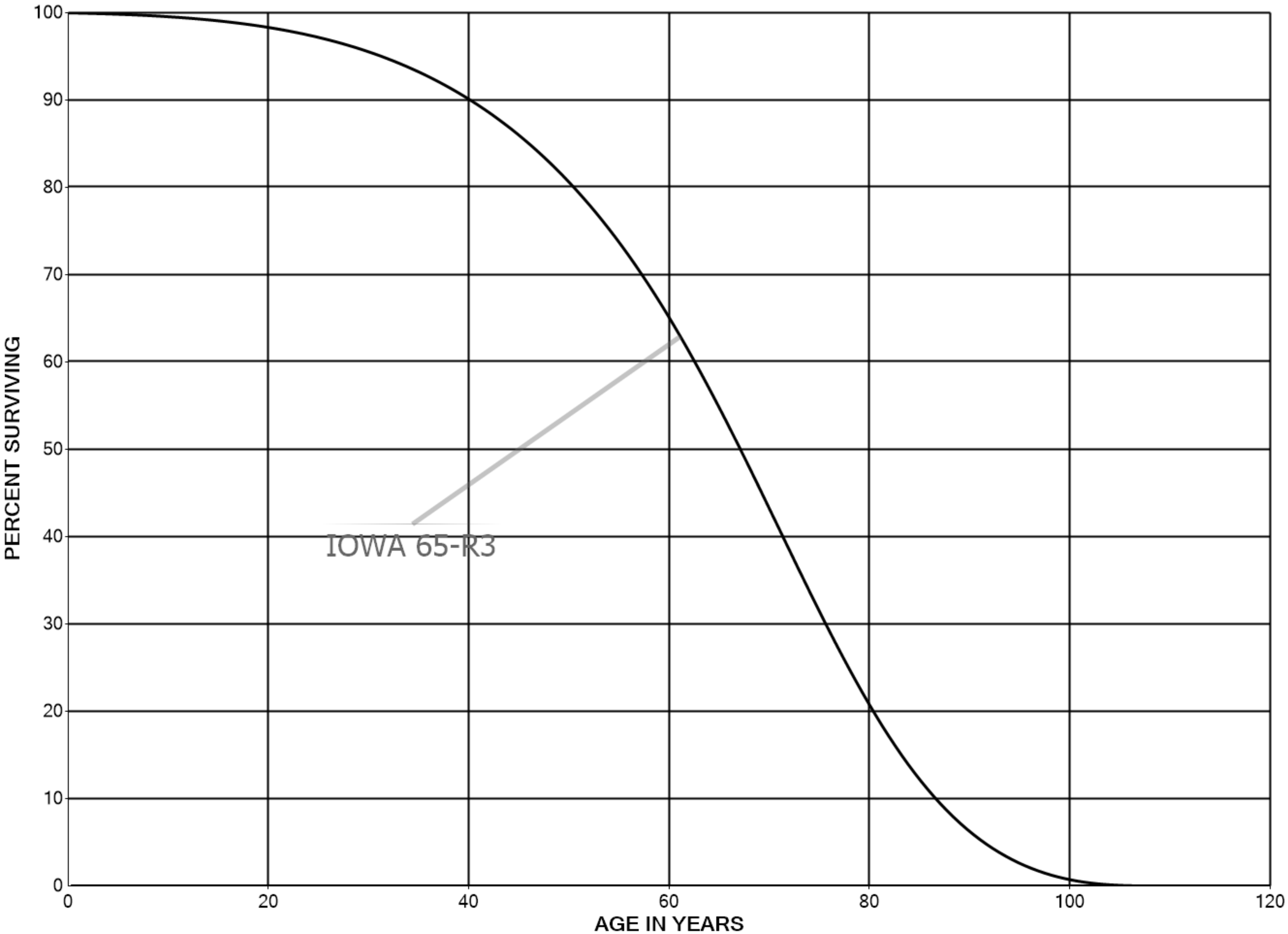
ACCOUNT 365 - OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

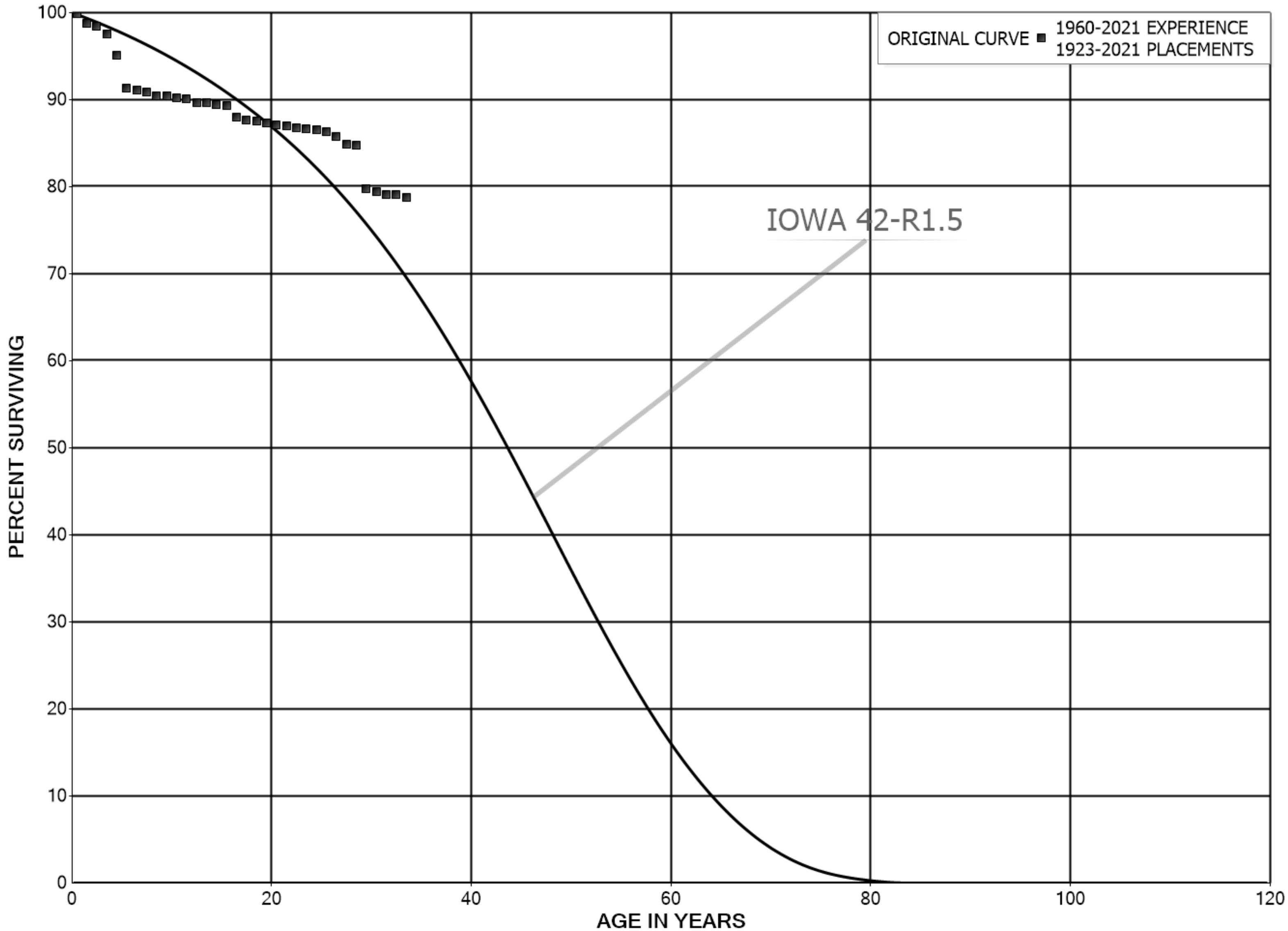
PLACEMENT BAND 1917-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	315,190	4,723	0.0150	0.9850	50.79
80.5	301,085	2,601	0.0086	0.9914	50.03
81.5	286,067	1,677	0.0059	0.9941	49.59
82.5	265,819	2,442	0.0092	0.9908	49.30
83.5	253,801	1,733	0.0068	0.9932	48.85
84.5	247,156	1,543	0.0062	0.9938	48.52
85.5	243,714	1,825	0.0075	0.9925	48.21
86.5	233,624	1,864	0.0080	0.9920	47.85
87.5	213,888	954	0.0045	0.9955	47.47
88.5	189,483	2,215	0.0117	0.9883	47.26
89.5	170,870	1,432	0.0084	0.9916	46.71
90.5	155,404	1,095	0.0070	0.9930	46.31
91.5	123,944	3,401	0.0274	0.9726	45.99
92.5	105,324	1,734	0.0165	0.9835	44.73
93.5	83,410	762	0.0091	0.9909	43.99
94.5	65,815	309	0.0047	0.9953	43.59
95.5	20,924		0.0000	1.0000	43.38
96.5	4,829	1,190	0.2464	0.7536	43.38
97.5					32.69

UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 366 - UNDERGROUND CONDUIT
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 367 - UNDERGROUND CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 367 - UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1923-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	15,229,376	26,459	0.0017	0.9983	100.00
0.5	14,112,736	156,386	0.0111	0.9889	99.83
1.5	12,711,851	48,013	0.0038	0.9962	98.72
2.5	11,638,414	95,535	0.0082	0.9918	98.35
3.5	10,069,747	258,049	0.0256	0.9744	97.54
4.5	8,782,349	347,870	0.0396	0.9604	95.04
5.5	8,349,645	20,323	0.0024	0.9976	91.28
6.5	8,084,184	17,928	0.0022	0.9978	91.05
7.5	7,502,902	36,109	0.0048	0.9952	90.85
8.5	7,087,727	5,116	0.0007	0.9993	90.41
9.5	6,908,064	12,815	0.0019	0.9981	90.35
10.5	6,457,976	12,025	0.0019	0.9981	90.18
11.5	6,174,225	24,129	0.0039	0.9961	90.01
12.5	5,984,480	3,059	0.0005	0.9995	89.66
13.5	5,286,305	10,493	0.0020	0.9980	89.62
14.5	5,120,809	11,752	0.0023	0.9977	89.44
15.5	4,856,965	69,661	0.0143	0.9857	89.23
16.5	4,489,302	15,236	0.0034	0.9966	87.95
17.5	4,368,092	5,574	0.0013	0.9987	87.65
18.5	4,320,961	11,916	0.0028	0.9972	87.54
19.5	4,148,988	11,750	0.0028	0.9972	87.30
20.5	3,706,579	4,992	0.0013	0.9987	87.05
21.5	3,497,343	7,614	0.0022	0.9978	86.94
22.5	3,294,196	6,754	0.0021	0.9979	86.75
23.5	3,016,385	941	0.0003	0.9997	86.57
24.5	2,667,628	8,159	0.0031	0.9969	86.54
25.5	2,345,420	13,603	0.0058	0.9942	86.28
26.5	2,113,353	24,569	0.0116	0.9884	85.78
27.5	1,947,992	1,715	0.0009	0.9991	84.78
28.5	1,802,474	105,056	0.0583	0.9417	84.71
29.5	1,579,127	7,358	0.0047	0.9953	79.77
30.5	1,364,824	5,867	0.0043	0.9957	79.40
31.5	1,232,641	601	0.0005	0.9995	79.06
32.5	1,056,636	3,230	0.0031	0.9969	79.02
33.5	932,150	2,757	0.0030	0.9970	78.78
34.5	872,686	3,163	0.0036	0.9964	78.54
35.5	794,558	2,776	0.0035	0.9965	78.26
36.5	758,950	123	0.0002	0.9998	77.98
37.5	732,710		0.0000	1.0000	77.97
38.5	674,814		0.0000	1.0000	77.97

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 367 - UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	647,769	2,610	0.0040	0.9960	77.97
40.5	608,871		0.0000	1.0000	77.66
41.5	577,600		0.0000	1.0000	77.66
42.5	516,508		0.0000	1.0000	77.66
43.5	465,091		0.0000	1.0000	77.66
44.5	380,327		0.0000	1.0000	77.66
45.5	335,277		0.0000	1.0000	77.66
46.5	234,432		0.0000	1.0000	77.66
47.5	163,575		0.0000	1.0000	77.66
48.5	129,054	289	0.0022	0.9978	77.66
49.5	87,683	1,755	0.0200	0.9800	77.48
50.5	75,455	504	0.0067	0.9933	75.93
51.5	64,459		0.0000	1.0000	75.43
52.5	57,835		0.0000	1.0000	75.43
53.5	51,915		0.0000	1.0000	75.43
54.5	40,085	928	0.0232	0.9768	75.43
55.5	39,031		0.0000	1.0000	73.68
56.5	39,031	14,198	0.3638	0.6362	73.68
57.5	23,908		0.0000	1.0000	46.88
58.5	23,908	958	0.0401	0.9599	46.88
59.5	22,951	151	0.0066	0.9934	45.00
60.5	22,800		0.0000	1.0000	44.70
61.5	22,800	1,898	0.0832	0.9168	44.70
62.5	20,902		0.0000	1.0000	40.98
63.5	20,902		0.0000	1.0000	40.98
64.5	159		0.0000	1.0000	40.98
65.5	159		0.0000	1.0000	40.98
66.5	159		0.0000	1.0000	40.98
67.5	159		0.0000	1.0000	40.98
68.5	159		0.0000	1.0000	40.98
69.5	159		0.0000	1.0000	40.98
70.5	159		0.0000	1.0000	40.98
71.5	159		0.0000	1.0000	40.98
72.5	159		0.0000	1.0000	40.98
73.5	159		0.0000	1.0000	40.98
74.5	159		0.0000	1.0000	40.98
75.5	159		0.0000	1.0000	40.98
76.5	159		0.0000	1.0000	40.98
77.5	159		0.0000	1.0000	40.98
78.5	159		0.0000	1.0000	40.98

UGI UTILITIES, INC. - ELECTRIC DIVISION

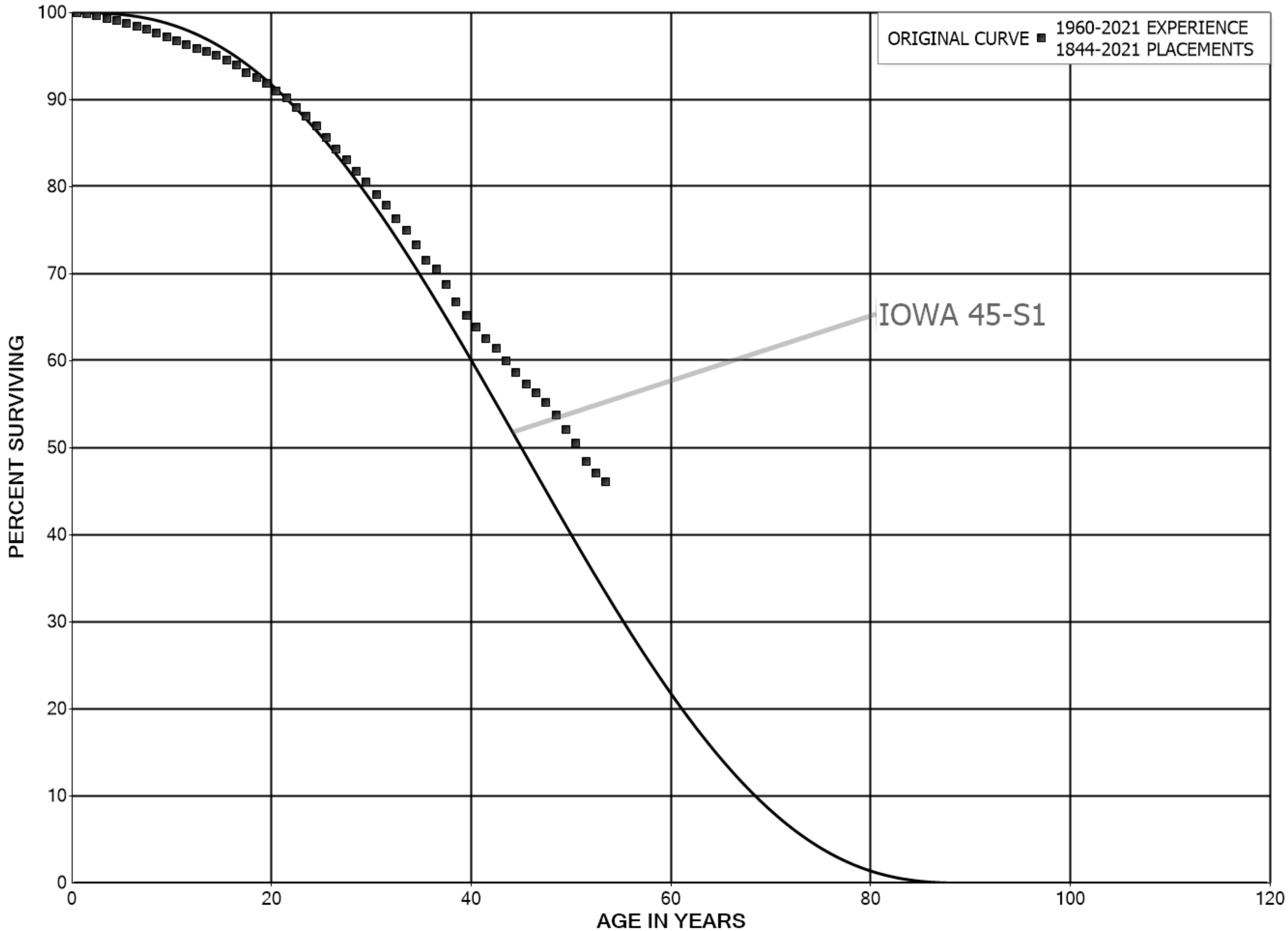
ACCOUNT 367 - UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	159		0.0000	1.0000	40.98
80.5	159		0.0000	1.0000	40.98
81.5	159		0.0000	1.0000	40.98
82.5	159		0.0000	1.0000	40.98
83.5	159		0.0000	1.0000	40.98
84.5	159		0.0000	1.0000	40.98
85.5	159		0.0000	1.0000	40.98
86.5	159		0.0000	1.0000	40.98
87.5	159		0.0000	1.0000	40.98
88.5	159	159	1.0000		40.98
89.5					

UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 368.1 - TRANSFORMERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 368.1 - TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1844-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	19,004,310	4,965	0.0003	0.9997	100.00
0.5	18,055,466	27,695	0.0015	0.9985	99.97
1.5	17,159,938	44,051	0.0026	0.9974	99.82
2.5	16,643,795	38,017	0.0023	0.9977	99.56
3.5	16,053,348	46,226	0.0029	0.9971	99.34
4.5	15,594,704	59,595	0.0038	0.9962	99.05
5.5	15,363,498	36,652	0.0024	0.9976	98.67
6.5	15,054,740	58,318	0.0039	0.9961	98.44
7.5	14,893,741	70,392	0.0047	0.9953	98.06
8.5	14,491,238	64,111	0.0044	0.9956	97.59
9.5	14,034,534	55,719	0.0040	0.9960	97.16
10.5	13,736,565	62,909	0.0046	0.9954	96.77
11.5	13,597,469	63,201	0.0046	0.9954	96.33
12.5	13,166,515	52,453	0.0040	0.9960	95.88
13.5	12,626,434	52,464	0.0042	0.9958	95.50
14.5	12,143,326	72,043	0.0059	0.9941	95.10
15.5	11,977,463	77,361	0.0065	0.9935	94.54
16.5	11,632,251	110,196	0.0095	0.9905	93.93
17.5	11,244,096	69,271	0.0062	0.9938	93.04
18.5	11,013,082	77,693	0.0071	0.9929	92.47
19.5	10,617,335	95,162	0.0090	0.9910	91.81
20.5	10,213,215	92,929	0.0091	0.9909	90.99
21.5	9,725,172	120,952	0.0124	0.9876	90.16
22.5	9,200,557	97,132	0.0106	0.9894	89.04
23.5	8,722,439	108,939	0.0125	0.9875	88.10
24.5	8,281,969	132,198	0.0160	0.9840	87.00
25.5	7,815,576	116,928	0.0150	0.9850	85.61
26.5	7,364,231	109,588	0.0149	0.9851	84.33
27.5	6,995,402	113,637	0.0162	0.9838	83.08
28.5	6,675,526	101,584	0.0152	0.9848	81.73
29.5	6,199,337	105,306	0.0170	0.9830	80.48
30.5	5,787,767	95,840	0.0166	0.9834	79.12
31.5	5,382,320	105,754	0.0196	0.9804	77.81
32.5	4,980,523	85,772	0.0172	0.9828	76.28
33.5	4,676,322	102,814	0.0220	0.9780	74.96
34.5	4,366,611	105,200	0.0241	0.9759	73.32
35.5	4,134,901	62,085	0.0150	0.9850	71.55
36.5	3,853,649	96,662	0.0251	0.9749	70.48
37.5	3,612,783	104,216	0.0288	0.9712	68.71
38.5	3,367,643	79,402	0.0236	0.9764	66.73

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 368.1 - TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1844-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,075,187	64,741	0.0211	0.9789	65.15
40.5	2,898,410	56,732	0.0196	0.9804	63.78
41.5	2,665,758	50,609	0.0190	0.9810	62.53
42.5	2,469,469	54,925	0.0222	0.9778	61.35
43.5	2,250,689	53,323	0.0237	0.9763	59.98
44.5	2,036,395	42,551	0.0209	0.9791	58.56
45.5	1,836,045	34,728	0.0189	0.9811	57.34
46.5	1,591,279	31,279	0.0197	0.9803	56.25
47.5	1,391,407	37,246	0.0268	0.9732	55.15
48.5	1,113,926	32,917	0.0296	0.9704	53.67
49.5	961,163	29,300	0.0305	0.9695	52.08
50.5	830,087	34,013	0.0410	0.9590	50.50
51.5	662,226	18,975	0.0287	0.9713	48.43
52.5	541,877	10,919	0.0202	0.9798	47.04
53.5	439,152	9,287	0.0211	0.9789	46.09
54.5	361,558	11,091	0.0307	0.9693	45.12
55.5	309,145	7,635	0.0247	0.9753	43.73
56.5	287,742	4,510	0.0157	0.9843	42.65
57.5	259,785	7,307	0.0281	0.9719	41.98
58.5	245,659	3,952	0.0161	0.9839	40.80
59.5	234,257	5,385	0.0230	0.9770	40.15
60.5	212,875	4,488	0.0211	0.9789	39.22
61.5	189,915	5,399	0.0284	0.9716	38.40
62.5	158,679	6,006	0.0378	0.9622	37.31
63.5	99,823	2,707	0.0271	0.9729	35.89
64.5	85,036	6,186	0.0728	0.9272	34.92
65.5	76,839	1,455	0.0189	0.9811	32.38
66.5	53,747	3,369	0.0627	0.9373	31.77
67.5	43,956	898	0.0204	0.9796	29.78
68.5	42,389	1,373	0.0324	0.9676	29.17
69.5	40,506	423	0.0105	0.9895	28.22
70.5	40,083	1,253	0.0313	0.9687	27.93
71.5	38,830	539	0.0139	0.9861	27.05
72.5	25,529	454	0.0178	0.9822	26.68
73.5	16,361	4,109	0.2511	0.7489	26.20
74.5	12,252	1,157	0.0944	0.9056	19.62
75.5	11,095	336	0.0303	0.9697	17.77
76.5	10,759		0.0000	1.0000	17.23
77.5	10,759		0.0000	1.0000	17.23
78.5	10,094	51	0.0050	0.9950	17.23

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 368.1 - TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1844-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	10,043	539	0.0537	0.9463	17.15
80.5	7,680	34	0.0045	0.9955	16.23
81.5	7,646		0.0000	1.0000	16.15
82.5	16,310		0.0000	1.0000	16.15
83.5	16,310		0.0000	1.0000	16.15
84.5	16,310		0.0000	1.0000	16.15
85.5	16,310		0.0000	1.0000	16.15
86.5	16,310		0.0000	1.0000	16.15
87.5	16,310		0.0000	1.0000	16.15
88.5	16,310	51	0.0031	0.9969	16.15
89.5	16,259	4,931	0.3033	0.6967	16.10
90.5	11,329	92	0.0081	0.9919	11.22
91.5	11,237	190	0.0169	0.9831	11.13
92.5	11,047		0.0000	1.0000	10.94
93.5	11,047		0.0000	1.0000	10.94
94.5	11,047		0.0000	1.0000	10.94
95.5	11,047		0.0000	1.0000	10.94
96.5	10,000		0.0000	1.0000	10.94
97.5	833		0.0000	1.0000	10.94
98.5	833		0.0000	1.0000	10.94
99.5	833		0.0000	1.0000	10.94
100.5	399		0.0000	1.0000	10.94
101.5	399		0.0000	1.0000	10.94
102.5	399		0.0000	1.0000	10.94
103.5					10.94
104.5					
105.5					
106.5					
107.5					
108.5					
109.5					
110.5					
111.5					
112.5					
113.5					
114.5					
115.5	296		0.0000		
116.5	296		0.0000		
117.5	296		0.0000		
118.5	296		0.0000		

UGI UTILITIES, INC. - ELECTRIC DIVISION

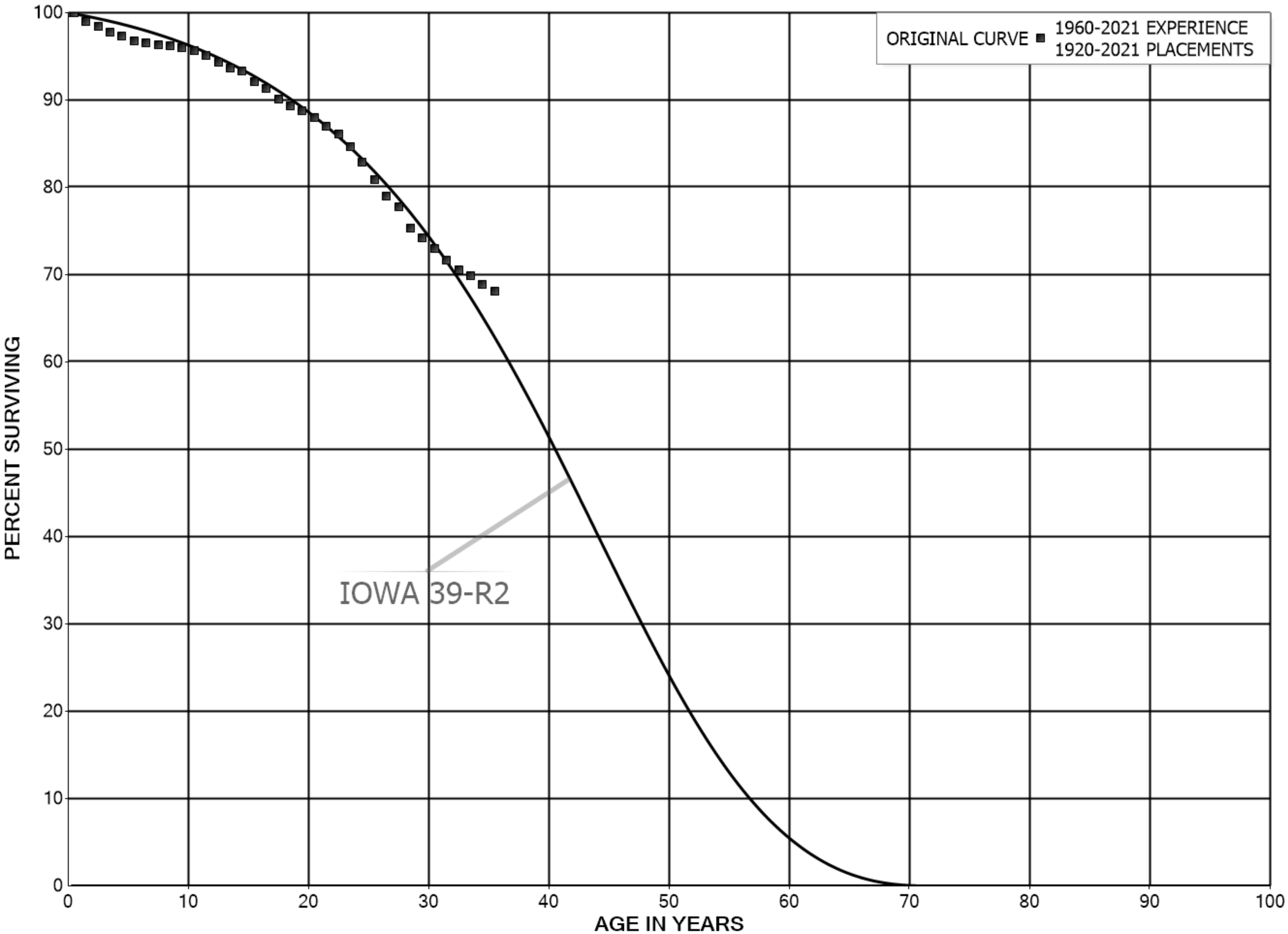
ACCOUNT 368.1 - TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1844-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	296		0.0000		
120.5	296		0.0000		
121.5	296		0.0000		
122.5	296		0.0000		
123.5	296		0.0000		
124.5	296		0.0000		
125.5	296		0.0000		
126.5	296		0.0000		
127.5	296		0.0000		
128.5	296		0.0000		
129.5	296		0.0000		
130.5	296		0.0000		
131.5	296		0.0000		
132.5	296		0.0000		
133.5	296		0.0000		
134.5	296		0.0000		
135.5	296		0.0000		
136.5	296		0.0000		
137.5	296		0.0000		
138.5	296		0.0000		
139.5	296		0.0000		
140.5	296		0.0000		
141.5	296		0.0000		
142.5	296		0.0000		
143.5	296		0.0000		
144.5	296		0.0000		
145.5	296	296	1.0000		
146.5					

UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 368.2 - TRANSFORMER INSTALLATIONS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 368.2 - TRANSFORMER INSTALLATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1920-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	13,190,468	1,240	0.0001	0.9999	100.00
0.5	12,408,211	122,344	0.0099	0.9901	99.99
1.5	11,995,091	79,426	0.0066	0.9934	99.00
2.5	10,907,026	63,175	0.0058	0.9942	98.35
3.5	10,768,662	58,478	0.0054	0.9946	97.78
4.5	10,352,114	51,298	0.0050	0.9950	97.25
5.5	10,029,218	23,810	0.0024	0.9976	96.77
6.5	9,794,779	26,276	0.0027	0.9973	96.54
7.5	9,634,470	6,506	0.0007	0.9993	96.28
8.5	9,358,307	22,706	0.0024	0.9976	96.21
9.5	9,141,355	37,673	0.0041	0.9959	95.98
10.5	9,012,134	49,779	0.0055	0.9945	95.58
11.5	8,802,240	68,171	0.0077	0.9923	95.06
12.5	8,511,654	64,039	0.0075	0.9925	94.32
13.5	8,213,652	24,721	0.0030	0.9970	93.61
14.5	7,787,529	101,494	0.0130	0.9870	93.33
15.5	7,375,937	65,061	0.0088	0.9912	92.11
16.5	7,030,043	99,217	0.0141	0.9859	91.30
17.5	6,619,495	54,047	0.0082	0.9918	90.01
18.5	6,114,259	35,570	0.0058	0.9942	89.28
19.5	5,807,717	50,411	0.0087	0.9913	88.76
20.5	5,516,396	61,763	0.0112	0.9888	87.99
21.5	5,238,576	58,965	0.0113	0.9887	87.00
22.5	4,909,397	80,155	0.0163	0.9837	86.02
23.5	4,534,404	92,655	0.0204	0.9796	84.62
24.5	4,043,308	100,195	0.0248	0.9752	82.89
25.5	3,614,494	85,691	0.0237	0.9763	80.83
26.5	3,115,183	45,983	0.0148	0.9852	78.92
27.5	2,745,220	87,460	0.0319	0.9681	77.75
28.5	2,425,964	34,408	0.0142	0.9858	75.28
29.5	2,048,354	33,707	0.0165	0.9835	74.21
30.5	1,773,414	33,826	0.0191	0.9809	72.99
31.5	1,568,995	23,635	0.0151	0.9849	71.60
32.5	1,396,177	13,864	0.0099	0.9901	70.52
33.5	1,239,943	16,511	0.0133	0.9867	69.82
34.5	1,110,666	13,381	0.0120	0.9880	68.89
35.5	964,583	8,149	0.0084	0.9916	68.06
36.5	849,475	8,123	0.0096	0.9904	67.48
37.5	778,747	6,583	0.0085	0.9915	66.84
38.5	707,704	6,102	0.0086	0.9914	66.27

UGI UTILITIES, INC. - ELECTRIC DIVISION

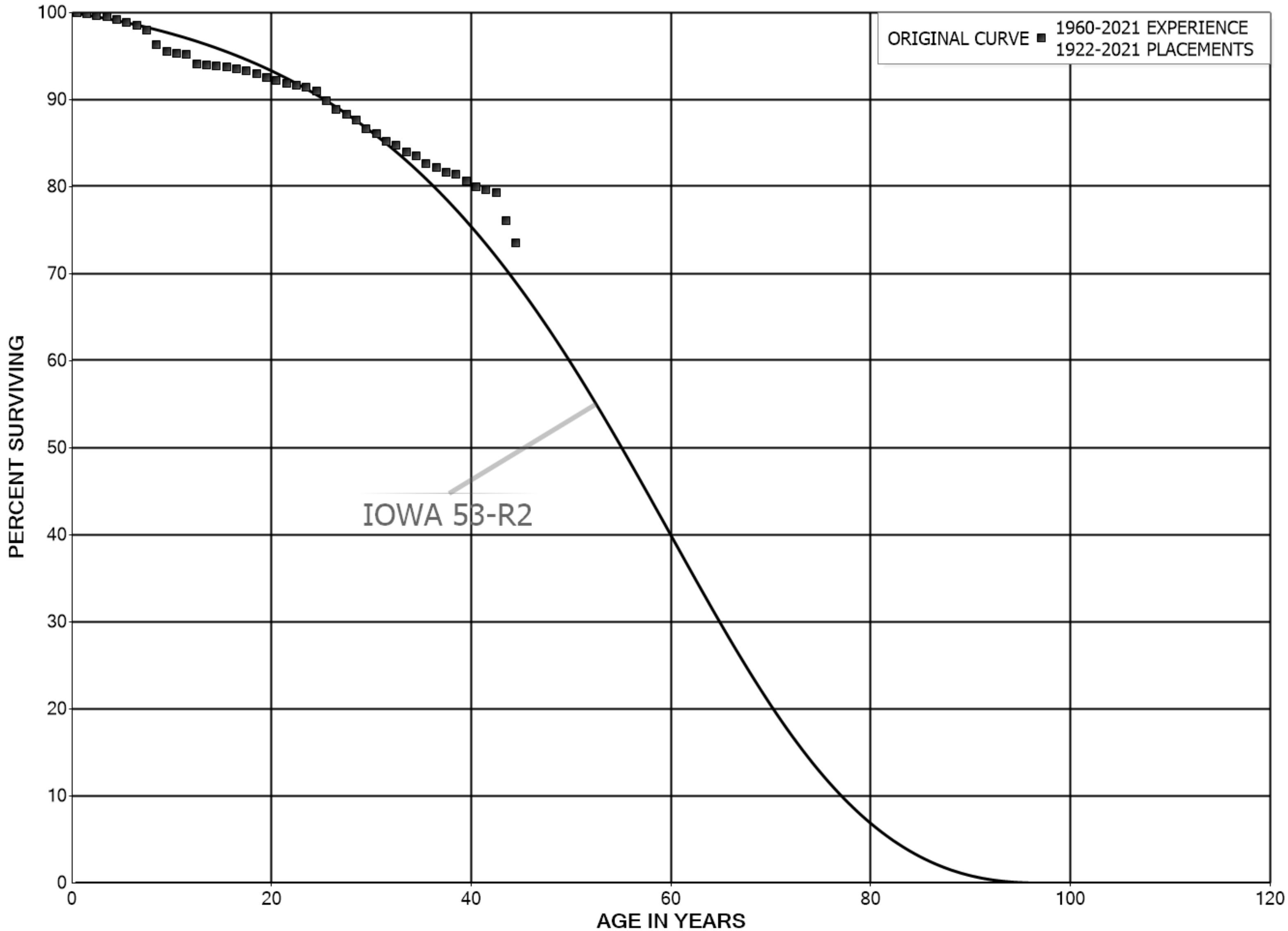
ACCOUNT 368.2 - TRANSFORMER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1920-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	634,069	6,087	0.0096	0.9904	65.70
40.5	571,140	3,223	0.0056	0.9944	65.07
41.5	509,277	1,107	0.0022	0.9978	64.70
42.5	424,723	1,145	0.0027	0.9973	64.56
43.5	408,322	1,339	0.0033	0.9967	64.39
44.5	387,767	1,503	0.0039	0.9961	64.18
45.5	332,866	4,138	0.0124	0.9876	63.93
46.5	251,787	18,577	0.0738	0.9262	63.13
47.5	194,725	7,365	0.0378	0.9622	58.48
48.5	150,424	3,662	0.0243	0.9757	56.26
49.5	127,373	5,865	0.0460	0.9540	54.89
50.5	116,314	12,833	0.1103	0.8897	52.37
51.5	102,142	7,500	0.0734	0.9266	46.59
52.5	94,641	3,626	0.0383	0.9617	43.17
53.5	90,484	14,086	0.1557	0.8443	41.51
54.5	74,227	24,998	0.3368	0.6632	35.05
55.5	47,156	16,055	0.3405	0.6595	23.25
56.5	30,519	9,812	0.3215	0.6785	15.33
57.5	19,592	7,302	0.3727	0.6273	10.40
58.5	11,739	4,436	0.3778	0.6222	6.53
59.5	6,497	2,073	0.3191	0.6809	4.06
60.5	3,322	631	0.1899	0.8101	2.76
61.5	2,691	288	0.1072	0.8928	2.24
62.5	2,402	193	0.0805	0.9195	2.00
63.5	2,209	166	0.0752	0.9248	1.84
64.5	2,043	152	0.0745	0.9255	1.70
65.5	1,891	252	0.1331	0.8669	1.57
66.5	1,639	198	0.1206	0.8794	1.36
67.5	1,441	106	0.0732	0.9268	1.20
68.5	1,336	491	0.3675	0.6325	1.11
69.5	845	61	0.0721	0.9279	0.70
70.5	784	127	0.1623	0.8377	0.65
71.5	657	29	0.0435	0.9565	0.55
72.5	628	6	0.0091	0.9909	0.52
73.5	622	29	0.0461	0.9539	0.52
74.5	594	80	0.1345	0.8655	0.49
75.5	514	93	0.1806	0.8194	0.43
76.5	421	138	0.3274	0.6726	0.35
77.5	283	239	0.8452	0.1548	0.24
78.5	44	44	1.0000		0.04
79.5					

UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 369 - SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 369 - SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1922-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	16,342,483	10,843	0.0007	0.9993	100.00
0.5	16,158,269	23,819	0.0015	0.9985	99.93
1.5	15,781,182	23,464	0.0015	0.9985	99.79
2.5	15,334,124	26,158	0.0017	0.9983	99.64
3.5	14,938,819	46,107	0.0031	0.9969	99.47
4.5	14,504,963	49,049	0.0034	0.9966	99.16
5.5	13,976,559	47,993	0.0034	0.9966	98.83
6.5	13,527,613	78,804	0.0058	0.9942	98.49
7.5	12,963,040	211,514	0.0163	0.9837	97.91
8.5	12,364,275	97,530	0.0079	0.9921	96.32
9.5	11,908,801	28,955	0.0024	0.9976	95.56
10.5	11,660,379	22,397	0.0019	0.9981	95.32
11.5	11,303,519	123,927	0.0110	0.9890	95.14
12.5	10,856,926	12,678	0.0012	0.9988	94.10
13.5	10,368,205	14,524	0.0014	0.9986	93.99
14.5	9,766,106	13,564	0.0014	0.9986	93.86
15.5	9,640,247	18,539	0.0019	0.9981	93.72
16.5	9,174,914	27,726	0.0030	0.9970	93.54
17.5	8,868,690	31,373	0.0035	0.9965	93.26
18.5	8,625,168	43,637	0.0051	0.9949	92.93
19.5	8,353,691	30,193	0.0036	0.9964	92.46
20.5	8,135,134	26,888	0.0033	0.9967	92.13
21.5	7,938,504	15,531	0.0020	0.9980	91.82
22.5	7,603,554	22,591	0.0030	0.9970	91.64
23.5	7,292,105	33,529	0.0046	0.9954	91.37
24.5	6,928,517	85,403	0.0123	0.9877	90.95
25.5	6,565,478	73,635	0.0112	0.9888	89.83
26.5	6,192,182	38,045	0.0061	0.9939	88.82
27.5	5,994,441	47,157	0.0079	0.9921	88.28
28.5	5,764,048	60,471	0.0105	0.9895	87.58
29.5	5,454,405	37,495	0.0069	0.9931	86.66
30.5	5,158,041	56,029	0.0109	0.9891	86.07
31.5	4,830,122	24,702	0.0051	0.9949	85.13
32.5	4,546,402	36,944	0.0081	0.9919	84.70
33.5	4,267,747	24,907	0.0058	0.9942	84.01
34.5	4,009,997	41,292	0.0103	0.9897	83.52
35.5	3,758,603	23,234	0.0062	0.9938	82.66
36.5	3,573,314	20,917	0.0059	0.9941	82.15
37.5	3,349,212	11,468	0.0034	0.9966	81.67
38.5	3,159,905	28,415	0.0090	0.9910	81.39

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 369 - SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1922-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,968,918	26,174	0.0088	0.9912	80.66
40.5	2,752,420	10,534	0.0038	0.9962	79.94
41.5	2,594,498	12,387	0.0048	0.9952	79.64
42.5	2,382,562	97,554	0.0409	0.9591	79.26
43.5	2,117,115	68,556	0.0324	0.9676	76.01
44.5	1,893,493	5,931	0.0031	0.9969	73.55
45.5	1,734,438	9,029	0.0052	0.9948	73.32
46.5	1,584,611	9,946	0.0063	0.9937	72.94
47.5	1,427,255	9,402	0.0066	0.9934	72.48
48.5	1,140,438	4,653	0.0041	0.9959	72.00
49.5	938,728	1,646	0.0018	0.9982	71.71
50.5	704,788	779	0.0011	0.9989	71.58
51.5	468,963	392	0.0008	0.9992	71.51
52.5	305,866	692	0.0023	0.9977	71.45
53.5	217,867	488	0.0022	0.9978	71.28
54.5	157,642	623	0.0039	0.9961	71.12
55.5	125,947	312	0.0025	0.9975	70.84
56.5	102,365	653	0.0064	0.9936	70.67
57.5	94,011	831	0.0088	0.9912	70.22
58.5	66,294	859	0.0130	0.9870	69.60
59.5	60,286	590	0.0098	0.9902	68.69
60.5	59,218	295	0.0050	0.9950	68.02
61.5	57,635	184	0.0032	0.9968	67.68
62.5	56,810	117	0.0021	0.9979	67.47
63.5	56,476	580	0.0103	0.9897	67.33
64.5	55,896	1,515	0.0271	0.9729	66.64
65.5	54,252	25	0.0005	0.9995	64.83
66.5	53,894	26	0.0005	0.9995	64.80
67.5	53,750	130	0.0024	0.9976	64.77
68.5	53,620	737	0.0138	0.9862	64.61
69.5	52,883	625	0.0118	0.9882	63.72
70.5	52,258	2,925	0.0560	0.9440	62.97
71.5	49,333	4,647	0.0942	0.9058	59.45
72.5	44,686	9,896	0.2215	0.7785	53.85
73.5	34,790	2,166	0.0622	0.9378	41.92
74.5	32,554	5,025	0.1544	0.8456	39.31
75.5	27,529	4,198	0.1525	0.8475	33.24
76.5	23,331	3,302	0.1415	0.8585	28.17
77.5	20,029	4,037	0.2016	0.7984	24.19
78.5	15,992	3,159	0.1975	0.8025	19.31

UGI UTILITIES, INC. - ELECTRIC DIVISION

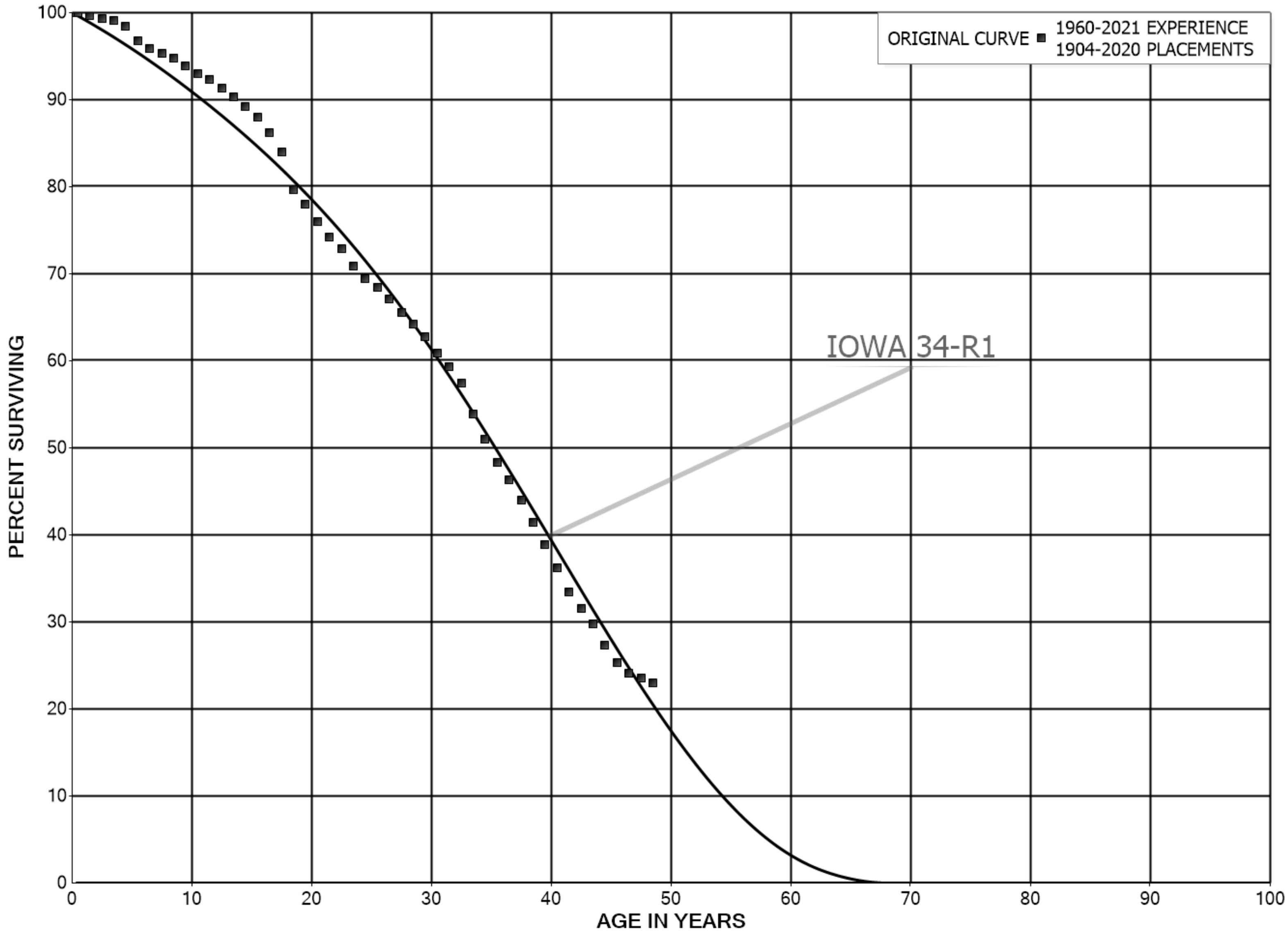
ACCOUNT 369 - SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1922-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	12,833	24	0.0018	0.9982	15.50
80.5	12,810		0.0000	1.0000	15.47
81.5	12,810		0.0000	1.0000	15.47
82.5	12,810	12,810	1.0000		15.47
83.5					

UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 370.1 - METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.1 - METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1904-2020 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	8,786,400	89	0.0000	1.0000	100.00
0.5	8,443,944	35,145	0.0042	0.9958	100.00
1.5	8,090,947	21,930	0.0027	0.9973	99.58
2.5	7,818,175	22,435	0.0029	0.9971	99.31
3.5	7,181,397	46,186	0.0064	0.9936	99.03
4.5	6,956,824	119,350	0.0172	0.9828	98.39
5.5	6,843,232	57,892	0.0085	0.9915	96.70
6.5	4,502,508	27,445	0.0061	0.9939	95.88
7.5	4,522,202	29,665	0.0066	0.9934	95.30
8.5	4,395,643	40,425	0.0092	0.9908	94.68
9.5	4,475,432	38,609	0.0086	0.9914	93.80
10.5	4,385,731	35,698	0.0081	0.9919	93.00
11.5	4,342,833	43,410	0.0100	0.9900	92.24
12.5	4,390,999	47,477	0.0108	0.9892	91.32
13.5	4,402,349	55,566	0.0126	0.9874	90.33
14.5	4,381,891	60,161	0.0137	0.9863	89.19
15.5	4,298,008	87,319	0.0203	0.9797	87.96
16.5	4,198,189	107,297	0.0256	0.9744	86.18
17.5	3,978,120	205,938	0.0518	0.9482	83.97
18.5	3,742,633	77,548	0.0207	0.9793	79.63
19.5	3,675,228	92,797	0.0252	0.9748	77.98
20.5	3,569,169	87,230	0.0244	0.9756	76.01
21.5	3,278,577	60,597	0.0185	0.9815	74.15
22.5	3,141,012	83,137	0.0265	0.9735	72.78
23.5	2,904,602	57,620	0.0198	0.9802	70.85
24.5	2,780,081	42,065	0.0151	0.9849	69.45
25.5	2,665,142	50,410	0.0189	0.9811	68.40
26.5	2,514,598	58,598	0.0233	0.9767	67.10
27.5	2,350,699	47,068	0.0200	0.9800	65.54
28.5	2,214,509	51,260	0.0231	0.9769	64.23
29.5	2,050,761	60,888	0.0297	0.9703	62.74
30.5	1,927,719	49,291	0.0256	0.9744	60.88
31.5	1,791,395	58,988	0.0329	0.9671	59.32
32.5	1,686,710	104,652	0.0620	0.9380	57.37
33.5	1,539,794	82,692	0.0537	0.9463	53.81
34.5	1,414,469	73,069	0.0517	0.9483	50.92
35.5	1,365,874	58,108	0.0425	0.9575	48.29
36.5	1,307,414	66,296	0.0507	0.9493	46.23
37.5	1,230,503	70,112	0.0570	0.9430	43.89
38.5	1,141,596	69,448	0.0608	0.9392	41.39

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.1 - METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1904-2020 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,046,175	73,564	0.0703	0.9297	38.87
40.5	952,555	72,436	0.0760	0.9240	36.14
41.5	839,983	46,418	0.0553	0.9447	33.39
42.5	759,954	44,753	0.0589	0.9411	31.54
43.5	659,508	52,634	0.0798	0.9202	29.69
44.5	571,797	41,460	0.0725	0.9275	27.32
45.5	489,096	23,837	0.0487	0.9513	25.34
46.5	440,370	11,161	0.0253	0.9747	24.10
47.5	410,699	9,240	0.0225	0.9775	23.49
48.5	368,615	11,142	0.0302	0.9698	22.96
49.5	183,808	5,333	0.0290	0.9710	22.27
50.5	145,998	3,405	0.0233	0.9767	21.62
51.5	129,102	697	0.0054	0.9946	21.12
52.5	115,477	1,584	0.0137	0.9863	21.00
53.5	99,819	3,088	0.0309	0.9691	20.72
54.5	89,038	3,319	0.0373	0.9627	20.08
55.5	81,498	3,779	0.0464	0.9536	19.33
56.5	72,743	7,952	0.1093	0.8907	18.43
57.5	62,331	5,128	0.0823	0.9177	16.42
58.5	53,794	8,059	0.1498	0.8502	15.07
59.5	39,364	3,221	0.0818	0.9182	12.81
60.5	34,224	4,569	0.1335	0.8665	11.76
61.5	29,655	3,087	0.1041	0.8959	10.19
62.5	25,693	2,943	0.1145	0.8855	9.13
63.5	22,119	3,695	0.1671	0.8329	8.08
64.5	17,947	1,980	0.1103	0.8897	6.73
65.5	15,967	1,640	0.1027	0.8973	5.99
66.5	14,327	318	0.0222	0.9778	5.38
67.5	14,009	37	0.0027	0.9973	5.26
68.5	13,972		0.0000	1.0000	5.24
69.5	13,972		0.0000	1.0000	5.24
70.5	13,972		0.0000	1.0000	5.24
71.5	13,972	55	0.0040	0.9960	5.24
72.5	13,916		0.0000	1.0000	5.22
73.5	13,854	135	0.0098	0.9902	5.22
74.5	13,718	1,474	0.1075	0.8925	5.17
75.5	12,176	513	0.0421	0.9579	4.61
76.5	11,663	942	0.0808	0.9192	4.42
77.5	10,721	608	0.0567	0.9433	4.06
78.5	10,113	1,756	0.1736	0.8264	3.83

UGI UTILITIES, INC. - ELECTRIC DIVISION

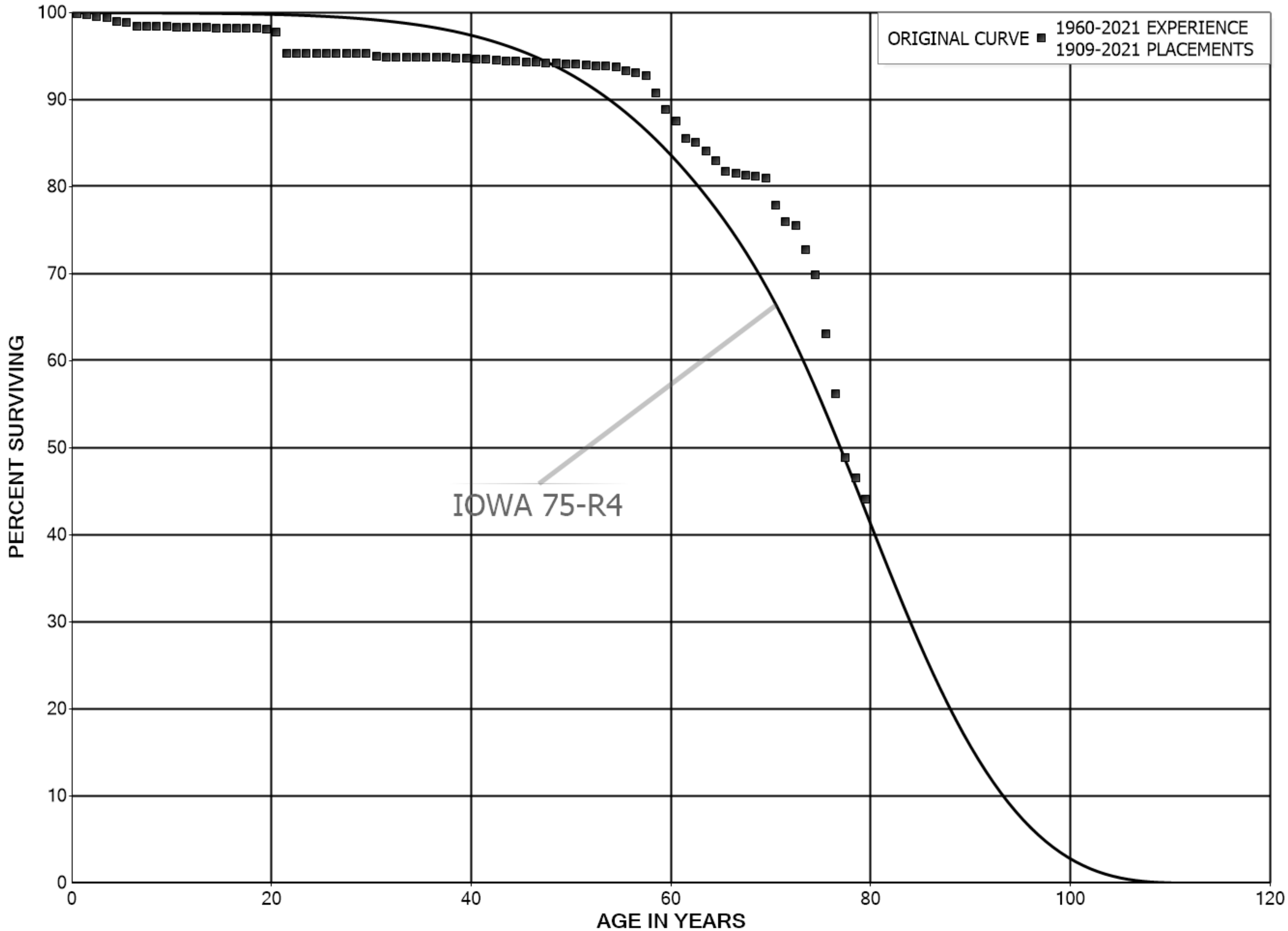
ACCOUNT 370.1 - METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1904-2020 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	8,357	317	0.0379	0.9621	3.17
80.5	8,040	572	0.0711	0.9289	3.05
81.5	7,469	1,814	0.2429	0.7571	2.83
82.5	5,655	3,343	0.5912	0.4088	2.14
83.5	2,311	232	0.1003	0.8997	0.88
84.5	2,080		0.0000	1.0000	0.79
85.5	2,080		0.0000	1.0000	0.79
86.5	2,080		0.0000	1.0000	0.79
87.5	2,080	2,069	0.9949	0.0051	0.79
88.5	11		0.0000	1.0000	0.00
89.5	11		0.0000	1.0000	0.00
90.5	11		0.0000	1.0000	0.00
91.5	11	11	1.0000		0.00
92.5					

UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 370.2 - METER INSTALLATIONS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.2 - METER INSTALLATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1909-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,879,431	2,598	0.0014	0.9986	100.00
0.5	1,873,258	2,780	0.0015	0.9985	99.86
1.5	1,871,335	4,024	0.0022	0.9978	99.71
2.5	1,849,281	1,287	0.0007	0.9993	99.50
3.5	1,838,799	9,677	0.0053	0.9947	99.43
4.5	1,809,877	1,940	0.0011	0.9989	98.91
5.5	1,790,082	6,358	0.0036	0.9964	98.80
6.5	1,672,389	591	0.0004	0.9996	98.45
7.5	1,629,860	626	0.0004	0.9996	98.41
8.5	1,593,040	569	0.0004	0.9996	98.38
9.5	1,565,925	346	0.0002	0.9998	98.34
10.5	1,559,703	385	0.0002	0.9998	98.32
11.5	1,545,729	434	0.0003	0.9997	98.30
12.5	1,520,498	329	0.0002	0.9998	98.27
13.5	1,480,245	649	0.0004	0.9996	98.25
14.5	1,459,302	294	0.0002	0.9998	98.20
15.5	1,439,965	348	0.0002	0.9998	98.18
16.5	1,277,143	247	0.0002	0.9998	98.16
17.5	1,155,290	182	0.0002	0.9998	98.14
18.5	1,037,304	221	0.0002	0.9998	98.13
19.5	981,661	4,213	0.0043	0.9957	98.11
20.5	974,242	23,593	0.0242	0.9758	97.68
21.5	920,579	143	0.0002	0.9998	95.32
22.5	922,806	105	0.0001	0.9999	95.30
23.5	906,337	75	0.0001	0.9999	95.29
24.5	872,210	121	0.0001	0.9999	95.28
25.5	846,773	52	0.0001	0.9999	95.27
26.5	811,562	54	0.0001	0.9999	95.27
27.5	781,217	85	0.0001	0.9999	95.26
28.5	754,732	147	0.0002	0.9998	95.25
29.5	722,769	2,461	0.0034	0.9966	95.23
30.5	694,749	233	0.0003	0.9997	94.91
31.5	666,574	98	0.0001	0.9999	94.87
32.5	637,232	90	0.0001	0.9999	94.86
33.5	607,228	103	0.0002	0.9998	94.85
34.5	576,523	71	0.0001	0.9999	94.83
35.5	552,717	135	0.0002	0.9998	94.82
36.5	524,673	79	0.0002	0.9998	94.80
37.5	504,088	71	0.0001	0.9999	94.78
38.5	487,769	283	0.0006	0.9994	94.77

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.2 - METER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1909-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	463,282	256	0.0006	0.9994	94.71
40.5	418,184	24	0.0001	0.9999	94.66
41.5	397,100	615	0.0015	0.9985	94.66
42.5	368,483	332	0.0009	0.9991	94.51
43.5	354,034	171	0.0005	0.9995	94.42
44.5	336,692	158	0.0005	0.9995	94.38
45.5	326,607	335	0.0010	0.9990	94.33
46.5	315,513	222	0.0007	0.9993	94.24
47.5	301,619	114	0.0004	0.9996	94.17
48.5	283,745	141	0.0005	0.9995	94.14
49.5	270,394	201	0.0007	0.9993	94.09
50.5	256,663	304	0.0012	0.9988	94.02
51.5	244,439	205	0.0008	0.9992	93.91
52.5	231,659	110	0.0005	0.9995	93.83
53.5	221,457	70	0.0003	0.9997	93.78
54.5	210,384	1,032	0.0049	0.9951	93.75
55.5	201,125	449	0.0022	0.9978	93.30
56.5	191,539	832	0.0043	0.9957	93.09
57.5	184,801	3,924	0.0212	0.9788	92.68
58.5	174,119	3,672	0.0211	0.9789	90.71
59.5	165,614	2,473	0.0149	0.9851	88.80
60.5	156,986	3,494	0.0223	0.9777	87.48
61.5	148,285	862	0.0058	0.9942	85.53
62.5	141,232	1,568	0.0111	0.9889	85.03
63.5	129,247	1,673	0.0129	0.9871	84.09
64.5	121,072	1,912	0.0158	0.9842	83.00
65.5	112,106	177	0.0016	0.9984	81.69
66.5	104,899	335	0.0032	0.9968	81.56
67.5	98,840	150	0.0015	0.9985	81.30
68.5	92,062	263	0.0029	0.9971	81.18
69.5	85,388	3,304	0.0387	0.9613	80.94
70.5	74,847	1,828	0.0244	0.9756	77.81
71.5	66,754	338	0.0051	0.9949	75.91
72.5	60,152	2,196	0.0365	0.9635	75.53
73.5	51,407	2,052	0.0399	0.9601	72.77
74.5	44,866	4,372	0.0974	0.9026	69.86
75.5	38,535	4,209	0.1092	0.8908	63.06
76.5	33,421	4,397	0.1316	0.8684	56.17
77.5	28,336	1,306	0.0461	0.9539	48.78
78.5	26,454	1,385	0.0523	0.9477	46.53

UGI UTILITIES, INC. - ELECTRIC DIVISION

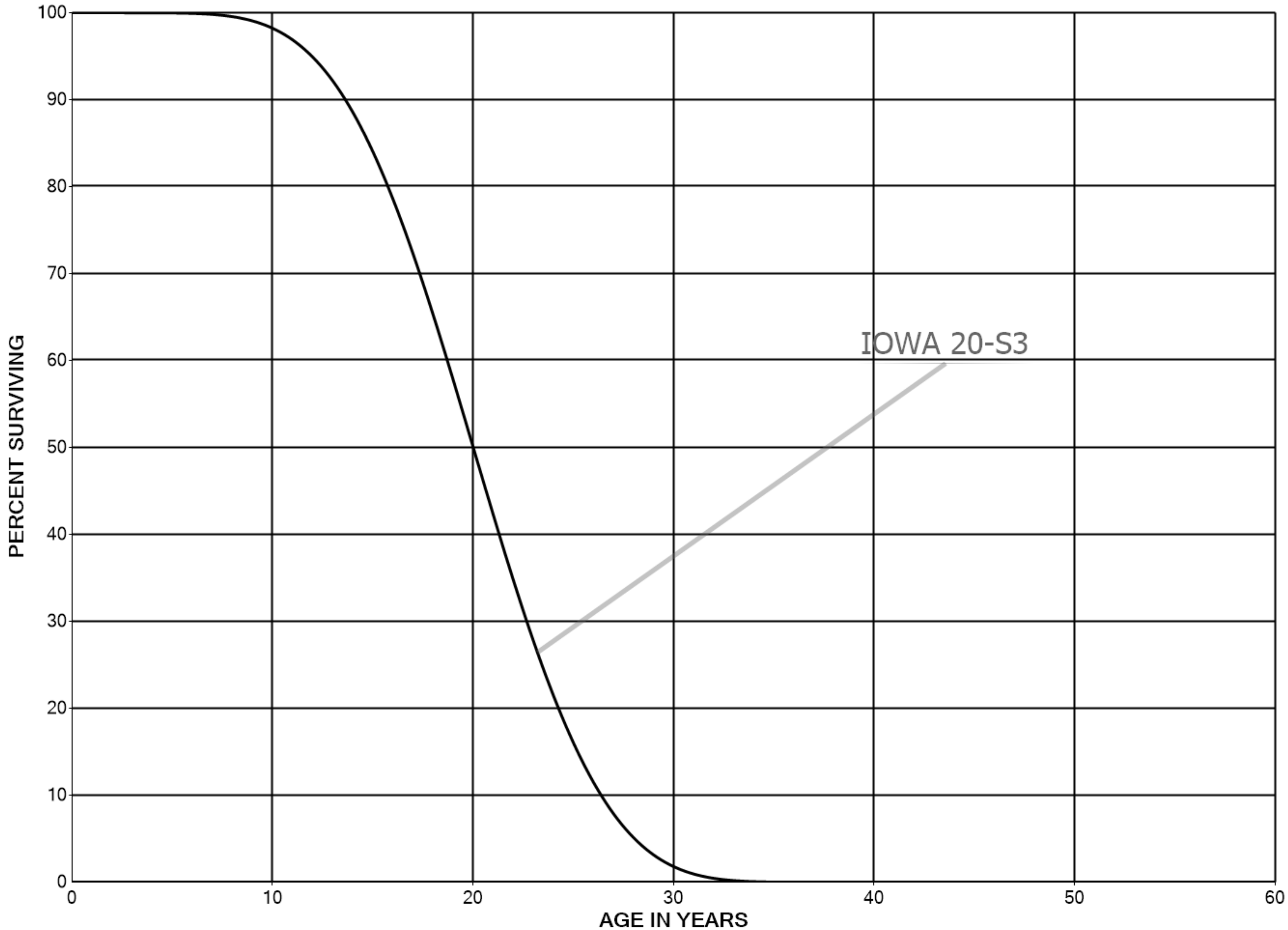
ACCOUNT 370.2 - METER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

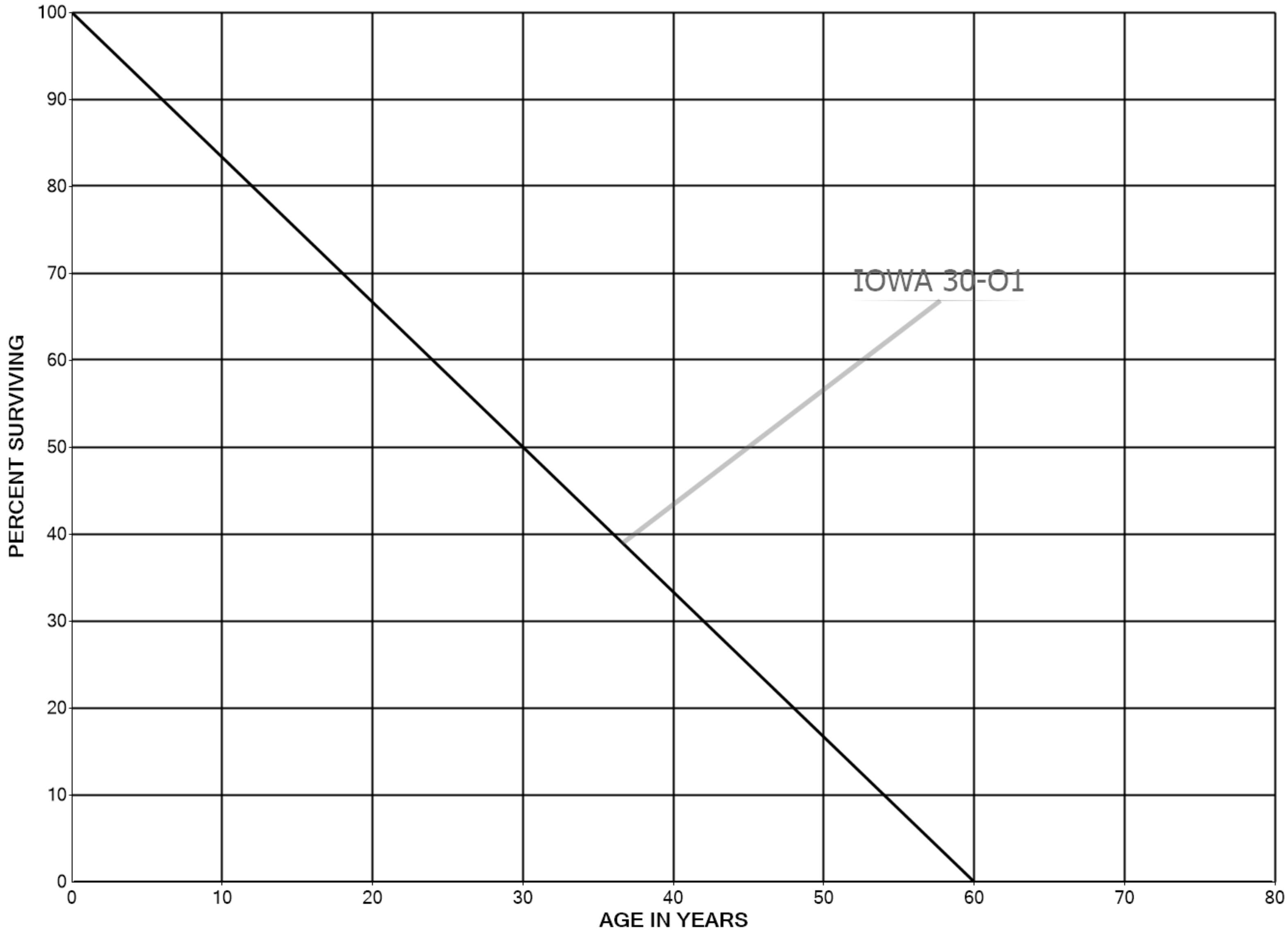
PLACEMENT BAND 1909-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	24,440	253	0.0104	0.9896	44.10
80.5	22,952	152	0.0066	0.9934	43.64
81.5	21,167	300	0.0142	0.9858	43.35
82.5	19,184	592	0.0309	0.9691	42.73
83.5	17,026	207	0.0121	0.9879	41.42
84.5	14,849	18	0.0012	0.9988	40.91
85.5	13,313	127	0.0095	0.9905	40.86
86.5	12,344	26	0.0021	0.9979	40.47
87.5	11,329	6	0.0005	0.9995	40.39
88.5	10,604	35	0.0033	0.9967	40.37
89.5	9,801	9	0.0010	0.9990	40.23
90.5	9,346	5	0.0005	0.9995	40.19
91.5	8,178	17	0.0020	0.9980	40.17
92.5	6,191	4	0.0006	0.9994	40.09
93.5	5,785	5	0.0008	0.9992	40.07
94.5	3,308	11	0.0032	0.9968	40.03
95.5	1,871		0.0000	1.0000	39.91
96.5	1,727		0.0000	1.0000	39.91
97.5					39.91

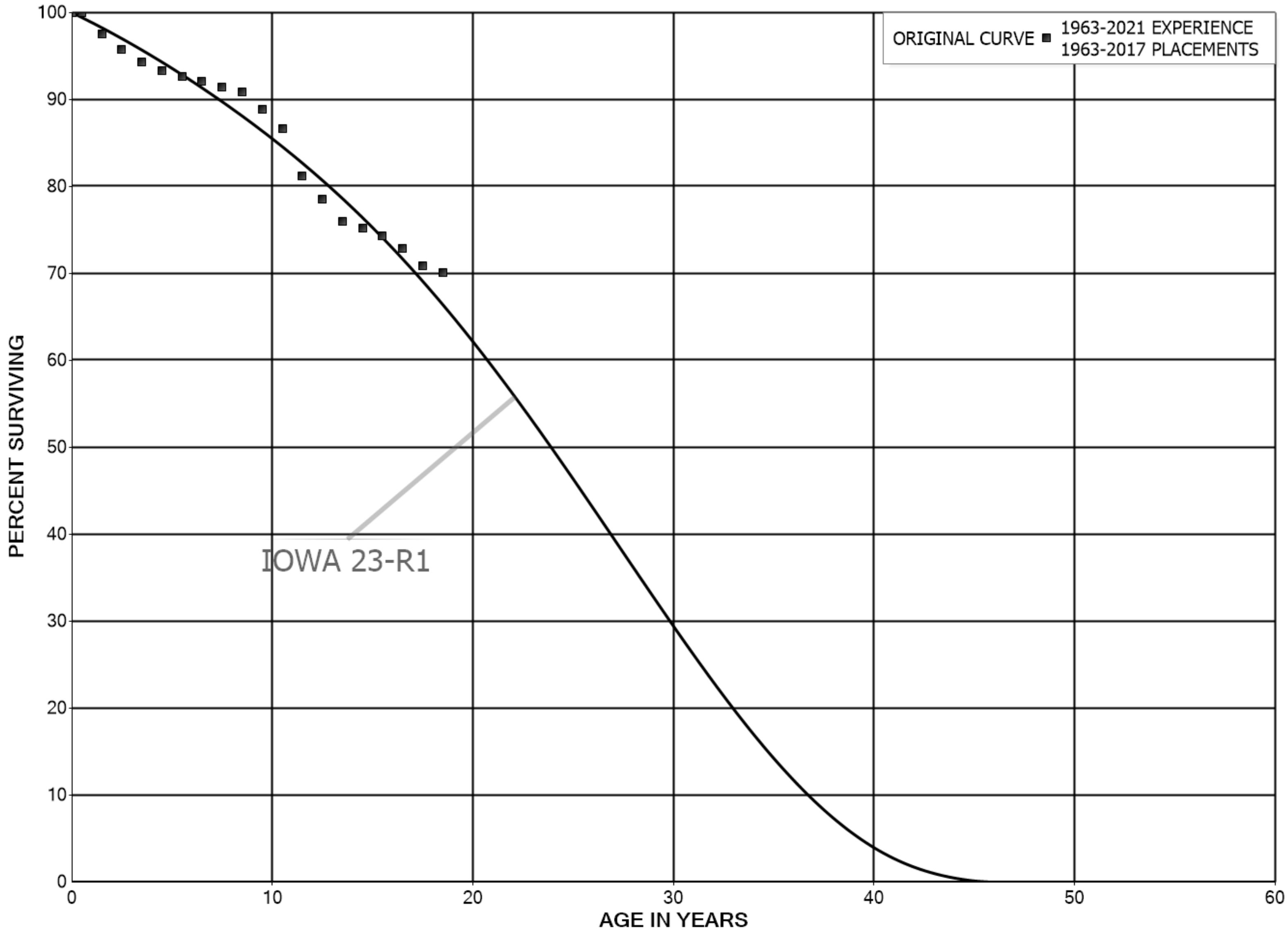
UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 370.3 - ELECTRONIC METERS
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 371 - INSTALLATIONS ON CUSTOMER PREMISES
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 371.5 - INSTALL. ON CUST. PREMISES - DUSK TO DAWN LIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 371.5 - INSTALL. ON CUST. PREMISES - DUSK TO DAWN LIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1963-2017 EXPERIENCE BAND 1963-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	502,524	211	0.0004	0.9996	100.00
0.5	502,061	12,586	0.0251	0.9749	99.96
1.5	489,475	8,746	0.0179	0.9821	97.45
2.5	480,730	7,062	0.0147	0.9853	95.71
3.5	473,667	5,341	0.0113	0.9887	94.30
4.5	467,176	3,080	0.0066	0.9934	93.24
5.5	464,096	3,059	0.0066	0.9934	92.63
6.5	464,161	3,227	0.0070	0.9930	92.02
7.5	460,934	2,532	0.0055	0.9945	91.38
8.5	458,076	10,251	0.0224	0.9776	90.87
9.5	447,825	10,948	0.0244	0.9756	88.84
10.5	436,877	27,739	0.0635	0.9365	86.67
11.5	409,138	13,244	0.0324	0.9676	81.17
12.5	395,894	13,075	0.0330	0.9670	78.54
13.5	368,735	3,701	0.0100	0.9900	75.94
14.5	365,034	4,112	0.0113	0.9887	75.18
15.5	360,922	7,458	0.0207	0.9793	74.34
16.5	353,464	9,482	0.0268	0.9732	72.80
17.5	343,982	3,557	0.0103	0.9897	70.85
18.5	340,425	2,660	0.0078	0.9922	70.11
19.5	337,765	1,158	0.0034	0.9966	69.57
20.5	336,606	900	0.0027	0.9973	69.33
21.5	304,787	818	0.0027	0.9973	69.14
22.5	242,087	297	0.0012	0.9988	68.96
23.5	180,011	1,307	0.0073	0.9927	68.87
24.5	125,041	493	0.0039	0.9961	68.37
25.5	86,585	646	0.0075	0.9925	68.10
26.5	76,275		0.0000	1.0000	67.59
27.5	67,656		0.0000	1.0000	67.59
28.5	65,340		0.0000	1.0000	67.59
29.5	60,480		0.0000	1.0000	67.59
30.5	57,908		0.0000	1.0000	67.59
31.5	53,579		0.0000	1.0000	67.59
32.5	52,086		0.0000	1.0000	67.59
33.5	49,784		0.0000	1.0000	67.59
34.5	47,859		0.0000	1.0000	67.59
35.5	46,869		0.0000	1.0000	67.59
36.5	44,527		0.0000	1.0000	67.59
37.5	42,377		0.0000	1.0000	67.59
38.5	40,146		0.0000	1.0000	67.59

UGI UTILITIES, INC. - ELECTRIC DIVISION

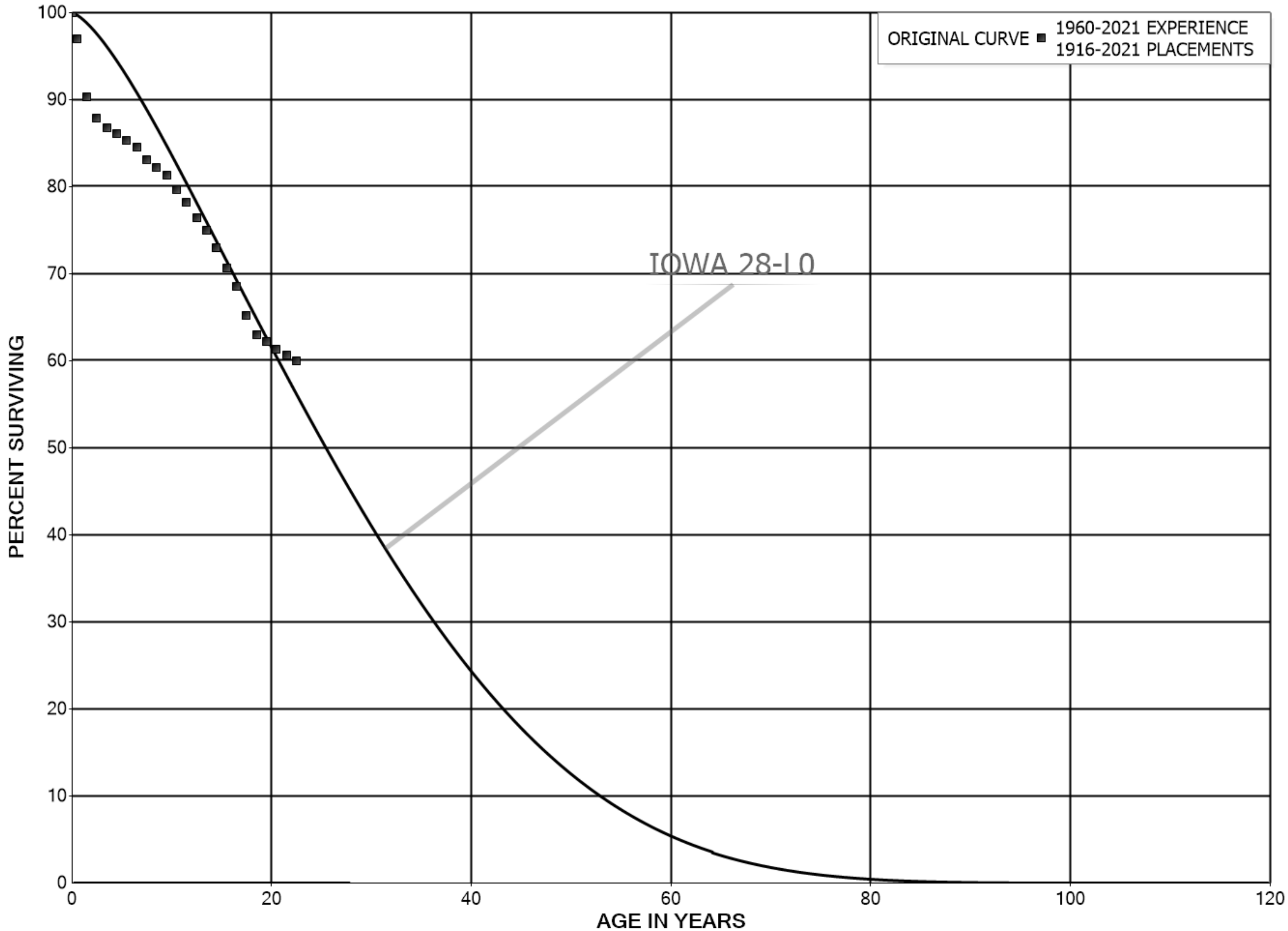
ACCOUNT 371.5 - INSTALL. ON CUST. PREMISES - DUSK TO DAWN LIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1963-2017 EXPERIENCE BAND 1963-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	38,584		0.0000	1.0000	67.59
40.5	35,667		0.0000	1.0000	67.59
41.5	30,805		0.0000	1.0000	67.59
42.5	24,820		0.0000	1.0000	67.59
43.5	20,590		0.0000	1.0000	67.59
44.5	15,893		0.0000	1.0000	67.59
45.5	11,490		0.0000	1.0000	67.59
46.5	7,907		0.0000	1.0000	67.59
47.5	1,435		0.0000	1.0000	67.59
48.5					67.59

UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 373 - STREET LIGHTING AND SIGNAL SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 373 - STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1916-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,961,816	91,040	0.0307	0.9693	100.00
0.5	2,853,623	196,524	0.0689	0.9311	96.93
1.5	2,412,524	63,499	0.0263	0.9737	90.25
2.5	2,368,853	30,357	0.0128	0.9872	87.88
3.5	2,017,612	14,697	0.0073	0.9927	86.75
4.5	1,957,586	19,457	0.0099	0.9901	86.12
5.5	1,982,581	18,210	0.0092	0.9908	85.26
6.5	1,907,238	30,958	0.0162	0.9838	84.48
7.5	1,893,033	22,345	0.0118	0.9882	83.11
8.5	1,859,315	18,166	0.0098	0.9902	82.13
9.5	1,851,298	38,895	0.0210	0.9790	81.32
10.5	1,834,325	34,188	0.0186	0.9814	79.62
11.5	1,812,796	39,240	0.0216	0.9784	78.13
12.5	1,789,651	35,275	0.0197	0.9803	76.44
13.5	1,748,538	47,082	0.0269	0.9731	74.93
14.5	1,734,718	53,888	0.0311	0.9689	72.92
15.5	1,710,878	51,176	0.0299	0.9701	70.65
16.5	1,508,739	74,381	0.0493	0.9507	68.54
17.5	1,381,840	45,853	0.0332	0.9668	65.16
18.5	1,250,217	15,377	0.0123	0.9877	63.00
19.5	1,225,212	17,872	0.0146	0.9854	62.22
20.5	1,137,080	11,994	0.0105	0.9895	61.31
21.5	1,112,414	12,845	0.0115	0.9885	60.67
22.5	1,085,562	8,440	0.0078	0.9922	59.97
23.5	1,091,403	8,577	0.0079	0.9921	59.50
24.5	1,101,434	8,886	0.0081	0.9919	59.03
25.5	1,067,910	12,456	0.0117	0.9883	58.56
26.5	1,035,237	6,415	0.0062	0.9938	57.87
27.5	1,001,866	4,526	0.0045	0.9955	57.51
28.5	872,722	8,092	0.0093	0.9907	57.26
29.5	856,514	12,694	0.0148	0.9852	56.72
30.5	837,208	8,151	0.0097	0.9903	55.88
31.5	806,067	8,881	0.0110	0.9890	55.34
32.5	779,463	14,642	0.0188	0.9812	54.73
33.5	732,337	8,382	0.0114	0.9886	53.70
34.5	749,749	9,296	0.0124	0.9876	53.09
35.5	767,189	13,880	0.0181	0.9819	52.43
36.5	761,701	5,271	0.0069	0.9931	51.48
37.5	725,823	15,475	0.0213	0.9787	51.12
38.5	663,033	12,077	0.0182	0.9818	50.03

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 373 - STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1916-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	589,508	18,030	0.0306	0.9694	49.12
40.5	545,621	12,582	0.0231	0.9769	47.62
41.5	515,058	42,821	0.0831	0.9169	46.52
42.5	458,002	16,285	0.0356	0.9644	42.65
43.5	420,150	8,050	0.0192	0.9808	41.14
44.5	405,958	2,938	0.0072	0.9928	40.35
45.5	378,831	1,880	0.0050	0.9950	40.06
46.5	327,172	224	0.0007	0.9993	39.86
47.5	317,082	186	0.0006	0.9994	39.83
48.5	297,249	10,338	0.0348	0.9652	39.81
49.5	280,969	89	0.0003	0.9997	38.42
50.5	277,208	1,116	0.0040	0.9960	38.41
51.5	262,162	113	0.0004	0.9996	38.26
52.5	253,390	896	0.0035	0.9965	38.24
53.5	232,409	1,380	0.0059	0.9941	38.11
54.5	196,289	115	0.0006	0.9994	37.88
55.5	148,124	1,589	0.0107	0.9893	37.86
56.5	102,055	3,215	0.0315	0.9685	37.45
57.5	91,328	597	0.0065	0.9935	36.27
58.5	81,720	107	0.0013	0.9987	36.03
59.5	79,748	1,013	0.0127	0.9873	35.99
60.5	75,103	74	0.0010	0.9990	35.53
61.5	75,218	2,272	0.0302	0.9698	35.49
62.5	60,712	197	0.0033	0.9967	34.42
63.5	60,023	1,374	0.0229	0.9771	34.31
64.5	55,328	960	0.0174	0.9826	33.52
65.5	37,567	260	0.0069	0.9931	32.94
66.5	33,978	289	0.0085	0.9915	32.72
67.5	31,283	95	0.0030	0.9970	32.44
68.5	26,943	422	0.0157	0.9843	32.34
69.5	23,422	163	0.0070	0.9930	31.83
70.5	21,531		0.0000	1.0000	31.61
71.5	18,887		0.0000	1.0000	31.61
72.5	17,588		0.0000	1.0000	31.61
73.5	15,787		0.0000	1.0000	31.61
74.5	15,676		0.0000	1.0000	31.61
75.5	15,625		0.0000	1.0000	31.61
76.5	15,598		0.0000	1.0000	31.61
77.5	15,598		0.0000	1.0000	31.61
78.5	15,598		0.0000	1.0000	31.61

UGI UTILITIES, INC. - ELECTRIC DIVISION

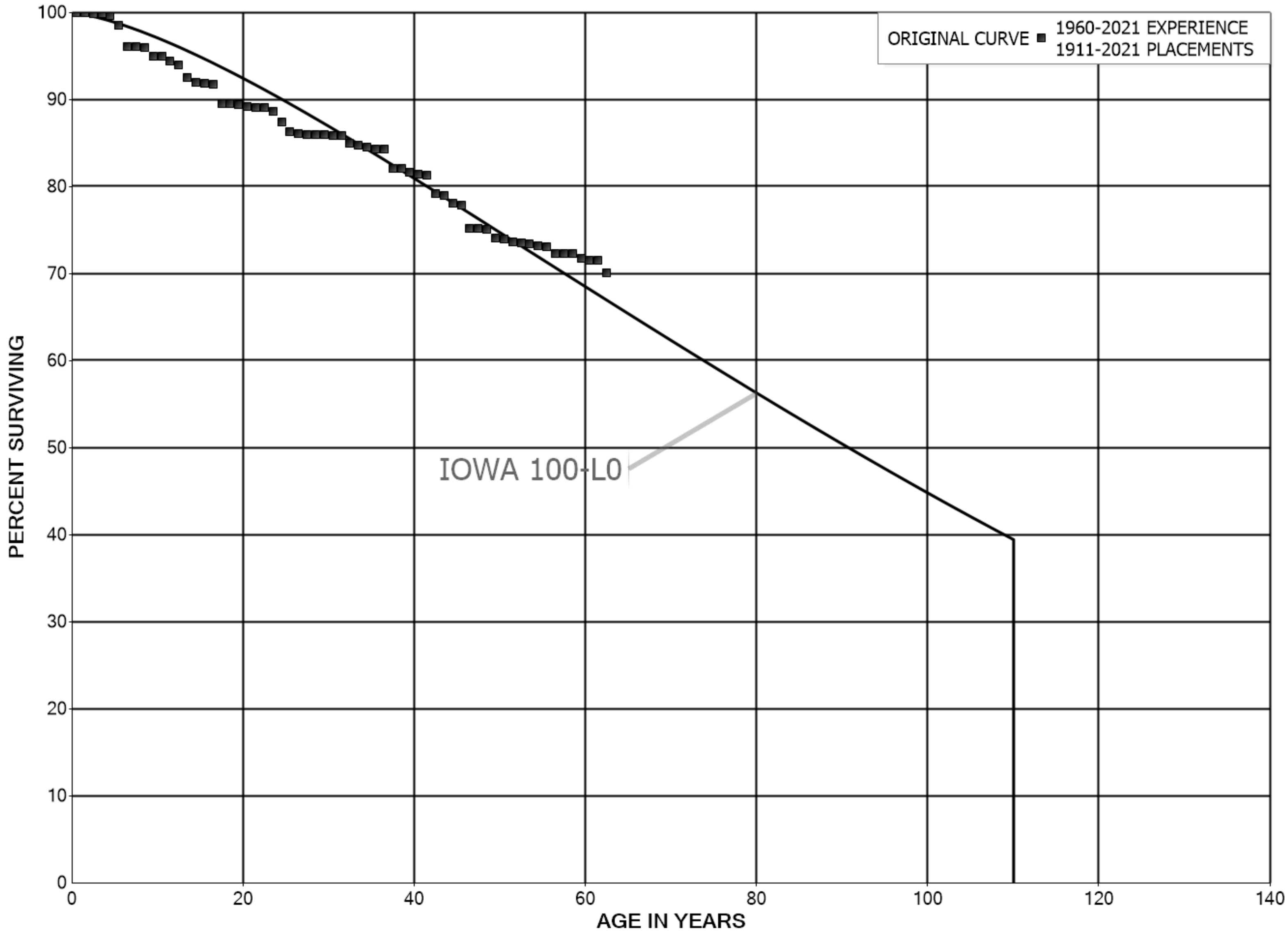
ACCOUNT 373 - STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1916-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	15,460		0.0000	1.0000	31.61
80.5	15,365		0.0000	1.0000	31.61
81.5	14,966		0.0000	1.0000	31.61
82.5	14,786		0.0000	1.0000	31.61
83.5	14,474		0.0000	1.0000	31.61
84.5	13,795		0.0000	1.0000	31.61
85.5	7,565		0.0000	1.0000	31.61
86.5	7,015		0.0000	1.0000	31.61
87.5	6,623		0.0000	1.0000	31.61
88.5	6,471		0.0000	1.0000	31.61
89.5	6,405		0.0000	1.0000	31.61
90.5	6,334		0.0000	1.0000	31.61
91.5	4,249		0.0000	1.0000	31.61
92.5	4,249		0.0000	1.0000	31.61
93.5	3,844		0.0000	1.0000	31.61
94.5	3,174		0.0000	1.0000	31.61
95.5	3,174		0.0000	1.0000	31.61
96.5	2,775		0.0000	1.0000	31.61
97.5	2,690		0.0000	1.0000	31.61
98.5	1,716		0.0000	1.0000	31.61
99.5	1,716		0.0000	1.0000	31.61
100.5	1,314		0.0000	1.0000	31.61
101.5	1,077		0.0000	1.0000	31.61
102.5	299		0.0000	1.0000	31.61
103.5	291		0.0000	1.0000	31.61
104.5					31.61

UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 390.1 - STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 390.1 - STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1911-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,357,832	1,000	0.0004	0.9996	100.00
0.5	2,233,079		0.0000	1.0000	99.96
1.5	2,162,220	2,617	0.0012	0.9988	99.96
2.5	2,183,473	1,043	0.0005	0.9995	99.84
3.5	2,130,111	3,686	0.0017	0.9983	99.79
4.5	2,131,610	24,247	0.0114	0.9886	99.62
5.5	1,976,546	48,458	0.0245	0.9755	98.48
6.5	1,621,407	380	0.0002	0.9998	96.07
7.5	1,595,743	978	0.0006	0.9994	96.05
8.5	1,574,193	16,154	0.0103	0.9897	95.99
9.5	1,534,367	628	0.0004	0.9996	95.00
10.5	1,477,056	8,755	0.0059	0.9941	94.96
11.5	1,459,841	6,367	0.0044	0.9956	94.40
12.5	1,440,975	22,516	0.0156	0.9844	93.99
13.5	1,410,856	9,263	0.0066	0.9934	92.52
14.5	1,368,382	1,886	0.0014	0.9986	91.91
15.5	1,291,079	1,559	0.0012	0.9988	91.79
16.5	1,268,032	29,884	0.0236	0.9764	91.68
17.5	1,237,141	717	0.0006	0.9994	89.51
18.5	1,233,917	1,631	0.0013	0.9987	89.46
19.5	1,228,183	3,000	0.0024	0.9976	89.34
20.5	1,216,980	498	0.0004	0.9996	89.13
21.5	1,204,568	295	0.0002	0.9998	89.09
22.5	1,205,252	6,106	0.0051	0.9949	89.07
23.5	1,199,297	16,145	0.0135	0.9865	88.62
24.5	1,197,009	15,461	0.0129	0.9871	87.42
25.5	1,180,266	3,366	0.0029	0.9971	86.29
26.5	1,145,140	679	0.0006	0.9994	86.05
27.5	1,055,839	244	0.0002	0.9998	86.00
28.5	1,043,767	973	0.0009	0.9991	85.98
29.5	1,018,029	722	0.0007	0.9993	85.90
30.5	493,354		0.0000	1.0000	85.84
31.5	467,364	4,543	0.0097	0.9903	85.84
32.5	494,532	1,745	0.0035	0.9965	85.00
33.5	514,618	986	0.0019	0.9981	84.70
34.5	506,914	1,544	0.0030	0.9970	84.54
35.5	531,586	10	0.0000	1.0000	84.28
36.5	472,162	12,597	0.0267	0.9733	84.28
37.5	467,447	114	0.0002	0.9998	82.03
38.5	454,467	2,390	0.0053	0.9947	82.01

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 390.1 - STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	440,686	872	0.0020	0.9980	81.58
40.5	435,382	476	0.0011	0.9989	81.42
41.5	255,130	6,660	0.0261	0.9739	81.33
42.5	230,337	727	0.0032	0.9968	79.21
43.5	216,002	2,478	0.0115	0.9885	78.96
44.5	208,847	651	0.0031	0.9969	78.05
45.5	207,441	7,143	0.0344	0.9656	77.81
46.5	177,958		0.0000	1.0000	75.13
47.5	231,855	257	0.0011	0.9989	75.13
48.5	227,976	2,986	0.0131	0.9869	75.05
49.5	228,671	469	0.0021	0.9979	74.06
50.5	224,172	970	0.0043	0.9957	73.91
51.5	220,068	152	0.0007	0.9993	73.59
52.5	218,249	435	0.0020	0.9980	73.54
53.5	217,654	732	0.0034	0.9966	73.39
54.5	210,839	285	0.0014	0.9986	73.15
55.5	207,189	2,249	0.0109	0.9891	73.05
56.5	203,466		0.0000	1.0000	72.25
57.5	198,342	40	0.0002	0.9998	72.25
58.5	196,894	1,476	0.0075	0.9925	72.24
59.5	195,300	503	0.0026	0.9974	71.70
60.5	193,078		0.0000	1.0000	71.51
61.5	189,116	3,792	0.0201	0.9799	71.51
62.5	181,984		0.0000	1.0000	70.08
63.5	181,404	412	0.0023	0.9977	70.08
64.5	180,377		0.0000	1.0000	69.92
65.5	179,680		0.0000	1.0000	69.92
66.5	179,680	717	0.0040	0.9960	69.92
67.5	178,963	854	0.0048	0.9952	69.64
68.5	177,051		0.0000	1.0000	69.31
69.5	176,820		0.0000	1.0000	69.31
70.5	174,179		0.0000	1.0000	69.31
71.5	151,396		0.0000	1.0000	69.31
72.5	139,745		0.0000	1.0000	69.31
73.5	135,750		0.0000	1.0000	69.31
74.5	106,296		0.0000	1.0000	69.31
75.5	106,296		0.0000	1.0000	69.31
76.5	106,296		0.0000	1.0000	69.31
77.5	106,296		0.0000	1.0000	69.31
78.5	106,296		0.0000	1.0000	69.31

UGI UTILITIES, INC. - ELECTRIC DIVISION

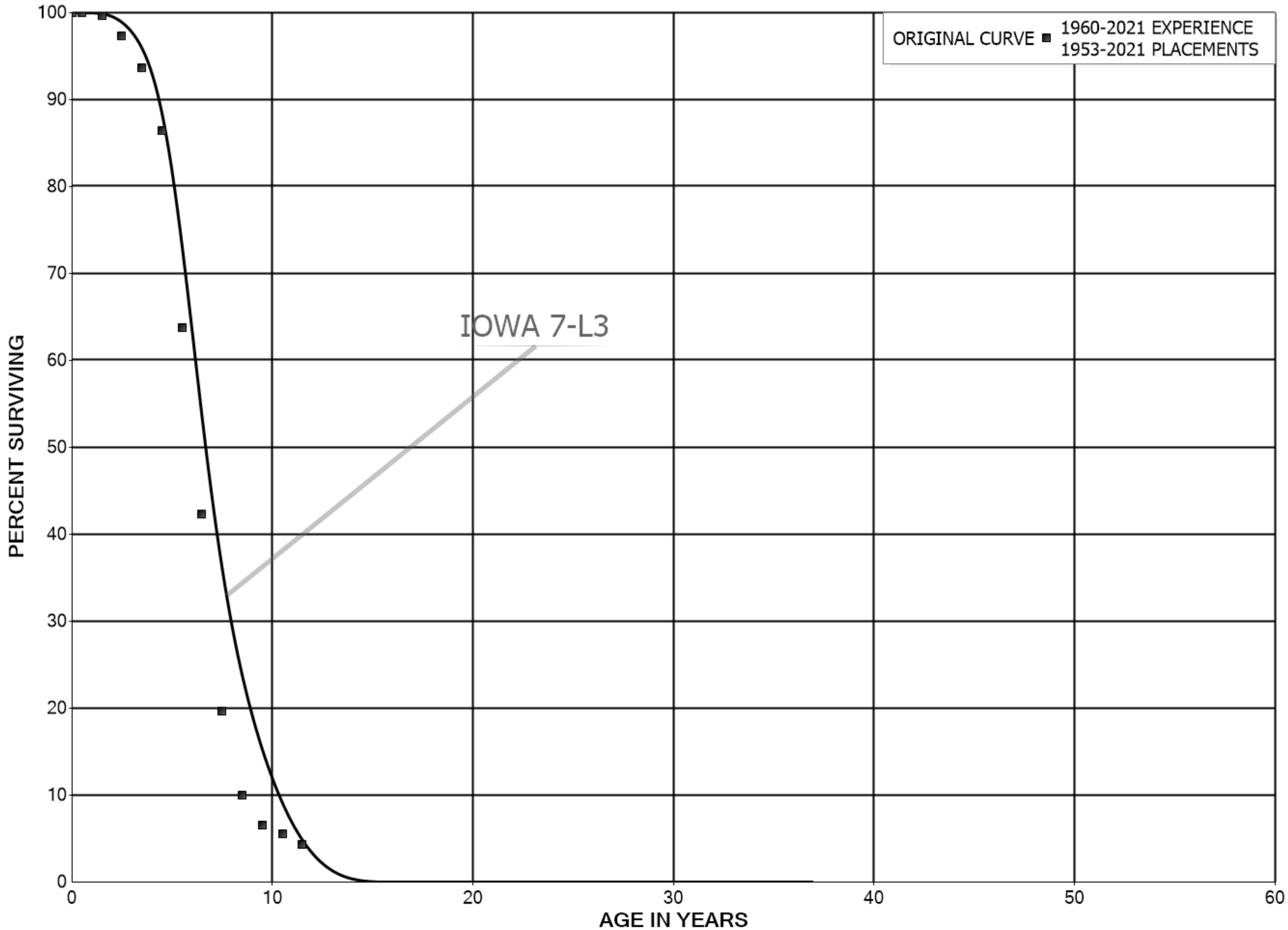
ACCOUNT 390.1 - STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	106,296		0.0000	1.0000	69.31
80.5	106,296		0.0000	1.0000	69.31
81.5	106,256		0.0000	1.0000	69.31
82.5	106,256		0.0000	1.0000	69.31
83.5	99,090		0.0000	1.0000	69.31
84.5	99,090		0.0000	1.0000	69.31
85.5	99,090		0.0000	1.0000	69.31
86.5	51,134		0.0000	1.0000	69.31
87.5	51,134		0.0000	1.0000	69.31
88.5	51,020		0.0000	1.0000	69.31
89.5	51,020		0.0000	1.0000	69.31
90.5	51,020		0.0000	1.0000	69.31
91.5	48,692		0.0000	1.0000	69.31
92.5	48,692		0.0000	1.0000	69.31
93.5	48,692		0.0000	1.0000	69.31
94.5	7,127		0.0000	1.0000	69.31
95.5	7,127		0.0000	1.0000	69.31
96.5	7,127		0.0000	1.0000	69.31
97.5	7,127		0.0000	1.0000	69.31
98.5	7,127		0.0000	1.0000	69.31
99.5	7,127		0.0000	1.0000	69.31
100.5	7,127		0.0000	1.0000	69.31
101.5	7,127		0.0000	1.0000	69.31
102.5	7,127		0.0000	1.0000	69.31
103.5	7,127		0.0000	1.0000	69.31
104.5					69.31

UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 392.1 - TRANSPORTATION EQUIPMENT - CARS
ORIGINAL AND SMOOTH SURVIVOR CURVES



GANNETT FLEMING

UGI UTILITIES, INC. - ELECTRIC DIVISION

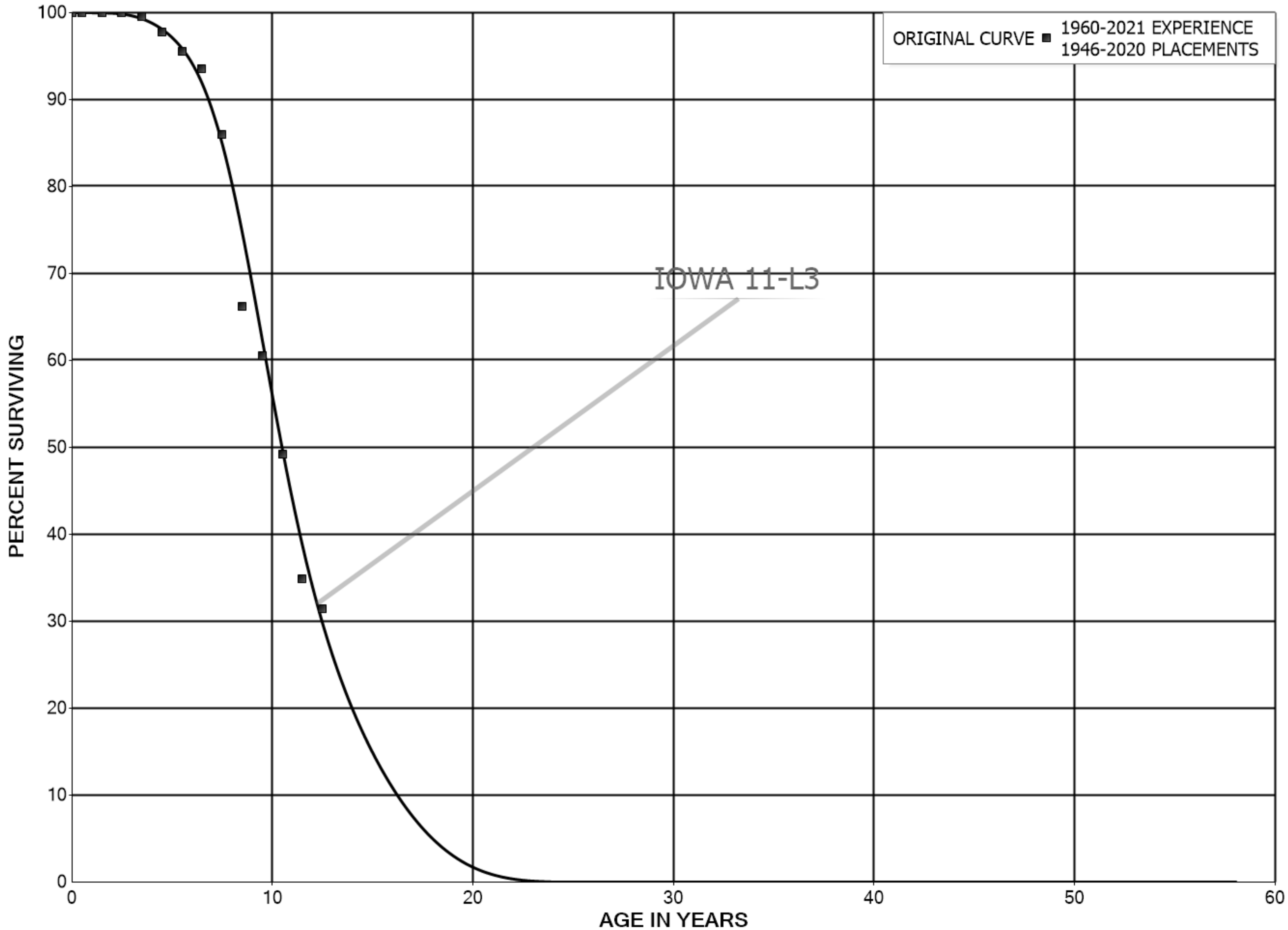
ACCOUNT 392.1 - TRANSPORTATION EQUIPMENT - CARS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1953-2021 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,461,493		0.0000	1.0000	100.00
0.5	1,232,051	5,156	0.0042	0.9958	100.00
1.5	1,101,712	25,842	0.0235	0.9765	99.58
2.5	1,058,867	39,899	0.0377	0.9623	97.25
3.5	1,028,819	79,215	0.0770	0.9230	93.58
4.5	959,281	251,179	0.2618	0.7382	86.38
5.5	708,102	238,696	0.3371	0.6629	63.76
6.5	471,642	253,123	0.5367	0.4633	42.27
7.5	218,519	107,400	0.4915	0.5085	19.58
8.5	111,118	39,127	0.3521	0.6479	9.96
9.5	71,992	9,961	0.1384	0.8616	6.45
10.5	62,031	14,504	0.2338	0.7662	5.56
11.5	47,527		0.0000	1.0000	4.26
12.5	47,527		0.0000	1.0000	4.26
13.5	47,527		0.0000	1.0000	4.26
14.5	47,527		0.0000	1.0000	4.26
15.5	47,527	23,426	0.4929	0.5071	4.26
16.5	24,102	12,438	0.5161	0.4839	2.16
17.5	11,664		0.0000	1.0000	1.05
18.5	11,664		0.0000	1.0000	1.05
19.5	11,664		0.0000	1.0000	1.05
20.5	11,664		0.0000	1.0000	1.05
21.5	11,664		0.0000	1.0000	1.05
22.5	11,664		0.0000	1.0000	1.05
23.5	11,664		0.0000	1.0000	1.05
24.5	11,664		0.0000	1.0000	1.05
25.5	11,664		0.0000	1.0000	1.05
26.5	11,664	11,634	0.9975	0.0025	1.05
27.5	29		0.0000	1.0000	0.00
28.5	29		0.0000	1.0000	0.00
29.5	29		0.0000	1.0000	0.00
30.5	29		0.0000	1.0000	0.00
31.5	29		0.0000	1.0000	0.00
32.5	29		0.0000	1.0000	0.00
33.5	29		0.0000	1.0000	0.00
34.5	29	29	1.0000		0.00
35.5					

UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 392.2 - TRANSPORTATION EQUIPMENT - LIGHT TRUCKS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - ELECTRIC DIVISION

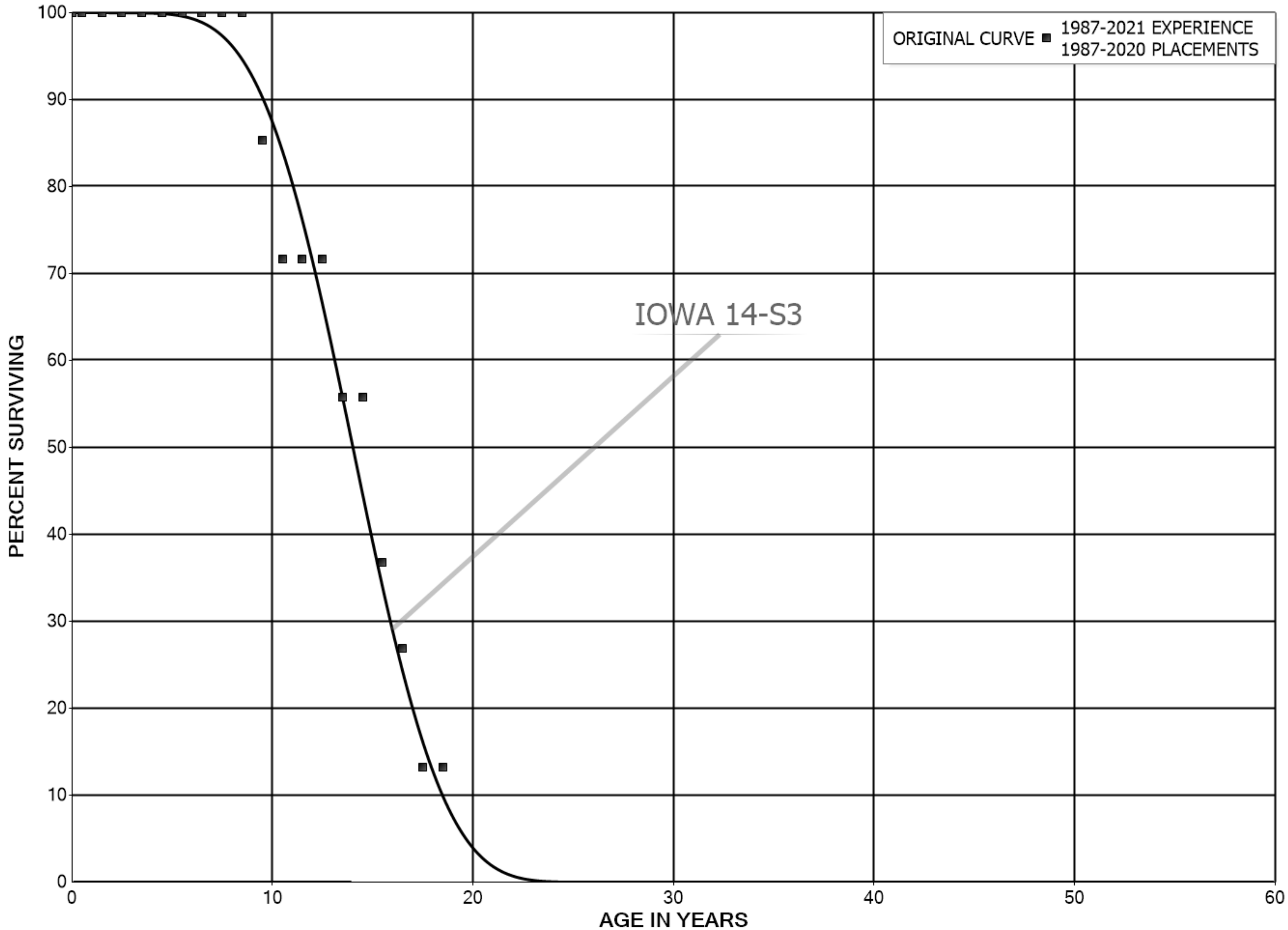
ACCOUNT 392.2 - TRANSPORTATION EQUIPMENT – LIGHT TRUCKS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1946-2020 EXPERIENCE BAND 1960-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,380,085		0.0000	1.0000	100.00
0.5	1,383,211		0.0000	1.0000	100.00
1.5	1,102,661		0.0000	1.0000	100.00
2.5	1,102,479	5,856	0.0053	0.9947	100.00
3.5	1,100,759	19,417	0.0176	0.9824	99.47
4.5	1,056,859	24,159	0.0229	0.9771	97.71
5.5	1,036,199	21,479	0.0207	0.9793	95.48
6.5	1,018,383	82,849	0.0814	0.9186	93.50
7.5	935,534	214,762	0.2296	0.7704	85.89
8.5	723,423	61,571	0.0851	0.9149	66.18
9.5	661,851	124,094	0.1875	0.8125	60.54
10.5	538,963	157,175	0.2916	0.7084	49.19
11.5	381,788	37,391	0.0979	0.9021	34.85
12.5	332,573	2,021	0.0061	0.9939	31.43
13.5	332,224	8,338	0.0251	0.9749	31.24
14.5	323,887	60,970	0.1882	0.8118	30.46
15.5	262,916	45,354	0.1725	0.8275	24.73
16.5	217,562	77,068	0.3542	0.6458	20.46
17.5	140,494	3,995	0.0284	0.9716	13.21
18.5	136,499		0.0000	1.0000	12.84
19.5	136,499		0.0000	1.0000	12.84
20.5	136,499	15,840	0.1160	0.8840	12.84
21.5	120,659	8,561	0.0710	0.9290	11.35
22.5	112,098	12,632	0.1127	0.8873	10.54
23.5	99,466	13,290	0.1336	0.8664	9.35
24.5	86,177	11,229	0.1303	0.8697	8.10
25.5	74,947	34,918	0.4659	0.5341	7.05
26.5	40,029		0.0000	1.0000	3.76
27.5	40,029	22,908	0.5723	0.4277	3.76
28.5	17,121		0.0000	1.0000	1.61
29.5	17,121	14,525	0.8484	0.1516	1.61
30.5	2,596		0.0000	1.0000	0.24
31.5	2,596	2,121	0.8172	0.1828	0.24
32.5	474		0.0000	1.0000	0.04
33.5	474	98	0.2068	0.7932	0.04
34.5	376	205	0.5455	0.4545	0.04
35.5	171		0.0000	1.0000	0.02
36.5	171	171	1.0000		0.02
37.5					

UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 392.4 - TRANSPORTATION EQUIPMENT - HEAVY TRUCKS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - ELECTRIC DIVISION

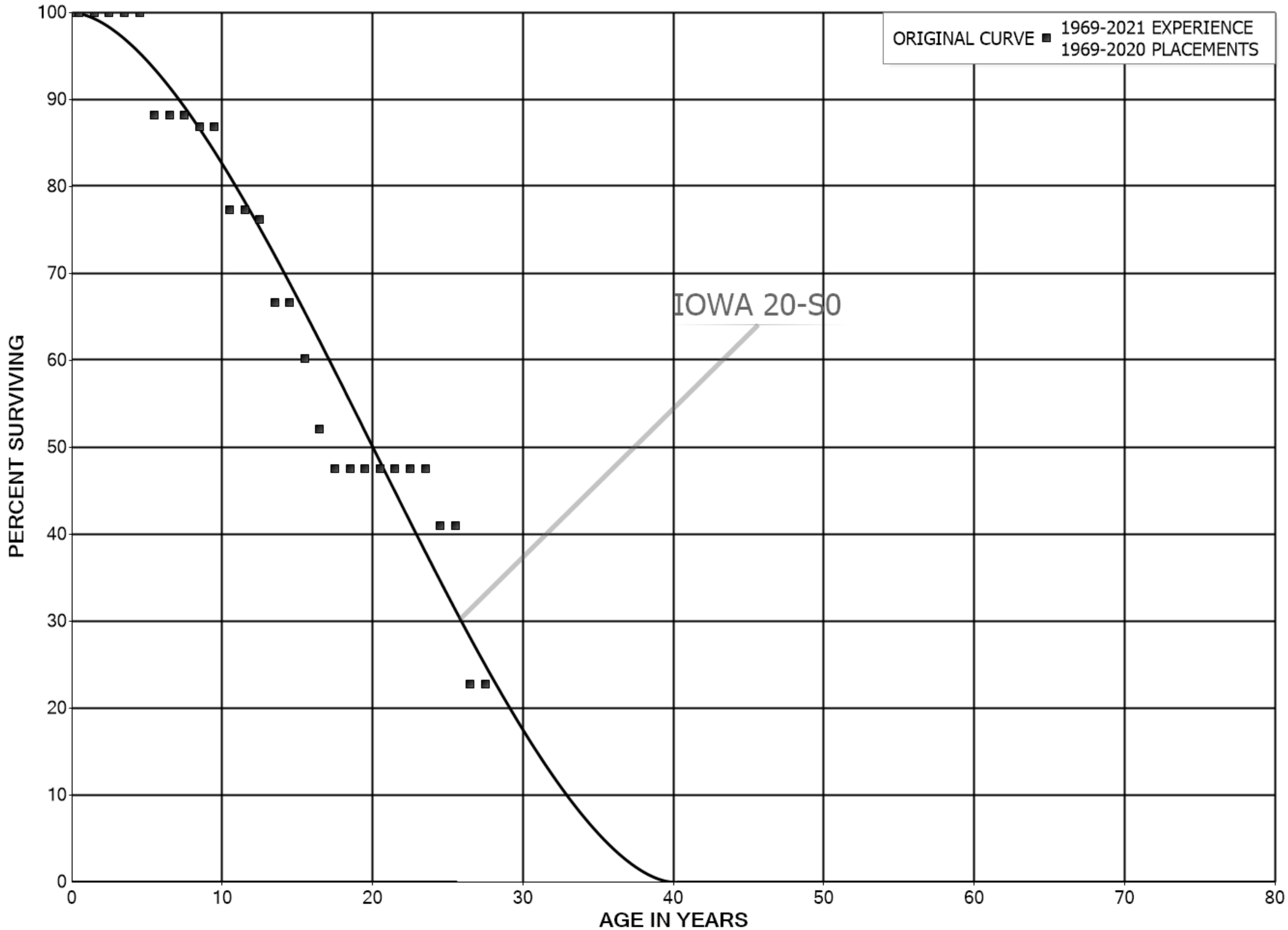
ACCOUNT 392.4 - TRANSPORTATION EQUIPMENT - HEAVY TRUCKS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1987-2020 EXPERIENCE BAND 1987-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	381,748		0.0000	1.0000	100.00
0.5	381,748		0.0000	1.0000	100.00
1.5	245,064		0.0000	1.0000	100.00
2.5	245,064		0.0000	1.0000	100.00
3.5	245,064		0.0000	1.0000	100.00
4.5	245,064		0.0000	1.0000	100.00
5.5	245,064		0.0000	1.0000	100.00
6.5	245,064		0.0000	1.0000	100.00
7.5	245,064		0.0000	1.0000	100.00
8.5	245,064	35,956	0.1467	0.8533	100.00
9.5	209,108	33,600	0.1607	0.8393	85.33
10.5	175,509		0.0000	1.0000	71.62
11.5	175,509		0.0000	1.0000	71.62
12.5	175,509	39,081	0.2227	0.7773	71.62
13.5	136,428		0.0000	1.0000	55.67
14.5	136,428	46,482	0.3407	0.6593	55.67
15.5	89,946	24,107	0.2680	0.7320	36.70
16.5	65,839	33,485	0.5086	0.4914	26.87
17.5	32,354		0.0000	1.0000	13.20
18.5	32,354		0.0000	1.0000	13.20
19.5	32,354		0.0000	1.0000	13.20
20.5	32,354		0.0000	1.0000	13.20
21.5	32,354		0.0000	1.0000	13.20
22.5	32,354		0.0000	1.0000	13.20
23.5	32,354	32,354	1.0000		13.20
24.5					

UGI UTILITIES, INC. - ELECTRIC DIVISION
ACCOUNT 396 - POWER OPERATED EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 396 - POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2020 EXPERIENCE BAND 1969-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	332,455		0.0000	1.0000	100.00
0.5	332,455		0.0000	1.0000	100.00
1.5	236,503		0.0000	1.0000	100.00
2.5	236,503		0.0000	1.0000	100.00
3.5	277,286		0.0000	1.0000	100.00
4.5	277,286	32,890	0.1186	0.8814	100.00
5.5	244,396		0.0000	1.0000	88.14
6.5	244,396		0.0000	1.0000	88.14
7.5	244,396	3,500	0.0143	0.9857	88.14
8.5	240,896		0.0000	1.0000	86.88
9.5	240,896	26,583	0.1103	0.8897	86.88
10.5	214,314		0.0000	1.0000	77.29
11.5	214,314	3,106	0.0145	0.9855	77.29
12.5	211,208	26,505	0.1255	0.8745	76.17
13.5	211,285		0.0000	1.0000	66.61
14.5	211,285	20,343	0.0963	0.9037	66.61
15.5	190,942	25,746	0.1348	0.8652	60.20
16.5	165,196	14,541	0.0880	0.9120	52.08
17.5	150,655		0.0000	1.0000	47.50
18.5	150,655		0.0000	1.0000	47.50
19.5	150,655		0.0000	1.0000	47.50
20.5	150,655		0.0000	1.0000	47.50
21.5	150,655		0.0000	1.0000	47.50
22.5	150,655		0.0000	1.0000	47.50
23.5	150,655	20,778	0.1379	0.8621	47.50
24.5	129,877		0.0000	1.0000	40.95
25.5	129,877	57,765	0.4448	0.5552	40.95
26.5	72,112		0.0000	1.0000	22.73
27.5	72,112		0.0000	1.0000	22.73
28.5	72,112	15,573	0.2160	0.7840	22.73
29.5	56,539		0.0000	1.0000	17.82
30.5	56,539		0.0000	1.0000	17.82
31.5	56,539		0.0000	1.0000	17.82
32.5	56,539		0.0000	1.0000	17.82
33.5	56,539		0.0000	1.0000	17.82
34.5	56,539		0.0000	1.0000	17.82
35.5	56,539		0.0000	1.0000	17.82
36.5	56,539		0.0000	1.0000	17.82
37.5	56,539		0.0000	1.0000	17.82
38.5	56,539	52,830	0.9344	0.0656	17.82

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 396 - POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2020 EXPERIENCE BAND 1969-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,709	2,345	0.6323	0.3677	1.17
40.5	1,364		0.0000	1.0000	0.43
41.5	1,364		0.0000	1.0000	0.43
42.5	1,364		0.0000	1.0000	0.43
43.5	1,364		0.0000	1.0000	0.43
44.5	1,364		0.0000	1.0000	0.43
45.5	1,364		0.0000	1.0000	0.43
46.5	1,364	1,040	0.7623	0.2377	0.43
47.5	324	324	1.0000		0.10
48.5					

PART VII. DETAILED DEPRECIATION CALCULATIONS

CUMULATIVE DEPRECIATED ORIGINAL COST

ELECTRIC PLANT

UGI UTILITIES, INC. - ELECTRIC DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1917	7,399	7,364	35	35	0.0
1918	8	8		35	0.0
1919	7,211	7,110	101	136	0.0
1920	5,477	5,444	33	169	0.0
1921	450	394	56	225	0.0
1922	46	46		225	0.0
1923	12,697	12,554	143	368	0.0
1924	4,425	4,412	13	381	0.0
1925	6,111	6,050	61	442	0.0
1926	11,275	11,257	18	460	0.0
1927	4,971	4,843	128	588	0.0
1928	3,073	2,979	94	682	0.0
1929	23,937	23,916	21	703	0.0
1930	6,124	5,672	452	1,155	0.0
1931	862	837	25	1,180	0.0
1932	4,660	4,463	197	1,377	0.0
1933	15,088	14,126	962	2,339	0.0
1934	15,851	14,707	1,144	3,483	0.0
1935	18,535	17,354	1,181	4,664	0.0
1936	23,507	21,356	2,151	6,815	0.0
1937	13,139	12,257	882	7,697	0.0
1938	12,788	11,684	1,104	8,801	0.0
1939	21,693	19,593	2,100	10,901	0.0
1940	19,271	17,451	1,820	12,721	0.0
1941	25,655	23,619	2,036	14,757	0.0
1942	17,367	16,268	1,099	15,856	0.0
1943	20,045	18,080	1,965	17,821	0.0
1944	18,578	16,704	1,874	19,695	0.0
1945	23,749	21,217	2,532	22,227	0.0
1946	42,396	37,350	5,046	27,273	0.0
1947	47,456	41,216	6,240	33,513	0.0
1948	67,575	59,749	7,826	41,339	0.0
1949	74,355	65,111	9,244	50,583	0.0
1950	66,621	55,893	10,728	61,311	0.0
1951	79,447	67,512	11,935	73,246	0.0
1952	73,776	61,221	12,555	85,801	0.1
1953	52,968	44,381	8,587	94,388	0.1
1954	74,369	62,865	11,504	105,892	0.1
1955	133,085	113,538	19,547	125,439	0.1
1956	90,234	72,152	18,082	143,521	0.1
1957	118,005	98,700	19,305	162,826	0.1
1958	169,709	146,223	23,486	186,312	0.1
1959	133,638	110,763	22,875	209,187	0.1
1960	99,360	81,716	17,644	226,831	0.1
1961	143,124	114,971	28,153	254,984	0.2
1962	153,169	120,198	32,971	287,955	0.2

UGI UTILITIES, INC. - ELECTRIC DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1963	185,569	146,669	38,900	326,855	0.2
1964	239,845	188,790	51,055	377,910	0.2
1965	294,389	225,355	69,034	446,944	0.3
1966	269,449	210,005	59,444	506,388	0.3
1967	348,247	276,927	71,320	577,708	0.4
1968	426,649	343,767	82,882	660,590	0.4
1969	649,809	504,776	145,033	805,623	0.5
1970	716,214	568,256	147,958	953,581	0.6
1971	802,660	625,202	177,458	1,131,039	0.7
1972	845,097	690,704	154,393	1,285,432	0.8
1973	943,411	732,947	210,464	1,495,896	0.9
1974	1,033,557	764,941	268,616	1,764,512	1.1
1975	1,177,778	876,336	301,442	2,065,954	1.3
1976	959,400	708,397	251,003	2,316,957	1.4
1977	1,138,114	801,719	336,395	2,653,352	1.6
1978	1,084,646	765,124	319,522	2,972,874	1.8
1979	1,241,924	879,651	362,273	3,335,147	2.1
1980	1,080,818	762,207	318,611	3,653,758	2.3
1981	977,802	659,047	318,755	3,972,513	2.5
1982	1,130,433	874,610	255,823	4,228,336	2.6
1983	1,036,909	790,920	245,989	4,474,325	2.8
1984	1,001,774	757,851	243,923	4,718,248	2.9
1985	1,142,437	873,343	269,094	4,987,342	3.1
1986	1,269,482	936,566	332,916	5,320,258	3.3
1987	1,396,570	1,012,170	384,400	5,704,658	3.5
1988	1,696,226	1,192,283	503,943	6,208,601	3.8
1989	2,158,740	1,472,672	686,068	6,894,669	4.3
1990	2,231,415	1,503,929	727,486	7,622,155	4.7
1991	2,493,940	1,628,689	865,251	8,487,406	5.2
1992	3,008,516	1,931,877	1,076,639	9,564,045	5.9
1993	2,209,579	1,395,364	814,215	10,378,260	6.4
1994	2,776,348	1,706,100	1,070,248	11,448,508	7.1
1995	3,820,913	2,260,995	1,559,918	13,008,426	8.0
1996	3,687,594	2,152,323	1,535,271	14,543,697	9.0
1997	3,593,759	2,102,222	1,491,537	16,035,234	9.9
1998	3,319,233	1,873,111	1,446,122	17,481,356	10.8
1999	3,036,291	1,746,149	1,290,142	18,771,498	11.6
2000	2,716,113	1,489,020	1,227,093	19,998,591	12.3
2001	3,221,905	1,637,186	1,584,719	21,583,310	13.3
2002	2,809,045	1,358,787	1,450,258	23,033,568	14.2
2003	2,999,120	1,417,848	1,581,272	24,614,840	15.2
2004	3,398,063	1,602,473	1,795,590	26,410,430	16.3
2005	4,500,374	2,010,032	2,490,342	28,900,772	17.8
2006	3,335,930	1,426,306	1,909,624	30,810,396	19.0
2007	6,137,898	3,505,102	2,632,796	33,443,192	20.6
2008	5,243,295	2,012,183	3,231,112	36,674,304	22.6

UGI UTILITIES, INC. - ELECTRIC DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2009	3,510,509	1,187,067	2,323,442	38,997,746	24.1
2010	3,102,468	1,004,269	2,098,199	41,095,945	25.4
2011	3,527,618	1,138,816	2,388,802	43,484,747	26.8
2012	3,555,328	1,015,914	2,539,414	46,024,161	28.4
2013	4,920,333	1,270,708	3,649,625	49,673,786	30.6
2014	5,048,177	1,220,403	3,827,774	53,501,560	33.0
2015	5,652,067	1,258,687	4,393,380	57,894,940	35.7
2016	8,550,496	1,744,649	6,805,847	64,700,787	39.9
2017	9,531,371	1,579,623	7,951,748	72,652,535	44.8
2018	8,449,615	1,359,570	7,090,045	79,742,580	49.2
2019	16,598,777	2,160,119	14,438,658	94,181,238	58.1
2020	14,900,237	1,719,238	13,180,999	107,362,237	66.2
2021	12,100,497	936,004	11,164,493	118,526,730	73.1
2022	22,861,873	1,726,540	21,135,333	139,662,063	86.2
2023	22,890,565	460,389	22,430,176	162,092,239	100.0
TOTAL	236,950,490	74,858,251	162,092,239		

COMMON PLANT

UGI UTILITIES, INC. - COMMON PLANT

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1952					0.0
1953					0.0
2004	38,772	37,359	1,413	1,413	0.0
2005	39,966	33,411	6,555	7,968	0.0
2006	2,469	1,952	517	8,485	0.0
2007	878	654	224	8,709	0.0
2008	23,109	22,937	172	8,881	0.0
2009	4,753	3,114	1,639	10,520	0.0
2010	747,319	455,898	291,421	301,941	0.8
2014	22,225	22,225		301,941	0.8
2017				301,941	0.8
2019	33,790,493	4,606,114	29,184,379	29,486,320	80.7
2020	1,945,898	196,540	1,749,358	31,235,678	85.5
2021	1,730,955	502,904	1,228,051	32,463,729	88.8
2022	4,030,382	210,267	3,820,115	36,283,844	99.3
2023	266,566	5,381	261,185	36,545,029	100.0
SUBTOTAL	42,643,785	6,098,756	36,545,029		
NONDEPRECIABLE	7,086,071		7,086,071		
TOTAL	49,729,856	6,098,756	43,631,100		

INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2004	5,699	5,552	147	147	0.0
2007	1,760	1,451	309	456	0.0
2011	425,873	351,472	74,401	74,857	0.1
2012	401,290	304,691	96,599	171,456	0.1
2013	142,365	98,694	43,671	215,127	0.2
2014	1,430,788	1,160,547	270,241	485,368	0.4
2015	732,103	595,148	136,955	622,323	0.5
2016	2,349,695	1,370,181	979,514	1,601,837	1.2
2017	77,621,819	33,571,459	44,050,360	45,652,197	33.6
2018	1,545,759	785,088	760,671	46,412,868	34.2
2019	74,177,124	29,201,309	44,975,815	91,388,683	67.3
2020	14,501,914	5,577,325	8,924,589	100,313,272	73.9
2021	15,645,524	3,440,614	12,204,910	112,518,182	82.9
2022	13,473,468	2,199,096	11,274,372	123,792,554	91.2
2023	12,571,538	564,769	12,006,769	135,799,323	100.0
TOTAL	215,026,719	79,227,396	135,799,323		

EMPIRE YARD

UGI UTILITIES, INC. - ELECTRIC DIVISION - EMPIRE YARD

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1960	127,875	106,017	21,858	21,858	0.4
1961	88,759	69,614	19,145	41,003	0.7
1962	151,954	120,303	31,651	72,654	1.2
1963	9,442	7,280	2,162	74,816	1.2
1964	3,887	3,030	857	75,673	1.2
1965	957	844	113	75,786	1.2
1966	296	225	71	75,857	1.2
1967	857	646	211	76,068	1.2
1968	3,557	2,669	888	76,956	1.3
1969	659	492	167	77,123	1.3
1970	2,317	1,717	600	77,723	1.3
1971	74,575	54,944	19,631	97,354	1.6
1972	10,108	8,697	1,411	98,765	1.6
1973	65,182	63,588	1,594	100,359	1.6
1974	1,074	776	298	100,657	1.6
1975	20,047	14,377	5,670	106,327	1.7
1976	98,759	70,526	28,233	134,560	2.2
1977	270,812	194,061	76,751	211,311	3.4
1978	38,942	34,518	4,424	215,735	3.5
1979	31,763	22,263	9,500	225,235	3.7
1980	58,831	43,305	15,526	240,761	3.9
1981	101,251	85,833	15,418	256,179	4.2
1982	38,345	33,915	4,430	260,609	4.3
1983	15,874	11,357	4,517	265,126	4.3
1984	58,889	45,162	13,727	278,853	4.5
1985	68,562	48,082	20,480	299,333	4.9
1986	250,911	183,984	66,927	366,260	6.0
1987	106,836	77,134	29,702	395,962	6.5
1988	94,509	69,443	25,066	421,028	6.9
1989	142,145	98,610	43,535	464,563	7.6
1990	95,808	95,316	492	465,055	7.6
1991	12,725	8,351	4,374	469,429	7.7
1992	114,077	75,870	38,207	507,636	8.3
1993	240,016	154,018	85,998	593,634	9.7
1994	48,066	44,641	3,425	597,059	9.7
1995	137,390	86,821	50,569	647,628	10.6
1996	78,977	48,740	30,237	677,865	11.1
1997	4,615,574	2,765,307	1,850,267	2,528,132	41.2
1998	283,485	168,016	115,469	2,643,601	43.1
1999	84,689	48,723	35,966	2,679,567	43.7
2000	89,552	50,568	38,984	2,718,551	44.3
2001	730,424	406,889	323,535	3,042,086	49.6
2002	50,866	31,477	19,389	3,061,475	49.9
2003	207,391	121,944	85,447	3,146,922	51.3
2004	408,577	337,299	71,278	3,218,200	52.5
2005	194,897	111,101	83,796	3,301,996	53.9

UGI UTILITIES, INC. - ELECTRIC DIVISION - EMPIRE YARD

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2006	139,745	67,349	72,396	3,374,392	55.0
2007	875,480	407,330	468,150	3,842,542	62.7
2008	108,455	64,844	43,611	3,886,153	63.4
2009	54,032	23,302	30,730	3,916,883	63.9
2010	385,242	270,302	114,940	4,031,823	65.8
2011	531,835	341,202	190,633	4,222,456	68.9
2012	49,336	18,364	30,972	4,253,428	69.4
2013	122,473	42,898	79,575	4,333,003	70.7
2014	183,409	73,285	110,124	4,443,127	72.5
2015	94,751	28,717	66,034	4,509,161	73.5
2016	644,139	204,477	439,662	4,948,823	80.7
2017	101,077	57,390	43,687	4,992,510	81.4
2018	130,187	74,144	56,043	5,048,553	82.3
2019	845,719	840,239	5,480	5,054,033	82.4
2020	45,607	6,886	38,721	5,092,754	83.1
2021	221,161	25,045	196,116	5,288,870	86.3
2022	780,865	200,517	580,348	5,869,218	95.7
2023	269,151	7,089	262,062	6,131,280	100.0
TOTAL	14,913,153	8,781,873	6,131,280		

UTILITY PLANT IN SERVICE

ELECTRIC PLANT

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. 0						
1925	4,675.49	4,675	4,675			
1926	1,561.20	1,561	1,561			
1943	642.32	629	453	189	1.01	187
1971	7,177.62	5,874	4,229	2,949	9.08	325
1975	12,539.90	9,796	7,052	5,488	10.94	502
1977	485.00	369	266	219	11.98	18
2018	50,277.08	6,249	4,499	45,778	38.75	1,181
2019	240,869.72	24,617	17,722	223,148	39.55	5,642
2020	34,409.01	2,746	1,977	32,432	40.36	804
2021	163,744.75	9,415	6,777	156,968	40.98	3,830
2022	111,114.35	3,867	2,784	108,330	41.60	2,604
	627,496.44	69,798	51,995	575,501		15,093

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.1   2.41

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 362 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-S1						
NET SALVAGE PERCENT.. 0						
1924	2,689.19	2,689	2,689			
1925	879.69	880	880			
1926	6,245.32	6,245	6,245			
1927	828.03	828	828			
1929	15,903.19	15,903	15,903			
1937	398.62	399	399			
1938	221.63	222	222			
1939	209.07	209	209			
1941	653.48	653	653			
1942	4,256.28	4,256	4,256			
1944	1,651.50	1,642	1,362	290	0.23	290
1945	168.42	166	138	30	0.47	30
1948	2,558.95	2,478	2,056	503	1.27	396
1949	925.90	890	738	188	1.54	122
1950	9,560.45	9,128	7,574	1,986	1.81	1,097
1951	6,855.53	6,497	5,391	1,465	2.09	701
1952	19,840.84	18,665	15,487	4,354	2.37	1,837
1955	3,969.94	3,651	3,029	941	3.21	293
1956	4,289.45	3,914	3,248	1,041	3.50	297
1957	940.26	851	706	234	3.79	62
1958	31,710.12	28,468	23,622	8,088	4.09	1,978
1959	11,224.11	9,995	8,293	2,931	4.38	669
1960	4,923.72	4,348	3,608	1,316	4.68	281
1961	9,084.01	7,951	6,597	2,487	4.99	498
1962	31,953.13	27,727	23,007	8,946	5.29	1,691
1963	5,578.92	4,798	3,981	1,598	5.60	285
1964	6,054.15	5,158	4,280	1,774	5.92	300
1965	4,470.56	3,774	3,132	1,339	6.23	215
1966	3,370.38	2,818	2,338	1,032	6.55	158
1967	25,433.75	21,059	17,474	7,960	6.88	1,157
1968	3,067.84	2,515	2,087	981	7.21	136
1969	40,013.65	32,471	26,943	13,071	7.54	1,734
1970	1,822.52	1,463	1,214	609	7.88	77
1971	733.85	583	484	250	8.22	30
1972	24,398.08	19,177	15,912	8,486	8.56	991
1973	2,761.76	2,146	1,781	981	8.92	110
1974	2,816.13	2,163	1,795	1,021	9.27	110
1975	5,699.01	4,327	3,590	2,109	9.63	219
1976	1,025.60	769	638	388	10.00	39
1977	7,267.62	5,383	4,467	2,801	10.37	270
1978	516.60	378	314	203	10.75	19
1982	3,021.86	2,381	1,976	1,046	11.10	94
1984	2,662.71	2,048	1,699	964	11.77	82

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 362 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-S1						
NET SALVAGE PERCENT.. 0						
1991	20,696.62	14,417	11,963	8,734	14.05	622
1997	24,264.83	15,047	12,485	11,780	16.24	725
2008	8,578.38	3,630	3,012	5,566	21.13	263
2011	2,254.74	803	666	1,589	22.59	70
2015	60,439.54	15,364	12,748	47,692	24.94	1,912
2016	16,191.46	3,679	3,053	13,138	25.50	515
2017	1,267,638.55	252,133	209,209	1,058,430	26.18	40,429
2018	226,510.46	38,507	31,951	194,559	26.86	7,243
2019	2,526,821.41	353,755	293,530	2,233,291	27.65	80,770
2020	1,494,030.62	164,194	136,241	1,357,790	28.35	47,894
2021	1,118,844.77	88,389	73,341	1,045,504	29.15	35,866
2022	3,899,657.98	185,624	154,023	3,745,635	30.04	124,688
2023	284,660.21	4,526	3,755	280,905	30.95	9,076
	11,263,245.39	1,412,134	1,177,222	10,086,023		366,341

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.5   3.25

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 364 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

SURVIVOR CURVE.. IOWA 59-R2.5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1919	6,463.95	6,314	6,464			
1920	5,249.44	5,104	5,249			
1921	62.69	61	63			
1922	46.32	45	46			
1923	201.24	193	201			
1924	123.98	118	124			
1926	1,487.96	1,405	1,471	17	3.27	5
1927	1,169.11	1,099	1,150	19	3.53	5
1928	1,325.37	1,241	1,299	26	3.77	7
1929	845.37	788	825	20	4.01	5
1930	3,004.22	2,788	2,918	86	4.24	20
1931	368.69	341	357	12	4.47	3
1932	2,916.72	2,685	2,810	107	4.69	23
1933	6,919.07	6,343	6,639	280	4.91	57
1934	5,961.83	5,444	5,698	264	5.12	52
1935	12,339.80	11,223	11,747	593	5.34	111
1936	14,756.97	13,366	13,990	767	5.56	138
1937	6,970.69	6,288	6,582	389	5.78	67
1938	3,616.51	3,249	3,401	216	6.00	36
1939	5,473.72	4,896	5,125	349	6.23	56
1940	7,436.74	6,622	6,931	506	6.46	78
1941	15,332.07	13,594	14,229	1,103	6.69	165
1942	10,635.32	9,386	9,824	811	6.93	117
1943	14,771.88	12,979	13,585	1,187	7.16	166
1944	13,274.32	11,609	12,151	1,123	7.40	152
1945	15,592.54	13,571	14,205	1,388	7.65	181
1946	21,530.67	18,648	19,519	2,012	7.90	255
1947	15,862.44	13,671	14,309	1,553	8.15	191
1948	24,345.33	20,875	21,850	2,495	8.41	297
1949	18,829.19	16,059	16,809	2,020	8.68	233
1950	17,430.85	14,784	15,474	1,957	8.96	218
1951	33,776.11	28,486	29,816	3,960	9.24	429
1952	24,839.14	20,827	21,800	3,039	9.53	319
1953	22,404.53	18,672	19,544	2,861	9.83	291
1954	26,640.27	22,057	23,087	3,553	10.15	350
1955	41,670.81	34,276	35,877	5,794	10.47	553
1956	28,628.93	23,384	24,476	4,153	10.81	384
1957	26,336.89	21,360	22,357	3,980	11.15	357
1958	44,975.99	36,194	37,884	7,092	11.52	616
1959	45,466.51	36,304	37,999	7,468	11.89	628
1960	37,017.06	29,312	30,681	6,336	12.28	516
1961	52,674.80	41,354	43,285	9,390	12.68	741
1962	44,578.09	34,680	36,299	8,279	13.10	632

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 364 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 59-R2.5						
NET SALVAGE PERCENT.. 0						
1963	60,880.52	46,909	49,099	11,782	13.54	870
1964	62,379.38	47,599	49,822	12,557	13.98	898
1965	101,550.75	76,679	80,260	21,291	14.45	1,473
1966	77,759.25	58,095	60,808	16,951	14.92	1,136
1967	58,397.09	43,134	45,148	13,249	15.42	859
1968	91,041.47	66,476	69,580	21,461	15.92	1,348
1969	133,536.36	96,328	100,826	32,710	16.44	1,990
1970	160,758.68	114,492	119,838	40,921	16.98	2,410
1971	216,765.25	152,360	159,475	57,290	17.53	3,268
1972	158,046.27	109,588	114,705	43,341	18.09	2,396
1973	237,670.85	162,462	170,048	67,623	18.67	3,622
1974	314,702.45	211,971	221,869	92,833	19.26	4,820
1975	247,321.75	164,071	171,732	75,590	19.86	3,806
1976	264,975.41	173,042	181,122	83,853	20.47	4,096
1977	289,293.68	185,834	194,512	94,782	21.10	4,492
1978	317,398.40	200,497	209,859	107,539	21.73	4,949
1979	383,513.10	238,039	249,154	134,359	22.38	6,004
1980	275,920.09	168,171	176,024	99,896	23.04	4,336
1981	266,487.01	159,397	166,840	99,647	23.71	4,203
1982	281,250.06	184,472	193,086	88,164	21.64	4,074
1983	314,794.04	202,727	212,193	102,601	22.25	4,611
1984	327,313.62	206,829	216,487	110,827	22.86	4,848
1985	306,016.37	189,608	198,462	107,554	23.48	4,581
1986	372,911.48	226,432	237,005	135,906	24.10	5,639
1987	445,446.16	264,818	277,184	168,262	24.73	6,804
1988	465,998.46	271,025	283,681	182,317	25.36	7,189
1989	692,311.33	393,648	412,030	280,281	25.99	10,784
1990	662,014.31	369,801	387,069	274,945	26.27	10,466
1991	729,835.19	397,760	416,334	313,501	26.92	11,646
1992	975,899.86	518,398	542,605	433,295	27.58	15,710
1993	749,955.64	388,852	407,010	342,946	28.32	12,110
1994	961,026.98	487,625	510,395	450,632	28.64	15,734
1995	1,302,137.74	641,954	671,930	630,208	29.31	21,501
1996	1,260,188.59	603,000	631,157	629,032	29.97	20,989
1997	955,062.92	442,958	463,642	491,421	30.64	16,039
1998	926,977.81	416,028	435,455	491,523	31.32	15,694
1999	775,579.93	336,291	351,994	423,586	32.00	13,237
2000	704,324.09	294,619	308,376	395,948	32.68	12,116
2001	949,056.33	382,280	400,131	548,925	33.36	16,455
2002	816,541.79	316,002	330,758	485,784	34.06	14,263
2003	973,262.81	361,081	377,942	595,321	34.75	17,132
2004	1,102,507.81	393,375	411,744	690,764	35.15	19,652
2005	1,120,350.91	381,367	399,175	721,176	35.85	20,116

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 364 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 59-R2.5						
NET SALVAGE PERCENT.. 0						
2006	1,079,312.49	349,481	365,800	713,512	36.55	19,522
2007	881,559.87	270,551	283,184	598,376	37.26	16,059
2008	1,075,158.14	311,581	326,130	749,028	37.98	19,722
2009	1,068,021.58	291,143	304,738	763,284	38.69	19,728
2010	1,013,157.87	259,875	272,010	741,148	39.13	18,941
2011	1,376,057.34	328,602	343,946	1,032,111	39.85	25,900
2012	866,536.63	191,331	200,265	666,272	40.58	16,419
2013	1,186,775.65	241,746	253,034	933,742	41.05	22,746
2014	1,691,447.92	313,256	327,884	1,363,564	41.78	32,637
2015	1,561,322.95	261,365	273,570	1,287,753	42.26	30,472
2016	1,805,233.00	269,341	281,918	1,523,315	42.75	35,633
2017	2,229,825.64	289,877	303,413	1,926,413	43.50	44,285
2018	1,676,538.90	186,263	194,961	1,481,578	44.00	33,672
2019	4,181,538.10	385,538	403,540	3,777,998	44.28	85,321
2020	2,965,917.66	215,919	226,001	2,739,917	44.58	61,461
2021	2,991,598.86	157,956	165,332	2,826,267	44.89	62,960
2022	3,801,612.79	123,933	129,720	3,671,893	44.58	82,366
2023	1,023,168.59	11,664	12,209	1,010,960	43.17	23,418
	55,047,300.10	16,177,211	16,932,371	38,114,929		1,018,082

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.4   1.85

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

SURVIVOR CURVE.. IOWA 58-R1.5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1932	945.99	831	867	79	7.07	11
1933	7,331.53	6,404	6,679	653	7.34	89
1934	8,559.13	7,436	7,755	804	7.61	106
1935	4,851.41	4,192	4,372	479	7.88	61
1936	1,252.08	1,076	1,122	130	8.16	16
1937	3,202.62	2,737	2,854	349	8.44	41
1938	7,126.44	6,054	6,314	812	8.73	93
1939	14,197.25	11,989	12,503	1,694	9.02	188
1940	9,657.77	8,108	8,456	1,202	9.31	129
1941	6,807.08	5,679	5,922	885	9.61	92
1942	1,777.60	1,474	1,537	241	9.91	24
1943	4,066.50	3,351	3,495	572	10.21	56
1944	2,976.33	2,436	2,540	436	10.52	41
1945	7,039.44	5,724	5,969	1,070	10.84	99
1946	18,561.14	14,990	15,633	2,928	11.16	262
1947	26,998.17	21,654	22,582	4,416	11.48	385
1948	23,393.27	18,630	19,429	3,964	11.81	336
1949	35,719.19	28,237	29,447	6,272	12.15	516
1950	30,858.45	24,213	25,251	5,607	12.49	449
1951	28,975.38	22,566	23,533	5,442	12.83	424
1952	19,161.18	14,804	15,439	3,722	13.19	282
1953	19,270.73	14,769	15,402	3,869	13.55	286
1954	31,986.86	24,310	25,352	6,635	13.92	477
1955	51,398.47	38,726	40,386	11,012	14.30	770
1956	31,699.94	23,677	24,692	7,008	14.68	477
1957	47,071.50	34,841	36,335	10,736	15.07	712
1958	23,412.70	17,164	17,900	5,513	15.48	356
1959	31,074.11	22,561	23,528	7,546	15.89	475
1960	32,867.82	23,631	24,644	8,224	16.30	505
1961	52,549.45	37,392	38,995	13,554	16.73	810
1962	50,894.68	35,828	37,364	13,531	17.17	788
1963	75,659.84	52,688	54,947	20,713	17.61	1,176
1964	107,314.19	73,880	77,047	30,267	18.07	1,675
1965	89,856.33	61,149	63,770	26,086	18.53	1,408
1966	52,236.54	35,124	36,630	15,607	19.00	821
1967	60,650.71	40,281	42,008	18,643	19.48	957
1968	94,954.97	62,261	64,930	30,025	19.97	1,504
1969	203,568.31	131,723	137,370	66,198	20.47	3,234
1970	173,311.40	110,621	115,363	57,948	20.98	2,762
1971	201,043.13	126,553	131,978	69,065	21.49	3,214
1972	122,604.99	76,057	79,317	43,288	22.02	1,966
1973	160,418.83	98,021	102,223	58,196	22.56	2,580
1974	257,016.68	154,652	161,281	95,736	23.10	4,144

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 58-R1.5						
NET SALVAGE PERCENT.. 0						
1975	275,093.71	162,921	169,905	105,189	23.65	4,448
1976	214,072.11	124,716	130,062	84,010	24.21	3,470
1977	331,352.83	189,786	197,922	133,431	24.78	5,385
1978	246,384.62	138,655	144,599	101,786	25.36	4,014
1979	217,233.83	120,078	125,225	92,009	25.94	3,547
1980	158,513.98	85,980	89,666	68,848	26.54	2,594
1981	198,705.13	105,725	110,257	88,448	27.14	3,259
1982	207,656.60	131,052	136,670	70,987	24.11	2,944
1983	117,645.50	73,399	76,545	41,100	24.26	1,694
1984	95,761.81	58,635	61,149	34,613	24.85	1,393
1985	116,506.51	69,962	72,961	43,546	25.45	1,711
1986	155,055.60	91,266	95,178	59,878	26.04	2,299
1987	137,121.95	79,531	82,940	54,182	26.25	2,064
1988	248,433.90	140,986	147,030	101,404	26.86	3,775
1989	294,015.11	163,120	170,112	123,903	27.48	4,509
1990	320,301.52	174,660	182,147	138,155	27.73	4,982
1991	507,719.56	270,158	281,739	225,981	28.36	7,968
1992	633,693.80	328,760	342,853	290,841	28.99	10,032
1993	380,732.29	195,087	203,450	177,282	29.02	6,109
1994	527,519.12	263,021	274,296	253,223	29.67	8,535
1995	837,836.14	405,932	423,333	414,503	30.32	13,671
1996	814,770.98	385,387	401,907	412,864	30.64	13,475
1997	674,212.40	310,879	324,206	350,006	30.97	11,301
1998	684,509.75	305,428	318,521	365,989	31.65	11,564
1999	534,325.80	231,684	241,616	292,710	32.00	9,147
2000	428,618.73	179,291	186,977	241,642	32.68	7,394
2001	652,502.31	264,263	275,591	376,911	33.06	11,401
2002	450,207.68	176,166	183,718	266,490	33.45	7,967
2003	613,066.77	231,249	241,162	371,905	33.85	10,987
2004	600,341.74	217,744	227,078	373,264	34.26	10,895
2005	1,043,334.53	362,872	378,427	664,908	34.69	19,167
2006	712,729.33	236,983	247,142	465,587	35.13	13,253
2007	1,173,878.41	371,885	387,827	786,051	35.58	22,092
2008	1,213,805.89	364,991	380,637	833,169	36.05	23,111
2009	1,158,576.11	330,889	345,073	813,503	36.26	22,435
2010	848,056.98	227,788	237,553	610,504	36.75	16,612
2011	821,668.09	207,471	216,365	605,303	37.00	16,360
2012	1,288,532.93	303,836	316,861	971,672	37.28	26,064
2013	1,836,535.83	401,099	418,293	1,418,243	37.58	37,739
2014	1,749,814.25	350,663	365,695	1,384,119	37.90	36,520
2015	2,083,300.05	380,827	397,152	1,686,148	38.01	44,361
2016	2,373,541.67	389,736	406,443	1,967,099	38.16	51,549
2017	2,762,274.83	402,187	419,427	2,342,848	38.14	61,428

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 58-R1.5						
NET SALVAGE PERCENT.. 0						
2018	2,016,359.70	254,061	264,952	1,751,408	38.17	45,884
2019	4,219,926.92	448,156	467,367	3,752,560	37.87	99,091
2020	5,580,739.34	476,595	497,025	5,083,714	37.48	135,638
2021	3,764,439.72	239,042	249,289	3,515,151	36.87	95,339
2022	5,252,410.97	213,248	222,389	5,030,022	35.40	142,091
2023	15,749,070.40	245,685	256,217	15,492,853	31.65	489,506
	69,557,227.86	13,392,029	13,966,110	55,591,118		1,625,571

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 34.2 2.34

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 365.7 REG AFUDC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	711,827.21-	44,489-	99,348-	612,479-		16,333-
	711,827.21-	44,489-	99,348-	612,479-		16,333-
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					37.5	2.29

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 366 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. 0						
1923	11,558.71	11,151	11,559			
1925	37.18	36	37			
1928	977.05	924	977			
1955	321.43	264	313	8	11.66	1
1957	1,089.51	879	1,042	48	12.54	4
1966	171.19	126	149	22	17.19	1
1967	2,233.28	1,622	1,924	309	17.78	17
1968	5,305.30	3,805	4,512	793	18.38	43
1969	482.65	342	406	77	18.99	4
1970	3,078.47	2,149	2,549	529	19.62	27
1971	3,756.90	2,586	3,067	690	20.26	34
1972	7,229.66	4,904	5,816	1,414	20.91	68
1973	9,574.39	6,397	7,586	1,988	21.57	92
1974	12,540.35	8,248	9,782	2,758	22.25	124
1975	9,522.75	6,163	7,309	2,214	22.93	97
1976	14,345.28	9,130	10,827	3,518	23.63	149
1977	17,590.28	11,006	13,052	4,538	24.33	187
1978	25,021.43	15,379	18,238	6,783	25.05	271
1979	43,579.82	26,295	31,184	12,396	25.78	481
1980	7,270.58	4,305	5,105	2,166	26.51	82
1981	11,294.79	6,558	7,777	3,518	27.26	129
1982	11,192.02	6,972	8,268	2,924	24.97	117
1983	14,496.16	8,811	10,449	4,047	25.97	156
1984	5,717.07	3,411	4,045	1,672	26.54	63
1985	15,585.87	9,121	10,817	4,769	27.11	176
1986	48,278.74	27,693	32,842	15,437	27.69	557
1987	29,523.06	16,480	19,544	9,979	28.69	348
1988	76,661.56	41,888	49,676	26,986	29.26	922
1989	113,372.28	60,575	71,837	41,535	29.85	1,391
1990	144,531.37	75,445	89,472	55,059	30.45	1,808
1991	53,431.24	27,052	32,082	21,349	31.45	679
1992	99,809.99	49,286	58,450	41,360	32.04	1,291
1993	36,156.76	17,536	20,796	15,361	32.39	474
1994	118,794.48	55,715	66,074	52,720	33.40	1,578
1995	150,384.17	68,575	81,325	69,059	34.00	2,031
1996	91,378.94	40,463	47,986	43,393	34.61	1,254
1997	233,401.22	100,199	118,829	114,572	35.23	3,252
1998	151,590.70	62,622	74,265	77,326	36.23	2,134
1999	192,024.40	76,695	90,955	101,069	36.85	2,743
2000	160,172.66	61,731	73,208	86,965	37.48	2,320
2001	227,349.82	83,892	99,490	127,860	38.48	3,323
2002	321,940.17	114,224	135,461	186,479	39.10	4,769
2003	161,435.90	54,598	64,749	96,687	40.11	2,411

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 366 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

SURVIVOR CURVE.. IOWA 65-R3
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
2004	172,849.36	55,951	66,354	106,495	40.74	2,614
2005	430,305.70	132,964	157,685	272,621	41.38	6,588
2006	313,210.56	91,520	108,536	204,675	42.38	4,830
2007	95,642.88	26,512	31,441	64,202	43.02	1,492
2008	693,812.85	181,779	215,577	478,236	43.67	10,951
2009	66,961.89	16,406	19,456	47,506	44.67	1,063
2010	173,900.46	39,910	47,330	126,570	45.32	2,793
2011	38,275.92	8,134	9,646	28,630	46.32	618
2012	105,122.31	20,667	24,510	80,612	46.98	1,716
2013	153,776.20	27,772	32,936	120,840	47.64	2,537
2014	138,890.11	22,695	26,915	111,975	48.64	2,302
2015	90,029.54	13,234	15,695	74,335	49.31	1,508
2016	421,879.54	54,760	64,941	356,939	50.30	7,096
2017	544,253.07	61,555	73,000	471,253	50.97	9,246
2018	751,950.64	72,338	85,787	666,164	51.65	12,898
2019	1,561,494.51	123,670	146,663	1,414,832	52.32	27,042
2020	200,300.10	12,419	14,728	185,572	52.99	3,502
2021	46,993.55	2,091	2,480	44,514	53.68	829
2022	136,059.64	3,646	4,324	131,736	54.37	2,423
	8,779,918.41	2,153,276	2,551,835	6,228,083		137,656

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 45.2 1.57

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 42-R1.5						
NET SALVAGE PERCENT.. 0						
1957	20,707.78	18,208	18,142	2,566	5.07	506
1966	125.61	103	103	23	7.66	3
1967	11,811.86	9,568	9,534	2,278	7.98	285
1968	5,910.90	4,743	4,726	1,185	8.30	143
1969	6,614.08	5,255	5,236	1,378	8.63	160
1970	10,476.99	8,239	8,209	2,268	8.97	253
1971	10,457.70	8,137	8,108	2,350	9.32	252
1972	41,022.39	31,577	31,463	9,559	9.67	989
1973	34,470.99	26,231	26,137	8,334	10.04	830
1974	70,756.38	53,202	53,010	17,746	10.42	1,703
1975	100,703.05	74,784	74,515	26,188	10.81	2,423
1976	44,986.54	32,980	32,861	12,126	11.21	1,082
1977	84,648.19	61,229	61,009	23,639	11.62	2,034
1978	51,345.84	36,627	36,495	14,851	12.04	1,233
1979	60,758.30	42,705	42,551	18,207	12.48	1,459
1980	31,228.09	21,622	21,544	9,684	12.92	750
1981	36,240.11	24,695	24,606	11,634	13.38	870
1982	27,009.95	20,722	20,647	6,363	12.52	508
1983	57,820.71	43,753	43,595	14,226	12.94	1,099
1984	25,437.32	19,070	19,001	6,436	13.10	491
1985	32,874.97	24,268	24,181	8,694	13.56	641
1986	74,868.77	54,385	54,189	20,680	14.03	1,474
1987	56,850.48	40,597	40,451	16,399	14.51	1,130
1988	119,822.52	84,055	83,752	36,071	15.00	2,405
1989	170,104.63	117,678	117,254	52,851	15.26	3,463
1990	128,174.30	86,941	86,628	41,546	15.77	2,634
1991	206,697.33	137,330	136,836	69,861	16.29	4,289
1992	118,331.32	76,915	76,638	41,693	16.83	2,477
1993	143,633.73	91,997	91,666	51,968	17.12	3,036
1994	139,936.47	87,936	87,619	52,317	17.45	2,998
1995	218,211.77	133,720	133,239	84,973	18.01	4,718
1996	313,688.48	187,209	186,535	127,153	18.58	6,844
1997	347,423.45	202,548	201,819	145,604	18.95	7,684
1998	271,072.64	153,454	152,902	118,171	19.55	6,045
1999	195,316.27	107,658	107,270	88,046	19.95	4,413
2000	204,019.61	109,314	108,920	95,100	20.36	4,671
2001	430,192.23	222,624	221,823	208,369	20.98	9,932
2002	159,884.38	80,102	79,814	80,070	21.42	3,738
2003	40,647.22	19,665	19,594	21,053	21.87	963
2004	101,913.30	47,492	47,321	54,592	22.34	2,444
2005	296,678.92	132,823	132,345	164,334	22.82	7,201
2006	195,487.36	83,825	83,523	111,964	23.31	4,803
2007	130,292.49	53,316	53,124	77,168	23.82	3,240

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 42-R1.5						
NET SALVAGE PERCENT.. 0						
2008	560,222.35	217,926	217,141	343,081	24.34	14,095
2009	106,307.78	39,313	39,171	67,137	24.71	2,717
2010	238,807.76	83,487	83,186	155,622	25.11	6,198
2011	196,426.89	64,585	64,353	132,074	25.52	5,175
2012	95,619.43	29,355	29,249	66,370	25.96	2,557
2013	436,712.42	124,288	123,841	312,871	26.40	11,851
2014	360,794.09	94,600	94,259	266,535	26.73	9,971
2015	136,483.69	32,715	32,597	103,887	26.96	3,853
2016	184,038.52	39,752	39,609	144,430	27.22	5,306
2017	1,081,168.20	206,611	205,867	875,301	27.51	31,818
2018	1,138,571.52	189,117	188,436	950,136	27.61	34,413
2019	1,249,867.68	174,981	174,351	1,075,517	27.65	38,898
2020	1,429,120.68	161,491	160,910	1,268,211	27.46	46,184
2021	1,256,116.80	105,765	105,385	1,150,732	27.18	42,337
2022	1,436,720.14	77,583	77,304	1,359,416	26.28	51,728
2023	315,801.17	6,569	6,545	309,256	23.54	13,137
	15,051,434.54	4,527,440	4,511,139	10,540,296		428,554

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 24.6   2.85

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 368.1 TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

SURVIVOR CURVE.. IOWA 45-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1941	1,298.74	1,239	1,299			
1948	7,574.80	6,891	7,575			
1949	11,185.08	10,104	11,185			
1952	455.38	402	455			
1953	603.00	529	603			
1954	5,810.31	5,055	5,810			
1955	19,671.90	16,979	19,672			
1956	2,236.14	1,915	2,234	2	6.47	
1957	11,077.70	9,409	10,978	100	6.78	15
1958	48,657.53	40,980	47,812	846	7.10	119
1959	23,874.84	19,938	23,262	613	7.42	83
1960	15,467.11	12,803	14,937	530	7.75	68
1961	14,777.48	12,124	14,145	632	8.08	78
1962	5,131.59	4,173	4,869	263	8.41	31
1963	6,380.41	5,141	5,998	382	8.74	44
1964	20,303.52	16,207	18,909	1,395	9.08	154
1965	14,759.17	11,666	13,611	1,148	9.43	122
1966	36,587.23	28,636	33,410	3,177	9.78	325
1967	63,290.02	49,043	57,219	6,071	10.13	599
1968	82,937.25	63,604	74,207	8,730	10.49	832
1969	58,608.82	44,478	51,893	6,716	10.85	619
1970	83,638.43	62,803	73,272	10,366	11.21	925
1971	66,371.23	49,277	57,492	8,879	11.59	766
1972	87,155.53	63,991	74,659	12,497	11.96	1,045
1973	113,859.82	82,612	96,384	17,476	12.35	1,415
1974	136,954.68	98,212	114,584	22,371	12.73	1,757
1975	193,505.77	137,045	159,891	33,615	13.13	2,560
1976	137,196.29	95,945	111,939	25,257	13.53	1,867
1977	156,541.14	108,082	126,100	30,441	13.93	2,185
1978	159,615.26	108,751	126,880	32,735	14.34	2,283
1979	156,619.64	105,248	122,793	33,827	14.76	2,292
1980	179,340.22	118,802	138,607	40,733	15.19	2,682
1981	103,108.14	67,318	78,540	24,568	15.62	1,573
1982	217,186.26	161,261	188,144	29,042	14.31	2,029
1983	163,253.42	120,252	140,298	22,955	14.39	1,595
1984	163,181.68	118,486	138,238	24,944	14.81	1,684
1985	227,419.89	162,673	189,791	37,629	15.22	2,472
1986	161,510.33	113,703	132,658	28,852	15.66	1,842
1987	242,084.70	168,491	196,579	45,506	15.83	2,875
1988	234,284.17	160,204	186,911	47,373	16.30	2,906
1989	283,267.48	190,157	221,857	61,410	16.77	3,662
1990	318,532.68	210,773	245,910	72,623	17.00	4,272
1991	294,719.25	191,037	222,884	71,835	17.50	4,105

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 368.1 TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

SURVIVOR CURVE.. IOWA 45-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1992	360,439.77	229,780	268,085	92,355	17.77	5,197
1993	211,918.94	133,149	155,345	56,574	18.04	3,136
1994	262,672.49	161,964	188,964	73,708	18.34	4,019
1995	322,816.35	194,142	226,506	96,310	18.89	5,098
1996	341,522.22	200,986	234,491	107,031	19.23	5,566
1997	326,961.93	188,003	219,344	107,618	19.59	5,494
1998	380,854.91	212,669	248,122	132,733	20.16	6,584
1999	389,677.42	211,946	247,278	142,399	20.55	6,929
2000	414,915.93	219,408	255,984	158,932	20.94	7,590
2001	252,222.64	129,390	150,960	101,263	21.36	4,741
2002	335,684.64	166,701	194,491	141,194	21.79	6,480
2003	177,855.50	85,317	99,540	78,316	22.24	3,521
2004	273,003.88	126,182	147,217	125,787	22.69	5,544
2005	270,171.85	119,956	139,953	130,219	23.17	5,620
2006	111,991.24	47,619	55,557	56,434	23.65	2,386
2007	438,353.07	177,928	207,589	230,764	24.15	9,555
2008	501,258.61	193,486	225,741	275,518	24.66	11,173
2009	417,660.63	152,613	178,054	239,607	25.18	9,516
2010	111,460.21	38,365	44,761	66,699	25.72	2,593
2011	316,876.08	102,193	119,229	197,647	26.26	7,527
2012	415,595.42	124,762	145,560	270,035	26.81	10,072
2013	311,280.67	85,976	100,308	210,973	27.52	7,666
2014	190,321.99	48,094	56,111	134,211	28.09	4,778
2015	325,120.02	74,322	86,712	238,408	28.68	8,313
2016	236,737.89	48,105	56,124	180,614	29.40	6,143
2017	499,124.65	88,894	103,713	395,412	30.00	13,180
2018	568,819.45	86,347	100,741	468,078	30.73	15,232
2019	506,180.29	63,323	73,879	432,301	31.47	13,737
2020	563,842.15	55,257	64,469	499,373	32.21	15,504
2021	1,177,343.06	82,649	96,427	1,080,916	33.09	32,666
2022	1,070,968.69	45,302	52,854	1,018,115	33.96	29,980
2023	1,850,095.85	26,271	30,650	1,819,446	34.83	52,238
	18,263,782.47	6,977,538	8,139,253	10,124,529		379,659

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 26.7 2.08

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 368.2 TRANSFORMER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 39-R2						
NET SALVAGE PERCENT.. 0						
1963	340.90	312	341			
1964	1,114.87	1,011	1,115			
1965	582.21	524	582			
1966	2,073.07	1,850	2,073			
1967	2,171.52	1,922	2,172			
1968	531.87	467	532			
1970	1,338.80	1,154	1,339			
1971	5,193.89	4,435	5,194			
1972	19,389.76	16,402	19,390			
1973	36,534.42	30,595	36,534			
1974	25,830.70	21,413	25,831			
1975	77,222.77	63,343	77,223			
1976	53,862.54	43,698	53,863			
1977	19,827.62	15,898	19,731	97	7.73	13
1978	15,484.66	12,265	15,222	263	8.11	32
1979	83,875.10	65,595	81,410	2,465	8.50	290
1980	59,278.94	45,751	56,782	2,497	8.90	281
1981	55,816.14	42,478	52,720	3,096	9.32	332
1982	68,532.57	56,258	68,533			
1983	64,528.69	52,462	64,529			
1984	62,113.98	49,735	61,746	368	9.77	38
1985	107,195.38	84,877	105,375	1,820	10.06	181
1986	132,903.73	103,466	128,453	4,451	10.60	420
1987	112,966.03	86,814	107,779	5,187	10.92	475
1988	142,398.69	107,426	133,369	9,030	11.48	787
1989	171,799.36	127,681	158,516	13,283	11.83	1,123
1990	170,667.36	124,280	154,293	16,374	12.41	1,319
1991	224,798.59	160,956	199,827	24,972	12.79	1,952
1992	347,636.46	244,423	303,451	44,185	13.20	3,347
1993	235,547.05	163,093	202,480	33,067	13.55	2,440
1994	330,013.78	222,957	276,801	53,213	14.17	3,755
1995	416,071.68	275,107	341,545	74,527	14.60	5,105
1996	340,140.08	219,799	272,880	67,260	15.06	4,466
1997	395,465.23	248,352	308,329	87,136	15.70	5,550
1998	306,285.24	187,447	232,715	73,570	16.17	4,550
1999	274,195.58	163,256	202,682	71,514	16.65	4,295
2000	220,040.19	126,699	157,297	62,743	17.31	3,625
2001	244,261.31	136,298	169,214	75,047	17.82	4,211
2002	274,461.19	148,099	183,865	90,596	18.34	4,940
2003	457,142.11	238,034	295,519	161,623	18.87	8,565
2004	313,458.73	157,106	195,047	118,412	19.41	6,101
2005	282,705.27	135,981	168,820	113,885	19.96	5,706
2006	312,876.74	143,986	178,758	134,119	20.52	6,536

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 368.2 TRANSFORMER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 39-R2						
NET SALVAGE PERCENT.. 0						
2007	341,351.24	149,819	186,000	155,351	21.09	7,366
2008	241,221.99	100,590	124,882	116,340	21.67	5,369
2009	227,989.20	89,919	111,634	116,355	22.26	5,227
2010	170,797.08	63,400	78,711	92,086	22.87	4,026
2011	99,169.83	34,590	42,943	56,227	23.34	2,409
2012	204,623.09	66,359	82,385	122,238	23.96	5,102
2013	275,807.21	82,825	102,827	172,980	24.47	7,069
2014	153,812.87	42,375	52,608	101,205	24.98	4,051
2015	204,738.46	51,164	63,520	141,218	25.51	5,536
2016	280,837.77	62,964	78,170	202,668	25.95	7,810
2017	373,270.95	73,758	91,570	281,701	26.39	10,675
2018	94,317.45	16,034	19,906	74,411	26.86	2,770
2019	1,038,937.24	147,321	182,899	856,038	27.24	31,426
2020	384,436.80	43,441	53,932	330,505	27.46	12,036
2021	350,077.32	29,126	36,160	313,917	27.53	11,403
2022	285,379.12	14,840	18,424	266,955	27.32	9,771
2023	22,833.49	434	539	22,294	25.82	863
	11,218,275.91	5,202,664	6,450,987	4,767,289		213,344

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 22.3   1.90

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 369 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 53-R2						
NET SALVAGE PERCENT.. 0						
1947	66.96	59	67			
1954	117.87	99	118			
1955	331.66	278	332			
1956	128.40	107	128			
1958	216.39	177	216			
1959	638.32	518	635	3	9.99	
1960	1,281.75	1,031	1,264	18	10.36	2
1961	476.42	380	466	10	10.73	1
1962	5,122.14	4,048	4,963	159	11.11	14
1963	13,883.19	10,871	13,329	554	11.50	48
1964	20,576.98	15,953	19,560	1,017	11.91	85
1965	23,188.67	17,798	21,822	1,367	12.32	111
1966	27,613.16	20,976	25,718	1,895	12.74	149
1967	55,792.04	41,928	51,407	4,385	13.17	333
1968	86,205.17	64,052	78,533	7,672	13.62	563
1969	163,478.72	120,049	147,189	16,290	14.08	1,157
1970	234,043.20	169,836	208,232	25,811	14.54	1,775
1971	230,163.54	164,935	202,223	27,941	15.02	1,860
1972	199,305.77	140,981	172,853	26,453	15.51	1,706
1973	269,059.57	187,782	230,235	38,825	16.01	2,425
1974	151,970.14	104,601	128,249	23,721	16.52	1,436
1975	142,128.42	96,406	118,201	23,927	17.05	1,403
1976	154,952.88	103,555	126,966	27,987	17.58	1,592
1977	154,609.72	101,721	124,718	29,892	18.13	1,649
1978	168,135.79	108,876	133,490	34,646	18.68	1,855
1979	198,402.56	126,341	154,904	43,499	19.25	2,260
1980	147,145.18	92,091	112,911	34,234	19.83	1,726
1981	189,857.47	116,709	143,094	46,763	20.42	2,290
1982	162,613.58	112,024	137,350	25,264	18.63	1,356
1983	178,144.09	120,461	147,694	30,450	19.27	1,580
1984	202,946.64	135,406	166,018	36,929	19.58	1,886
1985	174,874.44	114,385	140,245	34,629	20.23	1,712
1986	211,585.84	136,346	167,171	44,415	20.55	2,161
1987	239,927.60	151,346	185,562	54,366	21.22	2,562
1988	249,381.61	154,716	189,694	59,688	21.57	2,767
1989	262,382.38	159,056	195,015	67,367	22.25	3,028
1990	276,142.23	164,360	201,518	74,624	22.61	3,300
1991	262,041.57	152,115	186,505	75,537	23.31	3,241
1992	252,737.29	143,757	176,257	76,480	23.69	3,228
1993	188,591.17	105,272	129,071	59,520	24.14	2,466
1994	163,114.97	88,539	108,556	54,559	24.85	2,196
1995	314,767.87	166,858	204,581	110,187	25.26	4,362
1996	289,564.68	148,894	182,555	107,010	25.98	4,119

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 369 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 53-R2						
NET SALVAGE PERCENT.. 0						
1997	337,238.43	168,889	207,071	130,167	26.41	4,929
1998	292,802.14	141,863	173,935	118,867	27.13	4,381
1999	326,567.03	153,617	188,346	138,221	27.58	5,012
2000	176,242.61	80,349	98,514	77,729	28.05	2,771
2001	196,874.08	86,388	105,918	90,956	28.78	3,160
2002	236,864.12	100,336	123,020	113,844	29.26	3,891
2003	221,377.18	90,322	110,742	110,635	29.75	3,719
2004	284,120.18	111,375	136,554	147,566	30.25	4,878
2005	419,833.11	156,892	192,362	227,471	31.00	7,338
2006	147,911.11	52,804	64,742	83,169	31.52	2,639
2007	594,013.07	201,905	247,551	346,462	32.04	10,813
2008	487,448.99	157,154	192,683	294,766	32.58	9,047
2009	340,169.50	103,582	126,999	213,170	33.12	6,436
2010	355,385.27	101,711	124,705	230,680	33.67	6,851
2011	241,278.50	64,542	79,133	162,146	34.23	4,737
2012	383,690.71	95,769	117,420	266,271	34.58	7,700
2013	478,903.67	110,148	135,050	343,854	35.16	9,780
2014	440,393.86	92,879	113,877	326,517	35.55	9,185
2015	420,430.07	80,050	98,147	322,283	36.14	8,918
2016	502,242.35	85,482	104,807	397,435	36.56	10,871
2017	415,114.97	62,350	76,446	338,669	36.79	9,205
2018	389,129.90	50,081	61,403	327,727	37.24	8,800
2019	435,022.59	46,808	57,390	377,633	37.34	10,113
2020	410,773.90	35,080	43,011	367,763	37.48	9,812
2021	591,731.78	37,161	45,562	546,170	37.34	14,627
2022	535,299.87	20,984	25,728	509,572	36.81	13,843
2023	496,353.51	7,048	8,642	487,712	34.59	14,100
	16,224,920.54	6,361,262	7,799,373	8,425,548		271,960

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.0 1.68

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.1 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 34-R1						
NET SALVAGE PERCENT.. 0						
1946	44.15	44	44			
1948	47.09	47	47			
1957	417.20	409	417			
1958	499.67	485	500			
1959	778.62	747	779			
1961	1,730.89	1,628	1,731			
1962	5,780.95	5,386	5,781			
1963	3,110.60	2,871	3,111			
1964	2,257.14	2,063	2,257			
1965	4,505.15	4,078	4,505			
1966	3,886.32	3,484	3,886			
1967	5,792.22	5,141	5,792			
1968	13,062.89	11,476	13,063			
1969	11,539.91	10,030	11,540			
1970	12,317.60	10,590	12,318			
1971	29,924.65	25,436	29,925			
1972	158,390.54	133,048	156,679	1,712	5.44	315
1973	29,447.80	24,442	28,783	665	5.78	115
1974	17,214.16	14,111	16,617	597	6.13	97
1975	24,170.38	19,557	23,031	1,139	6.49	176
1976	38,833.20	30,998	36,504	2,329	6.86	340
1977	33,289.49	26,210	30,865	2,424	7.23	335
1978	56,826.20	44,107	51,941	4,885	7.61	642
1979	33,400.91	25,542	30,079	3,322	8.00	415
1980	41,194.07	31,029	36,540	4,654	8.39	555
1981	21,218.56	15,727	18,520	2,699	8.80	307
1982	41,888.00	34,729	40,897	991	8.50	117
1983	28,425.65	23,340	27,486	940	8.77	107
1984	29,955.21	24,222	28,524	1,431	9.29	154
1985	38,924.03	31,116	36,643	2,281	9.60	238
1986	55,854.87	44,109	51,943	3,912	9.92	394
1987	48,992.33	38,185	44,967	4,025	10.26	392
1988	56,693.60	43,563	51,300	5,394	10.62	508
1989	64,699.72	48,971	57,669	7,031	11.00	639
1990	86,686.64	64,564	76,032	10,655	11.39	935
1991	72,029.07	52,732	62,098	9,931	11.80	842
1992	123,338.73	88,656	104,403	18,936	12.23	1,548
1993	92,045.55	65,131	76,699	15,347	12.60	1,218
1994	109,907.71	76,188	89,720	20,188	13.06	1,546
1995	104,682.54	71,310	83,976	20,707	13.34	1,552
1996	79,789.91	53,100	62,531	17,259	13.82	1,249
1997	67,075.91	43,727	51,494	15,582	14.15	1,101
1998	159,511.52	101,290	119,281	40,231	14.66	2,744

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.1 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 34-R1						
NET SALVAGE PERCENT.. 0						
1999	77,357.53	47,946	56,462	20,896	15.03	1,390
2000	202,152.28	122,100	143,787	58,365	15.41	3,787
2001	18,401.67	10,765	12,677	5,725	15.96	359
2002	5,881.97	3,339	3,932	1,950	16.38	119
2003	40,927.07	22,567	26,575	14,352	16.68	860
2004	107,262.95	57,107	67,250	40,013	17.13	2,336
2005	3,437.96	1,762	2,075	1,363	17.60	77
2006	17,953.93	8,860	10,434	7,520	17.96	419
2017	91,510.46	21,413	25,216	66,294	21.28	3,115
2018	364,287.49	74,752	88,029	276,258	21.31	12,964
2020	142,165.66	20,301	23,906	118,260	21.01	5,629
2023	96,335.29	2,774	3,267	93,068	16.89	5,510
	2,977,855.61	1,747,305	2,054,528	923,328		55,146

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.7   1.85

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.2 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

SURVIVOR CURVE.. IOWA 75-R4
NET SALVAGE PERCENT.. 0

1924	1,529.90	1,462	1,530			
1925	134.62	128	135			
1926	1,338.33	1,270	1,338			
1927	2,327.74	2,201	2,328			
1928	380.18	358	380			
1929	1,866.86	1,752	1,867			
1930	1,106.10	1,034	1,106			
1931	425.10	396	425			
1932	733.99	681	734			
1933	689.72	637	690			
1934	951.15	876	951			
1935	811.99	744	812			
1936	1,467.66	1,340	1,468			
1937	1,909.78	1,736	1,905	5	6.83	1
1938	1,520.71	1,376	1,510	11	7.13	2
1939	1,638.43	1,476	1,620	18	7.44	2
1940	1,592.46	1,428	1,567	25	7.76	3
1941	1,206.40	1,076	1,181	25	8.10	3
1942	563.66	500	549	15	8.44	2
1943	564.75	498	547	18	8.80	2
1944	675.64	593	651	25	9.18	3
1945	889.47	776	852	37	9.57	4
1946	1,927.12	1,671	1,834	93	9.98	9
1947	4,420.60	3,807	4,178	243	10.41	23
1948	6,453.65	5,519	6,057	397	10.86	37
1949	6,178.43	5,245	5,757	421	11.33	37
1950	6,182.69	5,208	5,716	467	11.82	40
1951	7,147.99	5,972	6,554	594	12.34	48
1952	6,335.80	5,249	5,761	575	12.87	45
1953	6,555.32	5,381	5,906	649	13.43	48
1954	5,746.69	4,673	5,129	618	14.01	44
1955	6,960.41	5,605	6,152	808	14.61	55
1956	6,988.75	5,570	6,113	876	15.23	58
1957	6,445.77	5,083	5,579	867	15.86	55
1958	10,331.59	8,057	8,843	1,489	16.51	90
1959	6,143.71	4,737	5,199	945	17.17	55
1960	5,168.86	3,939	4,323	846	17.84	47
1961	6,114.21	4,604	5,053	1,061	18.52	57
1962	4,801.75	3,572	3,920	882	19.21	46
1963	6,718.01	4,935	5,416	1,302	19.91	65
1964	5,874.22	4,259	4,674	1,200	20.62	58
1965	9,089.77	6,505	7,139	1,951	21.33	91
1966	8,187.07	5,779	6,343	1,844	22.06	84

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.2 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1967	10,952.81	7,623	8,366	2,587	22.80	113
1968	10,050.25	6,894	7,566	2,484	23.55	105
1969	12,526.12	8,468	9,294	3,232	24.30	133
1970	11,876.46	7,907	8,678	3,198	25.07	128
1971	13,485.11	8,837	9,699	3,786	25.85	146
1972	13,329.71	8,597	9,435	3,895	26.63	146
1973	17,876.97	11,339	12,445	5,432	27.43	198
1974	13,790.38	8,598	9,437	4,353	28.24	154
1975	11,506.76	7,048	7,735	3,772	29.06	130
1976	10,141.69	6,101	6,696	3,446	29.88	115
1977	17,935.57	10,589	11,622	6,314	30.72	206
1978	16,016.68	9,275	10,180	5,837	31.57	185
1979	28,665.61	16,274	17,861	10,805	32.42	333
1980	21,337.43	11,869	13,027	8,310	33.28	250
1981	45,450.29	24,755	27,169	18,281	34.15	535
1982	27,266.87	15,297	16,789	10,478	32.28	325
1983	18,836.13	10,311	11,317	7,519	33.28	226
1984	23,963.65	12,885	14,142	9,822	33.74	291
1985	32,449.62	17,004	18,662	13,788	34.74	397
1986	32,218.23	16,441	18,044	14,174	35.74	397
1987	34,858.89	17,436	19,137	15,722	36.22	434
1988	33,837.22	16,458	18,063	15,774	37.22	424
1989	34,369.24	16,243	17,827	16,542	38.22	433
1990	31,742.34	14,563	15,983	15,759	39.22	402
1991	29,686.63	13,309	14,607	15,080	39.69	380
1992	34,219.29	14,865	16,315	17,904	40.69	440
1993	27,589.27	11,698	12,839	14,750	41.44	356
1994	31,652.60	12,978	14,244	17,409	42.45	410
1995	35,518.43	14,072	15,444	20,074	43.44	462
1996	27,266.64	10,498	11,522	15,745	43.93	358
1997	35,343.38	13,112	14,391	20,952	44.93	466
1998	18,207.40	6,500	7,134	11,073	45.93	241
2000	32,323.65	10,634	11,671	20,653	47.93	431
2001	3,047.52	960	1,054	1,994	48.93	41
2002	57,989.69	17,455	19,157	38,833	49.93	778
2003	120,567.42	34,844	38,242	82,325	50.43	1,632
2004	123,356.05	33,923	37,232	86,124	51.42	1,675
2005	164,397.59	42,875	47,057	117,341	52.43	2,238
2006	21,254.69	5,246	5,758	15,497	53.42	290
2007	22,558.20	5,247	5,759	16,799	54.43	309
2008	43,903.22	9,597	10,533	33,370	55.42	602
2009	30,702.46	6,276	6,888	23,814	56.43	422
2010	20,823.43	3,965	4,352	16,471	57.42	287

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.2 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
2011	12,948.61	2,282	2,505	10,444	58.43	179
2012	32,810.44	5,322	5,841	26,969	59.42	454
2013	43,329.92	6,413	7,038	36,292	60.43	601
2014	48,193.46	6,458	7,088	41,105	61.42	669
2015	116,515.45	13,959	15,320	101,195	62.43	1,621
2016	24,227.58	2,580	2,831	21,397	62.92	340
2017	27,102.54	2,502	2,746	24,357	63.92	381
2018	17,054.60	1,332	1,462	15,593	64.92	240
2019	27,035.31	1,728	1,897	25,138	65.92	381
2020	11,436.90	568	623	10,814	66.92	162
2021	20,944.20	744	817	20,127	67.92	296
2022	24,369.97	519	569	23,801	68.92	345
2023	11,414.97	81	89	11,326	69.92	162
	1,980,372.59	731,062	801,991	1,178,382		24,969

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 47.2   1.26

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.3 ELECTRONIC METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-S3						
NET SALVAGE PERCENT.. 0						
1995	280.36	266	280			
1996	68,883.81	64,785	68,884			
1997	102,737.04	95,833	102,737			
1998	28,763.57	26,552	28,764			
1999	188,041.11	171,381	188,041			
2000	79,287.63	71,359	79,288			
2001	138,189.12	122,505	138,189			
2002	53,297.66	46,524	52,760	538	3.13	172
2003	91,737.08	78,417	88,927	2,810	3.48	807
2004	199,255.57	166,697	189,039	10,217	3.81	2,682
2005	296,348.56	241,761	274,164	22,185	4.18	5,307
2006	207,413.16	164,437	186,476	20,937	4.57	4,581
2007	2,301,040.99	1,765,359	2,001,966	299,075	5.01	59,696
2008	303,024.99	224,057	254,087	48,938	5.46	8,963
2010	88,994.13	59,831	67,850	21,144	6.58	3,213
2011	231,480.17	146,712	166,375	65,105	7.22	9,017
2012	101,602.74	60,169	68,233	33,370	7.92	4,213
2013	64,307.89	35,176	39,891	24,417	8.69	2,810
2014	85,443.25	42,773	48,506	36,937	9.48	3,896
2015	44,174.73	19,940	22,612	21,563	10.33	2,087
2016	129,029.77	51,586	58,500	70,530	11.26	6,264
2018	4,662.78	1,375	1,559	3,104	13.16	236
2022	229,894.69	18,484	20,962	208,933	17.16	12,176
	5,037,890.80	3,675,979	4,148,090	889,801		126,120

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.1   2.50

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-O1						
NET SALVAGE PERCENT.. 0						
1926	642.41	642	642			
1929	5,321.34	5,321	5,321			
1940	197.92	198	198			
1941	263.93	264	264			
1945	32.62	33	33			
1946	283.36	283	283			
1948	1,451.21	1,451	1,451			
1949	253.79	254	254			
1950	17.14	17	17			
1951	453.74	454	454			
1952	127.16	127	127			
1954	1,722.53	1,723	1,723			
1955	5,517.30	5,517	5,517			
1956	70.84	71	71			
1957	1,458.37	1,458	1,458			
1958	8,469.70	8,470	8,470			
1959	4,103.33	4,103	4,103			
1960	1,507.24	1,507	1,507			
1961	2,700.54	2,701	2,701			
1962	2,255.35	2,255	2,255			
1963	5,671.86	5,672	5,672			
1964	8,035.28	7,933	7,303	732	0.38	732
1965	3,704.69	3,597	3,311	394	0.87	394
1966	9,174.56	8,753	8,058	1,117	1.38	809
1967	13,870.71	13,001	11,969	1,902	1.88	1,012
1968	14,200.92	13,079	12,041	2,160	2.37	911
1969	9,906.37	8,955	8,244	1,662	2.88	577
1970	14,122.73	12,532	11,537	2,586	3.38	765
1971	5,824.84	5,073	4,670	1,155	3.87	298
1972	9,178.06	7,838	7,216	1,962	4.38	448
1973	8,790.25	7,360	6,776	2,014	4.88	413
1974	13,190.14	10,829	9,969	3,221	5.37	600
1975	4,362.97	3,508	3,230	1,133	5.88	193
1976	3,177.16	2,501	2,302	875	6.38	137
1977	8,577.39	6,613	6,088	2,489	6.87	362
1978	2,737.09	2,064	1,900	837	7.38	113
1979	1,616.62	1,192	1,097	520	7.88	66
1980	11,925.65	8,598	7,915	4,011	8.37	479
1981	16,141.57	11,364	10,462	5,680	8.88	640
1982	18,883.68	15,579	14,342	4,542	8.75	519
1983	16,411.21	13,342	12,283	4,128	9.26	446
1984	22,000.61	17,702	16,297	5,704	9.53	599
1985	18,787.13	14,876	13,695	5,092	10.06	506

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-O1						
NET SALVAGE PERCENT.. 0						
1986	9,922.73	7,762	7,146	2,777	10.37	268
1987	16,483.16	12,667	11,661	4,822	10.92	442
1988	23,966.98	18,165	16,723	7,244	11.26	643
1989	33,211.86	24,796	22,828	10,384	11.62	894
1990	35,050.72	25,755	23,710	11,341	12.00	945
1991	24,596.13	17,768	16,358	8,238	12.39	665
1992	35,762.34	25,370	23,356	12,406	12.80	969
1993	11,592.34	8,096	7,453	4,139	13.17	314
1994	42,356.58	29,116	26,805	15,552	13.42	1,159
1995	59,961.02	40,330	37,128	22,833	13.87	1,646
1996	12,276.38	8,102	7,459	4,817	14.17	340
1997	31,396.73	20,301	18,689	12,708	14.48	878
1998	28,411.16	17,967	16,541	11,870	14.82	801
1999	15,625.56	9,647	8,881	6,745	15.18	444
2000	34,452.28	20,809	19,157	15,295	15.41	993
2001	43,335.86	25,546	23,518	19,818	15.67	1,265
2002	72,442.64	41,582	38,281	34,162	15.96	2,140
2003	29,016.52	16,180	14,896	14,121	16.26	868
2004	23,409.96	12,691	11,684	11,726	16.47	712
2005	12,053.15	6,333	5,830	6,223	16.71	372
2006	122,072.81	61,952	57,034	65,039	16.98	3,830
2007	69,471.83	34,041	31,339	38,133	17.17	2,221
2008	56,319.94	26,538	24,431	31,889	17.39	1,834
2009	33,569.02	15,187	13,981	19,588	17.55	1,116
2010	20,156.51	8,736	8,043	12,114	17.65	686
2011	91,834.61	37,882	34,875	56,960	17.80	3,200
2012	25,438.26	9,977	9,185	16,253	17.82	912
2013	61,860.47	22,864	21,049	40,811	17.91	2,279
2014	40,611.98	14,084	12,966	27,646	17.90	1,544
2015	189,149.16	61,095	56,245	132,904	17.82	7,458
2016	201,370.11	59,807	55,059	146,311	17.75	8,243
2017	130,859.86	35,385	32,576	98,284	17.54	5,603
2018	105,309.30	25,422	23,404	81,905	17.28	4,740
2019	49,677.75	10,442	9,613	40,065	16.91	2,369
2020	34,301.17	6,051	5,571	28,730	16.34	1,758
2021	25,224.02	3,501	3,223	22,001	15.52	1,418
2022	89,421.39	8,549	7,870	81,551	14.20	5,743
	2,219,113.60	1,069,306	987,794	1,231,320		82,731

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.9   3.73

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 371.5 INSTALLATIONS ON CUSTOMERS PREMISES - DUSK TO DAWN LIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 23-R1						
NET SALVAGE PERCENT.. 0						
1973	1,435.43	1,435	1,435			
1974	6,471.13	6,471	6,471			
1975	3,583.76	3,584	3,584			
1976	4,402.59	4,403	4,403			
1977	4,697.22	4,697	4,697			
1978	4,229.73	4,171	4,230			
1979	5,985.23	5,816	5,985			
1980	4,861.55	4,652	4,862			
1981	2,917.37	2,750	2,917			
1982	1,561.73	1,507	1,562			
1983	2,231.26	2,138	2,231			
1984	2,149.66	2,042	2,150			
1985	2,342.27	2,204	2,342			
1986	990.28	922	990			
1987	1,925.20	1,780	1,925			
1988	2,301.67	2,101	2,302			
1989	1,493.31	1,350	1,493			
1990	4,328.13	3,871	4,328			
1991	2,572.95	2,273	2,573			
1992	4,859.73	4,237	4,860			
1993	2,315.34	1,999	2,315			
1994	8,619.58	7,323	8,620			
1995	9,663.67	8,097	9,664			
1996	37,963.03	31,319	37,963			
1997	53,663.03	43,370	53,244	419	6.29	67
1998	61,778.99	48,991	60,144	1,635	6.66	245
1999	61,882.53	48,213	59,190	2,693	6.95	387
2000	30,918.71	23,542	28,902	2,017	7.36	274
2008	14,410.22	8,554	10,501	3,909	10.61	368
2017	1,150.61	365	448	703	13.99	50
	347,705.91	284,177	336,331	11,375		1,391

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.2 0.40

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 28-L0						
NET SALVAGE PERCENT.. 0						
1917	271.75	252	237	35	2.01	17
1918	8.22	8	8			
1919	747.40	688	646	101	2.24	45
1920	227.62	208	195	33	2.36	14
1921	387.10	353	331	56	2.48	23
1923	937.10	846	794	143	2.72	53
1924	81.88	74	69	13	2.84	5
1925	384.41	344	323	61	2.96	21
1927	646.14	572	537	109	3.21	34
1928	390.52	344	323	68	3.34	20
1930	2,013.30	1,755	1,648	365	3.59	102
1931	68.51	59	55	14	3.72	4
1932	63.43	55	52	11	3.85	3
1933	147.41	126	118	29	3.98	7
1934	379.14	323	303	76	4.12	18
1935	531.67	451	423	109	4.25	26
1936	6,030.23	5,087	4,776	1,254	4.38	286
1937	657.18	551	517	140	4.52	31
1938	302.73	252	237	66	4.66	14
1939	174.53	145	136	39	4.80	8
1940	386.01	318	299	87	4.94	18
1941	92.94	76	71	22	5.08	4
1942	133.76	109	102	32	5.22	6
1945	26.09	21	20	6	5.66	1
1946	49.68	39	37	13	5.81	2
1947	108.02	85	80	28	5.96	5
1948	1,750.33	1,368	1,284	466	6.11	76
1949	1,263.75	981	921	343	6.26	55
1950	2,571.24	1,982	1,861	710	6.42	111
1951	1,681.26	1,286	1,207	474	6.58	72
1952	3,016.73	2,292	2,152	865	6.73	129
1953	4,134.35	3,116	2,926	1,208	6.90	175
1954	2,344.55	1,753	1,646	699	7.06	99
1955	3,243.31	2,407	2,260	983	7.22	136
1956	16,191.57	11,918	11,190	5,002	7.39	677
1957	2,459.64	1,796	1,686	774	7.56	102
1958	1,434.98	1,039	976	459	7.73	59
1959	10,334.16	7,418	6,965	3,369	7.90	426
1960	1,125.95	801	752	374	8.07	46
1961	3,016.27	2,128	1,998	1,018	8.25	123
1962	2,651.51	1,853	1,740	912	8.43	108
1963	7,344.98	5,086	4,775	2,570	8.61	298
1964	5,935.27	4,072	3,823	2,112	8.79	240

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 28-L0						
NET SALVAGE PERCENT.. 0						
1965	42,681.52	28,993	27,223	15,459	8.98	1,721
1966	48,155.59	32,385	30,408	17,748	9.17	1,935
1967	35,663.54	23,742	22,292	13,372	9.36	1,429
1968	19,380.29	12,770	11,990	7,390	9.55	774
1969	9,534.32	6,214	5,835	3,699	9.75	379
1970	9,429.11	6,078	5,707	3,722	9.95	374
1971	7,733.19	4,930	4,629	3,104	10.15	306
1972	3,110.40	1,961	1,841	1,269	10.35	123
1973	21,509.88	13,398	12,580	8,930	10.56	846
1974	9,689.57	5,963	5,599	4,091	10.77	380
1975	48,595.71	29,539	27,735	20,861	10.98	1,900
1976	16,526.25	9,916	9,311	7,215	11.20	644
1977	11,997.96	7,104	6,670	5,328	11.42	467
1978	19,233.55	11,238	10,552	8,682	11.64	746
1979	15,390.12	8,866	8,325	7,065	11.87	595
1980	15,493.02	8,803	8,265	7,228	12.09	598
1981	30,109.49	16,850	15,821	14,288	12.33	1,159
1982	60,447.13	47,874	44,951	15,496	10.83	1,431
1983	46,494.36	36,493	34,265	12,229	11.03	1,109
1984	29,958.94	23,284	21,862	8,097	11.25	720
1985	17,189.00	13,215	12,408	4,781	11.50	416
1986	7,473.43	5,707	5,359	2,114	11.53	183
1987	15,849.99	11,951	11,221	4,629	11.83	391
1988	42,445.39	31,719	29,782	12,663	11.92	1,062
1989	32,128.02	23,768	22,317	9,811	12.05	814
1990	29,990.35	21,938	20,598	9,392	12.20	770
1991	20,773.14	15,007	14,091	6,682	12.39	539
1992	20,381.79	14,522	13,635	6,747	12.61	535
1993	120,219.11	85,067	79,873	40,346	12.60	3,202
1994	36,638.80	25,508	23,950	12,689	12.87	986
1995	25,627.47	17,601	16,526	9,101	13.00	700
1996	10,160.14	6,873	6,453	3,707	13.15	282
1997	9,512.24	6,328	5,942	3,570	13.34	268
1998	5,627.49	3,688	3,463	2,164	13.41	161
1999	5,697.79	3,657	3,434	2,264	13.67	166
2000	28,644.93	18,041	16,939	11,706	13.81	848
2001	66,472.29	41,133	38,621	27,851	13.86	2,009
2002	23,849.33	14,410	13,530	10,319	14.09	732
2003	72,084.27	42,559	39,960	32,124	14.22	2,259
2004	63,988.80	36,934	34,679	29,310	14.28	2,053
2005	72,930.24	40,885	38,389	34,541	14.50	2,382
2008	28,815.10	14,739	13,839	14,976	14.80	1,012
2009	8,487.89	4,185	3,929	4,559	14.91	306

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 28-L0						
NET SALVAGE PERCENT.. 0						
2010	21,441.02	10,159	9,539	11,902	14.99	794
2011	1,708.59	775	728	981	15.05	65
2012	23,939.56	10,351	9,719	14,221	15.10	942
2013	1,992.34	816	766	1,226	15.14	81
2014	7,849.37	3,028	2,843	5,006	15.13	331
2015	28,338.61	10,191	9,569	18,770	15.14	1,240
2016	14,909.64	4,943	4,641	10,269	15.12	679
2017	31,540.47	9,513	8,932	22,608	15.05	1,502
2018	372,976.52	100,107	93,995	278,982	14.99	18,611
2019	13,789.15	3,207	3,011	10,778	14.84	726
2020	220,646.19	42,541	39,944	180,702	14.65	12,335
2021	84,495.00	12,548	11,782	72,713	14.34	5,071
2022	126,509.32	12,373	11,618	114,891	13.84	8,301
2023	168,767.62	6,363	5,974	162,794	12.76	12,758
	2,470,770.96	1,127,188	1,058,359	1,412,412		106,847

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.2   4.32

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FORTY FORT WAREHOUSE						
INTERIM SURVIVOR CURVE.. IOWA 100-L0						
PROBABLE RETIREMENT YEAR.. 6-2032						
NET SALVAGE PERCENT.. 0						
1966	108.93	92	81	28	8.41	3
1967	2,187.62	1,853	1,622	566	8.42	67
1972	1,935.70	1,620	1,418	518	8.43	61
1974	613.85	511	447	167	8.43	20
1975	798.60	663	580	218	8.44	26
1978	1,700.49	1,398	1,224	477	8.44	57
1979	11,951.94	9,791	8,569	3,383	8.45	400
1980	127,308.92	103,927	90,959	36,350	8.45	4,302
1981	455.52	370	324	132	8.45	16
1982	1,922.26	1,594	1,395	527	8.50	62
1983	217.27	179	157	61	8.53	7
1984	7,602.22	6,266	5,484	2,118	8.37	253
1985	15,907.41	13,022	11,397	4,510	8.48	532
1986	1,119.91	914	800	320	8.41	38
1987	4,566.46	3,708	3,245	1,321	8.39	157
1989	5,585.40	4,476	3,917	1,668	8.49	196
1990	23,253.54	18,556	16,241	7,013	8.42	833
1991	44,343.14	35,182	30,792	13,551	8.40	1,613
1992	1,405.23	1,107	969	436	8.43	52
1993	9,281.97	7,275	6,367	2,915	8.41	347
1994	44,094.84	34,341	30,056	14,039	8.38	1,675
1995	22,953.90	17,730	15,518	7,436	8.40	885
1998	2,839.86	2,136	1,869	970	8.40	115
2005	20,016.32	13,739	12,025	7,992	8.45	946
2006	66,889.22	45,070	39,446	27,443	8.47	3,240
2011	21,211.37	12,621	11,046	10,165	8.51	1,194
2014	8,821.57	4,660	4,079	4,743	8.49	559
2015	292,058.64	145,971	127,756	164,302	8.51	19,307
2016	122,947.66	57,638	50,446	72,502	8.50	8,530
2018	48,711.70	19,129	16,742	31,970	8.51	3,757
2020	32,951.46	9,619	8,419	24,533	8.49	2,890
2021	234,677.17	53,389	46,727	187,950	8.49	22,138
2022	1,342,937.93	202,246	177,009	1,165,929	8.46	137,817
2023	1,669,295.10	93,814	82,108	1,587,188	8.40	188,951
	4,192,673.12	924,607	809,231	3,383,442		401,046

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PLYMOUTH STOREROOM (BRICK STRUCTURE)						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1917	7,127.10	7,127	7,127			
1951	556.54	557	557			
1976	902.76	903	903			
1984	1,008.80	1,009	1,009			
2008	5,516.25	5,516	5,516			
	15,111.45	15,112	15,111			
IDETOWN						
INTERIM SURVIVOR CURVE.. IOWA 100-L0						
PROBABLE RETIREMENT YEAR.. 6-2046						
NET SALVAGE PERCENT.. 0						
1979	930.87	589	513	418	20.69	20
1983	13,610.31	9,039	7,878	5,732	20.36	282
2021	35,384.32	3,928	3,424	31,961	20.02	1,596
	49,925.50	13,556	11,815	38,110		1,898
NANTICOKE SERVICE CENTER						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1971	4,029.19	4,029	4,029			
1975	21,022.88	21,023	21,023			
1985	36,364.35	36,364	36,364			
1986	4,788.36	4,788	4,788			
1987	9,974.00	9,974	9,974			
	76,178.78	76,178	76,179			
EMPIRE YARD						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
2014	19,894.79	19,895	19,895			
	19,894.79	19,895	19,895			

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SYSTEM CONTROL CENTER						
INTERIM SURVIVOR CURVE.. IOWA 100-L0						
PROBABLE RETIREMENT YEAR.. 7-2056						
NET SALVAGE PERCENT.. 0						
2016	1,875,841.31	406,682	342,143	1,533,698	27.10	56,594
2021	3,575.00	308	259	3,316	26.49	125
2022	12,471.61	678	570	11,901	26.05	457
	1,891,887.92	407,668	342,973	1,548,915		57,176
	6,245,671.56	1,457,016	1,275,204	4,970,467		460,120

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.8 7.37

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2007	13,833.00	11,412	7,699	6,134	3.50	1,753
2015	15,627.39	6,642	4,481	11,146	11.50	969
2016	17,280.62	6,480	4,371	12,910	12.50	1,033
2018	19,327.09	5,315	3,586	15,741	14.50	1,086
	66,068.10	29,849	20,137	45,931		4,841

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.5 7.33

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	359,391.70	323,453	282,962	76,430	0.50	76,430
2022	9,823.55	2,947	2,578	7,246	3.50	2,070
	369,215.25	326,400	285,540	83,675		78,500

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.1   21.26

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 391.92 OFFICE FURNITURE AND EQUIPMENT - OUTAGE MANAGEMENT SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	20,008.56	10,004	6,804	13,205	2.50	5,282
2022	3,341,592.33	1,002,478	681,854	2,659,738	3.50	759,925
2023	134,434.40	13,443	9,143	125,291	4.50	27,842
	3,496,035.29	1,025,925	697,801	2,798,234		793,049

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.5   22.68

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - CARS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 7-L3						
NET SALVAGE PERCENT.. 0						
2020	209,034.47	111,123	128,335	80,699	3.08	26,201
2021	59,173.85	23,314	26,925	32,249	3.85	8,376
2022	33,888.94	8,181	9,448	24,441	4.71	5,189
2023	34,000.00	2,754	3,181	30,819	5.67	5,435
	336,097.26	145,372	167,889	168,208		45,201

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.7 13.45

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 392.2 TRANSPORTATION EQUIPMENT - LIGHT TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 11-L3						
NET SALVAGE PERCENT.. 0						
2020	709,058.60	250,652	196,622	512,437	6.40	80,068
2021	232,833.23	59,559	46,720	186,113	7.27	25,600
2022	453,079.46	69,955	54,876	398,203	8.22	48,443
2023	225,700.00	11,624	9,118	216,582	9.21	23,516
	1,620,671.29	391,790	307,336	1,313,335		177,627

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.4 10.96

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 392.4 TRANSPORTATION EQUIPMENT - HEAVY TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 14-S3						
NET SALVAGE PERCENT.. 0						
2020	136,684.28	36,645	28,830	107,854	9.55	11,294
2021	243,704.15	46,669	36,715	206,989	10.55	19,620
2022	110,248.00	12,679	9,975	100,273	11.54	8,689
	490,636.43	95,993	75,520	415,116		39,603

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.5 8.07

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 393 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	3,216.82	2,734	2,393	824	1.50	549
2020	11,401.12	3,990	3,492	7,909	6.50	1,217
	14,617.94	6,724	5,885	8,733		1,766

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.9 12.08

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	32,594.97	31,780	31,274	1,321	0.50	1,321
2005	67,810.09	62,724	61,725	6,085	1.50	4,057
2006	26,827.51	23,474	23,100	3,728	2.50	1,491
2007	75,903.01	62,620	61,623	14,280	3.50	4,080
2008	9,798.31	7,594	7,473	2,325	4.50	517
2009	52,062.46	37,745	37,144	14,918	5.50	2,712
2010	39,487.40	26,654	26,229	13,258	6.50	2,040
2011	76,427.62	47,767	47,006	29,422	7.50	3,923
2012	11,816.07	6,794	6,686	5,130	8.50	604
2013	69,050.65	36,252	35,675	33,376	9.50	3,513
2014	22,312.31	10,598	10,429	11,883	10.50	1,132
2015	64,165.13	27,270	26,836	37,329	11.50	3,246
2016	79,880.35	29,955	29,478	50,402	12.50	4,032
2017	64,019.56	20,806	20,475	43,545	13.50	3,226
2018	515,650.14	141,804	139,545	376,105	14.50	25,938
2019	162,882.48	36,649	36,065	126,817	15.50	8,182
2020	37,646.28	6,588	6,483	31,163	16.50	1,889
2021	93,757.93	11,720	11,534	82,224	17.50	4,699
2022	53,217.59	3,991	3,927	49,291	18.50	2,664
	1,555,309.86	632,785	622,707	932,603		79,266

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.8   5.10

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 395 LABORATORY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	36,231.68	34,420	36,232			
2015	8,105.79	6,890	7,466	640	1.50	427
2016	16,836.39	12,627	13,683	3,153	2.50	1,261
2020	12,796.72	4,479	4,853	7,944	6.50	1,222
	73,970.58	58,416	62,234	11,737		2,910

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.0   3.93

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 396 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-S0						
NET SALVAGE PERCENT.. 0						
2020	59,262.02	13,441	11,900	47,362	11.93	3,970
2022	117,369.54	12,840	11,367	106,003	12.22	8,675
2023	627,385.98	24,719	21,884	605,502	12.21	49,591
	804,017.54	51,000	45,151	758,867		62,236

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.2 7.74

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 397 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	53,343.52	50,676	41,016	12,328	0.50	12,328
2016	166,321.59	124,741	100,963	65,359	2.50	26,144
2017	12,516.18	8,136	6,585	5,931	3.50	1,695
2018	22,527.08	12,390	10,028	12,499	4.50	2,778
2019	25,342.02	11,404	9,230	16,112	5.50	2,929
2020	204,414.03	71,545	57,907	146,507	6.50	22,540
2021	221,515.29	55,379	44,823	176,692	7.50	23,559
2022	225,172.48	33,776	27,338	197,834	8.50	23,275
	931,152.19	368,047	297,890	633,262		115,248

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.5   12.38

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	8,850.87	7,523	5,868	2,983	1.50	1,989
2016	81,148.36	60,861	47,469	33,679	2.50	13,472
2018	66,633.01	36,648	28,584	38,049	4.50	8,455
2020	14,868.03	5,204	4,059	10,809	6.50	1,663
2021	76,140.46	19,035	14,846	61,294	7.50	8,173
2022	162,653.03	24,398	19,029	143,624	8.50	16,897
2023	181,248.28	9,062	7,068	174,180	9.50	18,335
	591,542.04	162,731	126,923	464,619		68,984

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.7 11.66

COMMON PLANT

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 301 ORGANIZATION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NONDEPRECIABLE						
1952	96,447.19					
1953	42,516.33					
	138,963.52					

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 389.1 LAND AND LAND RIGHTS - LAND

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NONDEPRECIABLE						
2017	6,947,107.66					
	6,947,107.66					

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI HEADQUARTERS BUILDING INTERIM SURVIVOR CURVE.. IOWA 70-R1 PROBABLE RETIREMENT YEAR.. 1-2069 NET SALVAGE PERCENT.. 0						
2019	29,987,923.48	3,670,522	3,678,926	26,308,997	32.26	815,530
2020	1,890,627.83	187,928	188,358	1,702,270	31.71	53,682
2021	654,570.06	49,093	49,205	605,365	30.83	19,636
2022	3,248,137.93	156,885	157,244	3,090,894	29.56	104,563
2023	166,566.49	3,115	3,122	163,444	26.24	6,229
	35,947,825.79	4,067,543	4,076,856	31,870,970		999,640

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.9 2.78

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	11,896.38	11,599	10,483	1,413	0.50	1,413
2005	39,965.68	36,968	33,411	6,555	1.50	4,370
2006	2,468.81	2,160	1,952	517	2.50	207
2007	878.14	724	654	224	3.50	64
2008	572.40	444	401	171	4.50	38
2009	4,753.12	3,446	3,114	1,639	5.50	298
2010	747,318.56	504,440	455,898	291,421	6.50	44,834
2019	3,525,373.71	793,209	716,879	2,808,495	15.50	181,193
2020	27,303.10	4,778	4,318	22,985	16.50	1,393
2022	782,244.07	58,668	53,023	729,221	18.50	39,417
2023	100,000.00	2,500	2,259	97,741	19.50	5,012
	5,242,773.97	1,418,936	1,282,392	3,960,382		278,239

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.2 5.31

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	277,195.89	249,476	210,309	66,887	0.50	66,887
2021	1,076,384.85	538,192	453,699	622,686	2.50	249,074
	1,353,580.74	787,668	664,008	689,573		315,961

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.2   23.34

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - CARS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 7-L2.5						
NET SALVAGE PERCENT.. 0						
2004	26,875.84	26,876	26,876			
2008	22,536.44	21,658	22,536			
2014	22,224.80	18,940	22,225			
	71,637.08	67,474	71,637			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2020	27,967.27	9,789	3,864	24,103	6.50	3,708
	27,967.27	9,789	3,864	24,103		3,708

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.5   13.26

INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	5,698.56	5,556	5,552	147	0.50	147
2007	1,760.05	1,452	1,451	309	3.50	88
2022	558.68	42	42	517	18.50	28
	8,017.29	7,050	7,045	972		263

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.7 3.28

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	9,507,270.50	8,556,543	8,555,399	951,872	0.50	951,872
2020	1,979,935.89	1,385,955	1,385,770	594,166	1.50	396,111
2021	847,064.50	423,532	423,475	423,590	2.50	169,436
2022	2,422,784.11	726,835	726,738	1,696,046	3.50	484,585
	14,757,055.00	11,092,865	11,091,382	3,665,673		2,002,004

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.8   13.57

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SUCCESS FACTORS INTERIM SURVIVOR CURVE.. SQUARE PROBABLE RETIREMENT YEAR.. 9-2024 NET SALVAGE PERCENT.. 0						
2019	2,803,866.07	2,243,093	2,046,868	756,998	1.00	756,998
	2,803,866.07	2,243,093	2,046,868	756,998		756,998
UNITE ERP INTERIM SURVIVOR CURVE.. SQUARE PROBABLE RETIREMENT YEAR.. 9-2034 NET SALVAGE PERCENT.. 0						
2019	10,695,816.43	2,852,253	2,395,208	8,300,608	11.00	754,601
	10,695,816.43	2,852,253	2,395,208	8,300,608		754,601
	13,499,682.50	5,095,346	4,442,076	9,057,606		1,511,599

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.0 11.20

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.3 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE - SYSTEM DEV. COSTS - 10 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	935,231.11	888,470	849,722	85,509	0.50	85,509
2015	732,102.69	622,287	595,148	136,955	1.50	91,303
2016	930,430.13	697,823	667,390	263,040	2.50	105,216
2017	1,349,992.48	877,495	839,226	510,767	3.50	145,933
2018	1,373,844.01	755,614	722,660	651,184	4.50	144,708
2019	7,509,579.44	3,379,311	3,231,933	4,277,646	5.50	777,754
2020	12,521,978.02	4,382,692	4,191,555	8,330,423	6.50	1,281,604
2021	7,759,405.05	1,939,851	1,855,251	5,904,154	7.50	787,221
2022	8,508,252.60	1,276,238	1,220,579	7,287,674	8.50	857,373
2023	10,663,545.78	533,177	509,924	10,153,622	9.50	1,068,802
	52,284,361.31	15,352,958	14,683,389	37,600,972		5,345,423

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.0   10.22

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.4 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE - SYSTEM DEV. COSTS - 15 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2011	425,873.07	354,893	351,472	74,401	2.50	29,760
2012	401,290.13	307,657	304,691	96,599	3.50	27,600
2013	142,364.69	99,655	98,694	43,671	4.50	9,705
2014	495,556.48	313,851	310,825	184,731	5.50	33,587
2016	1,419,264.44	709,632	702,791	716,473	7.50	95,530
2017	76,271,826.62	33,050,871	32,732,233	43,539,594	8.50	5,122,305
2018	171,914.66	63,036	62,428	109,487	9.50	11,525
2019	43,660,591.71	13,098,178	12,971,901	30,688,691	10.50	2,922,732
2021	7,039,054.95	1,173,199	1,161,888	5,877,167	12.50	470,173
2022	2,541,873.11	254,187	251,737	2,290,136	13.50	169,640
2023	1,661,521.87	55,379	54,845	1,606,677	14.50	110,805
	134,231,131.73	49,480,538	49,003,505	85,227,627		9,003,362

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.5 6.71

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.4 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE - SYSTEM DEV. COSTS - 15 YRS - 100% ELECTRIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2023	246,470.00	8,215		246,470	14.50	16,998
	246,470.00	8,215		246,470		16,998

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.5   6.90

EMPIRE YARD

UGI UTILITIES, INC. - ELECTRIC DIVISION - EMPIRE YARD

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MAJOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2047						
NET SALVAGE PERCENT.. 0						
1960	100,499.94	71,667	78,642	21,858	20.10	1,087
1961	86,508.37	61,389	67,363	19,145	20.21	947
1962	140,558.81	99,249	108,908	31,651	20.32	1,558
1963	9,442.40	6,634	7,280	2,163	20.42	106
1964	3,674.58	2,568	2,818	857	20.53	42
1965	477.14	332	364	113	20.63	5
1966	296.26	205	225	71	20.73	3
1967	857.15	589	646	211	20.82	10
1968	3,557.23	2,432	2,669	889	20.92	42
1969	658.89	448	492	167	21.01	8
1970	2,316.83	1,565	1,717	600	21.10	28
1971	74,575.40	50,071	54,944	19,631	21.18	927
1972	5,261.38	3,509	3,850	1,411	21.27	66
1973	5,843.65	3,873	4,250	1,594	21.35	75
1974	1,073.99	707	776	298	21.43	14
1975	20,047.09	13,102	14,377	5,670	21.51	264
1976	98,084.00	63,656	69,851	28,233	21.58	1,308
1977	261,697.27	168,544	184,947	76,751	21.66	3,543
1978	14,817.14	9,471	10,393	4,424	21.73	204
1979	31,221.86	19,796	21,723	9,499	21.80	436
1980	50,104.64	31,512	34,579	15,526	21.86	710
1981	48,820.38	30,440	33,402	15,418	21.93	703
1982	16,051.84	10,591	11,622	4,430	21.40	207
1983	15,874.20	10,350	11,357	4,517	21.61	209
1984	47,472.06	30,752	33,745	13,727	21.48	639
1985	68,561.79	43,818	48,082	20,479	21.74	942
1986	219,780.39	139,297	152,853	66,927	21.67	3,088
1987	95,473.78	59,938	65,771	29,703	21.64	1,373
1988	78,735.36	48,910	53,670	25,065	21.65	1,158
1989	133,490.77	81,977	89,955	43,536	21.68	2,008
1990	1,470.74	892	979	492	21.75	23
1991	12,725.02	7,610	8,351	4,374	21.85	200
1992	108,027.59	63,628	69,820	38,207	21.98	1,738
1993	238,417.49	138,902	152,420	85,998	21.85	3,936
1994	9,206.88	5,269	5,782	3,425	22.05	155
1995	132,803.20	74,941	82,234	50,569	22.01	2,298
1996	77,445.14	43,021	47,208	30,237	22.00	1,374
1997	4,614,443.82	2,519,025	2,764,177	1,850,267	22.04	83,950
1998	280,002.33	149,941	164,533	115,469	22.12	5,220
1999	84,688.61	44,402	48,723	35,965	22.23	1,618
2000	89,551.86	46,083	50,568	38,984	22.16	1,759

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MAJOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2047						
NET SALVAGE PERCENT.. 0						
2001	723,872.44	364,832	400,337	323,535	22.14	14,613
2002	42,180.55	20,770	22,791	19,389	22.17	875
2003	180,415.17	86,545	94,968	85,448	22.24	3,842
2004	145,868.26	67,975	74,590	71,278	22.34	3,191
2005	166,693.96	75,546	82,898	83,796	22.32	3,754
2006	139,745.07	61,376	67,349	72,396	22.34	3,241
2007	875,480.49	371,204	407,330	468,151	22.41	20,890
2008	79,151.97	32,389	35,541	43,611	22.38	1,949
2009	54,032.16	21,235	23,302	30,731	22.40	1,372
2010	195,892.96	73,773	80,953	114,940	22.34	5,145
2011	314,430.54	112,818	123,797	190,633	22.34	8,533
2012	49,336.39	16,735	18,364	30,973	22.40	1,383
2013	122,473.11	39,093	42,898	79,576	22.39	3,554
2014	163,711.37	48,835	53,588	110,124	22.35	4,927
2015	94,750.79	26,170	28,717	66,034	22.27	2,965
2016	607,709.35	153,143	168,047	439,662	22.26	19,751
2017	58,109.87	13,144	14,423	43,687	22.24	1,964
2018	71,659.02	14,231	15,616	56,043	22.20	2,524
2019	6,728.66	1,138	1,249	5,480	22.10	248
2020	45,606.51	6,275	6,886	38,721	21.94	1,765
2021	221,160.77	22,824	25,045	196,116	21.71	9,033
2022	625,364.39	41,024	45,016	580,348	21.38	27,144
2023	269,151.21	6,460	7,089	262,063	20.29	12,916
	12,538,142.28	5,838,641	6,406,858	6,131,284		279,560
PNG - EMPIRE YARD - MINOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2022						
NET SALVAGE PERCENT.. 0						
1960	27,374.98	27,375	27,375			
1961	2,250.14	2,250	2,250			
1962	11,395.40	11,395	11,395			
1964	212.41	212	212			
1965	479.69	480	480			
1972	4,846.95	4,847	4,847			
1973	59,338.04	59,338	59,338			
1976	674.99	675	675			
1977	9,114.69	9,115	9,115			

UGI UTILITIES, INC. - ELECTRIC DIVISION - EMPIRE YARD

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MINOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2022						
NET SALVAGE PERCENT.. 0						
1978	24,124.85	24,125	24,125			
1979	540.75	541	541			
1980	8,726.53	8,727	8,727			
1981	52,430.77	52,431	52,431			
1982	22,292.87	22,293	22,293			
1984	11,417.15	11,417	11,417			
1986	31,130.64	31,131	31,131			
1987	11,362.33	11,362	11,362			
1988	15,773.37	15,773	15,773			
1989	8,654.63	8,655	8,655			
1990	94,337.02	94,337	94,337			
1992	6,049.58	6,050	6,050			
1993	1,598.34	1,598	1,598			
1994	38,859.45	38,859	38,859			
1995	4,586.75	4,587	4,587			
1996	1,532.27	1,532	1,532			
1997	1,129.92	1,130	1,130			
1998	3,483.10	3,483	3,483			
2001	6,551.41	6,551	6,551			
2002	8,685.69	8,686	8,686			
2003	26,975.97	26,976	26,976			
2004	262,708.52	262,709	262,709			
2005	28,203.02	28,203	28,203			
2008	29,302.79	29,303	29,303			
2010	189,349.18	189,349	189,349			
2011	217,404.63	217,405	217,405			
2014	19,697.18	19,697	19,697			
2016	36,430.01	36,430	36,430			
2017	42,967.09	42,967	42,967			
2018	58,528.05	58,528	58,528			
2019	838,990.00	838,990	838,990			
2022	155,500.81	155,501	155,501			
	2,375,011.96	2,375,013	2,375,012			
	14,913,154.24	8,213,654	8,781,870	6,131,284		279,560

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.9   1.87

PART VIII. EXPERIENCED AND ESTIMATED NET SALVAGE

UGI UTILITIES, INC. - ELECTRIC DIVISION

EXPERIENCED AND ESTIMATED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2019 TRANSACTION YEAR				
362.00		5,944.00		5,944.00-
364.00	160,972.00	178,476.00		178,476.00-
365.00	36,704.00	54,263.00		54,263.00-
366.00		3,977.00		3,977.00-
367.00	133,789.00	4,285.00		4,285.00-
368.10		235.00		235.00-
368.20	30,908.00	17,595.00		17,595.00-
369.00	18,624.00	88,722.00		88,722.00-
370.10	41,739.00			
370.20	3,388.00	6,489.00		6,489.00-
371.00	51,349.00	7,910.00		7,910.00-
373.00	26,285.00	7,411.00		7,411.00-
394.00	17,552.00			
395.00	10,623.00			
397.00	346,775.00			
398.00	37,987.00			
	916,695.00	375,307.00		375,307.00-
2020 TRANSACTION YEAR				
362.00		24,880.00		24,880.00-
364.00	28,014.00	695,428.00		695,428.00-
365.00		121,069.00		121,069.00-
366.00		9,269.00		9,269.00-
367.00		14,036.00		14,036.00-
368.10		3,020.00		3,020.00-
368.20		58,648.00		58,648.00-
369.00		81,584.00		81,584.00-
370.10	222,832.00		59,469.00	59,469.00
370.20		3,781.00		3,781.00-
371.00		9,609.00		9,609.00-
373.00		19,433.00		19,433.00-
391.00	538.00			
391.10	10,122.00			
392.20			13,693.00	13,693.00
394.00	26,726.00			
397.00	337,961.00			
398.00	19,983.00	419.00		419.00-
	646,176.00	1,041,176.00	73,162.00	968,014.00-

UGI UTILITIES, INC. - ELECTRIC DIVISION

EXPERIENCED AND ESTIMATED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2021 TRANSACTION YEAR				
362.00		5,721.00		5,721.00-
364.00	210,322.00	628,085.00		628,085.00-
365.00	135,947.00	175,874.00		175,874.00-
366.00	3,158.00	49.00		49.00-
367.00	7,219.00	23,539.00		23,539.00-
368.10	259.00	4,895.00		4,895.00-
368.20	83,839.00	25,689.00		25,689.00-
369.00	26,812.00	72,000.00		72,000.00-
370.10	36,917.00	76,928.00-		76,928.00
370.20	26,564.00	3,263.00		3,263.00-
370.30	67,438.00			
371.00	141,173.00	30,601.00		30,601.00-
373.00	36,544.00	14,719.00		14,719.00-
391.10	7,084.00			
392.20		112.00-		112.00
395.00	55,959.00			
397.00	15,410.00	63.00		63.00-
398.00		8,277.00		8,277.00-
	854,645.00	915,735.00		915,735.00-
2022 TRANSACTION YEAR				
361.00		1,103.00		1,103.00-
362.00		9,451.00		9,451.00-
364.00	276,581.00	441,244.00		441,244.00-
365.00	133,125.00	138,834.00		138,834.00-
366.00	2,024.00	500.00		500.00-
367.00	25,277.00	16,452.00		16,452.00-
368.10	524,628.00	7,807.00		7,807.00-
368.20	95,304.00	33,600.00		33,600.00-
369.00	2,405.00	39,522.00		39,522.00-
370.10	28,484.00	68,289.00-		68,289.00
370.20	3,088.00	3,331.00		3,331.00-
370.30	21,404.00	2,299.00		2,299.00-
371.00	42,122.00	32,911.00		32,911.00-
373.00	70,453.00	28,409.00		28,409.00-
390.10		174.00		174.00-
391.00	2,580.00			
391.10	6,904.00			
392.20		1,099.00		1,099.00-
394.00	1,033.00			
395.00	17,678.00			
397.00	182,759.00			
398.00		30,752.00		30,752.00-
	1,435,849.00	719,199.00		719,199.00-

UGI UTILITIES, INC. - ELECTRIC DIVISION

EXPERIENCED AND ESTIMATED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2023 TRANSACTION YEAR				
362.00	2,651.00	265.00	195.00	70.00-
364.00	53,094.00	79,641.00		79,641.00-
365.00	787,454.00	787,454.00		787,454.00-
367.00	14,734.00	2,950.00		2,950.00-
368.10	246,521.00	14,447.00		14,447.00-
368.20	2,119.00	1,060.00		1,060.00-
369.00	24,818.00	43,432.00		43,432.00-
370.10	68,379.00		38,693.00	38,693.00
370.20	3,346.00	2,005.00		2,005.00-
373.00	29,580.00	14,699.00		14,699.00-
390.10	250,394.00			
391.92	662,056.00			
394.00	78,913.00			
395.00	23,859.00			
397.00	92,135.00	5.00		5.00-
	2,340,053.00	945,958.00	38,888.00	907,070.00-
TOTAL	6,193,418.00	3,997,375.00	112,050.00	3,885,325.00-

BOOK VII

UGI UTILITIES, INC. – ELECTRIC DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI ELECTRIC EXHIBIT C
(HISTORIC)
2022 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF SEPTEMBER 30, 2022

Witness: John F. Wiedmayer
Prepared by: Gannett Fleming
Valuation and Rate Consultants, LLC

UGI UTILITIES, INC. – ELECTRIC DIVISION
PA P.U.C. NO. 6, SUPPLEMENT NO. 51
PA P.U.C. NO. 2S, SUPPLEMENT NO. 7

DOCKET NO. R-2022-3037368

Issued: January 27, 2023 **Effective: March 28, 2023**

UGI Electric Exhibit C (Historic)
Witness: J. F. Wiedmayer

UGI UTILITIES, INC. - ELECTRIC DIVISION

DOCKET NO. R-2022-3037368

2022 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO ELECTRIC PLANT
AT SEPTEMBER 30, 2022

Prepared by:

GANNETT FLEMING

Excellence Delivered As Promised

UGI UTILITIES, INC. - ELECTRIC DIVISION

Docket No. R-2022-3037368

2022 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT
AT SEPTEMBER 30, 2022

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC
Valley Forge, Pennsylvania

Gannett Fleming
Valuation and Rate Consultants, LLC

Corporate Headquarters
207 Senate Avenue
Camp Hill, PA 17011
P 717.763.7211 | **F** 717.763.8150

gannettfleming.com

January 17, 2023

Mr. Christopher R. Brown
Vice President and General Manager, Rates and Supply
UGI Utilities, Inc. - Electric Division
1 UGI Drive
Denver, PA 17517

Ladies and Gentlemen:

Pursuant to your request, we have determined the annual depreciation accruals applicable to electric plant at September 30, 2022. Summaries of the original cost, annual accruals and the book depreciation reserve are presented in Tables 1 and 2 of the attached report.

A description of the methods and procedures upon which the study was based is set forth in a companion report, UGI Electric Exhibit C (Future), “2023 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant at September 30, 2023”.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

John F. Wiedmayer

JOHN F. WIEDMAYER, C.D.P.
Project Manager – Depreciation Studies

JFW:mle

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TABLE OF CONTENTS

PART I. INTRODUCTION

UGI UTILITIES, INC. - ELECTRIC DIVISION
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for UGI Utilities, Inc. - Electric Division to determine the annual depreciation accrual rates and amounts for ratemaking purposes applicable to the original cost of electric plant at September 30, 2022.

BASIS

Depreciation

The annual depreciation accruals and accrued depreciation were calculated using the straight-line method, the remaining life basis, the average service life (ASL) procedure for plant installed prior to 1982 and the equal life group procedure (ELG) for 1982 and subsequent vintages. The calculations were based on the attained ages and estimated service life characteristics for each depreciable group of electric property.

Service Life Estimates

The service life and survivor curve estimates used for the calculation of depreciation at September 30, 2022, are set forth in Table 1 and are based on company data through 2021. The company is not proposing any changes to the service life estimates. The service life estimates are the same estimates as submitted to the

Pennsylvania Public Utility Commission (PA PUC) in the company's most recent service life study report in May 2022.

Remaining Life Annual Accruals

For the purpose of calculating remaining life accruals at September 30, 2022, the book reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation for the average service life procedure are presented in Exhibit C (Future). The detailed calculations at September 30, 2022, are set forth in Part III of this report.

Amortization of Net Salvage

In accordance with Pennsylvania rate regulation practice, under which experienced costs of negative net salvage are amortized after their occurrence, no adjustments for expected net salvage were made to either the annual depreciation accrual or the calculated accrued depreciation for the individual accounts. The annual provision for recovering negative net salvage is based on the amortization of experienced net salvage over a five-year period.

PART II. RESULTS OF STUDY

PART II. RESULTS OF STUDY

DESCRIPTION OF SUMMARY TABULATIONS

The tables on pages II-3 through II-7 summarize the results of the depreciation studies for electric plant at September 30, 2022. Table 1 sets forth, by depreciable group, the estimated survivor curves, original cost, book depreciation reserve, and calculated annual accrual at September 30, 2022.

Table 2 presents the amortization of experienced net salvage based on the five-year period, 2018-2022. The total amortization amount is incorporated at the end of the annual accrual amount column in Table 1 on page II-3.

DETAILED TABULATIONS OF DEPRECIATION CALCULATIONS

Supporting data for the original cost depreciation calculations in account sequence are presented in Part III of this report. The tables indicate the estimated survivor curves used in the calculations and set forth, for each installation year, the original cost, calculated accrued depreciation, allocated book reserve, future book accruals, remaining life, and calculated remaining life accrual.

Detailed tabulations setting forth the experienced cost of removal and salvage amounts by year and account are presented in Part IV of this report. The net salvage amounts are carried forward to Table 2 which presents the five-year amortization.

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND
CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF SEPTEMBER 30, 2022

ACCOUNT	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
ELECTRIC PLANT							
DISTRIBUTION PLANT							
361 STRUCTURES AND IMPROVEMENTS		50 - R3	627,496	36,400	591,096	2.45	15,372
362 STATION EQUIPMENT		40 - S1	10,981,236	796,511	10,184,725	3.32	364,561
364 POLES, TOWERS AND FIXTURES		59 - R2.5	54,077,226	15,594,836	38,482,390	1.90	1,025,883
365 OVERHEAD CONDUCTORS AND DEVICES		58 - R1.5	54,595,611	14,111,095	40,484,516	2.13	1,162,621
365.7 REG AFUDC		40 - SQ	(711,827)	(83,047)	(628,780)	2.29	(16,332)
366 UNDERGROUND CONDUIT		65 - R3	8,779,918	2,409,512	6,370,406	1.58	138,468
367 UNDERGROUND CONDUCTORS AND DEVICES		42 - R1.5	14,750,367	4,071,859	10,678,508	2.98	439,540
368.1 TRANSFORMERS		45 - S1	16,660,208	8,046,476	8,613,732	1.99	331,767
368.2 TRANSFORMER INSTALLATIONS		39 - R2	11,197,561	6,195,958	5,001,603	1.98	221,283
369 SERVICES		53 - R2	15,753,385	7,527,834	8,225,551	1.68	264,868
370.1 METERS		34 - R1	2,949,899	2,073,283	876,616	1.75	51,724
370.2 METER INSTALLATIONS		75 - R4	1,972,304	778,252	1,194,052	1.26	24,945
370.3 ELECTRONIC METERS		20 - S3	5,037,891	4,010,096	1,027,795	2.73	137,298
371 INSTALLATIONS ON CUSTOMER PREMISES		30 - O1	2,219,114	873,689	1,345,425	4.25	94,254
371.5 INSTALLATIONS ON CUSTOMER PREMISES - DUSK TO DAWN LIGHTS		23 - R1	347,706	334,801	12,905	0.44	1,521
373 STREET LIGHTING AND SIGNAL SYSTEMS		28 - L0	2,331,583	980,610	1,350,973	4.41	102,747
TOTAL DISTRIBUTION PLANT			**201,569,678**	**67,758,165**	**133,811,513**	**2.16**	**4,360,520**
GENERAL PLANT							
390.1 STRUCTURES AND IMPROVEMENTS							
FORTY FORT	6-2032	* 100 - L0	2,773,772	745,320	2,028,452	7.84	217,488
PLYMOUTH		FULLY ACCRUED	15,111	15,111	0	-	0
IDETOWN	6-2046	* 100 - L0	49,926	11,035	38,891	3.78	1,887
NANTICOKE		FULLY ACCRUED	76,179	76,179	0	-	0
EMPIRE YARD		FULLY ACCRUED	19,895	19,895	0	-	0
SYSTEM CONTROL CENTER	7-2056	* 100 - L0	1,891,888	326,294	1,565,594	3.00	56,700
SUBTOTAL ACCOUNT 390.1			*4,826,771*	*1,193,834*	*3,632,937*	*5.72*	*276,075*
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	66,068	15,334	50,734	7.27	4,802
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	369,215	130,617	238,598	41.96	154,925
391.9 OFFICE FURNITURE AND EQUIPMENT - OUTAGE MANAGEMENT SOFTWARE		5 - SQ	4,023,657	660,150	3,363,507	-	748,719
393 STORES EQUIPMENT		10 - SQ	14,618	4,135	10,483	11.97	1,750
394 TOOLS, SHOP AND GARAGE EQUIPMENT		20 - SQ	1,634,223	615,343	1,018,880	5.16	84,339
395 LABORATORY EQUIPMENT		10 - SQ	97,830	83,568	14,262	2.94	2,881
397 COMMUNICATION EQUIPMENT		10 - SQ	1,023,287	152,259	871,028	18.92	193,580
398 MISCELLANEOUS EQUIPMENT		10 - SQ	410,294	51,910	358,384	13.40	54,979
TOTAL GENERAL PLANT			**12,465,963**	**2,907,150**	**9,558,813**	**12.21**	**1,522,050**

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF SEPTEMBER 30, 2022

ACCOUNT	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
SPECIAL DEPRECIABLE PLANT							
392.1 TRANSPORTATION EQUIPMENT - CARS		7 - L3	302,097	123,694	178,403	13.85	41,834
392.2 TRANSPORTATION EQUIPMENT - LIGHT TRUCKS		11 - L3	1,394,971	140,850	1,254,121	11.21	156,409
392.4 TRANSPORTATION EQUIPMENT - HEAVY TRUCKS		14 - S3	490,636	35,877	454,759	8.08	39,644
396 POWER OPERATED EQUIPMENT		20 - S0	176,632	6,317	170,315	7.92	13,990
TOTAL SPECIAL DEPRECIABLE PLANT			**2,364,336**	**306,738**	**2,057,598**	**10.65**	**251,877**
TOTAL DEPRECIABLE PLANT			**216,399,977**	**70,972,053**	**145,427,924**	**2.83**	**6,134,447**
NONDEPRECIABLE PLANT							
301 ORGANIZATION			1,602				
302.1 FRANCHISES AND CONSENTS - PERPETUAL			6,436				
360.1 LAND AND LAND RIGHTS - LAND			294,162				
360.2 LAND AND LAND RIGHTS - LAND RIGHTS			14,336				
389.1 LAND AND LAND RIGHTS - LAND			202,584	14,257			
TOTAL NONDEPRECIABLE PLANT			**519,120**	**14,257**			
TOTAL ELECTRIC PLANT			**216,919,097**	**70,986,310**			
LESS GENERAL AND INTANGIBLE PLANT ALLOCATED TO TRANSMISSION - 25.6247%			3,854,191	827,202	2,976,670		454,563
TOTAL ELECTRIC PLANT RELATED TO DISTRIBUTION OPERATIONS			**213,064,906**	**70,159,108**	**142,451,254**		**5,679,884**
OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION							
COMMON PLANT							
301 ORGANIZATION (NONDEPRECIABLE)			138,964				
389.1 LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)			6,947,108				
390.1 STRUCTURES AND IMPROVEMENTS	1-2069 *	70 - R1	35,781,259	3,018,983	32,762,276	2.92	1,045,229
390.2 STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY		FULLY ACCRUED	0	10,628	(10,628)	-	
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	5,149,957	1,011,569	4,138,388	5.33	274,631
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	1,442,199	272,031	1,170,168	30.76	443,561
392.1 TRANSPORTATION EQUIPMENT - CARS		7 - L2.5	71,637	71,637	0	-	0
TOTAL COMMON PLANT			**49,531,124**	**4,384,848**	**38,060,204**	**3.56**	**1,763,421**
TOTAL COMMON PLANT ALLOCATED TO ELECTRIC DIVISION - 9.83%			**4,868,909**	**431,031**	**3,741,318**		**173,344**

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND
CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF SEPTEMBER 30, 2022

ACCOUNT		PROBABLE RETIREMENT YEAR		SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)		(2)		(3)	(4)	(5)	(6)	(7)	(8)
	INFORMATION SERVICES (IS)								
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE			20 - SQ	30,702	28,853	1,849	2.90	890
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT			5 - SQ	20,341,486	13,083,477	7,258,009	17.57	3,573,527
391.2	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE								
	SUCCESS FACTORS	9-2024	**	SQUARE	2,803,866	1,289,824	1,514,042	27.00	757,021
	UNITE ERP	9-2034	***	SQUARE	10,695,816	1,640,083	9,055,733	7.06	754,644
	TOTAL OFFICE FURNITURE AND EQUIPMENT - SOFTWARE				13,499,682	2,929,907	10,569,775	11.20	1,511,665
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS			10 - SQ	54,302,404	22,617,829	31,684,575	8.00	4,344,724
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS			15 - SQ	141,049,948	48,592,264	92,457,684	6.38	8,995,919
	TOTAL INFORMATION SERVICES				**229,224,222**	**87,252,330**	**141,971,892**	**8.04**	**18,426,725**
	TOTAL INFORMATION SERVICES ALLOCATED TO ELECTRIC DIVISION - 9.08%				**20,813,559**	**7,922,512**	**12,891,048**		**1,673,147**
	EMPIRE YARD BUILDING								
390.1	STRUCTURES AND IMPROVEMENTS	12-2047	*	80 - R1.5	14,670,918	8,535,610	6,135,309	1.84	269,942
	TOTAL EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%				**1,917,489**	**1,115,604**	**801,885**		**35,281**
TOTAL OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION					**27,599,957**	**9,469,147**	**17,434,251**		**1,881,772**
	LESS OTHER UTILITY PLANT ALLOCATED TO ELECTRIC TRANSMISSION - 25.6247%				7,072,406	2,426,441	4,467,475		482,198
TOTAL OTHER PLANT ALLOCATED TO ELECTRIC RELATED TO DISTRIBUTION OPERATIONS					**20,527,551**	**7,042,706**	**12,966,776**		**1,399,574**
TOTAL PLANT IN SERVICE RELATED TO DISTRIBUTION OPERATIONS					**233,592,457**	**77,201,814**	**155,418,030**		**7,079,458**
AMORTIZATION OF NEGATIVE NET SALVAGE									**688,007**
GRAND TOTAL					**233,592,457**	**77,201,814**	**155,418,030**		**7,767,465**

* SURVIVOR CURVES FOR ACCOUNT 390 ARE INTERIM SURVIVOR CURVES. INDIVIDUAL BUILDINGS ARE LIFE SPANNED.
** REGULATORY ASSET DEPRECIATED OVER FOUR YEARS. TWO YEARS REMAINING.
*** REGULATORY ASSET DEPRECIATED OVER FOURTEEN YEARS. TWELVE YEARS REMAINING.

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 2. AMORTIZATION OF EXPERIENCED NET SALVAGE

ACCOUNT	2018 GROSS SALVAGE	2018 COST OF REMOVAL	2019 GROSS SALVAGE	2019 COST OF REMOVAL	2020 GROSS SALVAGE	2020 COST OF REMOVAL	2021 GROSS SALVAGE	2021 COST OF REMOVAL	2022 GROSS SALVAGE	2022 COST OF REMOVAL	FIVE YEAR NET SALVAGE TOTAL	NET SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=(12)/5
ELECTRIC PLANT												
DISTRIBUTION PLANT												
361	0	0	0	0	0	0	0	0	0	1,103	1,103	221
362	(6,395)	31,267	0	5,944	0	24,880	0	5,721	0	9,451	70,868	14,174
364	0	224,701	0	178,476	0	695,428	0	628,085	0	441,244	2,167,934	433,587
365	0	48,433	0	54,263	0	121,069	0	175,874	0	138,834	538,473	107,695
366	0	4,203	0	3,977	0	9,269	0	49	0	500	17,998	3,600
367	0	6,274	0	4,285	0	14,036	0	23,539	0	16,452	64,586	12,917
368.1	0	15,300	0	235	0	3,020	0	4,895	0	7,807	31,257	6,251
368.2	0	45,925	0	17,595	0	58,648	0	25,689	0	33,600	181,457	36,291
369	0	74,029	0	88,722	0	81,584	0	72,000	0	39,522	355,857	71,171
370.1	0	0	0	0	(59,469)	0	0	(76,928)	0	(68,289)	(204,686)	(40,937)
370.2	0	4,074	0	6,489	0	3,781	0	3,263	0	3,331	20,938	4,188
370.3	0	0	0	0	0	0	0	0	0	2,299	2,299	460
371	0	10,164	0	7,910	0	9,609	0	30,601	0	32,911	91,195	18,239
371.5	0	0	0	0	0	0	0	0	0	0	0	0
373	0	10,708	0	7,411	0	19,433	0	14,719	0	28,409	80,680	16,136
TOTAL	**(6,395)**	**475,078**	**0**	**375,307**	**(59,469)**	**1,040,757**	**0**	**907,507**	**0**	**687,174**	**3,419,959**	**683,993**
GENERAL PLANT												
390.1	0	0	0	0	0	0	0	0	0	174	174	35
390.2	0	0	0	0	0	0	0	0	0	0	0	0
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
391.92	0	0	0	0	0	0	0	0	0	0	0	0
392.1	0	0	0	0	0	0	0	0	0	0	0	0
392.2	0	0	0	0	(13,693)	0	0	(112)	0	1,099	(12,706)	(2,541)
392.4	0	0	0	0	0	0	0	0	0	0	0	0
393	0	0	0	0	0	0	0	0	0	0	0	0
394	0	0	0	0	0	0	0	0	0	0	0	0
395	0	0	0	0	0	0	0	0	0	0	0	0
396	0	0	0	0	0	0	0	0	0	0	0	0
397	0	0	0	0	0	0	0	63	0	0	63	13
398	0	0	0	0	0	419	0	8,277	0	30,752	39,448	7,890
TOTAL	**0**	**0**	**0**	**0**	**(13,693)**	**419**	**0**	**8,228**	**0**	**32,025**	**26,979**	**5,397**
TOTAL ELECTRIC	**(6,395)**	**475,078**	**0**	**375,307**	**(73,162)**	**1,041,176**	**0**	**915,735**	**0**	**719,199**	**3,446,938**	**689,390**
LESS GENERAL PLANT ALLOCATED TO TRANSMISSION - 25.6247%	0	0	0	0	(3,509)	107	0	2,108	0	8,206	6,913	1,383
TOTAL	**(6,395)**	**475,078**	**0**	**375,307**	**(69,653)**	**1,041,069**	**0**	**913,627**	**0**	**710,993**	**3,440,025**	**688,007**

UGI UTILITIES, INC. - ELECTRIC DIVISION

TABLE 2. AMORTIZATION OF EXPERIENCED NET SALVAGE

ACCOUNT	2018 GROSS SALVAGE	2018 COST OF REMOVAL	2019 GROSS SALVAGE	2019 COST OF REMOVAL	2020 GROSS SALVAGE	2020 COST OF REMOVAL	2021 GROSS SALVAGE	2021 COST OF REMOVAL	2022 GROSS SALVAGE	2022 COST OF REMOVAL	FIVE YEAR NET SALVAGE TOTAL	NET SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=(12)/5
OTHER UTILITY PLANT ALLOCATED TO ELECTRIC DIVISION												
COMMON PLANT												
390.2	0	0	0	0	0	0	0	0	0	0	0	0
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
392.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
INFORMATION SERVICES												
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
391.3	0	0	0	0	0	0	0	0	0	0	0	0
391.4	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
GRAND TOTAL	**(6,395)**	**475,078**	**0**	**375,307**	**(69,653)**	**1,041,069**	**0**	**913,627**	**0**	**710,993**	**3,440,025**	**688,007**

PART III. DETAILED DEPRECIATION CALCULATIONS

CUMULATIVE DEPRECIATED ORIGINAL COST

ELECTRIC PLANT

UGI UTILITIES, INC. - ELECTRIC DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1917	7,418	7,370	48	48	0.0
1918	408	406	2	50	0.0
1919	7,333	7,144	189	239	0.0
1920	5,553	5,443	110	349	0.0
1921	899	825	74	423	0.0
1922	47	46	1	424	0.0
1923	12,736	12,548	188	612	0.0
1924	17,283	17,263	20	632	0.0
1925	23,289	23,210	79	711	0.0
1926	56,043	55,981	62	773	0.0
1927	63,509	55,873	7,636	8,409	0.0
1928	23,303	23,094	209	8,618	0.0
1929	39,465	39,302	163	8,781	0.0
1930	38,974	37,540	1,434	10,215	0.0
1931	14,505	14,224	281	10,496	0.0
1932	20,173	19,591	582	11,078	0.0
1933	31,413	30,219	1,194	12,272	0.0
1934	25,264	24,143	1,121	13,393	0.0
1935	22,093	20,695	1,398	14,791	0.0
1936	24,518	21,737	2,781	17,572	0.0
1937	14,584	13,593	991	18,563	0.0
1938	22,486	20,198	2,288	20,851	0.0
1939	26,158	24,451	1,707	22,558	0.0
1940	22,132	20,453	1,679	24,237	0.0
1941	28,146	25,924	2,222	26,459	0.0
1942	17,942	16,602	1,340	27,799	0.0
1943	21,116	18,805	2,311	30,110	0.0
1944	19,354	17,033	2,321	32,431	0.0
1945	25,335	22,586	2,749	35,180	0.0
1946	46,217	41,197	5,020	40,200	0.0
1947	52,571	46,783	5,788	45,988	0.0
1948	73,043	64,942	8,101	54,089	0.0
1949	82,144	73,336	8,808	62,897	0.0
1950	91,941	76,559	15,382	78,279	0.1
1951	84,052	71,262	12,790	91,069	0.1
1952	76,837	62,003	14,834	105,903	0.1
1953	55,767	46,935	8,832	114,735	0.1
1954	79,073	67,672	11,401	126,136	0.1
1955	141,283	121,549	19,734	145,870	0.1
1956	94,519	75,446	19,073	164,943	0.1
1957	124,185	104,749	19,436	184,379	0.1
1958	176,786	149,618	27,168	211,547	0.1
1959	139,161	114,375	24,786	236,333	0.2
1960	103,743	85,410	18,333	254,666	0.2
1961	150,350	121,076	29,274	283,940	0.2
1962	159,522	123,415	36,107	320,047	0.2

UGI UTILITIES, INC. - ELECTRIC DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1963	192,853	152,311	40,542	360,589	0.2
1964	249,971	198,157	51,814	412,403	0.3
1965	303,453	231,098	72,355	484,758	0.3
1966	277,270	213,509	63,761	548,519	0.4
1967	361,201	283,128	78,073	626,592	0.4
1968	438,970	352,399	86,571	713,163	0.5
1969	666,746	516,113	150,633	863,796	0.6
1970	732,161	579,333	152,828	1,016,624	0.7
1971	819,630	636,247	183,383	1,200,007	0.8
1972	867,189	704,049	163,140	1,363,147	0.9
1973	959,593	739,780	219,813	1,582,960	1.1
1974	1,053,679	775,069	278,610	1,861,570	1.3
1975	1,201,193	888,482	312,711	2,174,281	1.5
1976	976,662	717,096	259,566	2,433,847	1.7
1977	1,159,525	813,619	345,906	2,779,753	1.9
1978	1,104,102	773,560	330,542	3,110,295	2.1
1979	1,262,954	885,252	377,702	3,487,997	2.4
1980	1,145,279	805,595	339,684	3,827,681	2.6
1981	989,752	659,078	330,674	4,158,355	2.9
1982	1,147,440	882,501	264,939	4,423,294	3.0
1983	1,047,966	788,880	259,086	4,682,380	3.2
1984	1,013,880	754,160	259,720	4,942,100	3.4
1985	1,158,650	874,790	283,860	5,225,960	3.6
1986	1,280,546	932,028	348,518	5,574,478	3.8
1987	1,409,807	1,004,990	404,817	5,979,295	4.1
1988	1,710,592	1,183,412	527,180	6,506,475	4.5
1989	2,176,229	1,461,839	714,390	7,220,865	5.0
1990	2,254,478	1,493,085	761,393	7,982,258	5.5
1991	2,521,949	1,623,262	898,687	8,880,945	6.1
1992	3,031,343	1,917,652	1,113,691	9,994,636	6.9
1993	2,226,553	1,378,571	847,982	10,842,618	7.5
1994	2,801,146	1,688,673	1,112,473	11,955,091	8.2
1995	3,846,777	2,233,845	1,612,932	13,568,023	9.3
1996	3,707,838	2,123,198	1,584,640	15,152,663	10.4
1997	3,610,606	2,062,795	1,547,811	16,700,474	11.5
1998	3,337,781	1,846,083	1,491,698	18,192,172	12.5
1999	3,050,470	1,716,916	1,333,554	19,525,726	13.4
2000	2,730,617	1,458,704	1,271,913	20,797,639	14.3
2001	3,234,467	1,596,416	1,638,051	22,435,690	15.4
2002	2,818,857	1,318,486	1,500,371	23,936,061	16.5
2003	3,088,320	1,454,436	1,633,884	25,569,945	17.6
2004	3,409,637	1,550,736	1,858,901	27,428,846	18.9
2005	4,516,466	1,947,960	2,568,506	29,997,352	20.6
2006	3,350,743	1,375,534	1,975,209	31,972,561	22.0
2007	6,151,731	3,391,065	2,760,666	34,733,227	23.9
2008	5,257,883	1,929,233	3,328,650	38,061,877	26.2

UGI UTILITIES, INC. - ELECTRIC DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST: AMOUNT (2) - (3) (4)	DEPRECIATED ORIGINAL COST: CUMULATIVE AMOUNT (5)	DEPRECIATED ORIGINAL COST: PCT OF COL 4 TOTAL (6)
2009	3,522,566	1,138,161	2,384,405	40,446,282	27.8
2010	3,110,414	951,532	2,158,882	42,605,164	29.3
2011	3,537,462	1,068,446	2,469,016	45,074,180	31.0
2012	3,566,312	959,663	2,606,649	47,680,829	32.8
2013	5,657,727	1,855,080	3,802,647	51,483,476	35.4
2014	5,061,201	1,112,923	3,948,278	55,431,754	38.1
2015	5,683,807	1,156,233	4,527,574	59,959,328	41.2
2016	8,626,597	1,578,999	7,047,598	67,006,926	46.1
2017	9,549,627	1,353,494	8,196,133	75,203,059	51.7
2018	8,469,931	1,129,495	7,340,436	82,543,495	56.8
2019	16,622,359	1,607,211	15,015,148	97,558,643	67.1
2020	14,931,512	1,213,882	13,717,630	111,276,273	76.5
2021	12,127,225	533,886	11,593,339	122,869,612	84.5
2022	22,915,614	357,295	22,558,319	145,427,931	100.0
TOTAL	216,399,982	70,972,051	145,427,931		

COMMON PLANT

UGI UTILITIES, INC. - COMMON PLANT

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	DEPRECIATED ORIGINAL COST CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1952					0.0
1953					0.0
2003	7,183	6,074	1,109	1,109	0.0
2004	38,772	36,420	2,352	3,461	0.0
2005	39,966	30,331	9,635	13,096	0.0
2006	2,469	1,767	702	13,798	0.0
2007	878	591	287	14,085	0.0
2008	23,109	22,896	213	14,298	0.0
2009	4,753	2,782	1,971	16,269	0.0
2010	747,319	405,108	342,211	358,480	0.9
2014	22,225	22,225		358,480	0.9
2017				358,480	0.9
2018	88,618	36,360	52,258	410,738	1.1
2019	33,790,493	3,422,485	30,368,008	30,778,746	80.8
2020	1,917,931	136,025	1,781,906	32,560,652	85.5
2021	1,730,955	176,889	1,554,066	34,114,718	89.6
2022	4,030,382	74,267	3,956,115	38,070,833	100.0
SUBTOTAL	42,445,053	4,374,220	38,070,833		
NONDEPRECIABLE	7,086,071		7,086,071		
TOTAL	49,531,124	4,374,220	45,156,904		

INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2000	802,206	802,206			0.0
2001	18,800	18,800			0.0
2002	447,659	447,659			0.0
2003	22,684	22,184	500	500	0.0
2004	1,408,963	1,408,552	411	911	0.0
2005	990,669	990,669		911	0.0
2006	3,975,788	3,975,788		911	0.0
2007	6,303,993	6,303,601	392	1,303	0.0
2008	3,168,505	3,047,016	121,489	122,792	0.1
2009	481,827	481,827		122,792	0.1
2010	172,048	172,048		122,792	0.1
2011	450,138	347,920	102,218	225,010	0.2
2012	3,393,988	3,271,150	122,838	347,848	0.2
2013	524,329	429,117	95,212	443,060	0.3
2014	1,430,788	1,022,650	408,138	851,198	0.6
2015	732,103	514,083	218,020	1,069,218	0.8
2016	2,349,695	1,175,880	1,173,815	2,243,033	1.6
2017	77,621,819	28,417,778	49,204,041	51,447,074	36.2
2018	7,130,189	5,623,892	1,506,297	52,953,371	37.3
2019	74,177,124	22,101,849	52,075,275	105,028,646	74.0
2020	14,501,914	3,914,637	10,587,277	115,615,923	81.4
2021	15,645,524	2,039,996	13,605,528	129,221,451	91.0
2022	13,473,468	723,030	12,750,438	141,971,889	100.0
TOTAL	229,224,221	87,252,332	141,971,889		

EMPIRE YARD

UGI UTILITIES, INC. - ELECTRIC DIVISION - EMPIRE YARD

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1960	128,305	105,830	22,475	22,475	0.4
1961	89,121	69,422	19,699	42,174	0.7
1962	152,532	119,964	32,568	74,742	1.2
1963	9,480	7,254	2,226	76,968	1.3
1964	3,902	3,020	882	77,850	1.3
1965	959	842	117	77,967	1.3
1966	297	224	73	78,040	1.3
1967	860	643	217	78,257	1.3
1968	3,570	2,654	916	79,173	1.3
1969	661	488	173	79,346	1.3
1970	2,325	1,706	619	79,965	1.3
1971	74,835	54,564	20,271	100,236	1.6
1972	10,126	8,670	1,456	101,692	1.7
1973	65,201	63,554	1,647	103,339	1.7
1974	1,078	769	309	103,648	1.7
1975	20,112	14,249	5,863	109,511	1.8
1976	99,072	69,857	29,215	138,726	2.3
1977	271,633	192,256	79,377	218,103	3.6
1978	38,988	34,408	4,580	222,683	3.6
1979	31,857	22,025	9,832	232,515	3.8
1980	58,980	42,891	16,089	248,604	4.1
1981	101,394	85,426	15,968	264,572	4.3
1982	38,391	33,837	4,554	269,126	4.4
1983	15,919	11,273	4,646	273,772	4.5
1984	59,022	44,680	14,342	288,114	4.7
1985	68,750	47,642	21,108	309,222	5.0
1986	251,503	182,455	69,048	378,270	6.2
1987	107,089	76,047	31,042	409,312	6.7
1988	94,714	68,521	26,193	435,505	7.1
1989	142,488	96,971	45,517	481,022	7.8
1990	95,811	95,296	515	481,537	7.8
1991	12,757	8,228	4,529	486,066	7.9
1992	114,341	74,766	39,575	525,641	8.6
1993	240,589	150,605	89,984	615,625	10.0
1994	48,088	44,535	3,553	619,178	10.1
1995	137,699	85,194	52,505	671,683	10.9
1996	79,155	47,515	31,640	703,323	11.5
1997	4,625,955	2,689,647	1,936,308	2,639,631	43.0
1998	284,105	164,037	120,068	2,759,699	45.0
1999	84,873	47,451	37,422	2,797,121	45.6
2000	89,744	49,161	40,583	2,837,704	46.3
2001	731,950	393,162	338,788	3,176,492	51.8
2002	50,954	30,643	20,311	3,196,803	52.1
2003	207,758	118,644	89,114	3,285,917	53.6
2004	408,869	334,525	74,344	3,360,261	54.8
2005	195,225	107,774	87,451	3,447,712	56.2

UGI UTILITIES, INC. - ELECTRIC DIVISION - EMPIRE YARD

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

				DEPRECIATED ORIGINAL COST	
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2006	140,016	64,428	75,588	3,523,300	57.4
2007	877,150	389,638	487,512	4,010,812	65.4
2008	108,603	63,019	45,584	4,056,396	66.1
2009	54,132	22,081	32,051	4,088,447	66.6
2010	385,597	265,362	120,235	4,208,682	68.6
2011	532,395	332,856	199,539	4,408,221	71.9
2012	49,423	17,053	32,370	4,440,591	72.4
2013	122,684	39,468	83,216	4,523,807	73.7
2014	183,686	68,442	115,244	4,639,051	75.6
2015	94,908	25,753	69,155	4,708,206	76.7
2016	645,132	184,896	460,236	5,168,442	84.2
2017	101,170	55,398	45,772	5,214,214	85.0
2018	130,300	71,610	58,690	5,272,904	85.9
2019	845,729	839,987	5,742	5,278,646	86.0
2020	45,676	5,055	40,621	5,319,267	86.7
2021	221,492	15,589	205,903	5,525,170	90.1
2022	781,786	171,649	610,137	6,135,307	100.0
TOTAL	14,670,916	8,535,609	6,135,307		

UTILITY PLANT IN SERVICE

ELECTRIC PLANT

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. 0						
1925	4,675.49	4,675	4,675			
1926	1,561.20	1,561	1,561			
1943	642.32	626	379	263	1.24	212
1971	7,177.62	5,811	3,519	3,659	9.52	384
1975	12,539.90	9,668	5,854	6,686	11.45	584
1977	485.00	363	220	265	12.53	21
2018	50,277.08	5,138	3,111	47,166	39.55	1,193
2019	240,869.72	19,221	11,639	229,231	40.36	5,680
2020	34,409.01	1,979	1,198	33,211	40.98	810
2021	163,744.75	5,698	3,450	160,295	41.60	3,853
2022	111,114.35	1,311	794	110,320	41.87	2,635
	627,496.44	56,051	36,400	591,096		15,372

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.5   2.45

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 362 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

SURVIVOR CURVE.. IOWA 40-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1924	2,726.13	2,726	2,726			
1925	891.49	891	891			
1926	6,327.63	6,328	6,328			
1927	838.75	839	839			
1929	16,102.09	16,102	16,102			
1937	402.93	403	403			
1938	223.98	224	224			
1939	211.25	211	211			
1941	660.04	660	660			
1942	4,298.16	4,298	4,298			
1944	1,667.13	1,648	1,202	465	0.47	465
1945	169.98	167	122	48	0.74	48
1948	2,581.26	2,482	1,810	771	1.54	501
1949	933.81	892	651	283	1.81	156
1950	9,640.41	9,137	6,664	2,976	2.09	1,424
1951	6,911.66	6,502	4,742	2,170	2.37	916
1952	19,999.85	18,680	13,623	6,377	2.64	2,416
1955	3,999.73	3,650	2,662	1,338	3.50	382
1956	4,320.90	3,911	2,852	1,469	3.79	388
1957	946.99	850	620	327	4.09	80
1958	31,931.85	28,435	20,738	11,194	4.38	2,556
1959	11,300.76	9,979	7,278	4,023	4.68	860
1960	4,956.55	4,338	3,164	1,793	4.99	359
1961	9,143.13	7,934	5,786	3,357	5.29	635
1962	32,156.01	27,654	20,168	11,988	5.60	2,141
1963	5,613.46	4,783	3,488	2,125	5.92	359
1964	6,090.69	5,142	3,750	2,341	6.23	376
1965	4,496.86	3,760	2,742	1,755	6.55	268
1966	3,389.69	2,807	2,047	1,343	6.88	195
1967	25,575.36	20,965	15,290	10,285	7.21	1,426
1968	3,084.45	2,503	1,825	1,259	7.54	167
1969	40,224.28	32,300	23,557	16,667	7.88	2,115
1970	1,831.84	1,455	1,061	771	8.22	94
1971	737.50	580	423	314	8.56	37
1972	24,515.81	19,049	13,893	10,623	8.92	1,191
1973	2,774.69	2,132	1,555	1,220	9.27	132
1974	2,828.91	2,148	1,567	1,262	9.63	131
1975	5,724.08	4,293	3,131	2,593	10.00	259
1976	1,029.97	763	556	474	10.37	46
1977	7,297.57	5,336	3,892	3,406	10.75	317
1978	518.65	374	273	246	11.13	22
1982	3,032.25	2,368	1,727	1,305	11.30	115
1984	2,671.18	2,033	1,483	1,188	12.00	99

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 362 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-S1						
NET SALVAGE PERCENT.. 0						
1991	20,744.60	14,198	10,355	10,390	14.41	721
1997	24,305.09	14,690	10,713	13,592	16.69	814
2008	8,584.00	3,447	2,514	6,070	21.60	281
2011	2,255.73	747	545	1,711	23.22	74
2015	60,452.48	13,735	10,017	50,435	25.50	1,978
2016	16,194.19	3,221	2,349	13,845	26.18	529
2017	1,267,799.99	215,526	157,184	1,110,616	26.86	41,348
2018	226,531.10	31,714	23,129	203,402	27.65	7,356
2019	2,526,973.54	277,714	202,538	2,324,436	28.35	81,991
2020	1,494,081.39	118,032	86,081	1,408,000	29.15	48,302
2021	1,118,861.05	53,258	38,841	1,080,020	30.04	35,953
2022	3,899,673.31	62,005	45,221	3,854,452	30.95	124,538
	10,981,236.18	1,080,019	796,511	10,184,725		364,561

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.9   3.32

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 364 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 59-R2.5						
NET SALVAGE PERCENT.. 0						
1919	6,555.46	6,373	6,501	54	1.64	33
1920	5,315.99	5,145	5,248	68	1.90	36
1921	63.46	61	62	1	2.17	
1922	46.87	45	46	1	2.45	
1923	203.56	194	198	6	2.72	2
1924	125.36	119	121	4	3.00	1
1926	1,503.55	1,414	1,442	62	3.53	18
1927	1,180.99	1,106	1,128	53	3.77	14
1928	1,338.43	1,247	1,272	66	4.01	16
1929	853.45	792	808	45	4.24	11
1930	3,031.98	2,802	2,858	174	4.47	39
1931	371.99	342	349	23	4.69	5
1932	2,942.03	2,697	2,751	191	4.91	39
1933	6,977.32	6,372	6,500	477	5.12	93
1934	6,010.53	5,467	5,577	434	5.34	81
1935	12,437.59	11,265	11,491	947	5.56	170
1936	14,870.44	13,414	13,683	1,187	5.78	205
1937	7,022.55	6,308	6,434	589	6.00	98
1938	3,642.58	3,258	3,323	320	6.23	51
1939	5,512.02	4,909	5,007	505	6.46	78
1940	7,487.24	6,638	6,771	716	6.69	107
1941	15,433.14	13,620	13,893	1,540	6.93	222
1942	10,703.38	9,404	9,593	1,110	7.16	155
1943	14,863.64	12,999	13,260	1,604	7.40	217
1944	13,354.15	11,623	11,856	1,498	7.65	196
1945	15,683.42	13,583	13,855	1,828	7.90	231
1946	21,652.52	18,661	19,035	2,618	8.15	321
1947	15,949.61	13,676	13,950	2,000	8.41	238
1948	24,475.25	20,874	21,292	3,183	8.68	367
1949	18,926.77	16,053	16,375	2,552	8.96	285
1950	17,518.57	14,775	15,071	2,448	9.24	265
1951	33,940.69	28,458	29,028	4,913	9.53	516
1952	24,956.45	20,798	21,215	3,741	9.83	381
1953	22,507.29	18,635	19,009	3,498	10.15	345
1954	26,758.93	22,010	22,451	4,308	10.47	411
1955	41,851.06	34,183	34,868	6,983	10.81	646
1956	28,749.19	23,316	23,783	4,966	11.15	445
1957	26,444.31	21,281	21,708	4,736	11.52	411
1958	45,153.60	36,054	36,777	8,377	11.89	705
1959	45,640.49	36,141	36,865	8,775	12.28	715
1960	37,154.60	29,169	29,754	7,401	12.68	584
1961	52,864.83	41,127	41,951	10,914	13.10	833
1962	44,734.22	34,468	35,159	9,575	13.54	707

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 364 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 59-R2.5						
NET SALVAGE PERCENT.. 0						
1963	61,087.52	46,613	47,547	13,541	13.98	969
1964	62,585.28	47,257	48,204	14,381	14.45	995
1965	101,875.09	76,113	77,639	24,236	14.92	1,624
1966	77,999.78	57,614	58,769	19,231	15.42	1,247
1967	58,572.41	42,768	43,625	14,947	15.92	939
1968	91,306.73	65,865	67,185	24,122	16.44	1,467
1969	133,913.91	95,373	97,285	36,629	16.98	2,157
1970	161,199.68	113,304	115,575	45,625	17.53	2,603
1971	217,342.16	150,703	153,724	63,618	18.09	3,517
1972	158,453.04	108,312	110,483	47,970	18.67	2,569
1973	238,262.79	160,484	163,701	74,562	19.26	3,871
1974	315,462.71	209,275	213,470	101,993	19.86	5,136
1975	247,901.22	161,892	165,137	82,764	20.47	4,043
1976	265,577.43	170,599	174,019	91,558	21.10	4,339
1977	289,930.96	183,146	186,817	103,114	21.73	4,745
1978	318,076.27	197,424	201,381	116,695	22.38	5,214
1979	384,304.55	234,230	238,925	145,380	23.04	6,310
1980	276,470.60	165,368	168,683	107,788	23.71	4,546
1981	267,002.37	156,626	159,766	107,236	24.39	4,397
1982	281,777.17	181,464	185,101	96,676	22.25	4,345
1983	315,365.72	199,280	203,275	112,091	22.86	4,903
1984	327,889.54	203,160	207,232	120,658	23.48	5,139
1985	306,537.98	186,130	189,861	116,677	24.10	4,841
1986	373,525.13	222,061	226,512	147,013	24.73	5,945
1987	446,154.21	259,483	264,684	181,470	25.36	7,156
1988	466,715.88	265,375	270,695	196,021	25.99	7,542
1989	693,343.46	387,302	395,066	298,277	26.27	11,354
1990	662,969.94	361,319	368,562	294,408	26.92	10,936
1991	730,855.14	388,230	396,012	334,843	27.58	12,141
1992	977,220.02	505,516	515,649	461,571	28.23	16,350
1993	750,934.32	381,024	388,662	362,272	28.64	12,649
1994	962,237.40	474,383	483,892	478,345	29.31	16,320
1995	1,303,724.94	623,832	636,337	667,388	29.97	22,269
1996	1,261,674.98	585,165	596,895	664,780	30.64	21,696
1997	956,152.88	429,121	437,723	518,430	31.32	16,553
1998	928,001.28	402,381	410,447	517,554	32.00	16,174
1999	776,408.25	324,772	331,282	445,126	32.68	13,621
2000	705,049.23	283,994	289,687	415,362	33.36	12,451
2001	949,998.54	367,649	375,018	574,981	34.06	16,881
2002	817,325.88	303,228	309,306	508,020	34.75	14,619
2003	974,166.61	347,583	354,550	619,617	35.15	17,628
2004	1,103,497.74	375,631	383,161	720,337	35.85	20,093
2005	1,121,323.51	363,085	370,363	750,961	36.55	20,546

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 364 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 59-R2.5						
NET SALVAGE PERCENT.. 0						
2006	1,080,218.34	331,519	338,164	742,054	37.26	19,916
2007	882,272.62	255,683	260,808	621,465	37.98	16,363
2008	1,075,995.80	293,316	299,196	776,800	38.69	20,078
2009	1,068,825.97	274,154	279,649	789,177	39.13	20,168
2010	1,013,895.37	242,118	246,971	766,924	39.85	19,245
2011	1,377,025.39	304,047	310,142	1,066,883	40.58	26,291
2012	867,125.76	176,634	180,175	686,951	41.05	16,734
2013	1,187,555.26	219,935	224,344	963,211	41.78	23,054
2014	1,692,517.73	283,327	289,006	1,403,512	42.26	33,211
2015	1,562,273.94	233,091	237,763	1,324,511	42.75	30,983
2016	1,806,295.46	234,818	239,525	1,566,770	43.50	36,018
2017	2,231,093.66	247,875	252,844	1,978,250	44.00	44,960
2018	1,677,459.92	154,662	157,762	1,519,698	44.28	34,320
2019	4,183,756.78	304,577	310,682	3,873,075	44.58	86,879
2020	2,967,437.66	156,681	159,822	2,807,616	44.89	62,544
2021	2,993,074.45	97,574	99,530	2,893,544	44.58	64,907
2022	3,803,417.65	43,359	44,228	3,759,190	43.17	87,079
	54,077,225.51	15,288,380	15,594,836	38,482,390		1,025,883

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.5 1.90

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 58-R1.5						
NET SALVAGE PERCENT.. 0						
1924	3,536.66	3,210	3,537			
1925	16,094.82	14,546	16,095			
1926	44,582.38	40,109	44,582			
1927	16,782.45	15,029	16,782			
1928	20,180.12	17,988	20,122	58	6.30	9
1929	15,218.58	13,500	15,101	118	6.55	18
1930	30,364.74	26,800	29,979	386	6.81	57
1931	13,616.11	11,956	13,374	242	7.07	34
1932	16,397.87	14,323	16,022	376	7.34	51
1933	23,450.72	20,374	22,791	660	7.61	87
1934	17,872.33	15,444	17,276	596	7.88	76
1935	8,263.96	7,101	7,943	321	8.16	39
1936	1,899.66	1,623	1,816	84	8.44	10
1937	4,509.81	3,831	4,285	225	8.73	26
1938	9,575.50	8,086	9,045	530	9.02	59
1939	18,571.96	15,591	17,440	1,132	9.31	122
1940	12,416.23	10,359	11,588	828	9.61	86
1941	8,634.53	7,159	8,008	627	9.91	63
1942	2,227.20	1,835	2,053	174	10.21	17
1943	5,034.33	4,121	4,610	424	10.52	40
1944	3,644.50	2,963	3,314	330	10.84	30
1945	8,517.29	6,878	7,694	823	11.16	74
1946	22,202.96	17,808	19,920	2,283	11.48	199
1947	31,950.41	25,445	28,463	3,487	11.81	295
1948	27,408.78	21,667	24,237	3,172	12.15	261
1949	41,486.25	32,553	36,414	5,072	12.49	406
1950	35,534.12	27,674	30,957	4,577	12.83	357
1951	33,104.22	25,576	28,610	4,494	13.19	341
1952	21,734.79	16,657	18,633	3,102	13.55	229
1953	21,715.88	16,504	18,462	3,254	13.92	234
1954	35,837.04	27,001	30,204	5,633	14.30	394
1955	57,265.49	42,772	47,846	9,419	14.68	642
1956	35,135.43	26,006	29,091	6,044	15.07	401
1957	51,921.23	38,063	42,578	9,343	15.48	604
1958	25,708.26	18,665	20,879	4,829	15.89	304
1959	33,979.25	24,430	27,328	6,651	16.30	408
1960	35,796.06	25,471	28,492	7,304	16.73	437
1961	57,009.69	40,133	44,893	12,117	17.17	706
1962	55,010.40	38,308	42,852	12,158	17.61	690
1963	81,488.58	56,101	62,756	18,733	18.07	1,037
1964	115,193.00	78,391	87,690	27,503	18.53	1,484
1965	96,138.19	64,644	72,312	23,826	19.00	1,254
1966	55,711.13	37,000	41,389	14,322	19.48	735

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 58-R1.5						
NET SALVAGE PERCENT.. 0						
1967	64,487.54	42,284	47,300	17,188	19.97	861
1968	100,665.15	65,137	72,863	27,802	20.47	1,358
1969	215,200.63	137,358	153,651	61,550	20.98	2,934
1970	182,715.65	115,016	128,659	54,057	21.49	2,515
1971	211,396.18	131,138	146,693	64,703	22.02	2,938
1972	128,594.41	78,575	87,895	40,699	22.56	1,804
1973	167,850.01	100,999	112,979	54,871	23.10	2,375
1974	268,300.47	158,898	177,746	90,554	23.65	3,829
1975	286,533.66	166,932	186,733	99,801	24.21	4,122
1976	222,504.16	127,441	142,558	79,946	24.78	3,226
1977	343,712.18	193,427	216,371	127,341	25.36	5,021
1978	255,085.48	141,001	157,726	97,359	25.94	3,753
1979	224,494.14	121,768	136,212	88,282	26.54	3,326
1980	163,524.70	87,007	97,328	66,197	27.14	2,439
1981	204,649.46	106,735	119,396	85,253	27.75	3,072
1982	213,535.43	133,225	149,028	64,507	24.26	2,659
1983	120,797.42	73,964	82,737	38,060	24.85	1,532
1984	98,189.51	58,963	65,957	32,233	25.45	1,267
1985	119,298.97	70,219	78,548	40,751	26.04	1,565
1986	158,573.42	91,973	102,883	55,690	26.25	2,122
1987	140,067.10	79,488	88,917	51,150	26.86	1,904
1988	253,486.41	140,634	157,316	96,170	27.48	3,500
1989	299,678.08	163,414	182,798	116,880	27.73	4,215
1990	326,137.46	173,538	194,123	132,014	28.36	4,655
1991	516,485.48	267,953	299,737	216,748	28.99	7,477
1992	644,064.61	327,314	366,139	277,926	29.27	9,495
1993	386,640.45	192,779	215,646	170,994	29.67	5,763
1994	535,284.22	259,345	290,108	245,176	30.32	8,086
1995	849,523.35	401,825	449,488	400,035	30.64	13,056
1996	825,559.89	380,666	425,820	399,740	30.97	12,907
1997	682,692.68	304,617	340,750	341,943	31.65	10,804
1998	692,692.30	300,351	335,978	356,714	32.00	11,147
1999	540,399.48	226,049	252,862	287,537	32.68	8,799
2000	433,248.80	175,466	196,279	236,970	33.06	7,168
2001	659,211.14	257,949	288,546	370,665	33.45	11,081
2002	454,617.95	171,482	191,823	262,795	33.85	7,764
2003	618,792.70	224,436	251,058	367,735	34.26	10,734
2004	605,691.43	210,659	235,647	370,044	34.69	10,667
2005	1,052,202.59	349,857	391,356	660,847	35.13	18,811
2006	718,514.98	227,626	254,626	463,889	35.58	13,038
2007	1,182,989.85	355,725	397,920	785,070	36.05	21,777
2008	1,222,820.03	349,237	390,662	832,158	36.26	22,950
2009	1,166,812.19	313,406	350,581	816,231	36.75	22,210

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 58-R1.5						
NET SALVAGE PERCENT.. 0						
2010	853,825.15	215,591	241,164	612,661	37.00	16,558
2011	827,016.29	195,010	218,142	608,874	37.28	16,332
2012	1,296,563.90	283,170	316,759	979,805	37.58	26,073
2013	1,847,495.02	370,238	414,155	1,433,340	37.90	37,819
2014	1,759,809.80	321,693	359,851	1,399,959	38.01	36,831
2015	2,094,682.69	343,947	384,745	1,709,938	38.16	44,810
2016	2,385,940.22	347,393	388,600	1,997,340	38.14	52,369
2017	2,776,079.17	349,786	391,277	2,384,802	38.17	62,478
2018	2,025,997.31	215,161	240,683	1,785,314	37.87	47,143
2019	4,239,212.38	362,029	404,971	3,834,241	37.48	102,301
2020	5,605,104.70	355,924	398,143	5,206,962	36.87	141,225
2021	3,780,125.74	153,473	171,677	3,608,449	35.40	101,934
2022	5,273,314.44	82,264	92,022	5,181,292	31.65	163,706
	54,595,611.46	12,615,250	14,111,095	40,484,516		1,162,621

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 34.8   2.13

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 365.7 REG AFUDC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	711,827.21-	26,694-	83,047-	628,780-		16,332-
	711,827.21-	26,694-	83,047-	628,780-		16,332-

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.5   2.29

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 366 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. 0						
1923	11,558.71	11,107	11,559			
1925	37.18	35	37			
1928	977.05	920	977			
1955	321.43	262	314	7	12.09	1
1957	1,089.51	872	1,045	45	13.00	3
1966	171.19	124	149	22	17.78	1
1967	2,233.28	1,602	1,919	314	18.38	17
1968	5,305.30	3,755	4,499	806	18.99	42
1969	482.65	337	404	79	19.62	4
1970	3,078.47	2,119	2,539	539	20.26	27
1971	3,756.90	2,548	3,053	704	20.91	34
1972	7,229.66	4,830	5,787	1,443	21.57	67
1973	9,574.39	6,297	7,545	2,029	22.25	91
1974	12,540.35	8,116	9,724	2,816	22.93	123
1975	9,522.75	6,061	7,262	2,261	23.63	96
1976	14,345.28	8,976	10,755	3,590	24.33	148
1977	17,590.28	10,811	12,953	4,637	25.05	185
1978	25,021.43	15,097	18,089	6,932	25.78	269
1979	43,579.82	25,806	30,920	12,660	26.51	478
1980	7,270.58	4,221	5,057	2,214	27.26	81
1981	11,294.79	6,428	7,702	3,593	28.01	128
1982	11,192.02	6,803	8,151	3,041	25.97	117
1983	14,496.16	8,648	10,362	4,134	26.54	156
1984	5,717.07	3,346	4,009	1,708	27.11	63
1985	15,585.87	8,940	10,711	4,875	27.69	176
1986	48,278.74	26,949	32,289	15,990	28.69	557
1987	29,523.06	16,131	19,327	10,196	29.26	348
1988	76,661.56	40,960	49,076	27,586	29.85	924
1989	113,372.28	59,180	70,907	42,465	30.45	1,395
1990	144,531.37	73,176	87,676	56,855	31.45	1,808
1991	53,431.24	26,384	31,612	21,819	32.04	681
1992	99,809.99	48,009	57,522	42,288	32.64	1,296
1993	36,156.76	16,958	20,318	15,839	33.40	474
1994	118,794.48	54,170	64,904	53,890	34.00	1,585
1995	150,384.17	66,590	79,785	70,599	34.61	2,040
1996	91,378.94	39,229	47,002	44,377	35.23	1,260
1997	233,401.22	96,418	115,523	117,878	36.23	3,254
1998	151,590.70	60,545	72,542	79,049	36.85	2,145
1999	192,024.40	74,006	88,670	103,354	37.48	2,758
2000	160,172.66	59,104	70,816	89,357	38.48	2,322
2001	227,349.82	80,664	96,648	130,702	39.10	3,343
2002	321,940.17	108,880	130,455	191,485	40.11	4,774
2003	161,435.90	52,257	62,612	98,824	40.74	2,426

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 366 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. 0						
2004	172,849.36	53,410	63,993	108,856	41.38	2,631
2005	430,305.70	125,735	150,650	279,656	42.38	6,599
2006	313,210.56	86,822	104,026	209,185	43.02	4,863
2007	95,642.88	25,058	30,023	65,620	43.67	1,503
2008	693,812.85	169,984	203,667	490,146	44.67	10,973
2009	66,961.89	15,368	18,413	48,549	45.32	1,071
2010	173,900.46	36,954	44,277	129,623	46.32	2,798
2011	38,275.92	7,525	9,016	29,260	46.98	623
2012	105,122.31	18,985	22,747	82,375	47.64	1,729
2013	153,776.20	25,127	30,106	123,670	48.64	2,543
2014	138,890.11	20,417	24,463	114,427	49.31	2,321
2015	90,029.54	11,686	14,002	76,028	50.30	1,511
2016	421,879.54	47,715	57,170	364,710	50.97	7,155
2017	544,253.07	52,357	62,731	481,522	51.65	9,323
2018	751,950.64	59,554	71,355	680,596	52.32	13,008
2019	1,561,494.51	96,813	115,996	1,445,499	52.99	27,279
2020	200,300.10	8,913	10,679	189,621	53.68	3,532
2021	46,993.55	1,259	1,509	45,485	54.37	837
2022	136,059.64	1,238	1,483	134,577	54.45	2,472
	8,779,918.41	2,012,591	2,409,512	6,370,406		138,468

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.0 1.58

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 42-R1.5						
NET SALVAGE PERCENT.. 0						
1957	20,742.69	18,105	17,608	3,135	5.34	587
1966	125.80	102	99	27	7.98	3
1967	11,829.84	9,492	9,232	2,598	8.30	313
1968	5,919.87	4,703	4,574	1,346	8.63	156
1969	6,623.95	5,209	5,066	1,558	8.97	174
1970	10,492.59	8,164	7,940	2,553	9.32	274
1971	10,473.00	8,062	7,841	2,632	9.67	272
1972	41,082.28	31,262	30,404	10,678	10.04	1,064
1973	34,520.43	25,956	25,244	9,276	10.42	890
1974	70,857.67	52,620	51,177	19,681	10.81	1,821
1975	100,844.65	73,929	71,901	28,944	11.21	2,582
1976	45,049.69	32,586	31,692	13,358	11.62	1,150
1977	84,764.87	60,465	58,806	25,959	12.04	2,156
1978	51,416.51	36,139	35,148	16,269	12.48	1,304
1979	60,840.40	42,125	40,970	19,870	12.92	1,538
1980	31,270.23	21,308	20,724	10,546	13.38	788
1981	36,288.12	24,313	23,646	12,642	13.86	912
1982	27,045.68	20,465	19,904	7,142	12.94	552
1983	57,895.80	43,404	42,213	15,683	13.10	1,197
1984	25,470.30	18,802	18,286	7,184	13.56	530
1985	32,916.83	23,911	23,255	9,662	14.03	689
1986	74,963.92	53,532	52,064	22,900	14.51	1,578
1987	56,921.44	39,930	38,835	18,086	15.00	1,206
1988	119,971.79	82,996	80,719	39,253	15.26	2,572
1989	170,312.77	115,523	112,354	57,959	15.77	3,675
1990	128,330.80	85,263	82,924	45,407	16.29	2,787
1991	206,945.26	134,514	130,824	76,121	16.83	4,523
1992	118,472.93	75,621	73,547	44,926	17.14	2,621
1993	143,802.60	90,366	87,887	55,916	17.45	3,204
1994	140,100.58	85,854	83,499	56,602	18.01	3,143
1995	218,463.23	130,379	126,803	91,660	18.58	4,933
1996	314,048.99	183,091	178,069	135,980	18.95	7,176
1997	347,815.86	196,899	191,498	156,318	19.55	7,996
1998	271,377.92	149,584	145,481	125,897	19.95	6,311
1999	195,532.47	104,766	101,892	93,640	20.36	4,599
2000	204,244.75	105,697	102,798	101,447	20.98	4,835
2001	430,658.90	215,760	209,842	220,817	21.42	10,309
2002	160,057.25	77,436	75,312	84,745	21.87	3,875
2003	40,690.43	18,962	18,442	22,248	22.34	996
2004	102,021.26	45,675	44,422	57,599	22.82	2,524
2005	296,987.96	127,348	123,855	173,133	23.31	7,427
2006	195,690.23	80,076	77,880	117,810	23.82	4,946
2007	130,425.47	50,736	49,344	81,081	24.34	3,331

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 42-R1.5						
NET SALVAGE PERCENT.. 0						
2008	560,791.88	207,381	201,693	359,099	24.71	14,533
2009	106,414.08	37,202	36,182	70,232	25.11	2,797
2010	239,045.56	78,598	76,442	162,604	25.52	6,372
2011	196,619.32	60,362	58,706	137,913	25.96	5,313
2012	95,712.69	27,240	26,493	69,220	26.40	2,622
2013	437,131.52	114,616	111,472	325,660	26.73	12,183
2014	361,138.74	86,565	84,190	276,949	26.96	10,273
2015	136,611.99	29,508	28,699	107,913	27.22	3,964
2016	184,210.69	35,203	34,237	149,974	27.51	5,452
2017	1,082,163.61	179,747	174,816	907,348	27.61	32,863
2018	1,139,614.48	159,546	155,170	984,444	27.65	35,604
2019	1,250,994.66	141,362	137,484	1,113,511	27.46	40,550
2020	1,430,402.48	120,440	117,137	1,313,265	27.18	48,317
2021	1,257,225.93	67,890	66,028	1,191,198	26.28	45,327
2022	1,437,981.73	29,910	29,089	1,408,893	23.54	59,851
	14,750,367.37	4,186,700	4,071,859	10,678,508		439,540

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 24.3   2.98

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 368.1 TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S1						
NET SALVAGE PERCENT.. 0						
1918	399.30	399	399			
1921	433.46	433	433			
1924	9,167.19	9,167	9,167			
1925	1,047.45	1,047	1,047			
1941	1,823.77	1,729	1,824			
1948	8,714.34	7,872	8,714			
1949	12,761.42	11,446	12,761			
1952	508.91	446	509			
1953	670.00	583	670			
1954	6,421.85	5,543	6,422			
1955	21,636.63	18,526	21,637			
1956	2,448.69	2,080	2,449			
1957	12,079.64	10,174	12,030	50	7.10	7
1958	52,850.62	44,136	52,187	664	7.42	89
1959	25,837.47	21,388	25,290	547	7.75	71
1960	16,681.29	13,686	16,183	498	8.08	62
1961	15,886.33	12,917	15,273	613	8.41	73
1962	5,500.17	4,432	5,240	260	8.74	30
1963	6,819.27	5,443	6,436	383	9.08	42
1964	21,641.31	17,106	20,226	1,415	9.43	150
1965	15,691.33	12,281	14,521	1,170	9.78	120
1966	38,803.45	30,068	35,553	3,250	10.13	321
1967	66,968.61	51,358	60,727	6,242	10.49	595
1968	87,565.13	66,452	78,574	8,991	10.85	829
1969	61,750.21	46,368	54,826	6,924	11.21	618
1970	87,944.02	65,293	77,204	10,740	11.59	927
1971	69,653.56	51,141	60,470	9,184	11.96	768
1972	91,296.96	66,241	78,324	12,973	12.35	1,050
1973	119,058.96	85,378	100,952	18,107	12.73	1,422
1974	142,964.77	101,251	119,721	23,244	13.13	1,770
1975	201,667.05	141,032	166,759	34,908	13.53	2,580
1976	142,756.59	98,565	116,545	26,212	13.93	1,882
1977	162,636.86	110,809	131,022	31,615	14.34	2,205
1978	165,586.26	111,274	131,572	34,014	14.76	2,304
1979	162,247.01	107,479	127,085	35,162	15.19	2,315
1980	185,527.62	121,129	143,225	42,303	15.62	2,708
1981	106,522.45	68,506	81,003	25,519	16.06	1,589
1982	224,085.43	165,061	195,171	28,914	14.39	2,009
1983	168,226.79	122,149	144,431	23,796	14.81	1,607
1984	167,946.59	120,132	142,046	25,901	15.22	1,702
1985	233,781.32	164,582	194,604	39,177	15.66	2,502
1986	165,835.24	115,421	136,476	29,359	15.83	1,855
1987	248,285.86	169,778	200,748	47,538	16.30	2,916

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 368.1 TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

SURVIVOR CURVE.. IOWA 45-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1988	240,016.09	161,123	190,515	49,501	16.77	2,952
1989	289,884.63	191,817	226,808	63,077	17.00	3,710
1990	325,630.21	211,074	249,577	76,053	17.50	4,346
1991	300,975.98	191,872	226,873	74,103	17.77	4,170
1992	367,721.25	230,267	272,271	95,450	18.06	5,285
1993	215,987.22	133,178	157,472	58,515	18.34	3,191
1994	267,453.83	160,847	190,188	77,266	18.89	4,090
1995	328,379.28	193,251	228,503	99,876	19.23	5,194
1996	347,086.39	199,575	235,981	111,105	19.59	5,672
1997	331,988.12	185,382	219,199	112,789	20.16	5,595
1998	386,366.72	210,145	248,479	137,888	20.55	6,710
1999	394,973.68	208,862	246,962	148,012	20.94	7,068
2000	420,195.96	215,561	254,883	165,313	21.36	7,739
2001	255,214.78	126,740	149,859	105,356	21.79	4,835
2002	339,390.23	162,805	192,503	146,887	22.24	6,605
2003	179,675.60	83,046	98,195	81,481	22.69	3,591
2004	275,583.08	122,359	144,679	130,904	23.17	5,650
2005	272,517.16	115,874	137,011	135,506	23.65	5,730
2006	112,879.80	45,818	54,176	58,704	24.15	2,431
2007	441,505.33	170,421	201,509	239,996	24.66	9,732
2008	504,507.80	184,347	217,975	286,533	25.18	11,379
2009	420,083.53	144,593	170,969	249,115	25.72	9,686
2010	112,033.57	36,131	42,722	69,312	26.26	2,639
2011	318,305.98	95,555	112,986	205,320	26.81	7,658
2012	417,219.62	115,236	136,257	280,963	27.52	10,209
2013	312,316.17	78,922	93,319	218,997	28.09	7,796
2014	190,849.75	43,628	51,586	139,264	28.68	4,856
2015	325,856.71	66,214	78,293	247,564	29.40	8,421
2016	237,163.32	42,239	49,944	187,219	30.00	6,241
2017	499,808.15	75,871	89,711	410,097	30.73	13,345
2018	569,381.33	71,230	84,224	485,157	31.47	15,416
2019	506,512.79	49,638	58,693	447,820	32.21	13,903
2020	564,054.25	39,597	46,820	517,234	33.09	15,631
2021	1,177,544.11	49,810	58,896	1,118,648	33.96	32,940
2022	1,071,014.02	15,208	17,982	1,053,032	34.83	30,233
	16,660,207.62	6,808,537	8,046,476	8,613,732		331,767

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 26.0 1.99

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 368.2 TRANSFORMER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

SURVIVOR CURVE.. IOWA 39-R2
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1961	1,102.22	1,016	1,102			
1962	806.54	738	807			
1963	551.14	500	551			
1964	1,114.87	1,003	1,115			
1965	582.21	520	582			
1966	2,073.07	1,834	2,073			
1967	2,171.52	1,905	2,172			
1968	531.87	462	532			
1970	1,338.80	1,143	1,339			
1971	5,193.89	4,394	5,194			
1972	19,389.76	16,238	19,390			
1973	36,534.42	30,286	36,534			
1974	25,830.70	21,188	25,831			
1975	77,222.77	62,649	77,223			
1976	53,862.54	43,186	53,863			
1977	19,827.62	15,704	19,587	241	8.11	30
1978	15,484.66	12,110	15,104	381	8.50	45
1979	83,875.10	64,734	80,739	3,136	8.90	352
1980	59,278.94	45,113	56,267	3,012	9.32	323
1981	55,816.14	41,848	52,195	3,621	9.76	371
1982	68,532.57	55,717	68,533			
1983	64,528.69	51,668	64,454	75	9.77	8
1984	62,113.98	49,182	61,353	761	10.06	76
1985	107,195.38	83,452	104,103	3,092	10.60	292
1986	132,903.73	102,137	127,412	5,492	10.92	503
1987	112,966.03	85,222	106,311	6,655	11.48	580
1988	142,398.69	105,831	132,020	10,379	11.83	877
1989	171,799.36	125,104	156,062	15,737	12.41	1,268
1990	170,667.36	122,198	152,437	18,230	12.79	1,425
1991	224,798.59	158,056	197,169	27,630	13.20	2,093
1992	347,636.46	238,722	297,796	49,840	13.80	3,612
1993	235,547.05	159,136	198,516	37,031	14.17	2,613
1994	330,013.78	218,205	272,202	57,812	14.60	3,960
1995	416,071.68	268,866	335,400	80,672	15.06	5,357
1996	340,140.08	213,608	266,467	73,673	15.70	4,693
1997	395,465.23	242,025	301,916	93,549	16.17	5,785
1998	306,285.24	182,362	227,489	78,796	16.65	4,732
1999	274,195.58	157,882	196,952	77,244	17.31	4,462
2000	220,040.19	122,782	153,166	66,874	17.82	3,753
2001	244,261.31	131,803	164,419	79,842	18.34	4,353
2002	274,461.19	142,912	178,277	96,184	18.87	5,097
2003	457,142.11	229,120	285,818	171,324	19.41	8,827
2004	313,458.73	150,774	188,084	125,375	19.96	6,281

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 368.2 TRANSFORMER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 39-R2						
NET SALVAGE PERCENT.. 0						
2005	282,705.27	130,101	162,296	120,409	20.52	5,868
2006	312,876.74	137,322	171,304	141,573	21.09	6,713
2007	341,351.24	142,343	177,567	163,784	21.67	7,558
2008	241,221.99	95,138	118,681	122,541	22.26	5,505
2009	227,989.20	84,630	105,572	122,417	22.87	5,353
2010	170,797.08	59,574	74,316	96,481	23.34	4,134
2011	99,169.83	32,161	40,120	59,050	23.96	2,465
2012	204,623.09	61,448	76,654	127,969	24.47	5,230
2013	275,807.21	75,985	94,788	181,019	24.98	7,247
2014	153,812.87	38,438	47,950	105,863	25.51	4,150
2015	204,738.46	45,902	57,261	147,477	25.95	5,683
2016	280,837.77	55,494	69,227	211,611	26.39	8,019
2017	373,270.95	63,456	79,159	294,112	26.86	10,950
2018	94,317.45	13,374	16,683	77,634	27.24	2,850
2019	1,038,937.24	117,400	146,452	892,485	27.46	32,501
2020	384,436.80	31,985	39,900	344,537	27.53	12,515
2021	350,077.32	18,204	22,708	327,369	27.32	11,983
2022	285,379.12	5,422	6,764	278,615	25.82	10,791
	11,197,561.42	4,971,712	6,195,958	5,001,603		221,283

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 22.6 1.98

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 369 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 53-R2						
NET SALVAGE PERCENT.. 0						
1947	69.98	61	70			
1954	118.41	99	118			
1955	333.15	277	333			
1956	128.96	106	129			
1958	217.29	176	217			
1959	640.93	516	636	5	10.36	
1960	1,286.86	1,026	1,264	23	10.73	2
1961	478.27	378	466	12	11.11	1
1962	5,141.54	4,026	4,961	181	11.50	16
1963	13,934.56	10,803	13,312	623	11.91	52
1964	20,651.36	15,851	19,532	1,119	12.32	91
1965	23,270.54	17,677	21,782	1,489	12.74	117
1966	27,708.38	20,823	25,659	2,049	13.17	156
1967	55,979.34	41,594	51,253	4,726	13.62	347
1968	86,487.36	63,511	78,260	8,227	14.08	584
1969	164,001.42	119,009	146,646	17,355	14.54	1,194
1970	234,774.08	168,239	207,309	27,465	15.02	1,829
1971	230,865.51	163,305	201,229	29,637	15.51	1,911
1972	199,899.40	139,514	171,913	27,986	16.01	1,748
1973	269,839.68	185,731	228,863	40,977	16.52	2,480
1974	152,399.64	103,373	127,379	25,021	17.05	1,468
1975	142,520.68	95,247	117,366	25,155	17.58	1,431
1976	155,370.48	102,221	125,960	29,410	18.13	1,622
1977	155,016.59	100,381	123,692	31,325	18.68	1,677
1978	168,567.81	107,342	132,270	36,298	19.25	1,886
1979	198,898.76	124,481	153,389	45,510	19.83	2,295
1980	147,503.69	90,673	111,730	35,774	20.42	1,752
1981	190,309.08	114,832	141,499	48,810	21.02	2,322
1982	162,991.20	110,215	135,810	27,181	19.27	1,411
1983	178,547.92	119,127	146,792	31,756	19.58	1,622
1984	203,395.71	133,041	163,937	39,459	20.23	1,951
1985	175,251.01	112,932	139,158	36,093	20.55	1,756
1986	212,029.41	133,748	164,808	47,221	21.22	2,225
1987	240,418.51	149,156	183,794	56,625	21.57	2,625
1988	249,879.57	151,477	186,654	63,226	22.25	2,842
1989	262,893.61	156,474	192,812	70,082	22.61	3,100
1990	276,667.19	160,605	197,902	78,765	23.31	3,379
1991	262,526.28	149,325	184,003	78,523	23.69	3,315
1992	253,192.08	140,167	172,718	80,474	24.39	3,299
1993	188,922.24	102,547	126,361	62,561	24.85	2,518
1994	163,394.29	86,615	106,730	56,664	25.26	2,243
1995	315,293.58	162,124	199,774	115,520	25.98	4,446
1996	290,036.33	145,250	178,981	111,055	26.41	4,205

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 369 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 53-R2						
NET SALVAGE PERCENT.. 0						
1997	337,772.75	163,651	201,656	136,117	27.13	5,017
1998	293,253.03	137,946	169,981	123,272	27.58	4,470
1999	327,057.39	149,105	183,732	143,325	28.05	5,110
2000	176,500.61	77,448	95,434	81,067	28.78	2,817
2001	197,155.03	83,515	102,910	94,245	29.26	3,221
2002	237,193.60	96,775	119,249	117,945	29.75	3,965
2003	221,676.57	86,897	107,077	114,600	30.25	3,788
2004	284,493.31	106,315	131,004	153,489	31.00	4,951
2005	420,370.39	150,072	184,923	235,447	31.52	7,470
2006	148,095.54	50,338	62,028	86,068	32.04	2,686
2007	594,734.65	191,742	236,270	358,465	32.58	11,003
2008	488,025.77	148,604	183,114	304,912	33.12	9,206
2009	340,560.70	97,468	120,103	220,458	33.67	6,548
2010	355,781.68	95,172	117,274	238,508	34.23	6,968
2011	241,540.60	60,289	74,290	167,251	34.58	4,837
2012	384,096.54	88,342	108,858	275,239	35.16	7,828
2013	479,396.78	101,105	124,585	354,812	35.55	9,981
2014	440,835.25	83,935	103,427	337,408	36.14	9,336
2015	420,839.39	71,627	88,261	332,578	36.56	9,097
2016	502,716.07	75,508	93,043	409,673	36.79	11,135
2017	415,496.01	53,474	65,892	349,604	37.24	9,388
2018	389,477.41	41,908	51,640	337,837	37.34	9,048
2019	435,400.49	37,183	45,818	389,582	37.48	10,394
2020	411,120.96	25,818	31,814	379,307	37.34	10,158
2021	592,217.13	23,215	28,606	563,611	36.81	15,311
2022	535,724.70	7,607	9,374	526,351	34.59	15,217
	15,753,385.03	6,109,134	7,527,834	8,225,551		264,868

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.1   1.68

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.1 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 34-R1						
NET SALVAGE PERCENT.. 0						
1946	67.51	68	68			
1948	62.81	63	63			
1957	476.96	463	477			
1958	566.33	544	566			
1959	875.34	832	875			
1961	1,919.08	1,788	1,919			
1962	6,370.55	5,880	6,371			
1963	3,408.87	3,116	3,409			
1964	2,460.74	2,228	2,461			
1965	4,888.47	4,382	4,888			
1966	4,198.14	3,726	4,198			
1967	6,231.70	5,475	6,232			
1968	13,999.72	12,167	14,000			
1969	12,323.67	10,595	12,324			
1970	13,110.01	11,144	13,110			
1971	31,750.00	26,670	31,750			
1972	167,556.35	139,072	165,680	1,876	5.78	325
1973	31,065.36	25,465	30,337	728	6.13	119
1974	18,112.20	14,655	17,459	653	6.49	101
1975	25,368.43	20,250	24,124	1,244	6.86	181
1976	40,662.56	32,016	38,142	2,521	7.23	349
1977	34,780.73	26,996	32,161	2,620	7.61	344
1978	59,246.51	45,306	53,974	5,273	8.00	659
1979	34,754.49	26,178	31,187	3,567	8.39	425
1980	42,782.00	31,709	37,776	5,006	8.80	569
1981	21,997.02	16,038	19,107	2,890	9.21	314
1982	43,350.39	35,595	42,405	945	8.77	108
1983	29,370.22	23,749	28,293	1,077	9.29	116
1984	30,902.85	24,704	29,431	1,472	9.60	153
1985	40,095.93	31,664	37,722	2,374	9.92	239
1986	57,456.61	44,782	53,350	4,107	10.26	400
1987	50,329.14	38,673	46,072	4,257	10.62	401
1988	58,167.72	44,027	52,451	5,717	11.00	520
1989	66,300.38	49,381	58,829	7,471	11.39	656
1990	88,730.69	64,960	77,389	11,342	11.80	961
1991	73,646.06	52,937	63,065	10,581	12.23	865
1992	125,977.74	88,789	105,777	20,201	12.67	1,594
1993	93,922.14	65,107	77,564	16,358	13.06	1,253
1994	112,043.69	76,324	90,927	21,117	13.34	1,583
1995	106,623.19	70,958	84,534	22,089	13.82	1,598
1996	81,200.43	52,935	63,063	18,137	14.15	1,282
1997	68,208.64	43,312	51,599	16,610	14.66	1,133
1998	162,081.96	100,458	119,678	42,404	15.03	2,821

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.1 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 34-R1						
NET SALVAGE PERCENT.. 0						
1999	78,550.23	47,444	56,521	22,029	15.41	1,430
2000	205,130.78	120,002	142,962	62,169	15.96	3,895
2001	18,661.47	10,592	12,619	6,042	16.38	369
2002	5,961.52	3,287	3,916	2,046	16.68	123
2003	41,458.30	22,072	26,295	15,163	17.13	885
2004	108,600.17	55,647	66,293	42,307	17.60	2,404
2005	3,479.18	1,717	2,046	1,433	17.96	80
2006	18,161.25	8,601	10,247	7,914	18.34	432
2017	92,232.24	18,926	22,547	69,685	21.31	3,270
2018	367,054.74	64,235	76,524	290,531	21.21	13,698
2020	143,166.11	15,534	18,506	124,660	20.54	6,069
	2,949,899.32	1,743,238	2,073,283	876,616		51,724

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.9   1.75

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.2 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

SURVIVOR CURVE.. IOWA 75-R4
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1924	1,642.55	1,564	1,643			
1925	143.96	137	144			
1926	1,426.26	1,349	1,426			
1927	2,472.29	2,329	2,472			
1928	402.46	378	402			
1929	1,969.88	1,842	1,970			
1930	1,163.48	1,084	1,163			
1931	445.79	414	446			
1932	767.37	709	767			
1933	719.01	662	719			
1934	988.80	907	989			
1935	841.89	769	842			
1936	1,517.87	1,380	1,517	1	6.83	
1937	1,970.39	1,783	1,960	10	7.13	1
1938	1,565.44	1,410	1,550	15	7.44	2
1939	1,683.08	1,509	1,659	24	7.76	3
1940	1,632.55	1,456	1,601	32	8.10	4
1941	1,234.51	1,096	1,205	30	8.44	4
1942	575.86	508	558	18	8.80	2
1943	576.13	506	556	20	9.18	2
1944	688.35	601	661	27	9.57	3
1945	905.14	785	863	42	9.98	4
1946	1,959.04	1,687	1,855	104	10.41	10
1947	4,489.63	3,840	4,221	269	10.86	25
1948	6,548.87	5,560	6,112	437	11.33	39
1949	6,264.43	5,277	5,801	463	11.82	39
1950	6,264.17	5,234	5,754	510	12.34	41
1951	7,237.13	5,995	6,590	647	12.87	50
1952	6,410.50	5,263	5,786	624	13.43	46
1953	6,628.34	5,390	5,925	703	14.01	50
1954	5,807.11	4,676	5,140	667	14.61	46
1955	7,029.44	5,602	6,158	871	15.23	57
1956	7,054.06	5,562	6,114	940	15.86	59
1957	6,502.32	5,071	5,575	927	16.51	56
1958	10,416.69	8,032	8,830	1,587	17.17	92
1959	6,191.27	4,719	5,188	1,003	17.84	56
1960	5,206.43	3,921	4,310	896	18.52	48
1961	6,155.91	4,579	5,034	1,122	19.21	58
1962	4,832.44	3,550	3,903	929	19.91	47
1963	6,758.22	4,900	5,387	1,371	20.62	66
1964	5,907.10	4,227	4,647	1,260	21.33	59
1965	9,137.29	6,450	7,091	2,046	22.06	93
1966	8,226.81	5,726	6,295	1,932	22.80	85

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.2 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

SURVIVOR CURVE.. IOWA 75-R4
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1967	11,002.39	7,548	8,298	2,704	23.55	115
1968	10,092.63	6,823	7,501	2,592	24.30	107
1969	12,575.28	8,372	9,204	3,371	25.07	134
1970	11,919.79	7,811	8,587	3,333	25.85	129
1971	13,530.79	8,726	9,593	3,938	26.63	148
1972	13,371.59	8,481	9,323	4,049	27.43	148
1973	17,929.00	11,178	12,288	5,641	28.24	200
1974	13,827.36	8,470	9,311	4,516	29.06	155
1975	11,535.20	6,940	7,629	3,906	29.88	131
1976	10,164.83	6,001	6,597	3,568	30.72	116
1977	17,973.30	10,408	11,442	6,531	31.57	207
1978	16,047.71	9,111	10,016	6,032	32.42	186
1979	28,716.68	15,974	17,561	11,156	33.28	335
1980	21,372.34	11,641	12,797	8,575	34.15	251
1981	45,518.50	24,258	26,667	18,852	35.03	538
1982	27,304.32	14,946	16,431	10,873	33.28	327
1983	18,859.62	10,141	11,148	7,712	33.74	229
1984	23,990.96	12,571	13,820	10,171	34.74	293
1985	32,483.36	16,576	18,222	14,261	35.74	399
1986	32,248.75	16,131	17,733	14,516	36.22	401
1987	34,888.93	16,970	18,656	16,233	37.22	436
1988	33,863.71	16,004	17,594	16,270	38.22	426
1989	34,393.64	15,780	17,347	17,047	39.22	435
1990	31,762.75	14,239	15,653	16,110	39.69	406
1991	29,703.79	12,903	14,185	15,519	40.69	381
1992	34,237.09	14,397	15,827	18,410	41.69	442
1993	27,602.21	11,317	12,441	15,161	42.45	357
1994	31,665.96	12,546	13,792	17,874	43.44	411
1995	35,531.90	13,680	15,039	20,493	43.93	466
1996	27,275.92	10,119	11,124	16,152	44.93	359
1997	35,354.15	12,621	13,875	21,479	45.93	468
1998	18,212.36	6,247	6,867	11,345	46.93	242
2000	32,330.57	10,184	11,196	21,135	48.93	432
2001	3,048.10	917	1,008	2,040	49.93	41
2002	57,999.50	16,762	18,427	39,572	50.43	785
2003	120,585.50	33,161	36,455	84,130	51.42	1,636
2004	123,372.42	32,176	35,372	88,000	52.43	1,678
2005	164,416.83	40,578	44,608	119,809	53.42	2,243
2006	21,256.88	4,944	5,435	15,822	54.43	291
2007	22,560.24	4,932	5,422	17,138	55.42	309
2008	43,906.69	8,975	9,866	34,041	56.43	603
2009	30,704.57	5,846	6,427	24,278	57.42	423
2010	20,824.68	3,669	4,033	16,792	58.43	287

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.2 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
2011	12,949.29	2,100	2,309	10,640	59.42	179
2012	32,811.94	4,856	5,338	27,474	60.43	455
2013	43,331.64	5,806	6,383	36,949	61.42	602
2014	48,195.11	5,774	6,347	41,848	62.43	670
2015	116,518.90	12,409	13,641	102,878	62.92	1,635
2016	24,228.20	2,236	2,458	21,770	63.92	341
2017	27,103.13	2,117	2,327	24,776	64.92	382
2018	17,054.92	1,090	1,198	15,857	65.92	241
2019	27,035.74	1,344	1,478	25,558	66.92	382
2020	11,437.05	406	446	10,991	67.92	162
2021	20,944.44	446	491	20,453	68.92	297
2022	24,370.21	173	190	24,180	69.92	346
	1,972,303.62	708,270	778,252	1,194,052		24,945

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 47.9   1.26

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 370.3 ELECTRONIC METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-S3						
NET SALVAGE PERCENT.. 0						
1995	280.36	264	280			
1996	68,883.81	64,255	68,884			
1997	102,737.04	94,837	102,737			
1998	28,763.57	26,215	28,764			
1999	188,041.11	169,237	188,041			
2000	79,287.63	70,288	79,288			
2001	138,189.12	120,625	137,605	584	3.13	187
2002	53,297.66	45,559	51,972	1,326	3.48	381
2003	91,737.08	76,747	87,551	4,186	3.81	1,099
2004	199,255.57	162,553	185,435	13,821	4.18	3,306
2005	296,348.56	234,945	268,018	28,331	4.57	6,199
2006	207,413.16	159,127	181,527	25,886	5.01	5,167
2007	2,301,040.99	1,701,390	1,940,891	360,150	5.46	65,962
2008	303,024.99	214,420	244,603	58,422	5.99	9,753
2010	88,994.13	56,404	64,344	24,650	7.22	3,414
2011	231,480.17	137,083	156,380	75,100	7.92	9,482
2012	101,602.74	55,577	63,400	38,203	8.69	4,396
2013	64,307.89	32,193	36,725	27,583	9.48	2,910
2014	85,443.25	38,569	43,998	41,445	10.33	4,012
2015	44,174.73	17,661	20,147	24,028	11.26	2,134
2016	129,029.77	44,877	51,194	77,836	12.19	6,385
2018	4,662.78	1,125	1,283	3,380	14.16	239
2022	229,894.69	6,161	7,029	222,866	18.16	12,272
	5,037,890.80	3,530,112	4,010,096	1,027,795		137,298

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.5   2.73

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-O1						
NET SALVAGE PERCENT.. 0						
1926	642.41	642	642			
1929	5,321.34	5,321	5,321			
1940	197.92	198	198			
1941	263.93	264	264			
1945	32.62	33	33			
1946	283.36	283	283			
1948	1,451.21	1,451	1,451			
1949	253.79	254	254			
1950	17.14	17	17			
1951	453.74	454	454			
1952	127.16	127	127			
1954	1,722.53	1,723	1,723			
1955	5,517.30	5,517	5,517			
1956	70.84	71	71			
1957	1,458.37	1,458	1,458			
1958	8,469.70	8,470	8,470			
1959	4,103.33	4,103	4,103			
1960	1,507.24	1,507	1,507			
1961	2,700.54	2,701	2,701			
1962	2,255.35	2,255	2,255			
1963	5,671.86	5,600	4,763	909	0.38	909
1964	8,035.28	7,802	6,635	1,400	0.87	1,400
1965	3,704.69	3,534	3,006	699	1.38	507
1966	9,174.56	8,600	7,314	1,861	1.88	990
1967	13,870.71	12,775	10,865	3,006	2.37	1,268
1968	14,200.92	12,838	10,918	3,283	2.88	1,140
1969	9,906.37	8,790	7,475	2,431	3.38	719
1970	14,122.73	12,301	10,461	3,662	3.87	946
1971	5,824.84	4,974	4,230	1,595	4.38	364
1972	9,178.06	7,685	6,536	2,642	4.88	541
1973	8,790.25	7,217	6,138	2,652	5.37	494
1974	13,190.14	10,605	9,019	4,171	5.88	709
1975	4,362.97	3,435	2,921	1,442	6.38	226
1976	3,177.16	2,450	2,084	1,093	6.87	159
1977	8,577.39	6,467	5,500	3,077	7.38	417
1978	2,737.09	2,018	1,716	1,021	7.88	130
1979	1,616.62	1,166	992	625	8.37	75
1980	11,925.65	8,396	7,140	4,786	8.88	539
1981	16,141.57	11,095	9,436	6,706	9.38	715
1982	18,883.68	15,352	13,056	5,828	9.26	629
1983	16,411.21	13,204	11,229	5,182	9.53	544
1984	22,000.61	17,420	14,815	7,186	10.06	714
1985	18,787.13	14,695	12,497	6,290	10.37	607

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-O1						
NET SALVAGE PERCENT.. 0						
1986	9,922.73	7,626	6,486	3,437	10.92	315
1987	16,483.16	12,493	10,625	5,858	11.26	520
1988	23,966.98	17,894	15,218	8,749	11.62	753
1989	33,211.86	24,404	20,754	12,458	12.00	1,038
1990	35,050.72	25,321	21,534	13,517	12.39	1,091
1991	24,596.13	17,448	14,839	9,757	12.80	762
1992	35,762.34	24,883	21,162	14,600	13.23	1,104
1993	11,592.34	7,969	6,777	4,815	13.42	359
1994	42,356.58	28,489	24,229	18,128	13.87	1,307
1995	59,961.02	39,574	33,656	26,305	14.17	1,856
1996	12,276.38	7,938	6,751	5,525	14.48	382
1997	31,396.73	19,855	16,886	14,511	14.82	979
1998	28,411.16	17,541	14,918	13,493	15.18	889
1999	15,625.56	9,438	8,027	7,599	15.41	493
2000	34,452.28	20,310	17,273	17,179	15.67	1,096
2001	43,335.86	24,875	21,155	22,181	15.96	1,390
2002	72,442.64	40,394	34,353	38,090	16.26	2,343
2003	29,016.52	15,730	13,378	15,639	16.47	950
2004	23,409.96	12,300	10,461	12,949	16.71	775
2005	12,053.15	6,117	5,202	6,851	16.98	403
2006	122,072.81	59,816	50,871	71,202	17.17	4,147
2007	69,471.83	32,735	27,840	41,632	17.39	2,394
2008	56,319.94	25,479	21,669	34,651	17.55	1,974
2009	33,569.02	14,549	12,373	21,196	17.65	1,201
2010	20,156.51	8,315	7,071	13,086	17.80	735
2011	91,834.61	36,018	30,632	61,203	17.82	3,435
2012	25,438.26	9,402	7,996	17,442	17.91	974
2013	61,860.47	21,453	18,245	43,615	17.90	2,437
2014	40,611.98	13,118	11,156	29,456	17.82	1,653
2015	189,149.16	56,177	47,776	141,373	17.75	7,965
2016	201,370.11	54,450	46,307	155,063	17.54	8,841
2017	130,859.86	31,590	26,865	103,995	17.28	6,018
2018	105,309.30	22,136	18,825	86,484	16.91	5,114
2019	49,677.75	8,763	7,453	42,225	16.34	2,584
2020	34,301.17	4,761	4,049	30,252	15.52	1,949
2021	25,224.02	2,411	2,050	23,174	14.20	1,632
2022	89,421.39	3,800	3,232	86,189	11.26	7,654
	2,219,113.60	1,020,840	873,689	1,345,425		94,254

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.3 4.25

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 371.5 INSTALLATIONS ON CUSTOMERS PREMISES - DUSK TO DAWN LIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 23-R1						
NET SALVAGE PERCENT.. 0						
1973	1,435.43	1,435	1,435			
1974	6,471.13	6,471	6,471			
1975	3,583.76	3,584	3,584			
1976	4,402.59	4,403	4,403			
1977	4,697.22	4,632	4,697			
1978	4,229.73	4,110	4,230			
1979	5,985.23	5,728	5,985			
1980	4,861.55	4,583	4,862			
1981	2,917.37	2,711	2,917			
1982	1,561.73	1,496	1,562			
1983	2,231.26	2,119	2,231			
1984	2,149.66	2,023	2,150			
1985	2,342.27	2,181	2,342			
1986	990.28	915	990			
1987	1,925.20	1,758	1,925			
1988	2,301.67	2,081	2,302			
1989	1,493.31	1,336	1,493			
1990	4,328.13	3,824	4,328			
1991	2,572.95	2,243	2,573			
1992	4,859.73	4,175	4,860			
1993	2,315.34	1,967	2,315			
1994	8,619.58	7,222	8,620			
1995	9,663.67	7,973	9,664			
1996	37,963.03	30,682	37,963			
1997	53,663.03	42,555	53,004	659	6.66	99
1998	61,778.99	48,132	59,950	1,829	6.95	263
1999	61,882.53	47,117	58,686	3,197	7.36	434
2000	30,918.71	23,028	28,682	2,237	7.71	290
2008	14,410.22	8,171	10,177	4,233	11.07	382
2017	1,150.61	321	400	751	14.22	53
	347,705.91	278,976	334,801	12,905		1,521

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.5   0.44

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

SURVIVOR CURVE.. IOWA 28-L0
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1917	290.75	269	243	48	2.12	23
1918	8.56	8	7	2	2.24	1
1919	777.88	712	643	135	2.36	57
1920	236.79	216	195	42	2.48	17
1921	402.50	365	330	72	2.60	28
1923	973.52	875	791	183	2.84	64
1924	85.02	76	69	16	2.96	5
1925	398.99	355	321	78	3.09	25
1927	670.06	590	533	137	3.34	41
1928	404.81	355	321	84	3.47	24
1930	2,085.16	1,808	1,634	451	3.72	121
1931	70.92	61	55	16	3.85	4
1932	65.64	56	51	15	3.98	4
1933	152.49	130	117	35	4.12	8
1934	392.04	333	301	91	4.25	21
1935	549.53	464	419	131	4.38	30
1936	6,230.32	5,225	4,721	1,509	4.52	334
1937	678.72	566	511	168	4.66	36
1938	312.54	259	234	79	4.80	16
1939	180.12	148	134	46	4.94	9
1940	398.21	326	295	103	5.08	20
1941	95.84	78	70	26	5.22	5
1942	137.88	111	100	38	5.37	7
1945	26.87	21	19	8	5.81	1
1946	51.14	40	36	15	5.96	3
1947	111.15	87	79	32	6.11	5
1948	1,800.49	1,398	1,263	537	6.26	86
1949	1,299.52	1,002	905	395	6.42	62
1950	2,643.12	2,022	1,827	816	6.58	124
1951	1,727.67	1,312	1,185	543	6.73	81
1952	3,098.96	2,335	2,110	989	6.90	143
1953	4,245.68	3,175	2,869	1,377	7.06	195
1954	2,406.91	1,786	1,614	793	7.22	110
1955	3,328.48	2,450	2,214	1,114	7.39	151
1956	16,611.39	12,126	10,957	5,654	7.56	748
1957	2,522.60	1,826	1,650	873	7.73	113
1958	1,471.26	1,056	954	517	7.90	65
1959	10,592.19	7,539	6,812	3,780	8.07	468
1960	1,153.70	814	736	418	8.25	51
1961	3,089.66	2,159	1,951	1,139	8.43	135
1962	2,715.20	1,880	1,699	1,016	8.61	118
1963	7,519.15	5,159	4,662	2,857	8.79	325
1964	6,074.26	4,126	3,728	2,346	8.98	261

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

SURVIVOR CURVE.. IOWA 28-L0
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1965	43,667.99	29,367	26,535	17,133	9.17	1,868
1966	49,254.06	32,789	29,627	19,627	9.36	2,097
1967	36,466.43	24,029	21,712	14,754	9.55	1,545
1968	19,810.88	12,913	11,668	8,143	9.75	835
1969	9,743.47	6,281	5,675	4,068	9.95	409
1970	9,633.21	6,141	5,549	4,084	10.15	402
1971	7,898.36	4,979	4,499	3,399	10.35	328
1972	3,175.95	1,978	1,787	1,389	10.56	132
1973	21,957.12	13,512	12,209	9,748	10.77	905
1974	9,888.41	6,011	5,431	4,457	10.98	406
1975	49,579.52	29,748	26,879	22,701	11.20	2,027
1976	16,856.29	9,981	9,019	7,837	11.42	686
1977	12,234.31	7,148	6,459	5,775	11.64	496
1978	19,607.26	11,295	10,206	9,401	11.87	792
1979	15,685.12	8,912	8,053	7,632	12.09	631
1980	15,785.92	8,834	7,982	7,804	12.33	633
1981	30,670.82	16,913	15,282	15,389	12.56	1,225
1982	61,558.37	48,317	43,658	17,900	11.03	1,623
1983	47,337.15	36,790	33,242	14,095	11.25	1,253
1984	30,494.43	23,444	21,183	9,311	11.50	810
1985	17,491.93	13,357	12,069	5,423	11.53	470
1986	7,603.27	5,733	5,180	2,423	11.83	205
1987	16,121.42	12,048	10,886	5,235	11.92	439
1988	43,161.84	31,931	28,852	14,310	12.05	1,188
1989	32,662.53	23,893	21,589	11,074	12.20	908
1990	30,482.09	22,020	19,897	10,585	12.39	854
1991	21,108.78	15,040	13,590	7,519	12.61	596
1992	20,706.27	14,594	13,187	7,519	12.67	593
1993	122,104.77	85,009	76,811	45,294	12.87	3,519
1994	37,204.97	25,552	23,088	14,117	13.00	1,086
1995	26,017.57	17,601	15,904	10,114	13.15	769
1996	10,312.44	6,860	6,198	4,114	13.34	308
1997	9,652.54	6,326	5,716	3,937	13.41	294
1998	5,709.09	3,665	3,312	2,397	13.67	175
1999	5,778.94	3,640	3,289	2,490	13.81	180
2000	29,045.10	17,973	16,240	12,805	13.86	924
2001	67,382.50	40,713	36,787	30,596	14.09	2,171
2002	24,169.10	14,269	12,893	11,276	14.22	793
2003	73,029.64	42,153	38,088	34,942	14.28	2,447
2004	64,808.73	36,332	32,828	31,981	14.50	2,206
2005	73,841.53	40,317	36,429	37,413	14.55	2,571
2008	29,146.56	14,369	12,983	16,164	14.91	1,084
2009	8,582.55	4,066	3,674	4,909	14.99	327

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 28-L0						
NET SALVAGE PERCENT.. 0						
2010	21,672.11	9,835	8,887	12,785	15.05	850
2011	1,726.35	746	674	1,052	15.10	70
2012	24,178.90	9,901	8,946	15,233	15.14	1,006
2013	2,011.43	776	701	1,310	15.13	87
2014	7,921.18	2,848	2,573	5,348	15.14	353
2015	28,584.43	9,476	8,562	20,022	15.12	1,324
2016	15,031.38	4,533	4,096	10,935	15.05	727
2017	31,781.03	8,530	7,707	24,074	14.99	1,606
2018	375,600.98	87,365	78,940	296,661	14.84	19,991
2019	13,877.06	2,675	2,417	11,460	14.65	782
2020	221,880.46	32,949	29,772	192,108	14.34	13,397
2021	84,884.01	8,302	7,501	77,383	13.84	5,591
2022	126,917.10	4,785	4,324	122,593	12.76	9,608
	2,331,583.34	1,085,263	980,610	1,350,973		102,747

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.1   4.41

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FORTY FORT WAREHOUSE						
INTERIM SURVIVOR CURVE.. IOWA 100-L0						
PROBABLE RETIREMENT YEAR.. 6-2032						
NET SALVAGE PERCENT.. 0						
1927	41,564.72	36,562	34,119	7,445	9.20	809
1930	2,328.61	2,043	1,907	422	9.21	46
1933	113.59	99	92	21	9.22	2
1938	7,165.64	6,239	5,822	1,343	9.24	145
1949	217.87	187	175	43	9.28	5
1950	20,323.38	17,434	16,269	4,054	9.28	437
1951	120.00	103	96	24	9.28	3
1964	216.76	181	169	48	9.33	5
1966	434.07	361	337	97	9.33	10
1967	5,811.38	4,825	4,503	1,309	9.34	140
1972	3,446.06	2,823	2,634	812	9.35	87
1974	1,004.63	818	763	241	9.36	26
1975	1,263.13	1,025	957	307	9.36	33
1978	2,476.76	1,988	1,855	622	9.37	66
1979	17,025.00	13,608	12,699	4,326	9.38	461
1980	177,705.09	141,476	132,024	45,681	9.38	4,870
1981	624.19	495	462	162	9.38	17
1982	2,589.66	2,105	1,964	625	9.26	67
1983	288.18	233	217	71	9.29	8
1984	9,938.45	7,983	7,450	2,489	9.37	266
1985	20,517.47	16,432	15,334	5,183	9.26	560
1986	1,426.45	1,132	1,056	370	9.41	39
1987	5,748.63	4,539	4,236	1,513	9.39	161
1989	6,883.34	5,379	5,020	1,864	9.30	200
1990	29,189.02	22,592	21,083	8,106	9.42	861
1991	53,558.93	41,176	38,425	15,134	9.40	1,610
1992	1,682.78	1,283	1,197	485	9.43	51
1993	11,025.36	8,359	7,801	3,225	9.41	343
1994	51,976.41	39,107	36,494	15,482	9.38	1,651
1995	26,858.78	20,015	18,678	8,181	9.40	870
1998	3,257.06	2,354	2,197	1,060	9.40	113
2005	22,104.06	14,390	13,429	8,675	9.38	925
2006	73,525.00	46,828	43,699	29,826	9.41	3,170
2011	22,834.53	12,552	11,713	11,121	9.42	1,181
2014	9,393.33	4,455	4,157	5,236	9.42	556
2015	309,928.38	137,360	128,183	181,746	9.42	19,294
2016	130,028.86	53,078	49,532	80,497	9.42	8,545
2018	51,103.80	16,512	15,409	35,695	9.43	3,785

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FORTY FORT WAREHOUSE INTERIM SURVIVOR CURVE.. IOWA 100-L0 PROBABLE RETIREMENT YEAR.. 6-2032 NET SALVAGE PERCENT.. 0						
2020	34,214.66	7,185	6,705	27,510	9.40	2,927
2021	242,042.55	33,402	31,170	210,872	9.37	22,505
2022	1,371,815.45	69,963	65,289	1,306,527	9.29	140,638
	2,773,772.02	798,681	745,320	2,028,452		217,488
PLYMOUTH STOREROOM (BRICK STRUCTURE) FULLY ACCRUED NET SALVAGE PERCENT.. 0						
1917	7,127.10	7,127	7,127			
1951	556.54	557	557			
1976	902.76	903	903			
1984	1,008.80	1,009	1,009			
2008	5,516.25	5,516	5,516			
	15,111.45	15,112	15,111			
IDETOWN INTERIM SURVIVOR CURVE.. IOWA 100-L0 PROBABLE RETIREMENT YEAR.. 6-2046 NET SALVAGE PERCENT.. 0						
1979	930.87	575	535	396	21.53	18
1983	13,610.31	8,868	8,256	5,354	20.99	255
2021	35,384.32	2,410	2,244	33,141	20.53	1,614
	49,925.50	11,853	11,035	38,890		1,887
NANTICOKE SERVICE CENTER FULLY ACCRUED NET SALVAGE PERCENT.. 0						
1971	4,029.19	4,029	4,029			
1975	21,022.88	21,023	21,023			
1985	36,364.35	36,364	36,364			
1986	4,788.36	4,788	4,788			
1987	9,974.00	9,974	9,974			
	76,178.78	76,178	76,179			

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
EMPIRE YARD FULLY ACCRUED NET SALVAGE PERCENT.. 0						
2014	19,894.79	19,895	19,895			
	19,894.79	19,895	19,895			
SYSTEM CONTROL CENTER INTERIM SURVIVOR CURVE.. IOWA 100-L0 PROBABLE RETIREMENT YEAR.. 7-2056 NET SALVAGE PERCENT.. 0						
2016	1,875,841.31	357,160	325,903	1,549,938	27.63	56,096
2021	3,575.00	191	174	3,401	26.59	128
2022	12,471.61	237	216	12,255	25.75	476
	1,891,887.92	357,588	326,294	1,565,594		56,700
	4,826,770.46	1,279,307	1,193,834	3,632,936		276,075

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.2 5.72

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2007	13,833.00	10,721	6,193	7,640	4.50	1,698
2015	15,627.39	5,860	3,385	12,242	12.50	979
2016	17,280.62	5,616	3,244	14,037	13.50	1,040
2018	19,327.09	4,349	2,512	16,815	15.50	1,085
	66,068.10	26,546	15,334	50,734		4,802

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.6 7.27

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	359,391.70	251,574	130,109	229,283	1.50	152,855
2022	9,823.55	982	508	9,316	4.50	2,070
	369,215.25	252,556	130,617	238,598		154,925

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.5 41.96

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 391.92 OFFICE FURNITURE AND EQUIPMENT - OUTAGE MANAGEMENT SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2013	607,693.18	607,693	607,693			
2016	54,362.66	54,363	54,363			
2021	20,008.56	6,003	34-	20,043	3.50	5,727
2022	3,341,592.33	334,159	1,872-	3,343,464	4.50	742,992
	4,023,656.73	1,002,218	660,150	3,363,507		748,719

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.5   18.61

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - CARS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 7-L3						
NET SALVAGE PERCENT.. 0						
2020	209,034.47	82,360	102,500	106,534	3.85	27,671
2021	59,173.85	14,285	17,778	41,396	4.71	8,789
2022	33,888.94	2,745	3,416	30,473	5.67	5,374
	302,097.26	99,390	123,694	178,403		41,834

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.3   13.85

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 392.2 TRANSPORTATION EQUIPMENT - LIGHT TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 11-L3						
NET SALVAGE PERCENT.. 0						
2020	709,058.60	181,377	106,154	602,905	7.27	82,931
2021	232,833.23	35,949	21,040	211,793	8.22	25,766
2022	453,079.46	23,334	13,656	439,423	9.21	47,712
	1,394,971.29	240,660	140,850	1,254,121		156,409

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.0   11.21

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 392.4 TRANSPORTATION EQUIPMENT – HEAVY TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 14-S3						
NET SALVAGE PERCENT.. 0						
2020	136,684.28	26,175	16,071	120,613	10.55	11,433
2021	243,704.15	28,026	17,207	226,497	11.54	19,627
2022	110,248.00	4,234	2,599	107,649	12.54	8,584
	490,636.43	58,435	35,877	454,759		39,644

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.5 8.08

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 393 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	3,216.82	2,413	1,896	1,321	2.50	528
2020	11,401.12	2,850	2,239	9,162	7.50	1,222
	14,617.94	5,263	4,135	10,483		1,750

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.0 11.97

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	78,913.16	76,940	74,917	3,996	0.50	3,996
2004	32,594.97	30,150	29,357	3,238	1.50	2,159
2005	67,810.09	59,334	57,774	10,036	2.50	4,014
2006	26,827.51	22,133	21,551	5,277	3.50	1,508
2007	75,903.01	58,825	57,278	18,625	4.50	4,139
2008	9,798.31	7,104	6,917	2,881	5.50	524
2009	52,062.46	35,142	34,218	17,844	6.50	2,745
2010	39,487.40	24,680	24,031	15,456	7.50	2,061
2011	76,427.62	43,946	42,791	33,637	8.50	3,957
2012	11,816.07	6,203	6,040	5,776	9.50	608
2013	69,050.65	32,799	31,937	37,114	10.50	3,535
2014	22,312.31	9,483	9,234	13,078	11.50	1,137
2015	64,165.13	24,062	23,429	40,736	12.50	3,259
2016	79,880.35	25,961	25,278	54,602	13.50	4,045
2017	64,019.56	17,605	17,142	46,878	14.50	3,233
2018	515,650.14	116,021	112,970	402,680	15.50	25,979
2019	162,882.48	28,504	27,755	135,127	16.50	8,190
2020	37,646.28	4,706	4,582	33,064	17.50	1,889
2021	93,757.93	7,032	6,847	86,911	18.50	4,698
2022	53,217.59	1,330	1,295	51,923	19.50	2,663
	1,634,223.02	631,960	615,343	1,018,880		84,339

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.1 5.16

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 395 LABORATORY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2013	23,858.97	22,666	23,859			
2014	36,231.68	30,797	36,043	189	1.50	126
2015	8,105.79	6,079	7,114	992	2.50	397
2016	16,836.39	10,944	12,808	4,028	3.50	1,151
2020	12,796.72	3,199	3,744	9,053	7.50	1,207
	97,829.55	73,685	83,568	14,262		2,881

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.0 2.94

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 396 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-S0						
NET SALVAGE PERCENT.. 0						
2020	59,262.02	10,146	4,339	54,923	12.10	4,539
2022	117,369.54	4,624	1,978	115,392	12.21	9,451
	176,631.56	14,770	6,317	170,315		13,990

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.2 7.92

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 397 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2013	92,135.10	87,528	36,768	55,367	0.50	55,367
2014	53,343.52	45,342	19,047	34,297	1.50	22,865
2016	166,321.59	108,109	45,413	120,909	3.50	34,545
2017	12,516.18	6,884	2,892	9,624	4.50	2,139
2018	22,527.08	10,137	4,258	18,269	5.50	3,322
2019	25,342.02	8,870	3,726	21,616	6.50	3,326
2020	204,414.03	51,104	21,468	182,946	7.50	24,393
2021	221,515.29	33,227	13,957	207,558	8.50	24,419
2022	225,172.48	11,259	4,730	220,442	9.50	23,204
	1,023,287.29	362,460	152,259	871,028		193,580

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.5 18.92

UGI UTILITIES, INC. - ELECTRIC DIVISION

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	8,850.87	6,638	3,059	5,792	2.50	2,317
2016	81,148.36	52,746	24,308	56,840	3.50	16,240
2018	66,633.01	29,985	13,819	52,814	5.50	9,603
2020	14,868.03	3,717	1,713	13,155	7.50	1,754
2021	76,140.46	11,421	5,263	70,877	8.50	8,338
2022	162,653.03	8,133	3,748	158,905	9.50	16,727
	410,293.76	112,640	51,910	358,384		54,979

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.5 13.40

COMMON PLANT

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 301 ORGANIZATION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NONDEPRECIABLE						
1952	96,447.19					
1953	42,516.33					
	138,963.52					

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 389.1 LAND AND LAND RIGHTS - LAND

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NONDEPRECIABLE						
2017	6,947,107.66					
	6,947,107.66					

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI HEADQUARTERS BUILDING INTERIM SURVIVOR CURVE.. IOWA 70-R1 PROBABLE RETIREMENT YEAR.. 1-2069 NET SALVAGE PERCENT.. 0						
2019	29,987,923.48	2,950,812	2,798,935	27,188,988	32.09	847,273
2020	1,890,627.83	140,285	133,065	1,757,563	31.17	56,386
2021	654,570.06	31,288	29,678	624,892	29.85	20,934
2022	3,248,137.93	60,415	57,305	3,190,832	26.45	120,636
	35,781,259.30	3,182,800	3,018,983	32,762,276		1,045,229

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.3 2.92

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	7,182.75	7,003	6,074	1,109	0.50	1,109
2004	11,896.38	11,004	9,544	2,352	1.50	1,568
2005	39,965.68	34,970	30,331	9,635	2.50	3,854
2006	2,468.81	2,037	1,767	702	3.50	201
2007	878.14	681	591	287	4.50	64
2008	572.40	415	360	212	5.50	39
2009	4,753.12	3,208	2,782	1,971	6.50	303
2010	747,318.56	467,074	405,108	342,211	7.50	45,628
2019	3,525,373.71	616,940	535,091	2,990,283	16.50	181,229
2020	27,303.10	3,413	2,960	24,343	17.50	1,391
2022	782,244.07	19,556	16,961	765,283	19.50	39,245
	5,149,956.72	1,166,301	1,011,569	4,138,387		274,631

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.1   5.33

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2018	88,618.09	79,756	36,360	52,258	0.50	52,258
2019	277,195.89	194,037	88,459	188,737	1.50	125,825
2021	1,076,384.85	322,915	147,212	929,173	3.50	265,478
	1,442,198.83	596,708	272,031	1,170,168		443,561

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.6 30.76

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - CARS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 7-L2.5						
NET SALVAGE PERCENT.. 0						
2004	26,875.84	26,750	26,876			
2008	22,536.44	21,405	22,536			
2014	22,224.80	18,304	22,225			
	71,637.08	66,459	71,637			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	22,684.22	22,117	22,184	500	0.50	500
2004	5,698.56	5,271	5,287	412	1.50	275
2007	1,760.05	1,364	1,368	392	4.50	87
2022	558.68	14	14	545	19.50	28
	30,701.51	28,766	28,853	1,849		890

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.1 2.90

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2018	5,584,430.57	5,025,988	4,993,939	590,492	0.50	590,492
2019	9,507,270.50	6,655,089	6,612,651	2,894,620	1.50	1,929,747
2020	1,979,935.89	989,968	983,655	996,281	2.50	398,512
2021	847,064.50	254,119	252,499	594,566	3.50	169,876
2022	2,422,784.11	242,278	240,733	2,182,051	4.50	484,900
	20,341,485.57	13,167,442	13,083,477	7,258,009		3,573,527

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.0   17.57

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SUCCESS FACTORS INTERIM SURVIVOR CURVE.. SQUARE PROBABLE RETIREMENT YEAR.. 9-2024 NET SALVAGE PERCENT.. 0						
2019	2,803,866.07	1,682,320	1,289,824	1,514,042	2.00	757,021
	2,803,866.07	1,682,320	1,289,824	1,514,042		757,021
UNITE ERP INTERIM SURVIVOR CURVE.. SQUARE PROBABLE RETIREMENT YEAR.. 9-2034 NET SALVAGE PERCENT.. 0						
2019	10,695,816.43	2,139,163	1,640,083	9,055,733	12.00	754,644
	10,695,816.43	2,139,163	1,640,083	9,055,733		754,644
	13,499,682.50	3,821,483	2,929,907	10,569,775		1,511,665

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.0   11.20

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.3 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE - SYSTEM DEV. COSTS - 10 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
ALL OTHER						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2012	2,890,937.57	2,890,938	2,890,938			
2013	381,964.34	362,866	339,740	42,225	0.50	42,225
2014	935,231.11	794,946	744,283	190,949	1.50	127,299
2015	732,102.69	549,077	514,083	218,019	2.50	87,208
2016	930,430.13	604,780	566,236	364,194	3.50	104,055
2017	1,349,992.48	742,496	695,175	654,817	4.50	145,515
2018	1,373,844.01	618,230	578,829	795,015	5.50	144,548
2019	7,509,579.44	2,628,353	2,460,843	5,048,737	6.50	776,729
2020	12,521,978.02	3,130,495	2,930,982	9,590,996	7.50	1,278,799
2021	7,759,405.05	1,163,911	1,089,733	6,669,672	8.50	784,667
2022	8,508,252.60	425,413	398,301	8,109,952	9.50	853,679
	44,893,717.44	13,911,505	13,209,142	31,684,575		4,344,724
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
2000	802,205.51	802,206	802,206			
2001	18,799.62	18,800	18,800			
2002	447,659.05	447,659	447,659			
2004	1,403,264.52	1,403,265	1,403,265			
2005	122,880.00	122,880	122,880			
2006	2,314,890.18	2,314,890	2,314,890			
2007	3,259,581.05	3,259,581	3,259,581			
2008	259,506.50	259,506	259,507			
2009	481,827.39	481,827	481,827			
2010	172,048.21	172,048	172,048			
2011	24,265.04	24,265	24,265			
2012	101,760.00	101,760	101,760			
	9,408,687.07	9,408,687	9,408,687			
	54,302,404.51	23,320,192	22,617,829	31,684,575		4,344,724

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.3 8.00

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.4 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE - SYSTEM DEV. COSTS - 15 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2005	867,789.26	867,789	867,789			
2006	1,660,897.57	1,660,898	1,660,898			
2007	3,042,652.35	3,042,652	3,042,652			
2008	2,908,998.47	2,812,042	2,787,509	121,489	0.50	121,489
2011	425,873.07	326,504	323,655	102,218	3.50	29,205
2012	401,290.13	280,903	278,452	122,838	4.50	27,297
2013	142,364.69	90,164	89,377	52,988	5.50	9,634
2014	495,556.48	280,817	278,367	217,189	6.50	33,414
2016	1,419,264.44	615,010	609,644	809,620	8.50	95,249
2017	76,271,826.62	27,966,591	27,722,603	48,549,224	9.50	5,110,445
2018	171,914.66	51,574	51,124	120,791	10.50	11,504
2019	43,660,591.71	10,187,326	10,098,448	33,562,144	11.50	2,918,447
2021	7,039,054.95	703,905	697,764	6,341,291	13.50	469,725
2022	2,541,873.11	84,721	83,982	2,457,891	14.50	169,510
	141,049,947.51	48,970,896	48,592,264	92,457,683		8,995,919

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.3 6.38

EMPIRE YARD

UGI UTILITIES, INC. - ELECTRIC DIVISION - EMPIRE YARD

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

PNG - EMPIRE YARD - MAJOR STRUCTURES
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5
PROBABLE RETIREMENT YEAR.. 12-2047
NET SALVAGE PERCENT.. 0

1960	100,930.51	70,894	78,455	22,476	20.85	1,078
1961	86,871.16	60,698	67,171	19,700	20.97	939
1962	141,136.69	98,106	108,569	32,568	21.08	1,545
1963	9,480.45	6,555	7,254	2,226	21.19	105
1964	3,689.12	2,537	2,808	882	21.30	41
1965	479.00	327	362	117	21.41	5
1966	297.39	202	224	74	21.51	3
1967	860.37	581	643	217	21.61	10
1968	3,570.31	2,398	2,654	917	21.71	42
1969	661.27	441	488	173	21.81	8
1970	2,325.05	1,542	1,706	619	21.90	28
1971	74,835.43	49,306	54,564	20,271	21.99	922
1972	5,279.41	3,455	3,823	1,456	22.08	66
1973	5,863.34	3,810	4,216	1,647	22.17	74
1974	1,077.54	695	769	308	22.26	14
1975	20,112.15	12,876	14,249	5,863	22.34	262
1976	98,397.02	62,515	69,182	29,215	22.42	1,303
1977	262,518.62	165,492	183,142	79,377	22.49	3,529
1978	14,862.88	9,292	10,283	4,580	22.57	203
1979	31,316.64	19,414	21,484	9,832	22.64	434
1980	50,253.77	30,872	34,164	16,089	22.72	708
1981	48,963.34	29,815	32,995	15,969	22.78	701
1982	16,098.09	10,432	11,545	4,554	22.00	207
1983	15,919.21	10,187	11,273	4,646	22.23	209
1984	47,604.50	30,057	33,263	14,342	22.48	638
1985	68,749.88	43,051	47,642	21,108	22.38	943
1986	220,372.23	136,741	151,324	69,048	22.32	3,094
1987	95,726.84	58,451	64,685	31,042	22.64	1,371
1988	78,940.78	47,664	52,747	26,193	22.64	1,157
1989	133,833.58	79,805	88,316	45,517	22.68	2,007
1990	1,474.46	867	959	515	22.75	23
1991	12,756.63	7,435	8,228	4,529	22.55	201
1992	108,291.24	62,094	68,716	39,575	22.69	1,744
1993	238,990.24	134,647	149,007	89,983	22.86	3,936
1994	9,228.65	5,129	5,676	3,553	22.78	156
1995	133,112.29	72,839	80,607	52,505	22.75	2,308
1996	77,622.54	41,551	45,982	31,640	23.00	1,376
1997	4,624,824.64	2,429,420	2,688,517	1,936,308	23.04	84,041
1998	280,621.46	145,081	160,554	120,068	22.89	5,245
1999	84,872.92	42,878	47,451	37,422	23.01	1,626
2000	89,743.66	44,423	49,161	40,583	22.95	1,768

UGI UTILITIES, INC. - ELECTRIC DIVISION - EMPIRE YARD

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MAJOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2047						
NET SALVAGE PERCENT.. 0						
2001	725,398.24	349,352	386,610	338,788	23.14	14,641
2002	42,268.05	19,841	21,957	20,311	23.17	877
2003	180,782.36	82,834	91,668	89,114	23.06	3,864
2004	146,160.24	64,895	71,816	74,344	23.17	3,209
2005	167,022.30	71,903	79,571	87,451	23.15	3,778
2006	140,015.92	58,219	64,428	75,588	23.18	3,261
2007	877,150.17	352,088	389,638	487,512	23.11	21,095
2008	79,300.50	30,467	33,716	45,584	23.24	1,961
2009	54,131.55	19,953	22,081	32,051	23.13	1,386
2010	196,247.48	68,687	76,012	120,235	23.21	5,180
2011	314,990.40	104,325	115,451	199,539	23.22	8,593
2012	49,422.81	15,410	17,053	32,369	23.17	1,397
2013	122,684.15	35,664	39,468	83,217	23.18	3,590
2014	163,988.66	44,047	48,745	115,244	23.15	4,978
2015	94,908.17	23,271	25,753	69,155	23.08	2,996
2016	608,702.23	134,158	148,466	460,236	23.00	20,010
2017	58,203.25	11,233	12,431	45,772	22.99	1,991
2018	71,772.28	11,821	13,082	58,691	22.82	2,572
2019	6,739.12	901	997	5,742	22.68	253
2020	45,676.11	4,568	5,055	40,621	22.50	1,805
2021	221,491.88	14,087	15,589	205,903	22.08	9,325
2022	626,285.02	14,592	16,148	610,137	20.96	29,110
	12,295,906.19	5,566,891	6,160,598	6,135,309		269,942
PNG - EMPIRE YARD - MINOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2022						
NET SALVAGE PERCENT.. 0						
1960	27,374.98	27,375	27,375			
1961	2,250.14	2,250	2,250			
1962	11,395.40	11,395	11,395			
1964	212.41	212	212			
1965	479.69	480	480			
1972	4,846.95	4,847	4,847			
1973	59,338.04	59,338	59,338			
1976	674.99	675	675			
1977	9,114.69	9,115	9,115			
1978	24,124.85	24,125	24,125			

UGI UTILITIES, INC. - ELECTRIC DIVISION - EMPIRE YARD

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MINOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2022						
NET SALVAGE PERCENT.. 0						
1979	540.75	541	541			
1980	8,726.53	8,727	8,727			
1981	52,430.77	52,431	52,431			
1982	22,292.87	22,293	22,293			
1984	11,417.15	11,417	11,417			
1986	31,130.64	31,131	31,131			
1987	11,362.33	11,362	11,362			
1988	15,773.37	15,773	15,773			
1989	8,654.63	8,655	8,655			
1990	94,337.02	94,337	94,337			
1992	6,049.58	6,050	6,050			
1993	1,598.34	1,598	1,598			
1994	38,859.45	38,859	38,859			
1995	4,586.75	4,587	4,587			
1996	1,532.27	1,532	1,532			
1997	1,129.92	1,130	1,130			
1998	3,483.10	3,483	3,483			
2001	6,551.41	6,551	6,551			
2002	8,685.69	8,686	8,686			
2003	26,975.97	26,976	26,976			
2004	262,708.52	262,709	262,709			
2005	28,203.02	28,203	28,203			
2008	29,302.79	29,303	29,303			
2010	189,349.18	189,349	189,349			
2011	217,404.63	217,405	217,405			
2014	19,697.18	19,697	19,697			
2016	36,430.01	36,430	36,430			
2017	42,967.09	42,967	42,967			
2018	58,528.05	58,528	58,528			
2019	838,990.00	838,990	838,990			
2022	155,500.81	155,501	155,501			
	2,375,011.96	2,375,013	2,375,012			
	14,670,918.15	7,941,904	8,535,610	6,135,309		269,942

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 22.7 1.84

PART IV. EXPERIENCED NET SALVAGE

UGI UTILITIES, INC. - ELECTRIC DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2018 TRANSACTION YEAR				
362.00	86,850.00	31,267.00	6,395.00	24,872.00-
364.00	182,695.00	224,701.00		224,701.00-
365.00	37,148.00	48,433.00		48,433.00-
366.00		4,203.00		4,203.00-
367.00	156,340.00	6,274.00		6,274.00-
368.10	8,486.00	15,300.00		15,300.00-
368.20	36,845.00	45,925.00		45,925.00-
369.00	10,731.00	74,029.00		74,029.00-
370.10	31,755.00			
370.20	1,899.00	4,074.00		4,074.00-
371.00	41,391.00	10,164.00		10,164.00-
373.00	29,079.00	10,708.00		10,708.00-
390.20	53,383.00			
393.00	12,439.00			
396.00	145,839.00			
397.00	229,963.00			
398.00	18,794.00			
	1,083,637.00	475,078.00	6,395.00	468,683.00-
2019 TRANSACTION YEAR				
362.00		5,944.00		5,944.00-
364.00	160,972.00	178,476.00		178,476.00-
365.00	36,704.00	54,263.00		54,263.00-
366.00		3,977.00		3,977.00-
367.00	133,789.00	4,285.00		4,285.00-
368.10		235.00		235.00-
368.20	30,908.00	17,595.00		17,595.00-
369.00	18,624.00	88,722.00		88,722.00-
370.10	41,739.00			
370.20	3,388.00	6,489.00		6,489.00-
371.00	51,349.00	7,910.00		7,910.00-
373.00	26,285.00	7,411.00		7,411.00-
394.00	17,552.00			
395.00	10,623.00			
397.00	346,775.00			
398.00	37,987.00			
	916,695.00	375,307.00		375,307.00-

UGI UTILITIES, INC. - ELECTRIC DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2020 TRANSACTION YEAR				
362.00		24,880.00		24,880.00-
364.00	28,014.00	695,428.00		695,428.00-
365.00		121,069.00		121,069.00-
366.00		9,269.00		9,269.00-
367.00		14,036.00		14,036.00-
368.10		3,020.00		3,020.00-
368.20		58,648.00		58,648.00-
369.00		81,584.00		81,584.00-
370.10	222,832.00		59,469.00	59,469.00
370.20		3,781.00		3,781.00-
371.00		9,609.00		9,609.00-
373.00		19,433.00		19,433.00-
391.00	538.00			
391.10	10,122.00			
392.20			13,693.00	13,693.00
394.00	26,726.00			
397.00	337,961.00			
398.00	19,983.00	419.00		419.00-
	646,176.00	1,041,176.00	73,162.00	968,014.00-
2021 TRANSACTION YEAR				
362.00		5,721.00		5,721.00-
364.00	210,322.00	628,085.00		628,085.00-
365.00	135,947.00	175,874.00		175,874.00-
366.00	3,158.00	49.00		49.00-
367.00	7,219.00	23,539.00		23,539.00-
368.10	259.00	4,895.00		4,895.00-
368.20	83,839.00	25,689.00		25,689.00-
369.00	26,812.00	72,000.00		72,000.00-
370.10	36,917.00	76,928.00-		76,928.00
370.20	26,564.00	3,263.00		3,263.00-
370.30	67,438.00			
371.00	141,173.00	30,601.00		30,601.00-
373.00	36,544.00	14,719.00		14,719.00-
391.10	7,084.00			
392.20		112.00-		112.00
395.00	55,959.00			
397.00	15,410.00	63.00		63.00-
398.00		8,277.00		8,277.00-
	854,645.00	915,735.00		915,735.00-

UGI UTILITIES, INC. - ELECTRIC DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2022 TRANSACTION YEAR				
361.00		1,103.00		1,103.00-
362.00		9,451.00		9,451.00-
364.00	276,581.00	441,244.00		441,244.00-
365.00	133,125.00	138,834.00		138,834.00-
366.00	2,024.00	500.00		500.00-
367.00	25,277.00	16,452.00		16,452.00-
368.10	524,628.00	7,807.00		7,807.00-
368.20	95,304.00	33,600.00		33,600.00-
369.00	2,405.00	39,522.00		39,522.00-
370.10	28,484.00	68,289.00-		68,289.00
370.20	3,088.00	3,331.00		3,331.00-
370.30	21,404.00	2,299.00		2,299.00-
371.00	42,122.00	32,911.00		32,911.00-
373.00	70,453.00	28,409.00		28,409.00-
390.10		174.00		174.00-
391.00	2,580.00			
391.10	6,904.00			
392.20		1,099.00		1,099.00-
394.00	1,033.00			
395.00	17,678.00			
397.00	182,759.00			
398.00		30,752.00		30,752.00-
	1,435,849.00	719,199.00		719,199.00-
TOTAL	4,937,002.00	3,526,495.00	79,557.00	3,446,938.00-

BOOK VIII

UGI UTILITIES, INC. – ELECTRIC DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI ELECTRIC EXHIBIT D
(Fully Projected Future)

ALLOCATED COST OF SERVICE STUDY
AS OF SEPTEMBER 30, 2024

Witness: John D. Taylor
Prepared by: Atrium Economics

UGI UTILITIES, INC. – ELECTRIC DIVISION
PA P.U.C. NO. 6, SUPPLEMENT NO. 51
PA P.U.C. NO. 2S, SUPPLEMENT NO. 7

DOCKET NO. R-2022-3037368

Issued: January 27, 2023 Effective: March 28, 2023

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368

UGI UTILITIES, INC. – ELECTRIC DIVISION

EXHIBIT D

COST OF SERVICE ALLOCATION STUDY
FULLY PROJECTED FUTURE TEST YEAR
ENDED SEPTEMBER 30, 2024

Witness: John D. Taylor

ATRIUM ECONOMICS
CENTERED ON ENERGY

Contents

I. INTRODUCTION

The purpose of this document is to discuss the development and results of the Cost of Service Study ("COSS") model and related schedules prepared for UGI Utilities, Inc. ("UGI" or the "Company") based on the Fully Projected Future Test Year ended September 30, 2024 ("FPFTY").

The document is organized into three sections. The first section discusses the purpose of cost allocation and includes an overview of Atrium's COSS model used to develop the cost allocation study. The second section, UGI Cost of Service Procedures, includes details of the methodologies adopted in the development of the study. The last section exhibits the results of the cost of service allocation.

1. Purpose of Cost Allocation

The purpose of COSS is to determine the cost of service responsibilities of each customer class upon which the base rates may be established. The revenue requirement studies provide the overall level of costs of providing service, while the COSS is used to change the basic rate structures and/or the relative overall cost responsibility of each customer class. Based on the functionalization and classification of costs and allocation methodologies used in the COSS, the revenue requirement by customer class is determined and used in designing the Company's proposed base rates. In other words, the COSS measures each class's contribution to the Company's overall cost of service. Comparing the costs to serve any customer class with that class's rate revenues provides a measure of the return realized from that class and their associated revenue-to-cost ratio. This allows for a comparison across classes to ascertain the presence and extent of interclass subsidization (i.e., when one class pays more than its cost to serve and another pays less than its cost to serve).

2. COSS Procedures

Cost of service studies utilize a three-step process: functionalization, classification, and allocation.

In the first step, the functionalization sets off with assigning Federal Energy Regulatory Commission ("FERC") plant accounts and associated investment balances to appropriate cost of service functions. UGI's primary functional cost categories associated with electric distribution services include Primary Distribution, Secondary Distribution, and Customer Accounts and Services. The expenses related to particular property investments or groups of investments can often follow the same functionalization and are allocated based on the ratios of electric plant assigned to each function. These plant ratios can be used to functionalize most other cost items.

In the second step, classification, each functional cost category is further separated by cost causation. There are three basic cost-defining characteristics of electric services: demand, energy/commodity, and customer.

- Demand (Capacity) related costs are associated with the peak usage of the utility system. These costs are necessary to maintain the system at a level sufficient to satisfy the greatest demand that all the customers could place upon the system.
- Energy/Commodity-related costs are variable costs that vary with the quantity of electricity used. These costs reflect the number of units consumed or supplied during a period of time.

- Customer-related costs are associated with serving customers regardless of their usage or demand characteristics. They are allocated directly to the customers of a particular class of service.

The last step is to allocate these cost components among customer classes. An analysis of the utility's records may indicate specific costs that should be assigned directly to a particular customer class, including plant investments and associated expenses. All the remaining costs that cannot be directly attributable to a specific group of customers are allocated using allocation factors.

3. Atrium Economics Cost of Service Study Model Overview

The Cost of Service Study is submitted in support of the direct testimony of John D. Taylor in Exhibit D. The COSS model presented in this proceeding is an excel based model that allows the user to modify various inputs and assumptions.

COSS Model Capabilities

The Atrium Economics' COSS model provides a large range of analytical capabilities including:

- Unbundling of operations into functions: (i.e. production/supply, storage, transmission, distribution, metering, and billing services.)
- Classification and allocation of costs into customer classes.
- Reports on Rate of Return, Revenue Requirement, and Revenue-to-Cost ratio for each function and rate class.
- Development of unit costs of each functional classification for each rate class.
- Specification of the individual rate of return targets for each function or customer class.
- Provides detailed analyses of working capital, income taxes, depreciation reserve, and depreciation expenses.
- Use of detailed analysis of labor expenses by account to facilitate the analyses of administrative and general expenses and overhead costs.
- Facilitation of direct assignment of plant investment, expenses, and revenue dollars to individual functions, classifications, or customer classes.

Follows Traditional 3-Step Allocation

The Atrium COSS Model follows the standard three-step analysis process:1) functionalization of rate base and expenses into various functional categories; 2) classification of functionalized components into demand, energy/commodity, and customer cost categories; and 3) allocation of each component among the customer classes.

As part of the functionalization process, accounts for common costs that are not specifically related to the primary functions, such as general plant and administrative and general expenses, are automatically allocated to the proper function based on internally defined allocation factors. All components of the utility's total cost of service are grouped into one of the functions.

The Atrium COSS Model provides unbundled functionalized and classified cost information by customer class; develops unbundled revenue requirements by functional classification for each customer class; and calculates unit costs by function for customer, energy/commodity, and demand categories. Accounting costs are reported by the FERC account level, and the allocation of A&G expenses, general taxes, and income taxes are clearly reported.

Revenue requirements are calculated from the allocated rate base and expenses and are adjusted to reflect the user-determined target rate of return and statutory tax adjustments. The actual revenues collected are compared to the calculated cost-based revenue requirements to determine class-specific, revenue-to-cost ratios to assist in revenue allocation and pricing activities.

Unit Cost Output Functionality

The COSS model calculates the unit cost of each functional classification separately for each rate class based on the user-specified billing determinants. These unit cost data are among the most important outputs from an embedded cost of service analysis. They are defined as the average cost of providing service to customers per measure of service (i.e., per kilowatt hour, per kilowatt of daily demand, and per customer). Unit costs are a key consideration in developing prices for bundled, unbundled, and re-bundled services.

Acceptance by Utility Regulatory Commissions

The format and presentation of the model's outputs have been used in many rate case proceedings and conform to standard utility commission requirements. Where necessary the COSS model outputs can be easily modified to meet specific jurisdictional filing requirements.

II. UGI's COST OF SERVICE PROCEDURES

1. Functionalization

The following functional cost categories were identified for purposes of UGI's cost allocation:

- Purchased Power
- Distribution
- PA PUC Direct Customer

UGI's assigned functional categories are presented on Schedule 1.

2. Classification

The following classification categories were identified for purposes of UGI's cost allocation:

- Energy/Commodity
- Demand
- Customer

UGI's assigned classification categories are presented on Schedule 1.

3. Functional Split & Minimum System Study

To properly classify all distribution costs as either customer-related, demand-related or a combination of these two factors, UGI's distribution capital and operating costs are functionalized into their primary and secondary voltage level components using a primary secondary split study. Once functionalized, the plant is then classified into the demand and customer components based on a "minimum size system" study. These studies are based on historical electric distribution plant data and the results are applied to distribution plant for the fully projected future test year.

The cost allocation methodology utilized in the minimum system studies is based on the specific design and operating characteristics of the Company's distribution system. It provides a more accurate and consistent measure of class cost responsibility than other approaches for providing distribution service to its customers.

UGI's Functional Split & Minimum System Study is presented as Schedule 2.

4. Allocation

The allocation step involves assigning classified costs to the customer classes based on cost causation. Therefore, the allocation of costs is usually based on some measure of class loads or class service characteristics. The External and Internal Allocation Factors are utilized to allocate costs among various customer classes. UGI's assigned Allocation Factors are presented on Schedule 1.

4.1. Customer Classes and Tariff Schedules

The following customer classes were identified for purposes of cost allocation:

- Residential
- General Service
- General Service-4
- Flood Control Power ("FCP")
- Large Power
- Lighting

4.2. External Allocation Factors

UGI's External Allocation Factors are presented on Schedule 3. The External Allocation Factors are developed based on the special studies conducted using various detailed data.

ENERGY/COMMODITY AND REVENUE ALLCOATION FACTORS

Costs classified as "Energy/Commodity" are allocated among customer classes based on the megawatt-hour (MWh) sales volumes for the test year.

<u>ENERGY</u> – Factor developed to directly assign MWh sales to the specific class in the FPFTY, based on sales customers' volumes.

<u>DISTREV</u> – Factor developed to directly assign associated current distribution base rate revenues to the customer classes in the FPFTY.

<u>PWRREV</u> – Developed to allocate Purchased Power revenue across customer classes based on current Rider GDR revenues by customer classes in the FPFTY.

<u>DSICREV</u> – Factor developed to allocate Distribution System Improvement Charge (DSIC) revenue to customer classes.

STASREV – Factor to allocate State Tax Adjustment Surcharge (STAS) revenue to customer classes. The STAS is applicable to the net monthly rates and minimum charges in UGI's electric tariff.

USPREV – Factor developed to allocate Universal Service Program (USP) revenue to the Residential customer class. The USP was established to recover costs related to the Company's Universal Service and Conservation Programs, excluding internal administrative costs.

EECREV – Factor developed to allocated Energy Efficiency & Conservation (EEC) revenue to customer classes based on UGI's Rider E revenue. Rider E recovers costs related to the Company's Phase III EEC Plan for 2019-2024.

CUSTOMER ALLOCATION FACTORS

Customer-related costs are generally allocated based on the number of customers within each class of service, with appropriate weighting to recognize specific service characteristics.

CUST – Factor based on the average number of customers per customer class in the FPFTY.

PRI_CUST – Factor based on the average number of customers using the primary system per customer class in the FPFTY.

SEC_CUST – Average number of customers using the secondary system (excludes customers using primary system only) per customer class.

METERS – Factor based on the weighted customer unit cost of meters used to serve customers in different rate classes. The analysis relies upon the Company's records, which provide an inventory of each type and size of meter for a specific rate schedule. The average meter current replacement cost (including labor and overhead) was linked to the meter records dataset to develop the total current cost of the investment for each customer class. Then the relative customer class unit cost was developed and multiplied by the forecasted customer count for each customer class.

SERV – The analysis relies upon the data contained in the Company's property records which provide an inventory of average footage and count of service wires by customer type. Additionally, current unit costs per foot by service wire type and design (underground or overhead) were provided by UGI. The method employed to develop the service allocator was similar to that used for the meter allocator.

UNCOL – Uncollectible Accounts - This factor is based on the statistics related to the three-year average (2020 – 2022) of uncollectible accounts by rate class.

DEPCUST – Customer Deposits – Factor based on statistics of customer deposits by rate class from fiscal year 2022.

FORTDISC – Forfeited Deposits – This factor is based on the statistics related to the three-year average (2020 – 2022) of forfeited discounts by rate class.

LIGHT – Direct assignment for the Lighting customer class only.

CUSTPREMIS – This factor was developed to assign FERC Account 371 – Installation on Customer Premises to applicable customer classes. 50% of this allocation was based on customer count, and 50% was based on the primary demand allocator PRI_DEM, described below.

DEMAND ALLOCATION FACTORS

PRI_DEM – This factor analyzes each rate class's monthly contribution to the sum of the monthly maximum demands for all classes. The monthly demand is computed by taking a class's maximum non-coincident peak ("NCP") demand across all twelve months. This factor looks only at customers who utilize energy flowing through the primary distribution system.

SEC_DEM – This factor employs the same method described above for the PRI_DEM allocator. However, it only looks at customers who utilize energy flowing through the secondary distribution system.

4.3. Internal Allocation Factors

Internal Allocation Factors are developed within the COSS model based on the cost ratios of allocated costs. The Internal Allocation Factors are provided in Schedule 5 and described below.

INT_D361-364 – Account 361 – 364 – The factor is based on the allocation of plant accounts 361 through 364 by customer class.

INT_D364 – Account 364 – The factor is based on the allocation of plant account 364 by customer class.

INT_D365 – Account 365 - The factor is based on the allocation of plant account 365 by customer class.

INT_D367 – Account 367 - The factor is based on the allocation of plant account 367 by customer class.

INT_D368 – Account 368 - The factor is based on the allocation of plant account 368 by customer class.

INT_DISTPLT – Distribution Plant Total – The factor is based on the allocated total Distribution plant balance by customer class.

INT_GENPLT – General Plant Total – The factor is based on the allocated total General plant balance by customer class.

INT_TOTPLT – Production Plant Total - The factor is based on the allocated total plant balance by customer class.

INT_RATEBASE – Total Rate Base – The factor is based on the derived rate base by customer class.

INT_DISTOPS – Distribution Operations Expense – The factor is based on the distribution operations expense accounts 581 - 587 by customer class.

INT_DMAINT – Distribution Maintenance Expense – The factor is based on the distribution maintenance expense accounts 591 - 597 by customer class.

INT_DISTOM – Distribution Operations & Maintenance Expense – The factor is based on the total distribution operations and maintenance expense by customer class.

INT_LABOR – Operations and Maintenance Labor – The factor is based on the labor-related operations and maintenance expense by customer class.

INT_REV_REQ Pre-Tax – Pre-Tax Revenue Requirement – The factor is based on the pre-tax revenue requirement by customer class.

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Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
1	**RATE BASE**								
2	**Plant in Service**								
3	**Intangible Plant**								
4	Organization	301	11	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
5	Franchise & Consent	302	5	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
6	Miscellaneous Intangible Plant	303	0	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
7	Subtotal - Intangible Plant		16						
8	**Distribution Plant**								
9	Land & Land Rights	360	313	INT_D361_364	INT_D361_364	INT_D361_364	INT_D361_364	INT_D361_364	INT_D361_364
10	Structures & Improvements	361	627		DISTR	DEM	PRI_DEM		
11	Station Equipment	362	11,568		DISTR	DEM	PRI_DEM		
12	Storage Battery Equipment	363	0		DISTR	DEM	PRI_DEM		
13	Poles, Towers and Fixtures - PRI DEM	364	16,548		DISTR	DEM	PRI_DEM		
14	Poles, Towers and Fixtures - PRI CUS	364	15,455		DISTR	CUS			PRI_CUST
15	Poles, Towers and Fixtures - SEC DEM	364	9,219		DISTR	DEM	SEC_DEM		
16	Poles, Towers and Fixtures - SEC CUS	364	15,340		DISTR	CUS			SEC_CUST
17	Overhead Conductors and Devices - PRI DEM	365	25,626		DISTR	DEM	PRI_DEM		
18	Overhead Conductors and Devices - PRI CUS	365	33,621		DISTR	CUS			PRI_CUST
19	Overhead Conductors and Devices - SEC DEM	365	7,356		DISTR	DEM	SEC_DEM		
20	Overhead Conductors and Devices - SEC CUS	365	16,204		DISTR	CUS			SEC_CUST
21	Underground Conduit	366	8,780	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367
22	Underground Conductors and Devices - PRI DEM	367	7,404		DISTR	DEM	PRI_DEM		
23	Underground Conductors and Devices - PRI CUS	367	5,924		DISTR	CUS			PRI_CUST
24	Underground Conductors and Devices - SEC DEM	367	430		DISTR	DEM	SEC_DEM		
25	Underground Conductors and Devices - SEC CUS	367	1,808		DISTR	CUS			SEC_CUST
26	Transformers and Transformer Installations - SEC DEM	368.1	11,841		DISTR	DEM	SEC_DEM		
27	Transformers and Transformer Installations - SEC CUS	368.2	19,261		DISTR	CUS			SEC_CUST
28	Services	369	16,709		DRCUS	CUS			SERV
29	Meters	370.1	3,094		DRCUS	CUS			METERS
30	Meter Installations	370.2	1,989		DRCUS	CUS			METERS
31	Electronic Meters	370.3	5,038		DRCUS	CUS			METERS
32	Installations on Customers' Premises	371.0	2,219		DISTR	CUS			CUSTPREMIS
33	Installations on Customers' Premises - EV Charging Stations	371.1	0		DISTR	CUS			CUST
34	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	348		DISTR	CUS			LIGHT
35	Street Lighting and Signal Systems	373	2,615		DISTR	CUS			LIGHT
36	Subtotal - Distribution Plant		239,335						
37	**General Plant**								
38	Land & Land Rights	389	659	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
39	Structures & Improvements	390	10,646	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
40	Office Furniture & Equipment	391	18,441	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
41	Transportation Equipment	392	2,718	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
42	Stores Equipment	393	11	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
43	Tools & Garage Equipment	394	1,132	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
44	Laboratory Equipment	395	28	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
45	Power Operated Equipment	396	797	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
46	Communication Equipment	397	652	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
47	Miscellaneous Equipment	398	566	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
48	Other Tangible Property	399	0	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
49	Subtotal - General Plant		35,650						
50	**Total Plant in Service**		275,001						

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51	**Accumulated Depreciation & Amortization**								
52	**Intangible Plant**								
53	Organization	301.0	0	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
54	Franchise & Consent	302.0	0	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
55	Miscellaneous Intangible Plant	303.0	0	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
56	Subtotal - Intangible Plant		-						
57	**Distribution Plant**								
58	Land & Land Rights	360.0	0	INT_D361_364	INT_D361_364	INT_D361_364	INT_D361_364	INT_D361_364	INT_D361_364
59	Structures & Improvements	361.0	(67)	0	DISTR	DEM	PRI_DEM	0	
60	Station Equipment	362.0	(1,555)	0	DISTR	DEM	PRI_DEM	0	
61	Storage Battery Equipment	363.0	0	0	DISTR	DEM	PRI_DEM	0	
62	Poles, Towers and Fixtures	364.0	(18,154)	INT_D364	INT_D364	INT_D364	INT_D364	INT_D364	INT_D364
63	Overhead Conductors and Devices	365.0	(14,476)	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365
64	REG AFUDC	365.7	116	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365
65	Underground Conduit	366.0	(2,692)	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367
66	Underground Conductors and Devices	367.0	(4,928)	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367
67	Transformers	368.1	(8,267)	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368
68	Transformer Installations	368.2	(6,688)	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368
69	Services	369.0	(8,070)	0	DRCUS	CUS	0	0	SERV
70	Meters	370.1	(1,939)	0	DRCUS	CUS	0	0	METERS
71	Meter Installations	370.2	(825)	0	DRCUS	CUS	0	0	METERS
72	Electronic Meters	370.3	(4,275)	0	DRCUS	CUS	0	0	METERS
73	Installations on Customers' Premises	371.0	(1,088)	0	DISTR	CUS	0	0	CUSTPREMIS
74	Installations on Customers' Premises - EV Charging Stations	371.1	0	0	DISTR	CUS	0	0	CUST
75	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	(338)	0	DISTR	CUS	0	0	LIGHT
76	Street Lighting and Signal Systems	373.0	(1,139)	0	DISTR	CUS	0	0	LIGHT
77	Subtotal - Distribution Plant		(74,384)						
78	**General Plant**								
79	Land & Land Rights	389.0	(11)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
80	Structures & Improvements	390.0	(2,494)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
81	Office Furniture & Equipment	391.0	(7,201)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
82	Transportation Equipment	392.0	(612)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
83	Stores Equipment	393.0	(6)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
84	Tools & Garage Equipment	394.0	(498)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
85	Laboratory Equipment	395.0	(21)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
86	Power Operated Equipment	396.0	(87)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
87	Communication Equipment	397.0	(274)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
88	Miscellaneous Equipment	398.0	(157)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
89	Other Tangible Property	399.0	0	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
90	Subtotal - General Plant		(11,361)						
91	**Total Accumulated Depreciation & Amortization**		(85,745)						
92	**Other Rate Base Items**								
93	Working Capital	Sch. A-1	11,447	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
94	Accumulated Deferred Income Taxes	Sch. A-1	(29,665)	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
95	Customer Deposits	Sch. A-1	(949)		DRCUS	CUS			DEPCUST
96	Materials & Supplies	Sch. A-1	2,152	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
97	**Total Other Rate Base Items**		(17,015)						
98	**TOTAL RATE BASE**		172,242						

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99	**OPERATION AND MAINTENANCE EXPENSE**								
100	**Generation Production, Transmission, and Distribution Expense**								
101	**Other Power Generation Expense**								
102	Purchased Power	555	85,198		PRPWR	ENG		PWRREV	
103	Transmission of Electricty by Others	565	5,978		PRPWR	ENG		PWRREV	
104	Subtotal - Other Power Generation Expense		91,176						
105	**Distribution Operation Expenses**								
106	Operation Supervision and Engineering	580.0	609	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS
107	Load Dispatching	581.0	574	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT
108	Line and Station Expenses	581.1	0	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT
109	Station Expenses	582.0	96		DISTR	DEM	PRI_DEM		
110	Overhead Line Expenses	583.0	298	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365
111	Underground Line Expenses	584.0	42	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367
112	Operation of Energy Storage Equipment	584.1	0	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT
113	Street Lighting and Signal System Expenses	585.0	31		DISTR	CUS			LIGHT
114	Meter Expenses	586.0	785		DISTR	CUS			METERS
115	Customer Installation Expenses	587.0	79		DISTR	CUS			SERV
116	Miscellaneous Distribution Expenses	588.0	352	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS
117	Rents	589.0	55	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS
118	Subtotal - Distribution Operation Expenses		2,922						
119	**Distribution Maintenance Expenses**								
120	Maintenance Supervision and Engineering	590	222	INT_DMAINT	INT_DMAINT	INT_DMAINT	INT_DMAINT	INT_DMAINT	INT_DMAINT
121	Maintenance of Structures	591	0		DISTR	DEM	PRI_DEM		
122	Maintenance of Station Equipment	592.0	208		DISTR	DEM	PRI_DEM		
123	Maintenance of Pipe Lines	592.1	0	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT
124	Maintenance of Structures and Equipment	592.2	0		DISTR	DEM	PRI_DEM		
125	Maintenance of Overhead Lines	593	9,715	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365
126	Maintenance of Underground Lines	594.0	61	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367
127	Maintenance of Lines	594.1	0	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367
128	Maintenance of Line Transformers	595	83	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368
129	Maintenance of Street Lighting and Signal Systems	596	24		DISTR	CUS			LIGHT
130	Maintenance of Meters	597	15		DISTR	CUS			METERS
131	Maintenance of Miscellaneous Distribution Plant	598	23	INT_DMAINT	INT_DMAINT	INT_DMAINT	INT_DMAINT	INT_DMAINT	INT_DMAINT
132	Subtotal - Distribution Maintenance Expenses		10,352						
133	**Total Generation Production, Transmission, and Distribution Expense**		104,450						
134	**Customer Accounts, Service, and Sales Expense**								
135	**Customer Account**								
136	Supervision	901	91		DRCUS	CUS			CUST
137	Meter Reading Expenses	902	218		DRCUS	CUS			CUST
138	Customer Records and Collection Expenses	903.0	2,529		DRCUS	CUS			CUST
139	Customer Records and Collection Expenses (USP)	903.0	6,656		DRCUS	CUS			USPREV
140	Uncollectible Accounts	904	3,239		DRCUS	CUS			UNCOL
141	Miscellaneous Customer Accounts Expenses	905	139		DRCUS	CUS			CUST
142	Subtotal - Customer Account		12,873						
143	**Customer Service & Information Expenses**								
144	Customer Service and Informational Expenses	906	0		DRCUS	CUS			CUST
145	Supervision	907	17		DRCUS	CUS			CUST
146	Customer Assistance Expenses	908	12		DRCUS	CUS			CUST
147	Information and Instructional Advertising Expenses	909	0		DRCUS	CUS			CUST
148	Miscellaneous Customer Service & Informational Exps (EEC)	910	1,157		DRCUS	CUS			EECREV
149	Subtotal - Customer Service & Information Expenses		1,186						

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150	**Sales Expenses**								
151	Supervision	911	0		DRCUS	CUS			CUST
152	Demonstrating and Selling Expenses	912	5		DRCUS	CUS			CUST
153	Advertising Expenses	913	0		DRCUS	CUS			CUST
154	Miscellaneous Sales Expenses	916	(5)		DRCUS	CUS			CUST
155	Sales Expenses	917	0		DRCUS	CUS			CUST
156	Subtotal - Sales Expenses		0						
157	**Total Customer Accounts, Service, and Sales Expense**		14,059						
158	**Administrative and General Expenses**								
159	Administrative and General Salaries	920.0	2,757	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
160	Office Supplies and Expenses	921.0	1,787	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
161	Administrative Expenses Transferred - Credit	922.0	0	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
162	Outside Services Employed	923.0	1,887	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
163	Property Insurance	924.0	31	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
164	Injuries and Damages	925.0	251	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
165	Employee Pensions and Benefits	926.0	1,259	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
166	Franchise Requirements	927.0	0	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM
167	Regulatory Commission Expenses	928.0	298	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM
168	Duplicate Charges - Credit	929.0	(74)	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM
169	General Advertising Expenses	930.1	74	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
170	Miscellaneous General Expenses	930.2	259	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
171	Rents	931.0	2	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
172	Transportation Expenses	933.0	0	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM
173	Maintenance of General Plant	935.0	69	INT_GENPLT	INT_GENPLT	INT_GENPLT	INT_GENPLT	INT_GENPLT	INT_GENPLT
174	**Total Administrative and General Expenses**		8,598						
175	**TOTAL OPERATION AND MAINTENANCE EXPENSE**		127,107						
176	**Adjustments, Depreciation and Amortization Expense**								
177	**Depreciation Expense**								
178	Organization	301	0	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
179	Franchise & Consent	302	0	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
180	Miscellaneous Intangible Plant	303	0	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
181	Subtotal - Depreciation Expense		-						
182	**Distribution Plant**								
183	Land & Land Rights	360	0	INT_D361_364	INT_D361_364	INT_D361_364	INT_D361_364	INT_D361_364	INT_D361_364
184	Structures & Improvements	361	15	0	DISTR	DEM	PRI_DEM	0	
185	Station Equipment	362	370	0	DISTR	DEM	PRI_DEM	0	
186	Storage Battery Equipment	363	0	0	DISTR	DEM	PRI_DEM	0	
187	Poles, Towers and Fixtures	364	1,029	INT_D364	INT_D364	INT_D364	INT_D364	INT_D364	INT_D364
188	Overhead Conductors and Devices	365	2,001	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365
189	REG AFUDC	365.7	(16)	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365
190	Underground Conduit	366	137	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367
191	Underground Conductors and Devices	367	433	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367
192	Transformers	368.1	428	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368
193	Transformer Installations	368.2	207	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368
194	Services	369	280	0	DRCUS	CUS	0	0	SERV
195	Meters	370.1	66	0	DRCUS	CUS	0	0	METERS
196	Meter Installations	370.2	25	0	DRCUS	CUS	0	0	METERS
197	Electronic Meters	370.3	115	0	DRCUS	CUS	0	0	METERS
198	Installations on Customers' Premises	371.0	74	0	DISTR	CUS	0	0	CUSTPREMIS
199	Installations on Customers' Premises - EV Charging Stations	371.1	0	0	DISTR	CUS	0	0	CUST
200	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	1	0	DISTR	CUS	0	0	LIGHT
201	Street Lighting and Signal Systems	373	111	0	DISTR	CUS	0	0	LIGHT
202	Subtotal - Distribution Plant		5,275						

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203	**General Plant**								
204	Land & Land Rights	389	0	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
205	Structures & Improvements	390	541	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
206	Office Furniture & Equipment	391	1,857	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
207	Transportation Equipment	392	290	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
208	Stores Equipment	393	1	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
209	Tools & Garage Equipment	394	57	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
210	Laboratory Equipment	395	2	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
211	Power Operated Equipment	396	58	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
212	Communication Equipment	397	75	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
213	Miscellaneous Equipment	398	61	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
214	Other Tangible Property	399	0	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
215	Subtotal - General Plant		2,943						
216	**Amortization Expense**								
217	Amortization Expense & Depreciation Adjustments		336	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
218	Subtotal - Amortization Expense		336						
219	**Total Adjustments, Depreciation and Amortization Expense**		8,553						
220	**Taxes**								
221	**Taxes Other Than Income Taxes**								
222	PURTA & Property Taxes		76	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
223	Gross Receipts Tax		3,101	INT_REV_REQ Pre-tax	INT_REV_REQ Pre-t	INT_REV_REQ Pre-tax	INT_REV_REQ Pre-t	INT_REV_REQ Pre-	INT_REV_REQ Pre-tax
224	GRT - Purchased Power		5,717		PRPWR	ENG		PWRREV	
225	Payroll related		507	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
226	Real estate		297	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
227	PA Local Use and Miscellaneous		22	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
228	Subtotal - Taxes Other Than Income Taxes		9,718						
229	**Income Taxes**								
230	State Income Tax expense		(483)	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE
231	Federal Income Tax expense		1,306	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE
232	Subtotal - Income Taxes		823						
233	**Total Taxes**		10,542						
234	**REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**								
235	**Test Year Expenses at Current Rates**		146,201						
236	**Return on Rate Base**		14,038	INT_RATEBASE					
237	**Gross Up Items**								
238	Federal Income Tax		2,007	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE
239	State Income Tax		944	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE
240	Gross Receipts Tax		716	INT_REV_REQ Pre-tax	INT_REV_REQ Pre-t	INT_REV_REQ Pre-tax	INT_REV_REQ Pre-t	INT_REV_REQ Pre-	INT_REV_REQ Pre-tax
241	Uncollectible		210		DRCUS	CUS			UNCOL
242	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		**164,116**						

UGI Utilities, Inc. - Electric Division
Subfunctionalization/Classification of Distribution Plant
Schedule 2 - Functional Split & Minimum System Study

DIST. ACCT. NO.	DESCRIPTION	FUNCTIONALIZATION PRIMARY % OF ACCOUNT TOTAL	SECONDARY % OF ACCOUNT TOTAL	PRIMARY SPLIT CUSTOMER COMPONENT % OF	DEMAND COMPONENT % OF	SECONDARY SPLIT CUSTOMER COMPONENT % OF	DEMAND COMPONENT % OF
364	POLES, TOWERS AND FIXTURES	56.58%	43.42%	48.29%	51.71%	62.46%	37.54%
365	OVERHEAD CONDUCTORS AND DEVICES	71.55%	28.45%	56.75%	43.25%	68.78%	31.22%
367	UNDERGROUND CONDUCTORS	85.62%	14.38%	44.45%	55.55%	80.78%	19.22%
368	TRANSFORMERS	0.00%	100.00%	NA	NA	61.93%	38.07%

UGI Electric
Minimum Size System Study

Primary

			Minimum Size			Expand to Total Account				
Account	**Minimum Size (Asset Description)**	**Unit**	**Total Installed Cost**	**Total Installed Units**	**Average Unit Cost**	**Total Units**	**Total Customer Component**	**Account Total**	**% Customer**	**% Demand**
364	30 Foot Wood Pole	Pole			$ 945.22	25,400	$ 24,008,311	$ 49,713,744	48.29%	51.71%
365	365100 O/H COND. & DEV - 2 ACSR 15KV BARE WIRE	Feet	$ 3,968,789	1,511,533	$ 2.63	17,278,644	$ 45,368,048	$ 79,947,090	56.75%	43.25%
367	367100 URD COND & DEV: #2 CBL 15KV (C/C)	Feet	$ 770,645	131,655	$ 5.85	1,516,176	$ 8,874,962	$ 19,968,149	44.45%	55.55%

Secondary

			Minimum Size			Expand to Total Account				
Account	**Minimum Size (Asset Description)**	**Unit**	**Total Installed Cost**	**Total Installed Units**	**Average Unit Cost**	**Total Units**	**Total Customer Component**	**Account Total**	**% Customer**	**% Demand**
364	30 Foot Wood Pole	Pole			$ 945.22	25,210	$ 23,829,202	$ 38,149,969	62.46%	37.54%
365	365100 O/H COND. & DEV - 2 ALUM TRIPLEX WIRE	Feet	$ 1,954,587	239,918	$ 8.15	2,683,883	$ 21,865,317	$ 31,790,918	68.78%	31.22%
367	367100 URD COND & DEV: COND SEC #350 MCM AA	Feet	$ 1,725,729	195,122	$ 8.84	306,197	$ 2,708,117	$ 3,352,480	80.78%	19.22%
368 - OH					$ 1,840.94	22,368	$ 41,178,044	$ 63,692,769	64.65%	35.35%
368 - PAD					$ 5,063.97	1,234	$ 6,248,942	$ 12,890,912	48.48%	51.52%
368							$ 47,426,985	$ 76,583,681	61.93%	38.07%

Minimum Size (Asset Description)	**Unit**	**Total Installed Cost**	**Total Installed Units**	**Average Unit Cost**	**Non-Load Adjustment Factor**	**Min Sys Avg. Unit Cost**
7.5-15 KVA	OH	$ 4,794,199	2,938			$ -
10 KVA	OH	5,300,168	2,435			$ -
15 KVA	OH	7,502,457	3,826			$ -
Average		$ 17,596,824	9,199	$ 1,912.91	96.24%	$ 1,840.94
25 KVA	UG	$ 1,498,139	287	$ 5,220.00	97.01%	$ 5,063.97

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Class Allocation Factors

Line No.	Name	Description	Total	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
	DEMAND ALLOCATORS								
1	NCPs @ Primary								
2		NCPs @ Primary	245,500	152,649	7,548	33,011	352	50,496	1,443
3		Adjustment Factor		100%	100%	100%	100%	100%	100%
4	PRI_DEM	Primary Demand Allocator	245,500	152,649	7,548	33,011	352	50,496	1,443
5			100%	62.18%	3.07%	13.45%	0.14%	20.57%	0.59%
6	NCPs @ Secondary								
7		NCPs @ Secondary	240,852	149,544	7,395	32,354	-	50,145	1,414
8		Adjustment Factor		100%	100%	100%	100%	100%	100%
9	SEC_DEM	Secondary Demand Allocator	240,852	149,544	7,395	32,354	-	50,145	1,414
10			100%	62.09%	3.07%	13.43%	0.00%	20.82%	0.59%
11	**CUSTOMER ALLOCATORS**								
12	Customer Count								
13	CUST	2023 Forecasted Customer Count	62,937	54,998	5,331	2,330	7	211	60
14			100%	87.39%	8.47%	3.70%	0.01%	0.34%	0.10%
15	Number of Customers Using Primary System								
16	PRI_CUST	2023 Forecasted Customer Count	62,937	54,998	5,331	2,330	7	211	60
17			100%	87.39%	8.47%	3.70%	0.01%	0.34%	0.10%
18	Number of Customers Using Secondary System								
19	SEC_CUST	2023 Forecasted Customer Count	62,882	54,996	5,331	2,320	-	175	60
20			100%	87.46%	8.48%	3.69%	0.00%	0.28%	0.10%
21	Allocation of Meter Investments								
22		Average Cost per Meter		$ 139	$ 161	$ 302	$ 309	$ 309	$ -
23		Relative Weighting Factor		1.00	1.15	2.17	2.22	2.22	-
24		2023 Forecasted Customer Count		54,998	5,331	2,330	7	211	60
25		Weighted Meter Count	66,691	54,998	6,154	5,055	16	468	-
26	METERS		100%	82.47%	9.23%	7.58%	0.02%	0.70%	0.00%
27	Allocation of Services								
28		Service Cost per Service	$ 250	$ 68.46	$ 58.98	$ 59.56	$ -	$ 63.26	$ -
29		Relative Weighting Factor		1.00	0.86	0.87	-	0.92	-
30	SERV	Weighted Customers	61,813	54,998	4,593	2,027	-	195	-
31			100%	88.97%	7.43%	3.28%	0.00%	0.32%	0.00%
32	Uncollectible								
33	UNCOL	Uncollectibles	$ 1,448,134	$ 1,380,411	$ 26,726	$ 24,971	$ -	$ 11,873	$ 4,153
34			100%	95.32%	1.85%	1.72%	0.00%	0.82%	0.29%
35	Customer Deposits								
36	DEPCUST	Customer Deposits	$ 983,808	$ 630,284	$ 70,267	$ 228,408	$ -	$ 50,282	$ 4,568
37			100%	64.07%	7.14%	23.22%	0.00%	5.11%	0.46%

Line No.	Name	Description	Total	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
38	Forfeited Discounts								
39	FORTDISC	Forfeited Discounts	$ 395,644	$ 250,380	$ 36,968	$ 60,780	$ -	$ 43,173	$ 4,342
40			100%	63.28%	9.34%	15.36%	0.00%	10.91%	1.10%
41	Direct Assignment of Lighting								
42	LIGHT		1	-	-	-	-	-	1
43			100%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
44	Account 371 - Installation on Customer Premises								
45	CUSTPREMIS	Non-residential - 50% customer count and 50% demand	25%	-	5.77%	8.57%	0.08%	10.45%	0.34%
46		Installation on Customer Premises	100%	0.00%	22.89%	34.00%	0.31%	41.45%	1.35%
47	**ENERGY ALLOCATORS**								
48	MWh Sales								
49	ENERGY	MWh Sales	1,055,931	610,230	33,026	115,648	763	289,197	7,066
50			100%	57.79%	3.13%	10.95%	0.07%	27.39%	0.67%
51	**REVENUE ALLOCATORS**								
52	Distribution Revenue								
53	DISTREV	Total Revenue	44,267,882	30,111,450	2,545,379	4,687,856	17,185	5,713,469	1,192,542
54			100%	68.02%	5.75%	10.59%	0.04%	12.91%	2.69%
55	Total Purchased Power Revenue								
56	PWRREV	Total Purchased Power Revenue	96,893,373	78,084,084	3,928,239	9,236,799	-	5,063,150	581,102
57			100%	80.59%	4.05%	9.53%	0.00%	5.23%	0.60%
58	Total DSIC Revenue								
59	DSICREV		2,603,825	1,856,384	129,412	242,026	910	315,027	60,067
60		Total DSIC Revenue	39%	27.89%	1.94%	3.64%	0.01%	4.73%	0.90%
61	Total STAS Revenue								
62	STASREV		15,157	11,707	665	1,432	2	1,168	184
63		Total STAS Revenue	1%	1.02%	0.06%	0.12%	0.00%	0.10%	0.02%
64	Total USP Revenue								
65	USPREV		6,656,204	6,656,204	-	-	-	-	-
66		Total USP Revenue	100%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
67	Total EEC Revenue								
68	EECREV	Total EEC Revenue	1,152,420	360,036	42,855	152,656	1,008	587,071	8,795
69			100%	31.24%	3.72%	13.25%	0.09%	50.94%	0.76%

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Subfunctionalization/Classification Of Distribution Plant

			FUNCTIONALIZATION		PRIMARY SPLIT		SECONDARY SPLIT	
Line No.	DIST. ACCT. NO.	DESCRIPTION	PRIMARY % OF ACCOUNT TOTAL	SECONDARY % OF ACCOUNT TOTAL	CUSTOMER COMPONENT % OF	DEMAND COMPONENT % OF	CUSTOMER COMPONENT % OF	DEMAND COMPONENT % OF
1	364	POLES, TOWERS AND FIXTURES	56.58%	43.42%	48.29%	51.71%	62.46%	37.54%
2	365	OVERHEAD CONDUCTORS AND DEVICES	71.55%	28.45%	56.75%	43.25%	68.78%	31.22%
3	367	UNDERGROUND CONDUCTORS	85.62%	14.38%	44.45%	55.55%	80.78%	19.22%
4	368	Transformers	0.00%	100.00%			61.93%	38.07%
5		Poles, Towers and Fixtures - PRI DEM	29.26%					
6		Poles, Towers and Fixtures - PRI CUS	27.32%					
7		Poles, Towers and Fixtures - SEC DEM	16.30%					
8		Poles, Towers and Fixtures - SEC CUS	27.12%					
9		Overhead Conductors and Devices - PRI DEM	30.95%					
10		Overhead Conductors and Devices - PRI CUS	40.60%					
11		Overhead Conductors and Devices - SEC DEM	8.88%					
12		Overhead Conductors and Devices - SEC CUS	19.57%					
13		Underground Conductors and Devices - PRI DEM	47.57%					
14		Underground Conductors and Devices - PRI CUS	38.06%					
15		Underground Conductors and Devices - SEC DEM	2.76%					
16		Underground Conductors and Devices - SEC CUS	11.61%					
17		Transformers and Transformer Installations - SEC DEM	38.07%					
18		Transformers and Transformer Installations - SEC CUS	61.93%					

Notes:
1. Account 366 Underground Conduit is split the same for customer and demand percentages as Account 367 Underground Conductor

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Billing Determinants

Line No.		Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting	Total
1	Year End Book Report Customer Count	54,998	5,331	2,330	7	211	60	62,937
2	Sales-KWH	610,229,801	33,025,595	115,648,153	763,235	289,197,391	7,066,465	1,055,930,640
3	Distribution Revenue	30,111,450	2,545,379	4,687,856	17,185	5,713,469	1,192,542	44,267,882
4	STAS Revenue	11,707	665	1,432	2	1,168	184	15,157
5	GSR Revenue	78,084,084	3,928,239	9,236,799	-	5,063,150	581,102	96,893,373
6	USP Revenue	6,656,204	-	-	-	-	-	6,656,204
7	EEC Revenue	360,036	42,855	152,656	1,008	587,071	8,795	1,152,420
8	DSIC Revenue	1,856,384	129,412	242,026	910	315,027	60,067	2,603,825
9	Total Revenue - Sum from Above	117,079,865	6,646,549	14,320,768	19,104	11,679,885	1,842,691	151,588,862
10	Total Revenue - From Revenue Proof	117,079,865	6,646,549	14,320,768	19,104	11,679,885	1,842,691	151,588,862

Primary and Secondary Split

Line No.		Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting	Total
1	Year End Book Report Customer Count	54,998	5,331	2,330	7	211	60	62,937
2	Primary Customers	2		10	7	36	-	55
3	Secondary Customers	54,996	5,331	2,320	-	175	60	62,882

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Allocation Of Demand

Line No.		Residential	General Service	General Service-4	FCP	Large Power	Lighting	Total	Loss Factors from Generation
1	**NCP (kW) at Generation**	159,264	7,875	34,441	368	52,684	1,506	256,138	1.0000
2	**NCP at Primary**	152,649	7,548	33,011	352	50,496	1,443	245,500	1.0433
3	**NCP at Secondary**	149,544	7,395	32,354	-	50,145	1,414	240,505	1.0650
4									
5	**NCP (kW) at Primary**			735	352	33,264		34,351	
6	**NCP (kW) at Secondary**	149,544	7,395	31,619	-	16,881	1,414	206,853	
7	**Total**	149,544	7,395	32,354	352	50,145	1,414	241,204	

Rate	**R**	**GS**	**GS-4**	**FCP**	**LP**	**Lighting**	**Total**
NCP (kW) at Meter	149,544	7,395	32,354	352	50,145	1,414	241,204

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Allocation of Meter Costs

Line No.		Total	Residential	General Service	General Service-4	Flood Control Power	Large Power
1	Total Meter Costs	$ 9,374,343	$ 7,786,565	$ 883,308	$ 696,133	$ 2,162	$ 6,176
2	Count of Meters	63,711	55,889	5,492	2,303	7	20
3	Average Cost per Meter		$ 139	$ 161	$ 302	$ 309	$ 309
4	Relative Weighting Factor		1.00	1.15	2.17	2.22	2.22

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Allocation of Services

Line No.	Customer Class	Commerical Customer Count	Industrial Customer Count	Weighted Average Service Cost	Relative Weighting
1	Residential	NA	NA	$ 68.46	1.000
2	General Service	5,303	11	$ 58.98	0.862
3	General Service-4	2,181	87	$ 59.56	0.870
4	Large Power	153	57	$ 63.26	0.924

Line No.	Customer Group	Total Services in Study	Total Service Cost in Study	Average Service Cost	Relative Weighting
1	Commerical	3,989	$ 235,151	$ 58.95	0.861
2	Industrial	69	$ 5,167	$ 74.89	1.094
3	Residential	40,369	$ 2,763,689	$ 68.46	1.000
4	Total	44,427	$ 3,004,007	67.62	

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Average and Excess Method

Line No.		Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting	Total
1	**Sales-KWH**	610,229,801	33,025,595	115,648,153	763,235	289,197,391	7,066,465	1,055,930,640
2	**Average Demand**	69,661	3,770	13,202	87	33,013	807	120,540
3	**Class NCP**	149,544	7,395	32,354	352	50,145	1,414	241,204
4	**Class Excess**	79,883	3,625	19,152	265	17,132	607	120,664
5	**Average Allocator Component**	37.27%	2.02%	7.06%	0.05%	17.66%	0.43%	64%
6	**Excess Allocator Component**	22.01%	1.09%	4.76%	0.05%	7.38%	0.21%	36%
7	**Average and Excess Allocator**	59.28%	3.11%	11.83%	0.10%	25.05%	0.64%	100%

8	**System Load Factor**	64.49%

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Allocation of Customer Deposits

Line No.	Customer Class	Customer Deposits
1	Residential	$ 630,284
2	General Service	$ 70,267
3	General Service-4	$ 228,408
4	Large Power	$ 50,282
5	Lighting	$ 4,568
6	Total	$ 983,808

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Allocation of Forfeited Discounts

Line No.	Customer Class	Average 2020 - 2022	2022	2021	2020
1	Residential	$ 250,380	$ 355,503	$ 234,538	$ 161,100
2	General Service	$ 36,968	$ 52,139	$ 41,163	$ 17,603
3	General Service-4	$ 60,780	$ 83,115	$ 70,523	$ 28,702
4	Large Power	$ 43,173	$ 55,846	$ 56,017	$ 17,655
5	Lighting	$ 4,342	$ 5,136	$ 5,433	$ 2,457
6	Total	$ 395,644	$ 551,738	$ 407,674	$ 227,518

UGI Utilities, Inc. – Electric Division

Schedule 3 - External Allocation Factors

Allocation of Uncollectibles

Line No.	Customer Class	Average 2020 - 2022	2020	2021	2022
1	Residential	$ 1,380,411	$ 1,165,815	$ 1,188,195	$ 1,787,224
2	General Service	$ 26,726	$ 23,022	$ 27,504	$ 29,654
3	General Service-4	$ 24,971	$ 17,954	$ 23,227	$ 33,731
4	Large Power	$ 11,873	$ 48,225	$ 1,523	$ (14,130)
5	Lighting	$ 4,153	$ 4,328	$ 1,990	$ 6,139
6		$ 1,448,134	$ 1,259,344	$ 1,242,440	$ 1,842,618

UGI Utilities, Inc. - Electric Division
Electric Class Cost of Service Study
Fully Projected Future Test Year September 30, 2024
Schedule 4 - Internal Allocation Factors

Line	Allocator Code	Total	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
1	**ALLOCATION FACTOR BASIS ($ in thousands)**							
2	INT_D361_364	$ 68,756	$ 50,517	$ 3,776	$ 6,241	$ 43	$ 7,926	$ 252
3	INT_D364	$ 56,561	$ 42,934	$ 3,401	$ 4,602	$ 25	$ 5,417	$ 181
4	INT_D365	$ 82,806	$ 64,052	$ 5,235	$ 6,276	$ 41	$ 6,960	$ 241
5	INT_D367	$ 15,566	$ 11,629	$ 896	$ 1,339	$ 11	$ 1,637	$ 53
6	INT_D368	$ 31,102	$ 24,198	$ 1,996	$ 2,301	$ -	$ 2,519	$ 88
7	INT_DISTPLT	$ 239,335	$ 180,398	$ 15,110	$ 19,012	$ 111	$ 21,045	$ 3,659
8	INT_GENPLT	$ 35,650	$ 29,814	$ 2,008	$ 1,943	$ 11	$ 1,528	$ 346
9	INT_TOTPLT	$ 274,985	$ 210,212	$ 17,118	$ 20,955	$ 121	$ 22,573	$ 4,006
10	INT_RATEBASE	$ 172,242	$ 131,780	$ 10,452	$ 13,132	$ 82	$ 14,817	$ 1,978
11	INT_DISTOPS	$ 1,905	$ 1,472	$ 139	$ 147	$ 1	$ 105	$ 41
12	INT_DMAINT	$ 10,107	$ 7,767	$ 631	$ 777	$ 5	$ 873	$ 54
13	INT_DISTOM	$ 13,274	$ 10,213	$ 859	$ 1,021	$ 6	$ 1,056	$ 119
14	INT_LABOR	$ 4,498	$ 3,762	$ 253	$ 245	$ 1	$ 193	$ 44
15	INT_REV_REQ Pre-tax	$ 150,598	$ 121,666	$ 6,821	$ 12,255	$ 21	$ 8,731	$ 1,104
16	**ALLOCATION FACTOR (%)**							
17	INT_D361_364	100.0%	73.5%	5.5%	9.1%	0.1%	11.5%	0.4%
18	INT_D364	100.0%	75.9%	6.0%	8.1%	0.0%	9.6%	0.3%
19	INT_D365	100.0%	77.4%	6.3%	7.6%	0.0%	8.4%	0.3%
20	INT_D367	100.0%	74.7%	5.8%	8.6%	0.1%	10.5%	0.3%
21	INT_D368	100.0%	77.8%	6.4%	7.4%	0.0%	8.1%	0.3%
22	INT_DISTPLT	100.0%	75.4%	6.3%	7.9%	0.0%	8.8%	1.5%
23	INT_GENPLT	100.0%	83.6%	5.6%	5.5%	0.0%	4.3%	1.0%
24	INT_TOTPLT	100.0%	76.4%	6.2%	7.6%	0.0%	8.2%	1.5%
25	INT_RATEBASE	100.0%	76.5%	6.1%	7.6%	0.0%	8.6%	1.1%
26	INT_DISTOPS	100.0%	77.3%	7.3%	7.7%	0.0%	5.5%	2.2%
27	INT_DMAINT	100.0%	76.9%	6.2%	7.7%	0.1%	8.6%	0.5%
28	INT_DISTOM	100.0%	76.9%	6.5%	7.7%	0.0%	8.0%	0.9%
29	INT_LABOR	100.0%	83.6%	5.6%	5.5%	0.0%	4.3%	1.0%
30	INT_REV_REQ Pre-tax	100.0%	80.8%	4.5%	8.1%	0.0%	5.8%	0.7%

UGI Utilities, Inc. - Electric Division
Electric Class Cost of Service Study
Fully Projected Future Test Year September 30, 2024
Schedule 5 - Comparison of Cost of Service with Revenues under Present and Proposed Rates
($ in thousands)

				Pro Forma Revenues					
		Pro Forma Cost of Service		Under Present Rates		Under Proposed Rates		Revenue Increase	
Line	**Service Classification**	**Amount**	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**
1	Residential	$ 131,771	80.8%	$ 117,080	77.2%	$ 127,785	78.4%	$ 10,705	9.1%
2	General Service	7,386	4.5%	6,647	4.4%	7,361	4.5%	714	10.7%
3	General Service-4	13,161	8.1%	14,321	9.4%	14,321	8.8%	-	0.0%
4	Flood Control Power	24	0.0%	19	0.0%	24	0.0%	5	27.7%
5	Large Power	9,469	5.8%	11,680	7.7%	11,680	7.2%	-	0.0%
6	Lighting	1,203	0.7%	1,843	1.2%	1,843	1.1%	-	0.0%
7	**Total System**	**$ 163,014**	100%	**$ 151,589**	100%	**$ 163,014**	100%	**$ 11,425**	7.5%
8	Other Revenues	$ 1,102		$ 1,102		$ 1,102		-	0.0%
9	Total	**164,116**		**152,691**		**164,116**		**11,425**	7.5%

				Pro Forma Revenues w/o Purchase Power					
		Pro Forma Cost of Service		Under Present Rates		Under Proposed Rates		Revenue Increase	
10	**Service Classification**	**Amount**	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**
11	Residential	$ 53,687	81.2%	$ 38,996	71.3%	$ 49,701	75.2%	$ 10,705	27.5%
12	General Service	3,457	5.2%	2,718	5.0%	3,433	5.2%	714	26.3%
13	General Service-4	3,924	5.9%	5,084	9.3%	5,084	7.7%	-	0.0%
14	Flood Control Power	24	0.0%	19	0.0%	24	0.0%	5	27.7%
15	Large Power	4,406	6.7%	6,617	12.1%	6,617	10.0%	-	0.0%
16	Lighting	622	0.9%	1,262	2.3%	1,262	1.9%	-	0.0%
17	**Total System**	**$ 66,120**	100.0%	**$ 54,695**	100.0%	**$ 66,120**	100.0%	**$ 11,425**	20.9%
18	Other Revenues	$ 1,102		$ 1,102		$ 1,102		-	0.0%
19	Total	**67,223**		**55,798**		**67,223**		**11,425**	20.5%

UGI Utilities, Inc. - Electric Division
Electric Class Cost of Service Study
Fully Projected Future Test Year September 30, 2024
Schedule 6 - Summary of Cost of Service and Rate of Return Under Present and Proposed Rates
($ in thousands)

Line No.	Revenue Requirement Summary	Total System	Total Check	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
1	**Rate Base**								
2	Plant in Service	$ 275,001	-	$ 210,225	$ 17,119	$ 20,956	$ 121	$ 22,574	$ 4,006
3	Accumulated Reserve	(85,745)	-	(65,710)	(5,586)	(6,333)	(31)	(6,305)	(1,779)
4	Other Rate Base Items	(17,015)	-	(12,735)	(1,081)	(1,491)	(7)	(1,452)	(249)
5	**Total Rate Base**	**$ 172,242**	-	**$ 131,780**	**$ 10,452**	**$ 13,132**	**$ 82**	**$ 14,817**	**$ 1,978**
6	**Revenue at Current Rates**								
7	Total Distribution Margin	$ 44,268	-	$ 30,111	$ 2,545	$ 4,688	$ 17	$ 5,713	$ 1,193
8	STAS Revenue	15	-	12	1	1	0	1	0
9	DSIC Revenue	2,604	-	1,856	129	242	1	315	60
10	USP Rider	6,656	-	6,656	-	-	-	-	-
11	EEC Rider	1,152	-	360	43	153	1	587	9
12	**Total Base and Rider Revenue**	**$ 54,695**	-	**$ 38,996**	**$ 2,718**	**$ 5,084**	**$ 19**	**$ 6,617**	**$ 1,262**
13	Forfeited Discounts	$ 520	-	$ 329	$ 49	$ 80	$ -	$ 57	$ 6
14	Miscellaneous Revenues	582	-	445	34	46	0	54	2
15	**Total Base, Rider, and Other Revenue**	**$ 55,798**	-	**$ 39,770**	**$ 2,801**	**$ 5,210**	**$ 19**	**$ 6,728**	**$ 1,269**
16	Purchased Power Revenue	$ 96,893	-	$ 78,084	$ 3,928	$ 9,237	$ -	$ 5,063	$ 581
17	**Total Current Revenue**	**$ 152,691**	-	**$ 117,854**	**$ 6,730**	**$ 14,447**	**$ 19**	**$ 11,791**	**$ 1,850**
18	**Total Base, Rider, and Purchased Power Revenue**	**$ 151,589**	-	**$ 117,080**	**$ 6,647**	**$ 14,321**	**$ 19**	**$ 11,680**	**$ 1,843**
19	**Expenses at Current Rates**								
20	O&M and A&G Expenses	$ 35,930	-	$ 30,113	$ 1,703	$ 1,817	$ 10	$ 2,062	$ 224
21	Purchased Power Expense	91,176	-	73,477	3,696	8,692	-	4,764	547
22	Depreciation and Amortization Expense	8,553	-	6,611	516	618	4	643	162
23	Purchased Power GRT Expense	5,717	-	4,607	232	545	-	299	34
24	Taxes Other Than Income	901	-	1,101	48	(71)	0	(139)	(38)
25	Gross Receipts Tax	3,101	-	2,211	154	288	1	375	72
26	Income Taxes	823	-	(30)	43	288	0	426	96
27	**Total Expenses at Current Rates**	**$ 146,201**	-	**$ 118,090**	**$ 6,392**	**$ 12,177**	**$ 16**	**$ 8,430**	**$ 1,096**
28	**Operating Income - Current**	$ 6,490	-	$ (236)	$ 337	$ 2,270	$ 4	$ 3,361	$ 754
29	Current Rate of Return	3.77%	-	-0.18%	3.23%	17.29%	4.42%	22.68%	38.14%
30	Relative Rate of Return	1.00		(0.05)	0.86	4.59	1.17	6.02	10.12
31	Current Revenue to Cost Ratio	0.93		0.89	0.90	1.09	0.81	1.23	1.53
32	Current Parity Ratio	1.00		0.96	0.97	1.17	0.87	1.32	1.64
33	**Current Revenue at Equal Rates of Return**								
34	Current Rate of Return	3.77%	-	3.77%	3.77%	3.77%	3.77%	3.77%	3.77%
35	Current Operating Income at Equal ROR	$ 6,490	-	$ 4,965	$ 394	$ 495	$ 3	$ 558	$ 75
36	Income Taxes - Equal ROR	823	-	630	50	63	0	71	9
37	Gross Receipts Tax	3,101	-	2,587	149	159	1	182	23
38	Other Expenses - Equal ROR	142,277	-	115,909	6,195	11,601	14	7,629	929
39	**Total Margin @ Equal Rates of Return**	**$ 152,691**	-	**$ 124,092**	**$ 6,788**	**$ 12,318**	**$ 19**	**$ 8,439**	**$ 1,036**
40	Present (Subsidies)/Excesses	-	-	(6,237)	(59)	2,129	1	3,352	814

UGI Utilities, Inc. - Electric Division
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Schedule 6 - Summary of Cost of Service and Rate of Return Under Present and Proposed Rates
($ in thousands)

Line No.	Revenue Requirement Summary	Total System	Total Check	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
41	**Revenue Requirement at Equal Rates of Return**								
42	Required Return	8.15%	-	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%
43	Required Operating Income	$ 14,038	$ -	$ 10,740	$ 852	$ 1,070	$ 7	$ 1,208	$ 161
44	**Expenses at Required Return**								
45	O&M and A&G Expenses	$ 35,930	$ -	$ 30,113	$ 1,703	$ 1,817	$ 10	$ 2,062	$ 224
46	Purchased Power Expense	91,176	-	73,477	3,696	8,692	-	4,764	547
47	Depreciation and Amortization Expense	8,553	-	6,611	516	618	4	643	162
48	Purchased Power GRT Expense	5,717	-	4,607	232	545	-	299	34
49	Taxes Other Than Income	901	-	725	53	58	0	54	11
50	Gross Receipts Tax	3,101	-	2,587	149	159	1	182	23
51	Income Taxes	823	-	630	50	63	0	71	9
52	Gross Up - Income Taxes	2,951	-	2,258	179	225	1	254	34
53	Gross Up - Gross Receipts	716	-	598	34	37	0	42	5
54	Gross Up - Uncollectibles	210		200	4	4	-	2	1
55	**Total Expenses - Required**	**$ 150,079**	**-**	**$ 121,806**	**$ 6,617**	**$ 12,217**	**$ 17**	**$ 8,372**	**$ 1,050**
56	**Total Revenue Requirement at Equal Return**	**$ 164,116**	**-**	**$ 132,546**	**$ 7,469**	**$ 13,287**	**$ 24**	**$ 9,580**	**$ 1,211**
57	Current Miscellaneous Revenue	1,102	-	774	83	126	0	111	8
58	**Total Revenue @ Equal Rates of Return**	**$ 163,014**	**-**	**$ 131,771**	**$ 7,386**	**$ 13,161**	**$ 24**	**$ 9,469**	**$ 1,203**
59	**Revenue (Deficiency)/Surplus**	**$ (11,425)**	**-**	**$ (14,691)**	**$ (739)**	**$ 1,160**	**$ (5)**	**$ 2,211**	**$ 639**
60	Proposed Margin Increase	$ 11,425		$ 10,705	$ 714	$ -	$ 5	$ -	$ -
61	Total Base and Miscellaneous Revenue as Proposed	$ 67,223	-	$ 50,476	$ 3,515	$ 5,210	$ 25	$ 6,728	$ 1,269
62	Purchased Power Revenue	96,893	-	78,084	3,928	9,237	-	5,063	581
63	**Total Revenue as Proposed**	**$ 164,116**	-	**$ 128,560**	**$ 7,444**	**$ 14,447**	**$ 25**	**$ 11,791**	**$ 1,850**
64	**Total Base Revenue as Proposed**	**$ 66,120**	-	**$ 49,701**	**$ 3,433**	**$ 5,084**	**$ 24**	**$ 6,617**	**$ 1,262**
65	**Total Base and Purchased Power Revenue as Proposed**	**$ 163,014**	-	**$ 127,785**	**$ 7,361**	**$ 14,321**	**$ 24**	**$ 11,680**	**$ 1,843**
66	Proposed (Subsidies)/Excesses	$ -	-	$ (3,986)	$ (25)	$ 1,160	$ 1	$ 2,211	$ 639
67	Proposed Percentage Change	7.54%		9.14%	10.75%	0.00%	27.69%	0.00%	0.00%
68	Proposed Margin Percentage Change	20.89%		27.45%	26.27%	0.00%	27.69%	0.00%	0.00%
69	Gross Receipts Tax	$ 3,817	$ -	$ 2,869	$ 198	$ 294	$ 1	$ 382	$ 73
70	Income Prior to Taxes	17,812	-	9,957	1,041	2,420	9	3,585	800
71	Income Taxes	3,774	-	2,110	221	513	2	760	169
72	Operating Income	$ 14,038	-	$ 7,847	$ 820	$ 1,907	$ 7	$ 2,825	$ 630
73	Proposed Return	8.15%	-	5.95%	7.85%	14.53%	8.51%	19.07%	31.87%
74	Relative Rate of Return	1.00	-	0.73	0.96	1.78	1.04	2.34	3.91
75	Proposed Revenue to Cost Ratio	1.00		0.97	1.00	1.09	1.03	1.23	1.53
76	Proposed Parity Ratio	1.00		0.97	1.00	1.09	1.03	1.23	1.53

UGI Utilities, Inc. - Electric Division
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Schedule 7 - Cost of Service Allocation Study Detail by Account
($ in thousands)

Line No.	Account Description	FERC Account	Account Balance	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
1	**RATE BASE**								
2	**Plant in Service**								
3	**Intangible Plant**								
4	Organization	301	11	9	1	1	0	0	0
5	Franchise & Consent	302	5	4	0	0	0	0	0
6	Miscellaneous Intangible Plant	303	-	-	-	-	-	-	-
7	Subtotal - Intangible Plant		16	13	1	1	0	1	0
8	**Distribution Plant**			-	-	-	-	-	-
9	Land & Land Rights	360	313	230	17	28	0	36	1
10	Structures & Improvements	361	627	390	19	84	1	129	4
11	Station Equipment	362	11,568	7,193	356	1,555	17	2,379	68
12	Storage Battery Equipment	363	-	-	-	-	-	-	-
13	Poles, Towers and Fixtures - PRI DEM	364	16,548	10,289	509	2,225	24	3,404	97
14	Poles, Towers and Fixtures - PRI CUS	364	15,455	13,505	1,309	572	2	52	15
15	Poles, Towers and Fixtures - SEC DEM	364	9,219	5,724	283	1,238	-	1,919	54
16	Poles, Towers and Fixtures - SEC CUS	364	15,340	13,416	1,300	566	-	43	15
17	Overhead Conductors and Devices - PRI DEM	365	25,626	15,934	788	3,446	37	5,271	151
18	Overhead Conductors and Devices - PRI CUS	365	33,621	29,380	2,848	1,245	4	113	32
19	Overhead Conductors and Devices - SEC DEM	365	7,356	4,567	226	988	-	1,531	43
20	Overhead Conductors and Devices - SEC CUS	365	16,204	14,172	1,374	598	-	45	15
21	Underground Conduit	366	8,780	6,559	505	755	6	924	30
22	Underground Conductors and Devices - PRI DEM	367	7,404	4,604	228	996	11	1,523	44
23	Underground Conductors and Devices - PRI CUS	367	5,924	5,177	502	219	1	20	6
24	Underground Conductors and Devices - SEC DEM	367	430	267	13	58	-	90	3
25	Underground Conductors and Devices - SEC CUS	367	1,808	1,581	153	67	-	5	2
26	Transformers and Transformer Installations - SEC DEM	368.1	11,841	7,352	364	1,591	-	2,465	70
27	Transformers and Transformer Installations - SEC CUS	368.2	19,261	16,845	1,633	711	-	54	18
28	Services	369	16,709	14,867	1,242	548	-	53	-
29	Meters	370.1	3,094	2,552	286	235	1	22	-
30	Meter Installations	370.2	1,989	1,640	184	151	0	14	-
31	Electronic Meters	370.3	5,038	4,155	465	382	1	35	-
32	Installations on Customers' Premises	371	2,219	-	508	754	7	920	30
33	Installations on Customers' Premises - EV Charging Stations	371.1	-	-	-	-	-	-	-
34	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	348	-	-	-	-	-	348
35	Street Lighting and Signal Systems	373	2,615	-	-	-	-	-	2,615
36	Subtotal - Distribution Plant		239,335	180,398	15,110	19,012	111	21,045	3,659
37	**General Plant**			-	-	-	-	-	-
38	Land & Land Rights	389	659	551	37	36	0	28	6
39	Structures & Improvements	390	10,646	8,903	600	580	3	456	103
40	Office Furniture & Equipment	391	18,441	15,422	1,039	1,005	5	790	179
41	Transportation Equipment	392	2,718	2,273	153	148	1	116	26
42	Stores Equipment	393	11	9	1	1	0	0	0
43	Tools & Garage Equipment	394	1,132	947	64	62	0	49	11
44	Laboratory Equipment	395	28	23	2	2	0	1	0
45	Power Operated Equipment	396	797	667	45	43	0	34	8
46	Communication Equipment	397	652	545	37	36	0	28	6
47	Miscellaneous Equipment	398	566	473	32	31	0	24	5
48	Other Tangible Property	399	-	-	-	-	-	-	-
49	Subtotal - General Plant		35,650	29,814	2,008	1,943	11	1,528	346
50	**Total Plant in Service**		275,001	210,225	17,119	20,956	121	22,574	4,006

UGI Utilities, Inc. - Electric Division
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Schedule 7 - Cost of Service Allocation Study Detail by Account
($ in thousands)

Line No.	Account Description	FERC Account	Account Balance	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
51	**Accumulated Depreciation & Amortization**			-	-	-	-	-	-
52	**Intangible Plant**			-	-	-	-	-	-
53	Organization	301	-	-	-	-	-	-	-
54	Franchise & Consent	302	-	-	-	-	-	-	-
55	Miscellaneous Intangible Plant	303	-	-	-	-	-	-	-
56	Subtotal - Intangible Plant		-	-	-	-	-	-	-
57	**Distribution Plant**			-	-	-	-	-	-
58	Land & Land Rights	360	-	-	-	-	-	-	-
59	Structures & Improvements	361	(67)	(42)	(2)	(9)	(0)	(14)	(0)
60	Station Equipment	362	(1,555)	(967)	(48)	(209)	(2)	(320)	(9)
61	Storage Battery Equipment	363	-	-	-	-	-	-	-
62	Poles, Towers and Fixtures	364	(18,154)	(13,780)	(1,092)	(1,477)	(8)	(1,739)	(58)
63	Overhead Conductors and Devices	365	(14,476)	(11,198)	(915)	(1,097)	(7)	(1,217)	(42)
64	REG AFUDC	365.7	116	89	7	9	0	10	0
65	Underground Conduit	366	(2,692)	(2,011)	(155)	(232)	(2)	(283)	(9)
66	Underground Conductors and Devices	367	(4,928)	(3,681)	(284)	(424)	(4)	(518)	(17)
67	Transformers	368.1	(8,267)	(6,431)	(531)	(612)	-	(670)	(23)
68	Transformer Installations	368.2	(6,688)	(5,204)	(429)	(495)	-	(542)	(19)
69	Services	369	(8,070)	(7,180)	(600)	(265)	-	(25)	-
70	Meters	370.1	(1,939)	(1,599)	(179)	(147)	(0)	(14)	-
71	Meter Installations	370.2	(825)	(681)	(76)	(63)	(0)	(6)	-
72	Electronic Meters	370.3	(4,275)	(3,525)	(394)	(324)	(1)	(30)	-
73	Installations on Customers' Premises	371	(1,088)	-	(249)	(370)	(3)	(451)	(15)
74	Installations on Customers' Premises - EV Charging Stations	371.1	-	-	-	-	-	-	-
75	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	(338)	-	-	-	-	-	(338)
76	Street Lighting and Signal Systems	373	(1,139)	-	-	-	-	-	(1,139)
77	Subtotal - Distribution Plant		(74,384)	(56,209)	(4,946)	(5,714)	(28)	(5,818)	(1,669)
78	**General Plant**								
79	Land & Land Rights	389	(11)	(9)	(1)	(1)	(0)	(0)	(0)
80	Structures & Improvements	390	(2,494)	(2,086)	(141)	(136)	(1)	(107)	(24)
81	Office Furniture & Equipment	391	(7,201)	(6,022)	(406)	(393)	(2)	(309)	(70)
82	Transportation Equipment	392	(612)	(512)	(34)	(33)	(0)	(26)	(6)
83	Stores Equipment	393	(6)	(5)	(0)	(0)	(0)	(0)	(0)
84	Tools & Garage Equipment	394	(498)	(417)	(28)	(27)	(0)	(21)	(5)
85	Laboratory Equipment	395	(21)	(18)	(1)	(1)	(0)	(1)	(0)
86	Power Operated Equipment	396	(87)	(73)	(5)	(5)	(0)	(4)	(1)
87	Communication Equipment	397	(274)	(229)	(15)	(15)	(0)	(12)	(3)
88	Miscellaneous Equipment	398	(157)	(132)	(9)	(9)	(0)	(7)	(2)
89	Other Tangible Property	399	-	-	-	-	-	-	-
90	Subtotal - General Plant		(11,361)	(9,501)	(640)	(619)	(3)	(487)	(110)
91	**Total Accumulated Depreciation & Amortization**		(85,745)	(65,710)	(5,586)	(6,333)	(31)	(6,305)	(1,779)
92	Other Rate Base Items								
93	Working Capital	Sch. A-1	11,447	8,751	713	872	5	940	167
94	Accumulated Deferred Income Taxes	Sch. A-1	(29,665)	(22,677)	(1,847)	(2,261)	(13)	(2,435)	(432)
95	Customer Deposits	Sch. A-1	(949)	(608)	(68)	(220)	-	(49)	(4)
96	Materials & Supplies	Sch. A-1	2,152	1,800	121	117	1	92	21
97	Total Other Rate Base Items		(17,015)	(12,735)	(1,081)	(1,491)	(7)	(1,452)	(249)
98	**TOTAL RATE BASE**		172,242	131,780	10,452	13,132	82	14,817	1,978

UGI Utilities, Inc. - Electric Division
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Schedule 7 - Cost of Service Allocation Study Detail by Account
($ in thousands)

Line No.	Account Description	FERC Account	Account Balance	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
99	**OPERATION AND MAINTENANCE EXPENSE**			-	-	-	-	-	-
100	Generation Production, Transmission, and Distribution Expense			-	-	-	-	-	-
101	**Other Power Generation Expense**			-	-	-	-	-	-
102	Purchased Power	555	85,198	68,659	3,454	8,122	-	4,452	511
103	Transmission of Electricty by Others	565	5,978	4,818	242	570	-	312	36
104	Subtotal - Other Power Generation Expense		91,176	73,477	3,696	8,692	-	4,764	547
105	**Distribution Operation Expenses**			-	-	-	-	-	-
106	Operation Supervision and Engineering	580	609	471	44	47	0	34	13
107	Load Dispatching	581	574	432	36	46	0	50	9
108	Line and Station Expenses	581.1	-	-	-	-	-	-	-
109	Station Expenses	582	96	60	3	13	0	20	1
110	Overhead Line Expenses	583	298	231	19	23	0	25	1
111	Underground Line Expenses	584	42	31	2	4	0	4	0
112	Operation of Energy Storage Equipment	584.1	-	-	-	-	-	-	-
113	Street Lighting and Signal System Expenses	585	31	-	-	-	-	-	31
114	Meter Expenses	586	785	647	72	59	0	6	-
115	Customer Installation Expenses	587	79	71	6	3	-	0	-
116	Miscellaneous Distribution Expenses	588	352	272	26	27	0	20	8
117	Rents	589	55	42	4	4	0	3	1
118	Subtotal - Distribution Operation Expenses		2,922	2,258	213	225	1	162	63
119	**Distribution Maintenance Expenses**			-	-	-	-	-	-
120	Maintenance Supervision and Engineering	590	222	171	14	17	0	19	1
121	Maintenance of Structures	591	-	-	-	-	-	-	-
122	Maintenance of Station Equipment	592	208	130	6	28	0	43	1
123	Maintenance of Pipe Lines	592.1	-	-	-	-	-	-	-
124	Maintenance of Structures and Equipment	592.2	-	-	-	-	-	-	-
125	Maintenance of Overhead Lines	593	9,715	7,515	614	736	5	817	28
126	Maintenance of Underground Lines	594	61	46	4	5	0	6	0
127	Maintenance of Lines	594.1	-	-	-	-	-	-	-
128	Maintenance of Line Transformers	595	83	65	5	6	-	7	0
129	Maintenance of Street Lighting and Signal Systems	596	24	-	-	-	-	-	24
130	Maintenance of Meters	597	15	12	1	1	0	0	-
131	Maintenance of Miscellaneous Distribution Plant	598	23	18	1	2	0	2	0
132	Subtotal - Distribution Maintenance Expenses		10,352	7,955	646	796	5	894	55
133	**Total Generation Production, Transmission, and Distribution Expense**		104,450	83,690	4,555	9,713	6	5,820	666
134	**Customer Accounts, Service, and Sales Expense**								
135	**Customer Account**								
136	Supervision	901	91	80	8	3	0	0	0
137	Meter Reading Expenses	902	218	191	18	8	0	1	0
138	Customer Records and Collection Expenses	903	2,529	2,210	214	94	0	8	2
139	Customer Records and Collection Expenses (USP)	903	6,656	6,656	-	-	-	-	-
140	Uncollectible Accounts	904	3,239	3,087	60	56	-	27	9
141	Miscellaneous Customer Accounts Expenses	905	139	122	12	5	0	0	0
142	Subtotal - Customer Account		12,873	12,346	312	166	0	37	12
143	**Customer Service & Information Expenses**			-	-	-	-	-	-
144	Customer Service and Informational Expenses	906	-	-	-	-	-	-	-
145	Supervision	907	17	15	1	1	0	0	0
146	Customer Assistance Expenses	908	12	11	1	0	0	0	0
147	Information and Instructional Advertising Expenses	909	-	-	-	-	-	-	-
148	Miscellaneous Customer Service & Informational Exps (EEC)	910	1,157	361	43	153	1	589	9
149	Subtotal - Customer Service & Information Expenses		1,186	387	45	154	1	590	9

UGI Utilities, Inc. - Electric Division
Electric Class Cost of Service Study
Fully Projected Future Test Year September 30, 2024
Schedule 7 - Cost of Service Allocation Study Detail by Account
($ in thousands)

Line No.	Account Description	FERC Account	Account Balance	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
150	**Sales Expenses**			-	-	-	-	-	-
151	Supervision	911	-	-	-	-	-	-	-
152	Demonstrating and Selling Expenses	912	5	4	0	0	0	0	0
153	Advertising Expenses	913	-	-	-	-	-	-	-
154	Miscellaneous Sales Expenses	916	(5)	(4)	(0)	(0)	(0)	(0)	(0)
155	Sales Expenses	917	-	-	-	-	-	-	-
156	Subtotal - Sales Expenses		0	0	0	0	0	0	0
157	**Total Customer Accounts, Service, and Sales Expense**		14,059	12,733	357	320	1	626	21
				-	-	-	-	-	-
158	**Administrative and General Expenses**			-	-	-	-	-	-
159	Administrative and General Salaries	920	2,757	2,306	155	150	1	118	27
160	Office Supplies and Expenses	921	1,787	1,494	101	97	1	77	17
161	Administrative Expenses Transferred - Credit	922	-	-	-	-	-	-	-
162	Outside Services Employed	923	1,887	1,578	106	103	1	81	18
163	Property Insurance	924	31	24	2	2	0	3	0
164	Injuries and Damages	925	251	210	14	14	0	11	2
165	Employee Pensions and Benefits	926	1,259	1,053	71	69	0	54	12
166	Franchise Requirements	927	-	-	-	-	-	-	-
167	Regulatory Commission Expenses	928	298	229	19	23	0	24	3
168	Duplicate Charges - Credit	929	(74)	(57)	(5)	(6)	(0)	(6)	(1)
169	General Advertising Expenses	930.1	74	56	5	6	0	6	1
170	Miscellaneous General Expenses	930.2	259	216	15	14	0	11	3
171	Rents	931	2	1	0	0	0	0	0
172	Transportation Expenses	933	-	-	-	-	-	-	-
173	Maintenance of General Plant	935	69	58	4	4	0	3	1
174	Total Administrative and General Expenses		8,598	7,168	487	476	3	381	84
				-	-	-	-	-	-
175	**TOTAL OPERATION AND MAINTENANCE EXPENSE**		127,107	103,590	5,400	10,509	10	6,827	770
176	**Adjustments, Depreciation and Amortization Expense**			-	-	-	-	-	-
177	Depreciation Expense			-	-	-	-	-	-
178	Organization	301	-	-	-	-	-	-	-
179	Franchise & Consent	302	-	-	-	-	-	-	-
180	Miscellaneous Intangible Plant	303	-	-	-	-	-	-	-
181	Subtotal - Depreciation Expense		-	-	-	-	-	-	-
182	**Distribution Plant**			-	-	-	-	-	-
183	Land & Land Rights	360	-	-	-	-	-	-	-
184	Structures & Improvements	361	15	9	0	2	0	3	0
185	Station Equipment	362	370	230	11	50	1	76	2
186	Storage Battery Equipment	363	-	-	-	-	-	-	-
187	Poles, Towers and Fixtures	364	1,029	781	62	84	0	99	3
188	Overhead Conductors and Devices	365	2,001	1,548	126	152	1	168	6
189	REG AFUDC	365.7	(16)	(13)	(1)	(1)	(0)	(1)	(0)
190	Underground Conduit	366	137	102	8	12	0	14	0
191	Underground Conductors and Devices	367	433	323	25	37	0	46	1
192	Transformers	368.1	428	333	27	32	-	35	1
193	Transformer Installations	368.2	207	161	13	15	-	17	1
194	Services	369	280	249	21	9	-	1	-
195	Meters	370.1	66	54	6	5	0	0	-
196	Meter Installations	370.2	25	21	2	2	0	0	-
197	Electronic Meters	370.3	115	95	11	9	0	1	-
198	Installations on Customers' Premises	371	74	-	17	25	0	31	1
199	Installations on Customers' Premises - EV Charging Stations	371.1	-	-	-	-	-	-	-
200	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	1	-	-	-	-	-	1
201	Street Lighting and Signal Systems	373	111	-	-	-	-	-	111
202	Subtotal - Distribution Plant		5,275	3,894	329	432	3	489	128

UGI Utilities, Inc. - Electric Division
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Schedule 7 - Cost of Service Allocation Study Detail by Account
($ in thousands)

Line No.	Account Description	FERC Account	Account Balance	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
203	**General Plant**			-	-	-	-	-	-
204	Land & Land Rights	389	-	-	-	-	-	-	-
205	Structures & Improvements	390	541	453	31	30	0	23	5
206	Office Furniture & Equipment	391	1,857	1,553	105	101	1	80	18
207	Transportation Equipment	392	290	242	16	16	0	12	3
208	Stores Equipment	393	1	1	0	0	0	0	0
209	Tools & Garage Equipment	394	57	47	3	3	0	2	1
210	Laboratory Equipment	395	2	2	0	0	0	0	0
211	Power Operated Equipment	396	58	49	3	3	0	2	1
212	Communication Equipment	397	75	63	4	4	0	3	1
213	Miscellaneous Equipment	398	61	51	3	3	0	3	1
214	Other Tangible Property	399	-	-	-	-	-	-	-
215	Subtotal - General Plant		2,943	2,461	166	160	1	126	29
216	**Amortization Expense**			-	-	-	-	-	-
217	Amortization Expense & Depreciation Adjustments		336	257	21	26	0	28	5
218	Subtotal - Amortization Expense		336	257	21	26	0	28	5
				-	-	-	-	-	-
219	**Total Adjustments, Depreciation and Amortization Expense**		8,553	6,611	516	618	4	643	162
220	**Taxes**			-	-	-	-	-	-
221	**Taxes Other Than Income Taxes**			-	-	-	-	-	-
222	PURTA & Property Taxes		76	58	5	6	0	6	1
223	Gross Receipts Tax		3,101	2,587	149	159	1	182	23
224	GRT - Purchased Power		5,717	4,607	232	545	-	299	34
225	Payroll related		507	424	29	28	0	22	5
226	Real estate		297	227	18	23	0	24	4
227	PA Local Use and Miscellaneous		22	16	1	2	0	2	0
228	Subtotal - Taxes Other Than Income Taxes		9,718	7,919	434	762	1	534	68
229	**Income Taxes**			-	-	-	-	-	-
230	State Income Tax expense		(483)	(369)	(29)	(37)	(0)	(42)	(6)
231	Federal Income Tax expense		1,306	999	79	100	1	112	15
232	Subtotal - Income Taxes		823	630	50	63	0	71	9
233	**Total Taxes**		10,542	8,549	484	825	2	605	78
234	**REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**			-	-	-	-	-	-
235	Test Year Expenses at Current Rates		146,201	118,750	6,399	11,952	16	8,075	1,010
236	Return on Rate Base		14,038	10,740	852	1,070	7	1,208	161
237	**Gross Up Items**			-	-	-	-	-	-
238	Federal Income Tax		2,007	1,536	122	153	1	173	23
239	State Income Tax		944	722	57	72	0	81	11
240	Gross Receipts Tax		716	598	34	37	0	42	5
241	Uncollectible		210	200	4	4	-	2	1
242	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		**164,116**	**132,546**	**7,469**	**13,287**	**24**	**9,580**	**1,211**

UGI Utilities, Inc. - Electric Division
Electric Class Cost of Service Study
Fully Projected Future Test Year September 30, 2024
Schedule 8 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
($ in thousands)

Line	Description		TOTAL	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
1	**Functional Rate Base**								
2	**Purchased Power**								
3	Demand	Product_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Energy	Product_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Customer	Product_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Subtotal		$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	**Distribution**								
8	Demand	Dist_Dem	$ 68,346	$ 42,481	$ 2,101	$ 9,188	$ 72	$ 14,103	$ 402
9	Energy	Dist_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Customer	Dist_Cust	$ 85,254	$ 72,133	$ 7,272	$ 3,567	$ 9	$ 696	$ 1,577
11	Subtotal		$ 153,599	$ 114,613	$ 9,373	$ 12,754	$ 81	$ 14,799	$ 1,978
12	**PA PUC Direct Customer**								
13	Demand	DirCust_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Energy	DirCust_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Customer	DirCust_Cust	$ 18,642	$ 17,167	$ 1,079	$ 378	$ 1	$ 18	$ (1)
16	Subtotal		$ 18,642	$ 17,167	$ 1,079	$ 378	$ 1	$ 18	$ (1)
17	**Total**								
18	Demand		$ 68,346	$ 42,481	$ 2,101	$ 9,188	$ 72	$ 14,103	$ 402
19	Energy		$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Customer		$ 103,896	$ 89,299	$ 8,352	$ 3,944	$ 10	$ 714	$ 1,576
21	**TOTAL RATE BASE**		$ 172,242	$ 131,780	$ 10,452	$ 13,132	$ 82	$ 14,817	$ 1,978

UGI Utilities, Inc. - Electric Division
Electric Class Cost of Service Study
Fully Projected Future Test Year September 30, 2024
Schedule 8 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
($ in thousands)

Line	Description		TOTAL	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
22	**Functional Revenue Requirement**								
23	**Purchased Power**								
24	Demand	Product_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Energy	Product_Energy	$ 96,893	$ 78,084	$ 3,928	$ 9,237	$ -	$ 5,063	$ 581
26	Customer	Product_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Subtotal		$ 96,893	$ 78,084	$ 3,928	$ 9,237	$ -	$ 5,063	$ 581
28	**Distribution**								
29	Demand	Dist_Dem	$ 17,576	$ 10,925	$ 540	$ 2,363	$ 19	$ 3,626	$ 103
30	Energy	Dist_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31	Customer	Dist_Cust	$ 26,139	$ 22,051	$ 2,232	$ 1,166	$ 3	$ 187	$ 501
32	Subtotal		$ 43,715	$ 32,975	$ 2,772	$ 3,529	$ 22	$ 3,813	$ 604
33	**PA PUC Direct Customer**								
34	Demand	DirCust_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	Energy	DirCust_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36	Customer	DirCust_Cust	$ 23,508	$ 21,486	$ 768	$ 522	$ 2	$ 704	$ 26
37	Subtotal		$ 23,508	$ 21,486	$ 768	$ 522	$ 2	$ 704	$ 26
38	**Total**								
39	Demand		$ 17,576	$ 10,925	$ 540	$ 2,363	$ 19	$ 3,626	$ 103
40	Energy		$ 96,893	$ 78,084	$ 3,928	$ 9,237	$ -	$ 5,063	$ 581
41	Customer		$ 49,647	$ 43,537	$ 3,000	$ 1,688	$ 5	$ 891	$ 526
42	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		$ 164,116	$ 132,546	$ 7,469	$ 13,287	$ 24	$ 9,580	$ 1,211
43	Demand		10.71%	8.24%	7.23%	17.78%	79.51%	37.85%	8.53%
44	Energy		59.04%	58.91%	52.60%	69.52%	0.00%	52.85%	47.99%
45	Customer		30.25%	32.85%	40.17%	12.70%	20.49%	9.30%	43.48%

UGI Utilities, Inc. - Electric Division
Electric Class Cost of Service Study
Fully Projected Future Test Year September 30, 2024
Schedule 8 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
($ in thousands)

Line	Description		TOTAL	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
46	**Unit Costs (in $)**								
47	**Purchased Power**								
48	Demand	Product_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49	Energy	Product_Energy	$ 91.76	$ 127.96	$ 118.94	$ 79.87	$ -	$ 17.51	$ 82.23
50	Customer	Product_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51	**Distribution**								
52	Demand	Dist_Dem	$ 6.08	$ 6.09	$ 6.09	$ 6.09	$ -	$ 6.03	$ 6.09
53	Energy	Dist_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54	Customer	Dist_Cust	$ 34.61	$ 33.41	$ 34.89	$ 41.71	$ 35.69	$ 73.68	$ 695.70
55	**PA PUC Direct Customer**								
56	Demand	DirCust_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	Energy	DirCust_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	Customer	DirCust_Cust	$ 31.13	$ 32.56	$ 12.01	$ 18.66	$ 22.81	$ 278.09	$ 35.42
59	**Total**								
60	Energy		$ 91.76	$ 127.96	$ 118.94	$ 79.87	$ -	$ 17.51	$ 82.23
61	Customer (per cust month)		$ 65.74	$ 65.97	$ 46.90	$ 60.37	$ 58.50	$ 351.77	$ 731.12
62	Demand & Customer (per cust month)		$ 89.01	$ 82.52	$ 55.34	$ 144.87	$ 285.50	$ 1,783.83	$ 874.58
63	Demand (per kwh)					$ 5.37		$ 6.92	
64	**BILLING DETERMINANTS**								
65	Demand (Peak Day Demand * 12)	SEC_DEM	2,890,219	1,794,525	88,735	388,248	0	601,745	16,967
66	Energy	ENERGY	1,055,931	610,230	33,026	115,648	763	289,197	7,066
67	Customers (Number of Bills)	CUST	755,244	659,976	63,972	27,960	84	2,532	720
68	Demand					440,278		523,763	

BOOK X

UGI UTILITIES, INC. – ELECTRIC DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI ELECTRIC EXHIBIT F

PROPOSED SUPPLEMENT NO. 51 TO
UGI UTILITIES, INC. – ELECTRIC DIVISION PA P.U.C. NO. 6

AND

PROPOSED SUPPLEMENT NO. 7 TO
UGI UTILITIES, INC. – ELECTRIC DIVISION PA. P.U.C. NO. 2S

UGI UTILITIES, INC. – ELECTRIC DIVISION
PA P.U.C. NO. 6, SUPPLEMENT NO. 51
PA P.U.C. NO. 2S, SUPPLEMENT NO. 7

DOCKET NO. R-2022-3037368

Issued: January 27, 2023 **Effective: March 28, 2023**

PROPOSED SUPPLEMENT NO. 51

TO

UGI UTILITIES, INC. – ELECTRIC DIVISION

PA P.U.C. NO. 6

Supplement No. 51
to UGI Electric Pa. P.U.C. No. 6

UGI UTILITIES, INC. – ELECTRIC DIVISION

ELECTRIC SERVICE TARIFF

RULES AND RATES
FOR ELECTRIC DISTRIBUTION SERVICE AND
CHOICE AGGREGATION SERVICE

in the following service territory:

LUZERNE COUNTY

City of Nanticoke, and Boroughs of Courtdale, Dallas, Edwardsville, Forty-Fort, Harvey's Lake, Kingston, Larksville, Luzerne, New Columbus, Plymouth, Pringle, Shickshinny, Sugar Notch, Swoyersville, Warrior Run, West Wyoming and Wyoming.

First Class Townships of Hanover and Newport, and Second Class Townships, of Lehman, Plymouth, Ross and Union.

WYOMING COUNTY

Townships of Monroe and Noxen

Issued: January 27, 2023

Effective for Service Rendered on and after March 28, 2023.

Issued by:
Paul J. Szykman
Chief Regulatory Officer
1 UGI Drive
Denver, PA 17517

https://www.ugi.com/tariffs

NOTICE

This tariff makes increases, decreases, and changes to existing rates (see pages 2-2(d)).

LIST OF CHANGES MADE BY THIS SUPPLEMENT

(Page Numbers Refer to Official Tariff)

Cover Page
- Updated to reflect Supplement Number, Notice Language, Issue and Effective Dates.

Table of Contents, Page 3.
- Pagination changes.
- Removed 'and' from 'Rider G – Distribution System and Improvement Charge'
- Change in capitalization of 'lighting' to 'Lighting' for Rate Schedule OL.

Definitions General, Page 5.
- Definition added for Contribution in Aid of Construction.
- Term 'Electric Service: or service' was updated to 'Electric Service (or Service or service):'.
- Definition for Residential Applicant's reference to 'Residential Customers' was revised to 'Residential Customer'.

Rule 1 – General, Page 7.
- Capitalization in Subsection 1-b, was revised changing 'use of Service' to 'Use of Service'.
- Subsection 1-c was updated adding clarification for the application of rates and combined billing. The colon in the rule title was replaced with a period. Within the section 'service' was updated to 'Service'.
- Subsection 1-d was revised changing 'use of electric by the Customer' to 'use of electric service by the Customer'. The colon in the title of the section was replaced with a period. Commas were added following 'defend' and 'state'.

Rule 5 – Service and Supply System Extensions, Pages 15-17.
- In Subsections 5-e and 5-f, all references to 'aid to construction' and 'aid in construction' were revised to 'Contribution in Aid of Construction'.
- Capitalization changes in subsection 5-e revised 'residential' to 'Residential', 'commercial' to 'Commercial', and 'industrial' to 'Industrial'.
- In Subsection 5-f (2), all references to 'customer' or 'customer's' were updated to 'Customer' or Customer's'.
- Additional language was added to Subsection 5-g to clarify that payment is a Contribution in Aid of Construction. In addition, a hyphen was added to 'Company-Provided', 'system on private' was changed to 'system on a private' and 'The' was changed to 'the' immediately following subsection (b).
- In Subsection 5-h, a hyphen was added to 'Customer-Owned', a comma was added between 'may' and 'at' as well as between 'expense' and 'furnish', 'its' was replaced with 'their', a hyphen was added to 'Customer-owned' and 'Customer supplied' was changed to 'Customer-owned'.
- In Subsection 5-i, a space was added to '§§ 57.81', and 'year-around' was changed to 'year-round'. In subparts (2) and (3), 'its' was changed to 'Applicant's'.
- In Subsections 5-k and 5-l, all references to 'contribution' were revised to 'Contribution in Aid of Construction'.
- In Subsection 5-l 'pilot' was added to 'EV infrastructure pilot'.

Rule 16 – Administration of Rates, Page 29.
- Subsection 16-b's title was changed from 'Billing Changes' to 'Billing Corrections' along with other revisions for clarity and completeness.
- Subsection 16-c was revised to clarify Company and Customer obligations as pertaining to changing rates.
- Subsection 16-d was revised to clarify Company and Customer obligations as pertaining to changing rates during construction or emergency. At the end of subpart (3) 'or' was added. The last two sentences of subpart (4) were moved to become a standalone paragraph that relates to all of Rule 16-d. In the same section, 'contract' was changed to 'Contract'.

LIST OF CHANGES MADE BY THIS SUPPLEMENT – (Continued)
(Page Numbers Refer to Official Tariff)

Rule 17 – Net Metering, Page 31.
- Language was added to Subsection 17-b(2) and 17-b(3) to clarify that payment is a Contribution in Aid of Construction.
- In Subsection 17-b(4), 'his' was changed to 'their' and 'measureable' was corrected to 'measurable'.

Rule 19 – Pole Removal and Relocation Charges, Page 37.
- Subsections 19-b and 19-c have been updated to clarify that payment is a Contribution in Aid of Construction.
- Capitalization updates in Subsection 19-c to change 'non-residential' to 'Non-Residential' and 'company' to 'Company'.

Rider A – State Tax Adjustment Surcharge, Page 38.
- The State Tax Adjustment Surcharge rate was reset to 0.00%.

Rider C – Universal Service Plan Rider, Pages 42-43.
- Applicability and Purpose – capitalization updated to change 'residential' to 'Residential' and 'customers' to 'Customers'.
- Rate – capitalization was updated to change 'customers' to 'Customers'.
- Calculation of Rate – quotation marks were added to ("LIURP") and 'Customer Assistance Program (CAP)' was updated to 'CAP' because it was previously defined. An open parenthesis was added to 1) 2) and 3). At the end of item (1), 'and' was removed. In item (2) an extra space was removed between 'have' and 'been'. Quotation marks were added to "CAP Credit" and 'customer' was updated to 'Customer'.
- Quarterly Adjustment – capitalization was updated to change 'residential customers' to 'Residential Customers'.
- Annual Reconciliation – the CAP credit bad debt offset language was updated and will apply where CAP enrollment exceeds the number of CAP enrollees as of September 30, 2023.

Rider G – Distribution System Improvement Charge, Page 50.
- The Distribution System Improvement Charge rate was reset to 0.00%.
- Reference to prior docket number was removed and effective date was updated
- A.1 Purpose – capitalization was updated to change 'customers' to 'Customers'.

Rate Schedule R – Residential Service, Page 53.
- Availability – capitalization was updated to change 'non-residential' to 'Non-Residential'.
- The customer charge and distribution charge were increased on Page 53.
- Surcharges and Riders – a space was added to change 'Rider G-' to 'Rider G –' and the word 'and' was removed.
- Payment Terms – reference to 'Section 13' was changed to 'Rule 13'.

Rate Schedule OL – Outdoor Lighting Service, Pages 54-55.
- Availability – updated to address market phase-out of mercury vapor lighting.
- The distribution charge was increased on Page 54.
- A hyphen was removed which changed 'back-filling' to 'backfilling'.
- Standard Construction – clarifies that payments related to additional facilities are a Contribution in Aid of Construction. A hyphen was added to '120-volt'.
- Maintenance – language added to address market phase-out of mercury vapor lamps.
- Surcharges and Riders – a space was added to change 'Rider E-' to 'Rider E -' and 'Rider G-' to 'Rider G -'. The word 'and' was removed from Rider G.
- Payment Terms – reference to 'Section 13' was changed to 'Rule 13'.

LIST OF CHANGES MADE BY THIS SUPPLEMENT – (Continued)
(Page Numbers Refer to Official Tariff)

Rate Schedule SOL – Sodium Outdoor Lighting Service, Pages 56-57.
- The distribution charge was increased on Page 56.
- A spelling error was corrected which changed ‘backfiling’ to ‘backfilling’.
- General Provisions (a) – a hyphen was added to ‘120-volt’.
- General Provisions (c) – clarifies that payments related to additional facilities are a Contribution in Aid of Construction.
- General Provisions (f) – new subsection added to address market phase-out of sodium vapor lamps.
- Surcharges and Riders – a space was added to change ‘Rider G-‘ to ‘Rider G -’ and the word ‘and’ was removed.
- Payment Terms – reference to ‘Section 13’ was changed to ‘Rule 13’.

Rate Schedule MHOL – Metal Halide Outdoor Lighting Service, Pages 58-59.
- Availability – update to address market phase-out of metal halide lighting.
- The distribution charge was increased on Page 58.
- General Provisions (a) – a hyphen was added to ‘120-volt’.
- General Provisions (c) - reference to Contribution in Aid of Construction has been added.
- General Provisions (f) – new subsection added to address market phase-out of metal halide lamps
- Surcharges and Riders – a space was added to change ‘Rider G-‘ to ‘Rider G -’ and the word ‘and’ was removed.
- Payment Terms – reference to ‘Section 13’ was changed to ‘Rule 13’.

Rate LED-OL – Light-Emitting Diode Outdoor Lighting Service, Pages 60-61.
- The distribution charge was increased on Page 60.
- New rates were added for a standard decorative lighting fixture and decorative pole offering on Page 60.
- General Provisions (a) – a hyphen was added to ‘120-volt’.
- General Provisions (c) – clarifies that payments related to additional facilities are a Contribution in Aid of Construction.
- Surcharges and Riders – a space was added to change ‘Rider G-‘ to ‘Rider G -’ and the word ‘and’ was removed.
- Payment Terms – reference to ‘Section 13’ was changed to ‘Rule 13’.

Rate Schedule GS-1 – General Service, Page 62.
- The customer charge and distribution charge were increased on Page 62.
- Surcharges and Riders – a space was added to change ‘Rider G-‘ to ‘Rider G -’ and the word ‘and’ was removed.
- Payment Terms – reference to ‘Section 13’ was changed to ‘Rule 13’.

Rate Schedule GS-4 – General Service (5 kW minimum), Page 63.
- Revised language addressing character of service to consider other reasonable service configurations as determined by the Company.
- The distribution charge was increased on Page 63.
- Revised language to clarify that the minimum monthly charge includes the Customer Charge and billing demand amount.
- Surcharges and Riders – a space was added to change ‘Rider G-‘ to ‘Rider G -’ and the word ‘and’ was removed.
- Payment Terms – reference to ‘Section 13’ was changed to ‘Rule 13’.

Rate Schedule GS-5 – General Service, Page 65.
- The customer charge and distribution charge were increased on Page 65.
- Surcharges and Riders – a space was added to change ‘Rider G-‘ to ‘Rider G -’ and the word ‘and’ was removed.
- Payment Terms – reference to ‘Section 13’ was changed to ‘Rule 13’.

LIST OF CHANGES MADE BY THIS SUPPLEMENT – (Continued)
(Page Numbers Refer to Official Tariff)

Rate Schedule LP – Large Power Service, Pages 66 - 67.
- Clarifying language was added addressing availability and character of service.
- The distribution charge was increased on Page 66.
- Surcharges and Riders – a space was added to change 'Rider G-' to 'Rider–G -' and the word 'and' was removed.
- Payment Terms – reference to 'Section 13' was changed to 'Rule 13'.

Rate Schedule HTP – High Tension Power Service, Page 68.
- Payment Terms – reference to 'Section 13' was changed to 'Rule 13'.

Rate Schedule SL – Street Lighting Service, Pages 69-70.
- Availability – update to address market phase-out of mercury vapor lighting. A comma was added after 'parks'.
- The distribution charge was increased on Page 69.
- A hyphen was removed which changed 'back-filling' to 'backfilling'.
- Surcharges and Riders – a space was added to change 'Rider G-' to 'Rider G -' and the word 'and' was removed.
- Revised language addressing lamp renewals to address market phase-out of mercury vapor lamps. A comma was also added to 'broken, or giving'.
- Spacing of Lamps and Relocation of Lamps – clarified that payments made are a Contribution in Aid of Construction.
- Change in Lamp Size –a semi colon and 'and' were added to the end of item (2).
- Payment Terms – reference to 'Section 13' was changed to 'Rule 13'.

Rate Schedule SSL – Sodium Street Lighting Service, Pages 71 and 72.
- The distribution charge was increased on Page 71.
- A hyphen was removed which changed 'back-filling' to 'backfilling'.
- Surcharges and Riders – a space was added to change 'Rider G-' to 'Rider G -' and the word 'and' was removed.
- General Provisions (d) – added new language to address market phase-out of sodium lamps.
- Original General Provisions (d) – was relabeled as (e) and language changed to clarify that payments made are a Contribution in Aid of Construction.
- Payment Terms – reference to 'Section 13' was changed to 'Rule 13'.

Rate Schedule MHSL – Metal Halide Street Lighting Service, Pages 73 and 74.
- Availability – updated to address market phase-out of metal halide lighting. A comma was also added after 'parks'.
- The distribution charge was increased on Page 73.
- A hyphen was removed which changed 'back-filling' to 'backfilling'.
- Surcharges and Riders – a space was added to change 'Rider G-' to 'Rider G -' and the word 'and' was removed.
- General Provisions (e) – clarified that payments made are a Contribution in Aid of Construction.
- General Provisions (f) – added new language to address market phase-out of metal halide lamps.
- Payment Terms – reference to 'Section 13' was changed to 'Rule 13'.

LIST OF CHANGES MADE BY THIS SUPPLEMENT – (Continued)
(Page Numbers Refer to Official Tariff)

Rate Schedule LED-SL – Light-Emitting Diode Street Lighting Service, Pages 75 and 76.
- Availability – a comma was added after ‘parks’.
- The distribution charge was increased on Page 75.
- New rates were added for a standard decorative lighting fixture and decorative pole option on Page 75.
- Removal of Mercury Vapor, High Pressure Sodium and Metal Halide – the underline for this header was modified to no longer extend beyond the text.
- Surcharges and Riders – a space was added to change ‘Rider G-‘ to ‘Rider G -’ and the word ‘and’ was removed.
- General Provisions (d) and (e) – clarifies that payments made are a Contribution in Aid of Construction.
- Payment Terms – reference to ‘Section 13’ was changed to ‘Rule 13’.

Rate Schedule LED-CO – Customer-Owned Light-Emitting Diode Street Lighting Service, Pages 77 and 79.
- Availability – capitalization updated to change ‘non-residential’ to ‘Non-Residential’.
- The distribution charge was increased on Page 77.
- Surcharges and Riders – a space was added to change ‘Rider G-‘ to ‘Rider G -’ and the word ‘and’ was removed.
- Payment Terms – reference to ‘Section 13’ was changed to ‘Rule 13’.

Rate Schedule FCP – Flood Control Power Service, Page 80.
- The distribution charges were increased on Page 80.
- Surcharges and Riders – a space was added to change ‘Rider G-‘ to ‘Rider G -’ and the word ‘and’ was removed.
- Payment Terms – reference to ‘Section 13’ was changed to ‘Rule 13’.

Rate Schedule BLR – Borderline Resale Service, Page 81.
- Surcharges and Riders – a space was added to change ‘Rider G-‘ to ‘Rider G -’ and the word ‘and’ was removed.
- Payment Terms – reference to ‘Section 13’ was changed to ‘Rule 13’.

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(C) Indicates Change

DEFINITIONS – GENERAL

Applicant:	Any person, corporation or other entity that (i) desires Electric Service from the Company, (ii) complies completely with all Company requirements for obtaining Electric Service, (iii) has filed and is awaiting Company approval of its application for Electric Service, and (iv) is not yet lawfully receiving Electric Service from the Company.	
Automatic Meter Reading (AMR):	Metering using technologies that automatically read and collect data from metering devices and transfer that data to a central database for billing and other purposes and does not include a Remote Meter Reading Device.	
Contribution in Aid of Construction:	A non-refundable cash contribution from an Applicant or Customer for those costs associated with a line extension, temporary service, or relocation of Company facilities including all related activities.	**(C)**
Commercial Customer:	A Customer who is not classified as an Industrial Customer or a Residential Customer.	
Company:	UGI Utilities, Inc. – Electric Division	
Creditworthiness:	An assessment of an Applicant's or Customer's ability to meet bill payment obligations for Electric Service.	
Customer:	Any person, corporation or other entity receiving Electric Service from the Company.	
Discontinuance of Service:	The cessation of Electric Service with the consent of Customer.	
EGS:	A supplier of electric generation that has been licensed by the PUC to sell electricity directly to retail customers within the Commonwealth of Pennsylvania in accordance with the Electric Generation Customer Choice and Competition Act, 66 Pa.C.S. § 2801 *et seq*. and has met all requirements specified in the Company's Electric Generation Supplier Coordination Tariff.	
Electric Service (or Service or service):	The provision of electric distribution service in accordance with statutory and PUC requirements.	**(C)**
Industrial Customer:	A Customer engaged in the process which creates or changes raw materials or unfinished materials into another form or product.	
Occupant:	A natural person who resides in the premises to which Electric Service is provided.	
PUC:	The Pennsylvania Public Utility Commission	
Remote Meter Reading Device:	A device which by electrical impulse or otherwise transmits readings from a meter, usually located within a residence, to a more accessible location outside a residence. The term does not include AMR and devices that permit direct interrogation of the meter.	
Residential Applicant:	A person who is (1) a natural person at least 18 years of age not currently receiving Electric Service who applies for residential Electric Service or (2) an adult Occupant whose name appears on the mortgage, deed or lease of the property for which the residential Electric Service is requested. The term does not include (1) a Residential Customer who seeks to transfer Electric Service between locations in the Company's service territory, or (2) a Residential Customer who, within 30 days after Termination of Discontinuance of Service, seeks to have Electric Service reconnected within the Company's service territory.	**(C)**

(C) Indicates Change

RULES AND REGULATIONS

1. GENERAL

1-a Tariff Availability. A copy of this Tariff is on file with the PUC and is available on Company's website at https://www.ugi.com/tariffs and on the PUC's website at https://www.puc.pa.gov/filing-resources/tariffs/electric-tariffs/. This Tariff may be amended from time-to-time in accordance with the rules of the PUC.

1-b Scope and Application of Tariff. The Tariff, which is subject to a PUC-established review and approval process, contains rates, rules and regulations governing the supply by Company of Electric Service to all Customers, including, as applicable, Users Without Contract and those engaged in the Unauthorized Use of Service. It is the responsibility of Company and each of its employees to apply the provisions of the Tariff without unlawful privilege or advantage to any Customer, and mandatory provisions of the Tariff may not be modified by Company, any Company employee or representative, or Customer, whether by written agreement or otherwise, without the approval of the PUC. The failure by the Company to enforce any of the provisions of this Tariff shall not be deemed a waiver of its right to do so. **(C)**

1-c Application of Rates. The rates in this Tariff are based upon supply of service to one Customer through one meter at the same or contiguous property. Each service to a different location and/or of a different rate classification shall be billed as a separate Customer; the use of service at two or more properties will not be combined for billing purposes. However, customers who take service at two or more locations on the same or contiguous property under the same rate schedule may, by request, and at the Company's sole discretion, have their use combined for billing purposes by electing to take primary service at 13,800 volts. Customers electing to have their use combined shall pay a Contribution in Aid of Construction for the cost of all additional facilities required unless, in the Company's sole judgment, the Company's investment in such connections is warranted by the revenue anticipated from the Service to be supplied; the Company will not own, install, or maintain any facilities, including transformers, after the point of delivery as determined by the Company. The Company will provide Customers with a written explanation regarding its analysis of the arrangement's economics. Customers may not pool together for purposes of qualifying for a rate schedule. **(C)**

1-d Liability and Legal Remedies. The Customer will indemnify, defend, and hold harmless the Company against all claims, demands, costs or expenses for loss, damage or injury to person or property in any manner either directly or indirectly connected with or growing out of the supply or use of electric service by the Customer at or on the Customer's side of the point of delivery. Neither the Company nor the Customer will be liable to each other for any act or omission caused either directly or indirectly by strikes, labor troubles, accidents, litigation, federal, state, or municipal laws or interference, or other causes not a result of each party's own negligence or intentional misconduct. **(C)**

(C) Indicates Change

RULES AND REGULATIONS (continued)

5. SERVICE AND SUPPLY SYSTEM EXTENSIONS

5-e Supply Line Extensions to Seasonal Residential Customers and Temporary Commercial and Industrial Customers. Seasonal Residential Customers and temporary Commercial and Industrial Customers shall pay for new supply line extensions in advance a Contribution in Aid of Construction, equal to the estimated cost of construction of the required facilities. For temporary extensions, the aid shall include the estimated removal costs less anticipated salvage values. Where the Customer requires the Company's service or supply line to be disconnected but the Company facilities left in place, the Customer shall pay for the cost of each reconnection and disconnection prior to each reconnection. **(C)**

5-f Single-Phase Supply Line Extensions and Polyphase Line Extensions Exceeding Established Limits.

(1) Single-phase overhead supply line extensions - The Company will provide single-phase overhead supply line extensions to serve permanent residential, commercial, and industrial Customers in excess of twenty-five hundred (2500) feet along public road right-of-way and/or in excess of five hundred (500) feet on private right-of-way not along public road right-of-way provided the Customer pays in advance a Contribution in Aid of Construction equal to the estimated cost to extend the excess facilities. **(C)**

(2) Polyphase overhead supply line extensions - The Company will determine the necessary minimum annual revenue guarantee or Contribution in Aid of Construction when warranted, required for all polyphase extensions regardless of length. The minimum annual revenue guarantee shall be calculated by dividing the estimated polyphase line extension cost by five (5). This minimum annual revenue guarantee will be compared, on an annual basis, to the Customer’s actual billings for distribution services, over the five (5) year period following the commencement of service to the Customer through the polyphase overhead supply line extension. Any shortfall between a Customer’s actual billings for distribution services and the minimum annual revenue guarantee will be assessed to the Customer. Contributions in Aid of Construction will be utilized in lieu of minimum annual revenue guarantees when the Company has concluded that the polyphase line extension is associated with a speculative project, where the Company has determined the Customer/developer is a credit risk, or when the Customer/developer prefers to pay a Contribution in Aid of Construction rather than the minimum annual revenue guarantee. The Contribution in Aid of Construction will be calculated by subtracting the Customer’s projected five (5) year distribution service billing revenue from the estimated polyphase line extension cost. The result of this calculation will be the required Contribution in Aid of Construction that shall be paid to the Company before construction of the extension is undertaken. On an annual basis, over the five (5) year period following the commencement of service to the Customer through the polyphase overhead supply line extension, the Customer’s projected annual distribution service billing revenue will be compared to the Company’s actual distribution charges billed to the Customer. Any shortfall between the estimated annual distribution billing used in the calculation of the Contribution in Aid of Construction and the Customer’s actual distribution billing will be assessed to the Customer. On a case-by-case basis, the Company may allow a Customer to pay, via installments, any required Contribution in Aid of Construction. The terms and conditions of such arrangements shall be at the sole discretion of the Company. In cases where installment payment of a Contribution in Aid of Construction is permitted, the Customer will, unless the Company otherwise agrees, be required to provide financial security to the Company in a form acceptable to the Company. **(C)**

(C) Indicates Change

RULES AND REGULATIONS (continued)

5. SERVICE AND SUPPLY SYSTEM EXTENSIONS

5-g Company-Provided Underground Service and Supply Facilities. The Company may provide underground service and supply facilities to a new Customer, except as provided in Rule 5-i below, when, in the Company's opinion, the circumstances justify the investment. In such a case, the Customer at its sole expense must provide service entrance equipment suitable to receive service from underground equipment. On request of a new Customer, the company may establish an underground system on a private right-of-way on condition that: (a) the Customer pays the Company, in advance a Contribution in Aid of Construction equal to the entire cost of underground facilities in excess of five hundred (500) feet; (b) the Customer provides all trenching and backfilling and conduit required to establish an underground system according to the Company's specifications; (c) the supply line to be installed underground is not located along public road right-of-way; and (d) the Customer provides the Company a suitable right-of-way over all properties crossed by the new line. **(C)**

5-h Customer-Owned Underground Service Line. Where in the opinion of the Company it is not practical for the Company to provide an underground service line, the Customer may, at their own expense, furnish their own underground service line from the Customer's meter location to a point specified by the Company. Such Customer-owned service lines shall be built to Company specifications. Sufficient wire shall be provided for the Company to terminate the Customer-owned service line to the Company supply facilities. The Company will terminate the Customer-owned service lines to its supply facilities without charge to the Customer. The Customer shall be responsible for ownership, operation, maintenance, relocation, and replacement of such Customer-owned service line. **(C)**

5-i Underground Electric Service in New Residential Developments. Company shall install underground distribution and service facilities in new residential developments as required in the PUC regulations at 52 Pa. Code §§ 57.81 – 57.88 or any successor thereto. Such service shall only be provided for new residential developments being developed pursuant to a recorded plot plan with five or more adjoining unoccupied lots to be used for single-family residences, detached or otherwise, mobile homes or apartment houses, all of which are intended for year-round occupancy. Tracts of land which are subdivided, but not developed into utility-ready lots by a bona fide developer shall not qualify for the service. Applicants for such service must: **(C)**

(1) Request electric service at such time that the lines may be installed before curbs, pavements and sidewalks are laid; carefully coordinate scheduling of the Company's line and facility installation with the general project construction schedule, including coordination with any other Company sharing the same trench; keep the route of lines clear of machinery and other obstructions when the line installation crew is scheduled to appear; and otherwise cooperate with the Company to avoid unnecessary cost and delay; and

(2) At Applicant's own cost, provide the Company with a copy of the recorded development plot plan identifying property boundaries, and with easements satisfactory to the Company for occupancy by distribution, service and street-light lines and related facilities; and **(C)**

(C) Indicates Change

RULES AND REGULATIONS (continued)

5. SERVICE AND SUPPLY SYSTEM EXTENSIONS

(3) At Applicant's own cost, clear the ground in which the lines and related facilities are to be laid of trees, stumps and other obstructions, provide the excavating and backfilling subject to the inspection and approval of the Company, and rough grade it to within six inches of final grade, so that the Company's part of the installation shall consist only of laying of the lines and installing other service-related facilities. Excavating and backfilling performed or provided by the applicant shall follow the Company's underground construction standards and specifications set forth by the Company in written form and presented to the applicant at the time of application for service and presentation of the recorded plot plan to the Company. If the Company's specifications have not been met by the Applicant's excavating and backfilling, such excavating and backfilling shall be corrected or redone by the applicant or its authorized agent. Failure to comply with the Company's construction standards and specifications permits the Company to refuse service until such standards and specification are met. **(C)**

5-j Other Extension. The Company's obligation to extend its facilities to a new point of delivery, other than as set forth above, is limited to the assumption of new investment to the extent warranted by the revenue anticipated from the service to be supplied. Where the anticipated revenue does not warrant the investment required to serve, the Company will determine for each case what guarantees of revenue, financing or term of contract shall be required of the Customer.

5-k Taxes on Contributions in Aid of Construction. For any Contribution in Aid of Construction or other like amounts received from an Applicant or Customer which constitute taxable income as defined by the Internal Revenue Service, the Company shall maintain a segregated deferred income tax account for inclusion in rate base in a future rate proceeding. Such income taxes associated with a Contribution in Aid of Construction or other like amount will not be charged to the Applicant or Customer. **(C)**

5-l Service to Electric Vehicle Supply Equipment. Where Company provides service to Qualified Electric Vehicle Charging Stations ("Qualified EV Charging Stations") which will be accessible to the public for charging access, the Company shall provide all required investment without Contribution in Aid of Construction and will design and install the required infrastructure facilities necessary for operation of such Qualified EV Charging Stations (including any new conductor replacement, transformers, services, and meters; inclusive of any make ready work). Such facilities shall be provided at no required Contribution in Aid of Construction to the customer as part of an EV infrastructure pilot which will end September 30, 2026. Qualified EV Charging Stations may be supplied electricity by an EGS. **(C)**

5-m Qualified EV Charging Stations shall be defined as one (1) to four (4) DC Fast Charge ("DCFC") stations of 50kW or greater, or at least four (4) Level 2 charging stations, which are compatible with the Company's distribution system and are located within 400 feet of a Company 3-phase primary distribution circuit line, or in another location where the Company, in its sole discretion, anticipates that adequate public availability and access is being provided. DCFC installation locations may also be inclusive of one or more adjacent Level 2 charging stations. All qualifying chargers must have smart or network capabilities and be tested for safety by a national testing laboratory such as UL. Qualifying Level 2 chargers must be ENERGY STAR certified.

(C) Indicates Change

RULES AND REGULATIONS (continued)

16. ADMINISTRATION OF RATES

16-a Load Inspections. Where the supply of Electric Service is under rates which base the billing demand or minimum charge upon the Customer's connected load, Company's representative shall have access to the premises at reasonable times to inspect and count the connected load.

16-b Billing Corrections. Where demands or consumption are reassessed, or redetermined, or power factor recomputed or remeasured or Customers are found to be on an improper rate, as the result of investigation made at Customer's request or by Company initiative, the change of billing to the new demand or power factor, or to the proper rate or consumption will apply to the bill(s) for the month(s) over which the investigation period is related. **(C)**

16-c Change in Rate. After Customer provides actual notice of service conditions, including a change thereof, and upon request, Company will reasonably assist Customer in determining the most advantageous rate for which Customer may qualify. Company will notify Customer in writing or by new contract of the change in rate contemplated, provided that not more than one such change of rate shall be made in any twelve (12) month period, except as provided in Rule 16-d. **(C)**

16-d Billing During Periods of Construction or Emergency. After the Customer provides actual notice of service conditions, including a change thereof, and upon request, Company will reasonably assist the Customer in determining the applicable rate most advantageous to Customer or modify or waive the requirements of the applicable rate as to billing demand, minimum billing demand and/or minimum monthly charge when: **(C)**

(1) Customer is forced to suspend operations in part or entirely due to fire or flood;

(2) Unusual high demands are established by emergency pumping, or other abnormal load conditions;

(3) Customer's plant is under construction or gradual electrification; or **(C)**

(4) Government Orders, applicable to special classes of Customers, require changes in such Customer's loads.

Written request for relief must be made is all cases except (4), stating fully the circumstances on which the request is based. If appropriate, the contract term shall be extended for a period equal to that of the relief granted. **(C)**

(C) Indicates Change

RULES AND REGULATIONS (continued)

17. NET METERING

(2) If the customer-generator's existing electric metering equipment does not meet the requirements under option (1) above, the Company shall install new metering equipment for the customer-generator at the Company's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator as a Contribution in Aid of Construction. The customer-generator has the option of utilizing a qualified meter service provider to install metering equipment for the measurement of generation at the customer-generator's expense. **(C)**

(3) Additional metering equipment for the purpose of qualifying alternative energy credits owned by the customer-generator shall be paid for by the customer-generator as a Contribution in Aid of Construction. The Company shall take title to the alternative energy credits produced by a customer-generator where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits. The Company shall, prior to taking title to any alternate energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer-generator for the disposition of those credits. **(C)**

(4) Virtual meter aggregation on properties owned or leased and operated by the same customer-generator shall be allowed for purposes of net metering. Virtual meter aggregation shall be limited to meters located on properties owned or leased and operated by the same customer-generator within two (2) miles of the boundaries of the customer-generator's property and within the Company's service territory. All service locations to be aggregated must be Company service location accounts held by the same individual or legal entity receiving retail electric service from the Company and have measurable load independent of any alternative energy system. Physical meter aggregation shall be at the customer-generator's expense. The Company shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the Company at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing their account on a virtual meter aggregation basis. **(C)**

17-c Billing Provisions. The following billing provisions apply to customer-generators in conjunction with service under applicable Rate Schedule R, GS-1, GS-4, GS-5, and LP.

(1) The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at full retail rate, consistent with Commission regulations. If a customer-generator supplies more electricity to the electric distribution system than the Company delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's kilowatt-hour usage in subsequent billing periods at the full retail rate. Any excess kilowatt hours that are not offset by electricity used by the customer-generator in subsequent billing periods shall continue to accumulate until the end of the year. At the end of each year, the Company will compensate the customer-generator for any remaining excess kilowatt-hours generated by the customer-generator that were not previously credited against the customer-generator's usage in prior billing periods at the Company's Price to Compare rate. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

(C) Indicates Change

RULES AND REGULATIONS (continued)

19. POLE REMOVAL AND RELOCATION CHARGES

19-a For the purpose of this Rule only, the following terms shall have the meanings indicated for them.

(1) "Contractor Costs" - The amount paid by the Company to a contractor for work performed on a pole removal or relocation.

(2) "Direct Labor Costs" - The pay and expenses of Company employees directly attributable to work performed on pole removals or relocations, excluding construction overheads or payroll taxes, workmen's compensation expenses or similar expenses.

(3) "Direct Material Costs" - The purchase price of materials used in performing a pole removal or relocation, excluding related stores expenses. In computing direct materials costs, proper allowance shall be made for unused materials, materials recovered from temporary structures, and for discounts allowed and realized in the purchase of materials.

(4) "Pole Removal or Relocation" - The removal or relocation of distribution or transmission line poles and their associated attachments made under the request of a residential property owner who is not entitled to receive condemnation damages to cover the cost of the pole removal or relocation. The term does not include pole repairs or replacements necessitated by the intentional or negligent conduct of a party.

19-b When a Residential Customer requests the Company to remove or relocate a Company pole on said Customer's residential property the Residential Customer shall be required to pay the contractor costs, direct labor costs, and direct material costs associated with the pole removal or relocation less an amount equal to any maintenance expenses avoided as a result of such work as a Contribution in Aid of Construction. The Company shall provide the Residential Customer with an estimate of the above costs for performing such work and the Residential Customer shall pay that amount to the Company prior to construction. After completion of the work, the Company shall bill, or refund to, the Residential Customer the difference between the estimated cost and the actual direct cost of such work. **(C)**

19-c In all other respects, Non-Residential Customers or parties that request the removal, relocation or changes to Company facilities shall bear the total cost and expenses of the work, including the total direct and indirect costs. Where required by the Company, the Non-Residential Customer or party shall pay to the Company in advance a Contribution in Aid of Construction for the estimated cost to perform such work. After completion of the work, the Company shall bill, or refund to the non-residential Customer or party, the difference between the estimated cost and the total direct and indirect cost of such work. **(C)**

19-d All Customers or parties that request the removal, relocation or change of Company facilities shall furnish, without expense to the Company, satisfactory rights-of-way acceptable to the Company for the construction, maintenance and operation of the relocated facilities.

(C) Indicates Change

RIDER A

STATE TAX ADJUSTMENT SURCHARGE

The State Tax Adjustment Surcharge is applicable to the net monthly rates and minimum charges contained in this Tariff. The surcharge shown below will be recomputed when a tax rate used in the calculation changes and/or the Company implements a change in rates.

The recomputation of the surcharge will be submitted to the PUC within 10 days after the occurrence of a reason for surcharge recomputation shown above. If the recomputed surcharge is less than the one in effect the Company will, and if more may, submit a tariff or supplement to reflect such recomputed surcharge, the effective date of which shall be 10 days after the filing.

Rider A - State Tax Adjustment Surcharge is 0.00%. **(D)**

(D) Indicates Decrease

RIDER C
UNIVERSAL SERVICE PROGRAM RIDER

APPLICABILITY AND PURPOSE
This Rider shall be applicable to all Residential Customers except Customers in the Company's Customer Assistance Program ("CAP"). This Rider has been established to recover costs related to the Company's Universal Service and Conservation Programs, excluding internal administrative costs. **(C)**

RATE
In addition to the charges provided in this tariff, an amount shall be added to the otherwise applicable charge for each kWh of sales volumes or distribution volumes distributed by the Company to Customers receiving service under Rate Schedule R. **(C)**

The USP rate: 1.150 ¢/kWh

CALCULATION OF RATE
The Rider USP rate shall be calculated to recover costs for the following programs: Low Income Usage Reduction Program ("LIURP"); CAP; Hardship Funds; and any other replacement or Commission-mandated Universal Service Program or low income program that is implemented during the period that the Rider is in effect. **(C)**

LIURP costs will be calculated based on the projected number of Level 1 income homes to be weatherized. Hardship Fund costs will be calculated on the projected level of an allocated share of administrative funds incurred by the UGI Operation Share Energy Fund.

CAP costs will be calculated to include: **(C)**
(1) the projected CAP credit;
(2) projected CAP customer application and administrative costs paid to external agencies that would not have been incurred in the absence of CAP; and
(3) projected CAP pre-program arrearage forgiveness.

"CAP Credit" shall be defined as the difference between the total calculated Rate R bill, excluding Rider USP, and the CAP bill and an adjustment for unearned credit amounts based upon the current discounts at normalized annual volumes of the then-current CAP participants and the projected CAP Credit for projected Customer additions to CAP during the period that the CAP Rider rate will be in effect at the average discount of current CAP participants at normalized annual volumes. **(C)**

QUARTERLY ADJUSTMENT
Any time that the Company makes a change in base rates or GSR rate affecting Residential Customers, the Company shall recalculate the Rider USP rate pursuant to the calculation described above to reflect the Company's current data for the components used in the USP rate calculation. The Company shall file the updated rate with the PUC to be effective one (1) day after filing. **(C)**

ANNUAL RECONCILIATION
On or before November 1 of each year, the Company shall file with the PUC data showing the reconciliation of actual revenues received under this Rider and actual recoverable costs incurred for the preceding twelve months ended September. The resulting over/undercollection (plus interest calculated at 6% annually) will be reflected in the CAP quarterly rate adjustment to be effective December 1. Actual recoverable costs shall reflect actual CAP costs, actual application costs, actual pre-program arrearage forgiveness, actual LIURP costs, actual Hardship Administrative costs. Actual recoverable CAP credit costs and pre-program arrearage forgiveness shall be based upon actual CAP credits granted and pre-program arrearage forgiveness granted less a 7.40% adjustment for amounts granted to participants in excess of the number of CAP enrollees as of September 30, 2023. The 7.40% adjustment related to CAP credits and pre-program arrearage forgiveness will be based on the following: **(C)**

(C) Indicates Change

RIDER C

UNIVERSAL SERVICE PROGRAM RIDER (Continued)

For each reconciliation period, the average annual CAP credit per participant will be determined by dividing the total actual CAP credits granted during the reconciliation period by the average monthly number of participants receiving CAP credits during the reconciliation period. The average monthly number of participants receiving CAP credits exceeding the number of CAP enrollees as of September 30, 2023 will be **(C)** multiplied by the average annual CAP credit granted per participant and then multiplied by 0.0740 in order to determine the amount of the CAP Credits recovered through Rider USP.

For each reconciliation period, the average pre-program arrearage forgiveness per participant will be determined by dividing the total actual pre-program arrearage forgiven during the reconciliation period by the number of participants receiving pre-program arrearage forgiveness. The number of participants receiving pre-program arrearage forgiveness exceeding the number of CAP enrollees as of September 30, 2023 will **(C)** be multiplied by the average pre-program arrearage forgiveness per participant and then multiplied by 0.0740 in order to determine the amount of the pre-program arrearage forgiveness which will not be recovered through Rider USP.

(C) Indicates Change

RIDER G

DSIC – DISTRIBUTION SYSTEM IMPROVEMENT CHARGE

In addition to the net charges provided for in this Tariff, a charge of 0.00% will apply. **(D)**

A.1 Purpose. To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new Customers are not recoverable through the DSIC. **(C)**

A.2 Eligible Property.

The DSIC-eligible property will consist of the following:

- Poles and Tower (Acct. 364);
- Overhead conductors (Acct. 365)
- Underground Conduit and Conductors (Accts. 366 & 367)
- Line Transformers (Acct. 368)
- Substation Equipment (Acct. 362)
- Any fixture or device related to eligible property listed above, including insulators, circuit breakers, fuses, reclosers, grounding wires, crossarms and brackets, relays, capacitors, convertors and condensers;
- Unreimbursed costs related to highway relocation projects where an electric distribution company must relocate its facilities; and
- Other related capitalized costs.

A.3 Effective Date. The DSIC will become effective for bills rendered on and after, March 28, 2023. **(C)**

A.4 Computation of the DSIC. The DSIC will be updated on a quarterly basis to reflect eligible plant additions placed in service during the three-month periods ending one month prior to the effective date of each DSIC update.

Thus, changes in the DSIC rate will occur as follows:

Effective Date of Change	Date to which DSIC-Eligible Plant Additions Reflected
April 1	December 1 through February 28
July 1	March 1 through May 31
October 1	June 1 through August 31
January 1	September 1 through November 30

(D) Indicates Decrease (C) Indicates Change

RATE R
RESIDENTIAL SERVICE

AVAILABILITY
Available to Customers located on Company's distribution lines and desiring service for household and Non-Residential uses (where the Non-Residential use(s) is limited to less than 2 kW) in a single private dwelling, or an individual dwelling unit in a multiple dwelling structure, and its appurtenant detached buildings. **(C)**

CHARACTER OF SERVICE
Alternating current, 60 cycles, single phase; 120 volts, 2 wire; 120-208 volts, 3 wire; or 120-240 volts, 3 wire.

RATE TABLE

Customer Charge: $13.50 per Month **(I)**

Distribution Charge (all usage): 5.535 ¢/kWh **(I)**

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider C - Universal Service Program Rider
Rider E - Energy Efficiency and Conservation Rider
Rider G - Distribution System Improvement Charge **(C)**

MINIMUM MONTHLY CHARGE
The Minimum Monthly Charge shall be the Customer Charge.

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Rule 13, Payment Terms, paragraph 13-f. **(C)**

(I) Indicates Increase (C) Indicates Change

RATE OL
OUTDOOR LIGHTING SERVICE

AVAILABILITY
This Rate is available for outdoor lighting in the entire territory served by the Company, where contracted for by a Customer for private area lighting. Effective March 28, 2023, Rate OL is no longer available to new Customers or Applicants, or for new installations for existing Customers. **(C)**

CONTRACT TERM AND BILLING
Standard contracts are on a yearly basis with monthly payments for service.

RATE TABLE
Rates per month for standard construction with monthly payments for service rendered.

Flood Lighting Luminaire – Mercury Vapor

	Residential		Commercial		
	Customer Charge (Per Lamp)	Distribution (¢/kWh)	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
11,000 Lumen	$7.20	4.812	$6.79	5.626	**(I)**
20,000 Lumen	$8.05	4.812	$7.43	5.626	**(I)**
60,000 Lumen	$8.24	4.812	$6.69	5.626	**(I)**

Street Lighting Luminaire – Mercury Vapor

	Residential		Commercial		
	Customer Charge (Per Lamp)	Distribution (¢/kWh)	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
7,000 Lumen	$4.54	4.812	$4.26	5.626	**(I)**
11,000 Lumen	$7.20	4.812	$6.79	5.626	**(I)**
20,000 Lumen	$8.05	4.812	$7.43	5.626	**(I)**
60,000 Lumen	$8.24	4.812	$6.69	5.626	**(I)**

Low mounted, decorative fixture and pole ....$ 7.46 per month
for underground service, provided that in addition to charge **(C)**
no trenching and backfilling is required in Rate Tables above

Distribution and Generation Supply rates will be applied to per kilowatt hour of energy used each month. The number of kWh supplied is based upon the average hours' use and size of lamps.

STANDARD CONSTRUCTION
The prices specified in the Rate Table for Standard Construction cover the supply of lamps and equipment to mount floodlighting or street lighting luminaires and photo-electric switch control on Company's existing wood pole or other support approved by the Company and located within one span (150 feet) of existing 120-volt facilities. If Customer requires an additional wood pole, or poles, to be installed, a monthly charge of $5.99 per pole shall be added to the above Rates for standard installation poles. Any additional facilities other than specified herein shall be paid by the Customer in advance as a Contribution in Aid of Construction. **(C)**

HOURS OF BURNING
Operation shall be from dusk until dawn, a total of approximately 4,000 hours per year. Credit shall not be allowed for lamp outages.

(I) Indicates Increase (C) Indicates Change

RATE OL - (Continued)
OUTDOOR LIGHTING SERVICE

MAINTENANCE
All facilities shall be owned and maintained by the Company. Lamp renewal service, during normal working hours will be provided upon notice to the Company for lamps burned out or broken. Burned out or broken lamps will be replaced as long as the supply of mercury vapor lighting is readily available at reasonable costs **(C)** to the Company. Customer will be required to move to a different available lighting service rate when lamps cannot be replaced or replaced at reasonable cost.

RURAL LINE MINIMUMS
Rural line minimums shall not be applicable to charges under this Rate.

APPROVAL
Customer shall obtain proper approval for lights to be located on public thoroughfares.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E- Energy Efficiency and Conservation Rider
Rider G - Distribution System Improvement Charge **(C)**

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Rule 13, Payment Terms, paragraph 13-f. **(C)**

(C) Indicates Change

RATE SOL
SODIUM OUTDOOR LIGHTING SERVICE

AVAILABILITY
This Rate for high pressure sodium outdoor lighting is available in the entire territory served by the Company, where contracted for by a Customer for private area lighting.

CONTRACT TERM
Two years and thereafter in accordance with contract provisions. The contract may be terminated with sixty (60) days' notice prior to expiration period of contract by either party.

NET MONTHLY RATE
Rates per month for standard construction with monthly payments for service rendered.

Floodlighting Luminaire – High Pressure Sodium

	Residential		Commercial		
	Customer Charge (Per Lamp)	Distribution (¢/kWh)	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
16,000 Lumen	$7.96	4.812	$7.65	5.626	(I)
25,000 Lumen	$8.35	4.812	$7.88	5.626	(I)
50,000 Lumen	$10.42	4.812	$9.72	5.626	(I)

Street Lighting Luminaire – High Pressure Sodium

	Residential		Commercial		
	Customer Charge (Per Lamp)	Distribution (¢/kWh)	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
9,500 Lumen	$7.87	4.812	$7.66	5.626	(I)
16,000 Lumen	$7.96	4.812	$7.65	5.626	(I)
25,000 Lumen	$8.35	4.812	$7.88	5.626	(I)
50,000 Lumen	$10.42	4.812	$9.72	5.626	(I)

Low mounted, decorative fixture and pole ....$ 7.46 per month
for underground service, provided that in addition to charge
no trenching and backfilling is required in Rate Table above (C)

Distribution and Generation Supply rates will be applied to per kilowatt hour of energy used each month. The number of kWh supplied is based upon the average hours' use and size of lamps.

GENERAL PROVISIONS

(a) The prices specified in the Rate Table for Standard Overhead Construction cover the supply of lamps and equipment to mount flood lighting or street lighting luminaires and photo-electric switch control on Company's existing wood pole or other support approved by Company and located within 150 feet of existing 120-volt facilities. **(C)**

(b) If Customer requires an additional wood pole, or poles, to be installed for mounting heights up to 25 feet, a monthly charge of $5.99 per pole shall be added to the above rates.

(c) Any additional facilities other than specified herein shall be paid by the Customer in advance as a Contribution in Aid of Construction. **(C)**

(I) Indicates Increase (C) Indicates Change

RATE SOL - (Continued)
SODIUM OUTDOOR LIGHTING SERVICE

(d) Customer shall obtain proper approval for lights to be located on public thoroughfares

(e) Operation shall be from dusk to dawn, a total of approximately 4,000 hours per year. Lamp renewal service, during normal working hours, will be provided upon notice to Company for lamps burned out or broken and no credit for outages allowed. Company will supply, install, operate, and maintain necessary lighting facilities.

(f) Burned out or broken lamps will be replaced as long as the supply of sodium vapor lighting is readily available at reasonable costs to the Company. Customer will be required to move to a different available lighting service rate when lamps cannot be replaced or replaced at reasonable cost. **(C)**

REMOVAL OF MERCURY VAPOR
When, at the request of the Customer, a sodium vapor light replaces a fully operational mercury vapor light that has been installed for less than 10 years, the Customer shall pay the Company for the Company's estimated cost of removal and rehabilitation plus the estimated remaining value of the system. When, at the request of the Customer, a sodium vapor light replaces a failed mercury vapor light that can neither be repaired nor replaced, the installation will be completed at no charge to the Customer.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G - Distribution System Improvement Charge **(C)**

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Rule 13, Payment Terms, paragraph 13-f. **(C)**

(C) Indicates Change

RATE MHOL
METAL HALIDE OUTDOOR LIGHTING SERVICE

AVAILABILITY
This Rate is available in the entire territory served by the Company, where contracted for by a Customer for private area lighting. Effective March 28, 2023, Rate MHOL is no longer available to new Customers or Applicants, or for new installations for existing Customers. **(C)**

CONTRACT TERM
Two years and thereafter in accordance with contract provisions. The contract may be terminated with sixty (60) days' notice prior to expiration period of contract by either party.

NET MONTHLY RATE

Flood Lighting Luminaire

	Residential		Commercial		
	Customer Charge (Per Lamp)	Distribution (¢/kWh)	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
20,500 Lumen	$9.05	4.812	$8.65	5.626	**(I)**
36,000 Lumen	$9.20	4.812	$8.57	5.626	**(I)**
110,000 Lumen	$16.11	4.812	$14.58	5.626	**(I)**

Street Lighting Luminaire

	Residential		Commercial		
	Customer Charge (Per Lamp)	Distribution (¢/kWh)	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
9,000 Lumen	$8.07	4.812	$7.86	5.626	**(I)**
12,900 Lumen	$6.83	4.812	$6.57	5.626	**(I)**
13,000 Lumen	$6.36	4.812	$6.07	5.626	**(I)**
20,500 Lumen	$9.05	4.812	$8.65	5.626	**(I)**
36,000 Lumen	$9.20	4.812	$8.57	5.626	**(I)**

Low mounted, decorative fixture and pole ....$ 7.46 per month
for underground service, provided that in addition to charge
no trenching and backfilling is required in Rate Table above

Distribution and Generation Supply rates will be applied to per kilowatt hour of energy used each month. The number of kWh supplied is based upon the average hours' use and size of lamps.

GENERAL PROVISIONS

(a) The prices specified in the Rate Table for Standard Overhead Construction cover the supply of lamps and equipment to mount flood lighting or street lighting luminaries and photo-electric switch control on Company's existing wood pole or other support approved by Company and located within 150 feet of existing 120-volt facilities. **(C)**

(b) If Customer requires an additional wood pole, or poles, to be installed for mounting heights up to 25 feet, a monthly charge of $5.99 per pole shall be added to the above rates.

(c) Any additional facilities other than specified herein shall be paid by the Customer in advance as a Contribution in Aid of Construction. **(C)**

(I) Indicates Increase (C) Indicates Change

RATE MHOL - (Continued)
METAL HALIDE OUTDOOR LIGHTING SERVICE

(d) Customer shall obtain proper approval for lights to be located on public thoroughfares.

(e) Operation shall be from dusk to dawn, a total of approximately 4,000 hours per year. Lamp renewal service, during normal working hours, will be provided upon notice to Company for lamps burned out or broken and no credit for outages allowed. Company will supply, install, operate, and maintain necessary lighting facilities.

(f) Burned out or broken lamps will be replaced as long as the supply of metal halide lighting is readily available at reasonable costs to the Company. Customer will be required to move to a different available lighting service rate when lamps cannot be replaced or replaced at reasonable cost. **(C)**

<u>REMOVAL OF MERCURY VAPOR & HIGH PRESSURE SODIUM</u>
When, at the request of the Customer, a metal halide light replaces a fully operational mercury vapor or high pressure sodium light that has been installed for less than 1 or 2 years respectively, the Customer shall pay the Company for the Company's estimated cost of removal and rehabilitation plus the estimated remaining value of the system. When, at the request of the Customer, a metal halide light replaces a failed mercury vapor light that can neither be repaired nor replaced, the installation will be completed at no charge to the Customer.

<u>TERMINATION</u>
If Customer terminates outdoor lighting service under this schedule for any reason prior to expiration of the two-year term, Customer shall pay removal cost.

<u>SURCHARGES AND RIDERS</u>
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G - Distribution System Improvement Charge **(C)**

<u>PAYMENT TERMS</u>
Late Payment Charges shall be billed in accordance with Rule 13, Payment Terms, paragraph 13-f. **(C)**

(C) Indicates Change

RATE LED-OL
LIGHT-EMITTING DIODE OUTDOOR LIGHTING SERVICE

AVAILABILITY
This Rate is available in the entire territory served by the Company, where contracted for by a Customer for private area lighting.

CONTRACT TERM
Two years and thereafter in accordance with contract provisions, which shall be consistent with this rate schedule and shall be of a standard form provided by and satisfactory to the Company. The contract may be terminated with sixty (60) days' notice prior to expiration period of contract by either party subject to the termination provision below.

NET MONTHLY RATE

Flood Lighting Luminaire

	Residential		Commercial		
Nominal Lamp Wattage Range	Customer Charge (Per Lamp)	Distribution (¢/kWh)	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
85-100	$15.42	4.812	$15.42	5.626	**(I)**
170-210	$22.64	4.812	$22.64	5.626	**(I)**
250-280	$26.08	4.812	$26.08	5.626	**(I)**

Street Lighting Luminaire

	Residential		Commercial		
Nominal Lamp Wattage Range	Customer Charge (Per Lamp)	Distribution (¢/kWh)	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
50-60	$10.29	4.812	$10.29	5.626	**(I)**
100-110	$12.16	4.812	$12.16	5.626	**(I)**
140-160	$14.00	4.812	$14.00	5.626	**(I)**
250-280	$21.25	4.812	$21.25	5.626	**(I)**

Standard Decorative Luminaire (for installations on or after effective date of March 28, 2023) **(C)**

	Residential		Commercial		
Nominal Lamp Wattage Range	Customer Charge (Per Lamp)	Distribution (¢/kWh)	Customer Charge (Per Lamp)	Distribution (¢/kWh)	**(C)**
60-80	$11.77	4.812	$11.77	5.626	

Low mounted, decorative pole .... $ 13.62 per month
for underground service, provided that .... in addition to charge **(C)**
no trenching and backfilling is required .... in Rate Table above

(I) Indicates Increase (C) Indicates Change

RATE LED-OL (continued)
LIGHT-EMITTING DIODE OUTDOOR LIGHTING SERVICE

Distribution and Generation Supply rates will be applied to per kilowatt hour of energy used each month. Service hereunder is unmetered with the number of kWh billed for each size lamp calculated based on the estimated input wattage of the lamp and approximately 4,000 burning hours per year.

GENERAL PROVISIONS

(a) The prices specified in the Rate Table for Customer Charger (Per Lamp) cover the supply of lamps, fixtures, luminaries, and equipment, and installation of flood lighting or street lighting luminaries and photo-electric switch control on Company's existing wood pole or other support approved by Company and located within 150 feet of existing 120-volt facilities. Such charges include normal operation and maintenance. **(C)**

(b) If Customer requires an additional wood pole, or poles, to be installed for mounting heights up to 25 feet, a monthly charge of $5.99 per pole shall be added to the above rates.

(c) Any additional facilities other than specified herein and the cost of rearranging facilities required to change mounting height shall be paid by the Customer in advance as a Contribution in Aid of Construction. **(C)**

(d) Customer shall obtain proper approval for lights to be located on public thoroughfares.

(e) Operation shall be from dusk to dawn, a total of approximately 4,000 hours per year. Lamp renewal service, during normal working hours, will be provided upon notice to Company for lamps burned out or broken and with no credit for outages. Company will supply, install, operate, and maintain necessary lighting facilities.

REMOVAL OF MERCURY VAPOR, HIGH PRESSURE SODIUM AND METAL HALIDE
When, at the request of the Customer, a LED light replaces a fully operational mercury vapor, high pressure sodium or metal halide light that has been installed for less than the applicable contract term, the Customer shall pay the Company for the Company's estimated cost of removal and rehabilitation plus the estimated remaining value of the system. When, at the request of the Customer, a LED light replaces a failed mercury vapor, high pressure sodium or metal halide light that can neither be repaired nor replaced, the installation will be completed at no charge to the Customer.

TERMINATION
If Customer terminates outdoor lighting service under this schedule for any reason prior to expiration of the two-year term, Customer shall pay removal cost.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G - Distribution System Improvement Charge **(C)**

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Rule 13, Payment Terms, paragraph 13-f. **(C)**

(C) Indicates Change

RATE GS-1
GENERAL SERVICE

AVAILABILITY
Available to Customers located on Company's distribution lines desiring electric service for general lighting and/or power service outside the scope of the Residence Service Rate Schedules and whose demand at any time of the year is not in excess of five (5) kilowatts, and any building the primary use of which is public worship.

CHARACTER OF SERVICE
Alternating current, 60 cycles, single phase, 120 volts, 2 wire; or 120-240 volts, 3 wire; and 3 phase, 120-240 volts, 4 wire, except in areas where only 120/208 volts are available.

CONTRACT TERM AND BILLING
Standard contracts are on a yearly basis with monthly payments for service taken.

RATE TABLE

Customer Charge: $14.00 per Month **(I)**

Distribution Charge (all usage): 7.615 ¢/kWh **(I)**

MINIMUM MONTHLY CHARGE
The Minimum Monthly Charge is the Customer Charge.

DETERMINATION OF DEMAND
The demand will be determined at the option of the Company by estimate or by test at the time of maximum use or by demand meter measurement. Demands of Customers with monthly consumption over two thousand (2,000) kilowatt-hours on a recurring basis will be metered unless otherwise shown to be eligible for this rate.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G - Distribution System Improvement Charge **(C)**

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Rule 13, Payment Terms, paragraph 13-f. **(C)**

(I) Indicates Increase (C) Indicates Change

RATE GS-4 SERVICE
(5 kW minimum)

AVAILABILITY
Available to Customers located on Company's distribution lines desiring electric service for general lighting and/or power service and whose minimum billing demand is not less than five (5) kilowatts.

CHARACTER OF SERVICE
Alternating current, 60 cycles, 3 phase, 120-240 volts, 4 wire; 120-208 volts, 4 wire; or 240 volts, 3 wire; 480 volts, 3 wire; 277-480 volts, 4 wire, may be supplied. In addition, alternating current, 60 cycles, single phase, 120-240 volts, 3 wire, and where available 120-208 volts, 3 wire, or as otherwise determined to be reasonable by the Company. **(C)**

CONTRACT TERM AND BILLING
Contracts shall be for a term of not less than one (1) year with monthly payments for service taken. Contracts for a longer term may be required where new investment by Company is necessary.

RATE TABLE

Customer Charge: $15.00 per Month

	Distribution ($/kW)	Distribution (¢/kWh)	
First 20 kW of billing demand	$3.59		
Over 20 kW of billing demand	$2.20		
First 200 hours use of demand		3.126	**(I)**
Next 300 hours use of demand		1.968	**(I)**
All over 500 hours use of demand		1.640	**(I)**

MINIMUM MONTHLY CHARGE
The Minimum Monthly Charge is the Customer Charge plus the charge in the Rate Table for the billing demand. The minimum billing demand will not be less than five (5) kilowatts nor less than the minimum value stated in a contract for service. **(C)**

DETERMINATION OF DEMAND
The demand shall be the greatest fifteen (15) minute load in kilowatts established during the month, taken for billing purposes to the nearest kilowatt.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider F - Power Factor Surcharge
Rider G - Distribution System Improvement Charge **(C)**

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Rule 13, Payment Terms, paragraph 13-f. **(C)**

POWER FACTOR
The Power Factor Charge contained in this Tariff is applied to this Rate

(I) Indicates Increase (C) Indicates Change

RATE GS-5 (continued)
GENERAL SERVICE
(VOLUNTEER FIRE COMPANY, NON-PROFIT SENIOR CITIZEN CENTER, NON-PROFIT RESCUE SQUAD, AND NON-PROFIT AMBULANCE SERVICE)

RATE TABLE

Customer Charge: $13.50 per Month **(I)**

Distribution Charge (all usage): 5.535 ¢/kWh **(I)**

MINIMUM MONTHLY CHARGE
The Minimum Monthly Charge shall be the Customer Charge.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G - Distribution System Improvement Charge **(C)**

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Rule 13, Payment Terms, paragraph 13-f. **(C)**

(I) Indicates Increase (C) Indicates Change

RATE LP
LARGE POWER SERVICE

AVAILABILITY
Available to Customers taking general light and power service at each delivery point and whose minimum demand is not less than one hundred (100) kilowatts based on Customer's highest billing demand in the most recent twelve-month period ending September 30th. **(C)**

CHARACTER OF SERVICE
Alternating current, 60 cycles, 3 phase, primary service at 13,800 volts, or one (1) transformation to a lower available standard Company voltage with metering on the primary side of transformers and substation equipment supplied by the Company. **(C)**

CONTRACT TERM AND BILLING
Contracts shall be for a term of not less than one (1) year with monthly payments for service taken. Contracts for a longer term may be required where new investment by Company is necessary.

RATE TABLE
The Customer's monthly bill shall be the sum of the demand and energy charges.

	Distribution ($/kW)	Distribution (¢/kWh)	
Demand Charge:			
First 100 kW of billing demand	$135.80 *		
Next 400 kW of billing demand	$0.94		
Over 500 kW of billing demand	$0.69		
First 100 hours use of billing demand		2.341	**(I)**
Next 200 hours use of billing demand but not more than 200,000 kWh		1.691	**(I)**
Next 200 hours use of billing demand but not more than 200,000 kWh		1.547	**(I)**
Excess		1.455	**(I)**

* ..... Charge is for the First 100 kW of billing demand or any part thereof.

(I) Indicates Increase (C) Indicates Change

RATE LP - (Continued)
LARGE POWER SERVICE

DETERMINATION OF DEMAND
The demand shall be determined by meters which will, at the option of the Company, either indicate or record the demand. The billing demand shall be the highest fifteen (15) minute demand recorded during the month, provided that the Company reserves the right to use for billing purposes the single maximum demand established during a five (5) minute interval when power installation includes hoists, elevators, welding machines, electric furnaces, or other load having high intermittent peak load requirements. In no event, however, shall the billing demand be less than one hundred (100) kilowatts.

SECONDARY SERVICE
At the Company's option, service may be metered at secondary voltage of transforming equipment. When so metered energy charges will be increased two (2) percent.

POWER FACTOR
The Power Factor Charge contained in this Tariff is applied to this Rate.

MINIMUM MONTHLY CHARGE
The Minimum Monthly Charge shall be an amount equal to the demand charge plus the power factor charge for the month.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider F - Power Factor Surcharge
Rider G – Distribution System Improvement Charge **(C)**

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Rule 13, Payment Terms, paragraph 13-f. **(C)**

(C) Indicates Change

RATE HTP
HIGH TENSION POWER SERVICE

AVAILABILITY
This rate is available for large general service Customers taking supply from available transmission lines of 66,000 volts or higher.

CHARACTER OF SERVICE
Alternating current, 60 cycles, 3 phase, 66,000 volts (or higher) with metering on the primary side of transformers and substation equipment supplied by the Customer.

CONTRACT TERM AND BILLING
Contract shall be for a term of not less than one (1) year with monthly payments for service taken. Contracts for a longer term may be required where new investment by Company is necessary.

RATE TABLE

Customer Charge, Distribution Charge, Demand Charge, and Power Factor Surcharge are all fully negotiated rates.

MINIMUM MONTHLY CHARGE
As determined by negotiation between Customer and Company.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Rule 13, Payment Terms, paragraph 13-f. **(C)**

(C) Indicates Change

RATE SL
STREET LIGHTING SERVICE

AVAILABILITY
This Rate is available for street, bridge, parks, and outdoor lighting in the entire territory served by the Company. Effective March 28, 2023, Rate SL is no longer available to new Customers or Applicants, or for new installations for existing Customers. **(C)**

CONTRACT TERM
Standard contracts are for the term of five (5) years. Contracts for a longer term may be required where new investment by Company is necessary.

RATE TABLE
Rates per lamp per month for standard construction with monthly payments for service rendered.

Mercury Vapor

	Municipal or Public Authority		
	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
3,750 Lumen	$3.88	5.626	**(I)**
7,000 Lumen	$4.05	5.626	**(I)**
11,000 Lumen	$6.37	5.626	**(I)**
20,000 Lumen	$7.65	5.626	**(I)**
60,000 Lumen	$6.43	5.626	**(I)**

Low mounted, decorative fixture and pole ....$ 7.46 per month
for underground service, provided that in addition to charge **(C)**
no trenching and backfilling is required in Rate Table above

Additional wood pole installed for the sole..$ 5.99 per month
purpose of supporting lighting fixtures or circuits

The number of kWh supplied is based upon the average hours' use and size of lamps.

Distribution and Generation Supply rates will be applied to per kilowatt hour of energy used each month. The number of kWh supplied is based upon the average hours' use and size of lamps.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G - Distribution System Improvement Charge **(C)**

STANDARD CONSTRUCTION
The prices specified in the Rate Table for Standard Construction cover the supply of lamps and equipment to mount lighting fixtures on wood poles and include electric current and maintenance for complete street lighting service when supplied from circuits, mast arms, and fixtures of overhead construction. When Customer desires an underground or ornamental system, or non-standard construction conditions exist, the additional cost shall be borne by Customer; also, if Customer desires to supply equipment such as conductors, conduit, poles and fixtures, a monthly construction credit for such equipment supplied shall be given Customer over the term of the contract.

Other special equipment such as is used for channel lighting on bridges shall be installed and maintained by Customer except lamp bulbs which shall be furnished and renewed by Company.

(I) Indicates Increase (C) Indicates Change

RATE SL - (Continued)
STREET LIGHTING SERVICE

HOURS OF BURNING
All night lamps from one-half (1/2) hour after sunset to one-half (1/2) hour before sunrise, a total of approximately 4,000 hours per year.

LAMP RENEWALS
Free Lamp renewal service is provided upon notice to the Company for lamps burned out, broken, or giving less than eighty percent (80%) of initial lumens as rated by the manufacturers. Burned out or broken lamps will be replaced as long as the supply of mercury vapor lighting is readily available to the Company at a reasonable cost. Customer will be required to move to a different available lighting service rate when lamps cannot be replaced or are not available at reasonable cost. **(C)**

SPACING OF LAMPS
The standard spacing of lamps shall be a distance not to exceed four hundred (400) feet. Non-standard construction costs shall be paid by the customer as a Contribution in Aid of Construction. **(C)**

NOTE 1: 3,750 Lumen-Mercury Vapor Lamp Rate restricted to units installed as of July 27, 1994.

ADDITIONAL LAMPS
Additional lamps and fixtures of the type currently being used by the Company may be ordered installed by Customer at any time during the first four (4) years of a standard five (5) year contract. Additional lamps and fixtures ordered installed during last year of standard contract or contracts less than five (5) years may be deferred at Company's option until a new standard contract is executed, unless the Customer is willing to pay the cost of installation, subject to refund by Company when new standard five (5) year contract is executed.

No additional lamps and fixtures are available after July 1, 2007.

RELOCATION OF LAMPS
The cost of any change of location of lamps, from the original location specified by Customer, shall be borne by the Customer and paid to the Company as a Contribution in Aid of Construction. **(C)**

CHANGE IN SIZE OF LAMP
In the event that change in size of lamps is desired by the Customer, Company will make such change in accordance with the following requirements:

(1) That no further investment, except lamps, by Company in new fixtures shall be required;

(2) Mercury vapor lamps are available to the Company; and **(C)**

(3) Changes of lamp size other than those covered under Clause 1 hereof shall be subject to further agreement between Customer and Company.

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Rule 13, Payment Terms, paragraph 13-f. **(C)**

(C) Indicates Change

RATE SSL
SODIUM STREET LIGHTING SERVICE

AVAILABILITY
This Rate schedule for high pressure sodium vapor lighting is available for public roadway, bridge and parks.

CONTRACT TERM
Ten years and thereafter in accordance with contract provisions. The contract may be terminated with sixty (60) days' notice prior to expiration period of contract by either party.

NET MONTHLY RATE

	Municipal or Public Authority		
	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
9,500 Lumen	$7.51	5.626	**(I)**
16,000 Lumen	$7.58	5.626	**(I)**
25,000 Lumen	$8.57	5.626	**(I)**
50,000 Lumen	$9.10	5.626	**(I)**

Low mounted, decorative fixture and pole ....$ 7.46 per month
for underground service, provided that in addition to charge
no trenching and backfilling is required in Rate Table above **(C)**

Additional wood pole installed for the sole ....$ 5.99 per month
purpose of supporting lighting fixtures or circuits

The number of kWh supplied is based upon the average hours' use and size of lamp.

Distribution and Generation Supply rates will be applied to per kilowatt hour of energy used each month. The number of kWh supplied is based upon the average hours' use and size of lamps.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G - Distribution System Improvement Charge **(C)**

GENERAL PROVISIONS
(a) Necessary street lighting facilities are supplied and installed, operated and maintained by Company and are connected to Company's available general distribution system.

(b) Prices include the standard type luminaire currently being offered at the time service is contracted for and up to 150 circuit feet of overhead secondary extension.

(c) Customer shall pay the cost of any additional facilities required to extend service and the cost of rearranging facilities required to change mounting height.

(d) Burned out or broken lamps will be replaced as long as the supply of sodium vapor lighting is readily available at reasonable costs to the Company. Customer will be required to move to a different available lighting service rate when lamps cannot be replaced or replaced at reasonable cost. **(C)**

(I) Indicates Increase (C) Indicates Change

RATE SSL - (Continued)
SODIUM STREET LIGHTING

(e) Company will provide underground and decorative systems of a type being offered by the Company at the time service is contracted for when the additional cost in excess of the estimated cost of a standard overhead system for the same application is paid by Customer as a Contribution in Aid of Construction. Company shall take title to this system and shall operate and maintain the facilities. At the termination, for any reason, of the useful life of these systems or designated components, a new system or component shall be installed under similar conditions. **(C)**

<u>SPECIAL CUSTOMER EQUIPMENT</u>
Upon request, the Company may, at its option, operate and maintain special lighting equipment of a type not being offered by Company provided Customer installs equipment and supplies any nonstandard replacement parts at no cost to Company.

<u>REMOVAL OF MERCURY VAPOR</u>
When, at the request of the Customer, a sodium vapor light replaces a fully operational mercury vapor light that has been installed for less than 10 years, the Customer shall pay the Company for the Company's estimated cost of removal and rehabilitation plus the estimated remaining value of the system. When, at the request of the Customer, a sodium vapor light replaces a failed mercury vapor light that can neither be repaired nor replaced, the installation will be completed at no charge to the Customer.

<u>TERMINATION</u>
If Customer terminates street lighting service under this schedule for any reason prior to expiration of any 10-year term, Customer shall pay removal cost plus remaining value of system.

<u>PAYMENT TERMS</u>
Late Payment Charges shall be billed in accordance with Rule 13, Payment Terms, paragraph 13-f. **(C)**

(C) Indicates Change

RATE MHSL
METAL HALIDE STREET LIGHTING SERVICE

AVAILABILITY
This Rate is available to municipalities or other public authorities for street, bridge, parks, and outdoor lighting in the entire territory served by the Company. Effective March 28, 2023, Rate MHSL is no longer available to new Customers or Applicants, or to for installations for existing Customers. **(C)**

CONTRACT TERM
Ten years and thereafter in accordance with contract provisions. The contract may be terminated with sixty (60) days' notice prior to expiration period of contract by either party

NET MONTHLY RATE

	Municipal or Public Authority		
	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
9,000 Lumen	$6.71	5.626	**(I)**
12,900 Lumen	$5.42	5.626	**(I)**
13,000 Lumen	$4.92	5.626	**(I)**
20,500 Lumen	$7.29	5.626	**(I)**
36,000 Lumen	$6.20	5.626	**(I)**

(1) Low mounted, decorative fixture and pole for underground service, provided that no trenching and backfilling is required ....$ 7.46 per month in addition to charge in Rate Table above **(C)**

Additional wood pole installed for the sole purpose of supporting lighting fixtures or circuits ....$ 5.99 per month

The number of kWh supplied is based upon the average hours' use and size of lamp.

Distribution and Generation Supply rates will be applied to per kilowatt hour of energy used each month. The number of kWh supplied is based upon the average hours' use and size of lamps.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G - Distribution System Improvement Charge **(C)**

GENERAL PROVISIONS

(a) Necessary street lighting facilities are supplied and installed, operated and maintained by Company and are connected to Company's available general distribution system.
(b) Prices include the standard type luminaries currently being offered at the time service is contracted for and up to 150 circuit feet of overhead secondary extension.
(c) Customer shall pay the cost of any additional facilities required to extend service and the cost of rearranging facilities required to change mounting height.
(d) The cost of any change of location of lamps, from the original location specified by Customer, shall be borne by the Customer and paid to the Company.

(I) Indicates Increase (C) Indicates Change

RATE MHSL - (Continued)
METAL HALIDE STREET LIGHTING SERVICE

(e) Company will provide underground and decorative systems of a type being offered by the Company at the time service is contracted for when the additional cost in excess of the estimated cost of a standard overhead system for the same application is paid by Customer as a Contribution in Aid of Construction. Company shall take title to this system and shall operate and maintain the facilities. At the termination, for any reason, of the useful life of these systems or designated components, a new system or component shall be installed under similar conditions. **(C)**

(f) Burned out or broken lamps will be replaced as long as the supply of metal halide lighting is readily available at reasonable costs to the Company. Customer will be required to move to a different available lighting service rate when lamps cannot be replaced or replaced at reasonable cost. **(C)**

SPECIAL CUSTOMER EQUIPMENT
Upon request, the Company may, at its option, operate and maintain special lighting equipment of a type not being offered by Company provided Customer installs equipment and supplies any nonstandard replacement parts at no cost to Company.

REMOVAL OF MERCURY VAPOR AND HIGH PRESSURE SODIUM
When, at the request of the Customer, a metal halide light replaces a fully operational mercury vapor or high pressure sodium light that has been installed for less than 5 or 10 years respectively, the Customer shall pay the Company for the Company's estimated cost of removal and rehabilitation plus the estimated remaining value of the system. When, at the request of the Customer, a metal halide light replaces a fully operational mercury vapor light that can neither be repaired nor replaced, the installation will be completed at no charge to the customer.

TERMINATION
If Customer terminates street lighting service under this schedule for any reason prior to expiration of any 10-year term, Customer shall pay removal cost plus the estimated remaining value of system.

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Rule 13, Payment Terms, paragraph 13-f. **(C)**

(C) Indicates Change

RATE LED-SL
LIGHT-EMITTING DIODE STREET LIGHTING SERVICE

AVAILABILITY
This Rate is available to municipalities or other public authorities for street, bridge, parks, and outdoor public lighting in the entire territory served by the Company. **(C)**

CONTRACT TERM
Ten years and thereafter in accordance with contract provisions, which shall be consistent with this rate schedule and shall be of a standard form provided by and satisfactory to the Company. The contract may be terminated with sixty (60) days' notice prior to expiration period of contract by either party subject to the termination provision below.

NET MONTHLY RATE

	Municipal or Public Authority		
Nominal Lamp Wattage Range	Customer Charge (Per Lamp)	Distribution (¢/kWh)	
50-60	$10.29	5.626	**(I)**
100-110	$12.16	5.626	**(I)**
140-160	$14.00	5.626	**(I)**
250-280	$21.25	5.626	**(I)**

Additional wood pole installed for the sole purpose of supporting lighting fixtures or circuits .... $ 5.99 per month

Standard Decorative Luminaire (for installations on or after effective date of March 28, 2023) **(C)**

	Municipal or Public Authority		
Nominal Lamp Wattage Range	Customer Charge (Per Lamp)	Distribution (¢/kWh)	**(C)**
60-80	$11.77	5.626	

Low mounted, decorative pole for underground service, provided that no trenching and backfilling is required .... $ 13.62 per month in addition to charge in Rate Table above **(C)**

Distribution and Generation Supply rates will be applied to per kilowatt hour of energy used each month. Service hereunder is unmetered with the number of kWh billed for each size lamp calculated based on the estimated input wattage of the lamp and approximately 4,000 burning hours per year.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G - Distribution System Improvement Charge **(C)**

(I) Indicates Increase (C) Indicates Change

RATE LED-SL (continued)
LIGHT-EMITTING DIODE STREET LIGHTING SERVICE

GENERAL PROVISIONS

(a) Necessary street lighting facilities are supplied and installed, operated and maintained by Company and are connected to Company's available general distribution system.

(b) Prices include the standard type luminaries currently being offered at the time service is contracted for and up to 150 circuit feet of overhead secondary extension. Prices include normal operation and maintenance.

(c) Customer shall pay the cost of any additional facilities required to extend service and the cost of rearranging facilities required to change mounting height.

(d) The cost of any change of location of lamps, from the original location specified by Customer, shall be borne by the Customer and paid to the Company as a Contribution in Aid of Construction. **(C)**

(e) Company will provide underground and decorative systems of a type being offered by the Company at the time service is contracted for when the additional cost in excess of the estimated cost of a standard overhead system for the same application is paid by Customer as a Contribution in Aid of Construction. Company shall take title to this system and shall operate and maintain the facilities. At the termination, for any reason, of the useful life of these systems or designated components, a new system or component shall be installed under similar conditions. **(C)**

(f) Operation shall be from dusk to dawn, a total of approximately 4,000 hours per year. Lamp renewal service, during normal working hours, will be provided upon notice to Company for lamps burned out or broken and with no credit for outages.

SPECIAL CUSTOMER EQUIPMENT
Upon request, the Company may, at its option, operate and maintain special lighting equipment of a type not being offered by Company provided Customer installs equipment and supplies any nonstandard replacement parts at no cost to Company.

REMOVAL OF MERCURY VAPOR, HIGH PRESSURE SODIUM AND METAL HALIDE **(C)**
When, at the request of the Customer, a LED light replaces a fully operational mercury vapor, high pressure sodium or metal halide light that has been installed for less than the applicable contract term, the Customer shall pay the Company for the Company's estimated cost of removal and rehabilitation plus the estimated remaining value of the system. When, at the request of the Customer, a LED light replaces a fully operational mercury vapor, high pressure sodium or metal halide light that can neither be repaired nor replaced, the installation will be completed at no charge to the Customer.

TERMINATION
If Customer terminates street lighting service under this schedule for any reason prior to expiration of any 10-year term, Customer shall pay removal cost plus the estimated remaining value of system.

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Rule 13, Payment Terms, paragraph 13-f. **(C)**

(C) Indicates Change

RATE LED-CO
CUSTOMER-OWNED LIGHT-EMITTING DIODE STREET LIGHTING SERVICE

AVAILABILITY
This Rate is available to Non-Residential Customers and municipalities or other public authorities in the entire territory served by the Company for the operation of Light-Emitting Diode ("LED") street lighting systems on private or public areas where the Customer wholly owns and installs the street lighting system. **(C)**

CONTRACT TERM
Ten years and thereafter in accordance with contract provisions, which shall be consistent with this rate schedule and shall be of a standard form provided by and satisfactory to the Company. The contract may be terminated with sixty (60) days' notice prior to expiration period of contract by either party subject to the termination provision below.

NET MONTHLY RATE

Distribution Charge……………..……………………………………………………………………5.626 (¢/kWh) **(I)**

Customer Charge (Per Lamp)*……………………………………………………….………$2.00 per month

* Applicable where, upon Customer election, Company provides operation and maintenance of Customer-owned street lighting system in accordance with the provisions below.

Additional wood pole installed for the sole.. ..…..$ 5.99 per month
purpose of supporting lighting fixtures or circuits

Distribution and Generation Supply rates will be applied to per kilowatt hour of energy used each month. Service hereunder is unmetered with the number of kWh billed for each size lamp calculated based on the estimated input wattage of the lamp and approximately 4,000 burning hours per year. Rate offering applicable to Customer-owned street lights sized within the standard nominal lamp wattage ranges offered by the Company under Rate Schedule LED-SL, not to exceed 280 nominal lamp wattage. If the Customer-owned street light is of a size outside of the Company's standard size offerings under Rate Schedule LED-SL, but in no event not to exceed 280 nominal lamp wattage, the Customer's kWh billed will be determined based on the next higher nominal lamp wattage range set forth under Rate Schedule LED-SL.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G - Distribution System Improvement Charge **(C)**

STANDARD INSTALLATION AND SERVICE
Upon Customer election, the Company shall operate and maintain the Customer-owned street lighting system subject to Customer payment of the monthly Customer charge (per lamp) above.

Customer-owned street lighting equipment shall be installed in accordance with company and industry safety codes and, where installed on Company poles, in accordance with general Company specifications for similar equipment.

Company shall make all connections of Customer's street lighting system to the Company's available general distribution system.

(I) Indicates Increase (C) Indicates Change

RATE LED-CO (continued)
CUSTOMER-OWNED LIGHT-EMITTING DIODE STREET LIGHTING SERVICE

(c) All luminaires served hereunder are operated at alternating current, 60 hertz, single phase and are controlled by photo control for dusk to dawn operation every night, approximately 4,000 hours per year.

(d) The Attachment Agreement for the Customer-owned lighting system on Company's poles shall include indemnification of Company by Customer and provide for purchase of public liability and property damage insurance by Customer.

REMOVAL OF COMPANY-OWNED LIGHTS
When, at the request of the Customer, a Customer-owned lighting system replaces a fully operational Company-owned mercury vapor, high pressure sodium, metal halide or LED light that has been installed for less than the applicable contract term, the Customer shall pay the Company for the Company's estimated cost of removal and rehabilitation plus the estimated remaining value of the system.

AUDITING
The Company has the right to periodically audit the number and size of lamps of Customer's street lighting system. The Customer agrees to cooperate with Company during such audits.

TERMINATION
If Customer terminates street lighting service under this schedule for any reason prior to expiration of any 10-year term, Customer shall pay removal cost plus the estimated remaining value of system.

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Rule 13, Payment Terms, paragraph 13-f. **(C)**

(C) Indicates Change

RATE FCP
FLOOD CONTROL POWER SERVICE

AVAILABILITY
This Rate is available to municipalities and townships in Company's territory requiring power service for the operation of flood pumping stations during periods of public emergency, and for periodic testing of same as hereinafter provided.

CHARACTER OF SERVICE
Alternating current, 60 cycles, three phase, 13,800 volts.

CONTRACT TERM AND BILLING
Term of contract shall be not less than one (1) year, with monthly payments for service taken.

RATE TABLE

	Distribution ($/Month)	Distribution (¢/kWh)	
First 100 kWh or less per month for each electrically driven pump installed	$6.31		**(I)**
All additional kWh		2.961	**(I)**

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider G - Distribution System Improvement Charge **(C)**

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Rule 13, Payment Terms, paragraph 13-f. **(C)**

SPECIAL PROVISIONS

(1) The Customer shall own, install, operate and maintain the lines necessary to connect its pumping stations to the Company's existing facilities, and the transforming equipment and auxiliary apparatus necessary to secure voltages less than the supply voltage specified above.
(2) Periodic testing shall be prearranged between the Customer and Company upon at least twenty-four (24) hours' notice to the Company and shall occur on weekdays during the hours between 12 midnight and 6 A.M. unless otherwise justified by load conditions on Company's system, of which conditions the Company's judgment shall be final.
(3) Supply lines at each pumping station shall normally be disconnected and shall be connected only when necessary during periods of public emergency and for periodic testing.

(I) Indicates Increase (C) Indicates Change

RATE BLR
BORDERLINE RESALE SERVICE

AVAILABILITY
Available under reciprocal agreements to neighboring public utilities supplying electric service for resale in territory immediately adjacent to the charter territory of the Company, provided the Company, in its opinion has available capacity over and above that required to meet the demands, present and prospective, for service in its own territory.

CHARACTER OF SERVICE
Alternating current, 60 cycles, single or three phase, 2,400 volts, 4,160 volts, 8,320 volts, or 13,800 volts.

CONTRACT TERM AND BILLING
Standard contracts are for a term of five (5) years with monthly payments for service taken.

RATE TABLE
Service will be provided under the appropriate Company Tariff Rate. The appropriate rate is that under which the Customer would be served if they were located within the Company's franchised service territory.

SURCHARGES AND RIDERS
Rider A - State Tax Adjustment Surcharge
Rider B - Generation Supply Service
Rider E - Energy Efficiency and Conservation Rider
Rider F - Power Factor Surcharge
Rider G - Distribution System Improvement Charge **(C)**

PAYMENT TERMS
Late Payment Charges shall be billed in accordance with Rule 13, Payment Terms, paragraph 13-f. **(C)**

POWER FACTOR
The Power Factor Charge contained in this Tariff is applied to this Rate.

(C) Indicates Change

PROPOSED SUPPLEMENT NO. 7

TO

UGI UTILITIES, INC. – ELECTRIC DIVISION

PA. P.U.C. NO. 2S

UGI UTILITIES, INC. – ELECTRIC DIVISION

ELECTRIC GENERATION SUPPLIER COORDINATION TARIFF

Issued: January 27, 2023

Effective: March 28, 2023

Issued by:
Paul J. Szykman
Chief Regulatory Officer
1 UGI Drive
Denver, PA 17517

NOTICE

https://www.ugi.com/tariffs

This tariff makes Changes to existing rules and regulations (see page 2).

LIST OF CHANGES MADE BY THIS TARIFF
(Page Numbers Refer to Official Tariff)

Cover Page

- The issue and effective dates have been updated.
- The supplement number has been updated.

Definition of Terms and Explanation of Abbreviations, Pages 4 - 7.

- Definition of Commission has been moved to Page 4 from Page 7.
- Definition of The Company has been changed to Definition of Company and has been moved to Page 4 from Page 7.
- A period has been added to the end of the Definition of Coordination Services on Page 4.
- Definitions of both EDEWG and EGS Representative have been reordered and moved to appear before Electric Distribution Company on Page 5.
- The hyphen following Definition of Price to Compare (“PTC”) has been changed from – to -.

Rule 1 – The Tariff, Page 8.

- Subsection 1.1 language has been updated to provide website links where a copy of the Company Tariff can be found and the capitalization of ‘coordination’ has been updated to ‘Coordination’.

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS

Active Load Management - the process for arranging to have firm load become interruptible in accordance with criteria established by the PJM OI.

Appropriate Similar Day - hourly forecasted load comparable based on week day, month, season, and weather.

Bad Credit - an EGS has bad credit if it is insolvent (as evidenced by a credit report prepared by a reputable credit bureau or credit reporting agency or public financial data, liabilities exceeding assets or generally failing to pay debts as they become due) or has failed to pay Company invoices when they became due on two or more occasions within the last twelve billing cycles.

Charge - any fee or charge that is billable by the Company to an EGS under this Tariff, including any Coordination Services Charge.

Commission - The Pennsylvania Public Utility Commission. **(C)**

Company - UGI Utilities, Inc. - Electric Division **(C)**

Competition Act - the Electricity Generation Customer Choice and Competition Act, 66 Pa. C.S. §2801, et seq.

Competitive Energy Supply - unbundled energy and/or capacity provided by an Electric Generation Supplier.

Coordination Activities - all activities related to the provision of Coordination Services.

Coordination Obligations - all obligations identified in Rule 4 of the Tariff, relating to the provision of Coordination Services.

Coordination Services - those services that permit the type of interface and coordination between EGSs and the Company in connection with the delivery of Competitive Energy Supply to serve Customers located within the Company's service territory, including: load forecasting, certain scheduling-related functions and reconciliation. **(C)**

Coordination Services Charges - all Charges stated in this Tariff that are billed by the Company for Coordination Services performed hereunder.

Coordinated Supplier - an Electric Generation Supplier that has appointed a Scheduling Coordinator as its designated agent for the purpose of submitting energy schedules to the PJM OI.

(C) Indicates Change

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS (continued)

Creditworthy - a creditworthy EGS pays the Company's charges as and when due and otherwise complies with the Rules and Regulations of this Tariff or the Commission. To determine whether an EGS is creditworthy, the Company will evaluate the EGS's record of paying Company charges and may also take into consideration the EGS's credit.

Customer - any person, partnership, association, or corporation receiving Competitive Energy Supply from an Electric Generation Supplier in accordance with the Competition Act.

Deliver - to "Deliver" a document or other item under this Tariff shall mean to tender by certified mail, hand delivery, or overnight express package delivery service.

Direct Access - "Direct Access" shall have the meaning set forth in the Competition Act.

EDC Tariff - the Company's Electric Service Tariff, denominated Electric Pa. P.U.C. No. 6. **(C)**

EDEWG - the Commission's Electronic Data Exchange Working Group. **(C)**

EGS Representative - any officer, director, employee, consultant, contractor, or other agent or representative of an EGS in connection with the EGS's activity solely as an EGS. To the extent an EGS is a division or group of a company, the term EGS Representative does not include any person in that company who is not part of the EGS division.

Electric Distribution Company or "EDC" - a public utility that owns electric distribution facilities. At times, this term is used to refer to the role of the Company as a deliverer of Competitive Energy Supply in a Direct Access environment as contemplated in the Competition Act.

Electric Generation Supplier or "EGS" - a supplier of electric generation that has been certified or licensed by the Pennsylvania Public Utility Commission to sell electricity to retail customers within the Commonwealth of Pennsylvania in accordance with the Competition Act.

FERC - the Federal Energy Regulatory Commission.

Hourly or Sub-Hourly Metering Equipment - metering equipment that supplies half-hourly readings of kW and power factor via remote communications, and not metering equipment from which half-hourly or hourly demand readings may be obtained through on-site querying of the metering equipment.

Interest Index - an annual interest rate determined by the average of 1-Year Treasury Bills for September, October and November of the previous year.

(C) Indicates Change

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS (continued)

Kilowatt or kW - unit of measurement of useful power equivalent to 1000 watts.

Load Serving Entity or "LSE" - an entity that has been granted the authority or has an obligation pursuant to State or local law, regulation or franchise to sell electric energy to end-users located within the PJM Control Area.

Locational Marginal Price or "LMP" - the hourly integrated marginal price to serve load at individual locations throughout PJM, calculated by the PJM OI as specified in the PJM Open Access Transmission Tariff.

Megawatt or MW - one thousand kilowatts.

Meter Read Date - the date on which the Company schedules a meter to be read for purposes of producing a customer bill in accordance with the regularly scheduled billing cycles of the Company.

Month - a month under this Tariff means 1/12 of a year, or the period of approximately 30 days between two regular consecutive readings of the Company's meter or meters installed on the customer's premises.

Network Integration Transmission Service Reservation - a reservation under the PJM Tariff of Network Integration Transmission Service, which allows a transmission customer to integrate and economically dispatch generation resources located at one or more points in the PJM Control Area to serve its Network load therein.

(C)

PJM - the Pennsylvania-New Jersey-Maryland Interconnection.

PJM Control Area - that certain Control Area encompassing systems in Pennsylvania, New Jersey, Maryland, Delaware and the District of Columbia and which is recognized by the North American Electric Reliability Council as the "PJM Control Area."

PJM InSchedule System - software program administered by the PJM OI through which energy load schedules may be submitted., or any successor system.

PJM OI - the PJM Office of Interconnection, the system operator for the PJM Control Area.

PJM Tariff - the PJM Open Access Transmission Tariff on file with the FERC and which sets forth the rates, terms and conditions of transmission service over transmission facilities located in the PJM Control Area.

PLR Service - Provider of Last Resort Service.

(C) Indicates Change

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS (continued)

Price to Compare or "PTC" - the dollar amount charged by the Company, used by customers to compare prices with those offered by Electric Generation Suppliers. **(C)**

Scheduling Coordinator - an entity that performs one or more of an EGS's Coordination Obligations, including the submission of energy schedules to the PJM OI, and that either is (1) a member of the PJM Interconnection, L.L.C. or (2) is the agent, for scheduling purposes, of one or more Electric Generation Suppliers that are members of the PJM Interconnection, L.L.C.

Tariff - this Electric Generation Supplier Coordination Tariff.

(C) Indicates Change

RULES AND REGULATIONS

1. THE TARIFF

1.1 **Filing and Posting.** A copy of this Tariff, which comprises the Charges, Rules, and Regulations and Riders under which the Company will provide Coordination Services to EGSs, is on file with the PUC and is available on Company's website at https://www.ugi.com/tariffs and on the PUC's website at https://www.puc.pa.gov/filing-resources/tariffs/electric-tariffs/. This Tariff may be amended from time-to-time in accordance with the rules of the PUC. **(C)**

1.2 **Revisions.** This Tariff may be revised, amended, supplemented, or otherwise changed from time to time in accordance with the Pennsylvania Public Utility Code, and such changes, when effective, shall have the same force as the present Tariff.

1.3 **Application.** The Tariff provisions apply to all EGSs providing Competitive Energy Supply to Customers located in the Company's service territory including an affiliate or division of the Company that provides Competitive Energy Supply, and with whom the Company has executed an Individual Coordination Agreement as required herein. In addition, the Charges herein shall apply to anyone receiving service unlawfully or to any unauthorized or fraudulent receipt of Coordination Services.

1.4 **Rules and Regulations.** The Rules and Regulations, filed as part of this Tariff, are a part of every Individual Coordination Agreement entered into by the Company pursuant to this Tariff and govern all Coordination Activities, unless specifically modified by a Charge or Rider provision. The obligation imposed by EGSs in the Rules and Regulations shall apply as well to everyone receiving service unlawfully or to any unauthorized or fraudulent receipt of Coordination Services.

1.5 **Use of Riders.** The terms governing the supply of Coordination Services under this Tariff or a Charge therein may be modified or amended only by the application of those standard Riders, filed as part of this Tariff.

1.6 **Statement by Agents**. No Company representative has authority to modify a Tariff rule or provision, or to bind the Company by any promise or representation contrary thereto.

(C) Indicates Change

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2022-3037368, et al.

UGI Utilities, Inc. – Electric Division

Statement No. 1-R

Rebuttal Testimony of
Christopher R. Brown

Topics Addressed:	**Overview of Company's Rebuttal Case** **Management Performance and Recognition** **Public Input Hearings**

Dated: May 25, 2023

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christopher R. Brown. My business address is 1 UGI Drive, Denver, PA 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Electric Statement No. 1, on January 27, 2023.

Q. What is the purpose of your rebuttal testimony?

A. My testimony provides an overview of the Company's rebuttal case, as well as responding to certain portions of Bureau of Investigation and Enforcement ("I&E") Statement No. 3, the direct testimony and exhibit of D.C. Patel; Office of Consumer Advocate ("OCA") Statement No. 2, the direct testimony and exhibits of Aaron L. Rothschild; OCA Statement No. 4, the direct testimony of Roger D. Colton; and OCA Statement No. 5, the direct testimony of Morgan N. DeAngelo.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes, as part of my rebuttal testimony I am sponsoring UGI Electric Exhibit CRB-1R.

II. OVERVIEW OF COMPANY'S REBUTTAL CASE

Q. Would you please provide a summary of the Company's rebuttal testimony?

A. The Company's rebuttal testimony responds to each of the individual issues raised by the opposing parties. In some limited instances, the Company has agreed with the opposing party positions. However, for the most part, UGI Electric does not accept the other parties' adjustments, for the reasons identified in the Company's rebuttal testimony.

The major issues in this case are: (1) overall revenue requirement, including adjustments to rate base and expenses; (2) cost of common equity and capital structure; (3) cost allocation; and (4) rate design. As explained below and in more detail in the Company's rebuttal testimony, the Pennsylvania Public Utility Commission ("Commission" or "PUC") should adopt the Company's position on each of these issues and reject the unsound and unsupported proposals set forth in the other parties' direct testimony.

A. OVERALL REVENUE REQUIREMENT

Based on the Commission's precedent and practice, UGI Electric has requested an $11.425 million increase in annual operating revenues, although I note that the Company's most recent data and updates contained in the Company's rebuttal testimony justify an increase of $11.453 million. By comparison, OCA proposes an increase of approximately $3.54 million, and I&E proposes an increase of approximately $6.83 million. The OCA's and I&E's proposals simply do not reflect the facts or sound application of fundamental principles of ratemaking. UGI Electric will invest approximately $47.9 million during the future test year ("FTY") and fully projected future test year ("FPFTY") in infrastructure and business systems to ensure that its service is safe, reliable, and customer-focused. The critical infrastructure work that is driving a significant part of the Company's base rate increase must be completed to continue providing safe and reliable service to the Company's customers.

In addition, the parties have diverging positions on the Company's rate increase due to the other parties' flawed adjustments to some of the Company's revenue requirement, namely: (1) vegetation management expense; (2) incentive compensation expense; and (3) the Act 40 consolidated tax adjustment. As explained below, the other parties' positions lack support and, in some instances, depart without any justification from the Commission's and the Commonwealth Court's precedent.

1. Vegetation Management

OCA proposes a reduction of $1,431,151 to the vegetation management expense claim based on its use of a five-year historic average for the years 2018 through 2022. (OCA St. No. 1, pp. 24-25.) As explained in Mr. Sorber's rebuttal testimony (UGI Electric St. No. 4-R), OCA's proposal should be rejected.

Importantly, OCA does not challenge the reasonableness and prudency of the Company's current level of vegetation management activities and related expenses, which have unquestionably increased over time. By relying on a five-year historic average, OCA's proposal fails to account for the significant need for increased spending on vegetation management activities, both in recent years and in the future, and incorporates data from 2020, which was an anomaly year impacted by COVID-19. The bottom line is that UGI Electric's actual and projected spending in FY2023 demonstrates that the Company's vegetation management expense claim is justified and, accordingly, OCA's proposed adjustment should be rejected.

2. Incentive Compensation

I&E and OCA recommend a disallowance of the Company's claim for incentive compensation in the amounts of $725,800 and $716,450, respectively. The Commission rejected essentially identical arguments made by I&E in UGI Electric's 2018 base rate case and approved the Company's claim for allocated stock options and restricted stock awards.[1] As the Commission found in that proceeding, and as explained by Ms. Ressler in her rebuttal testimony (UGI Electric St. No. 3-R), ratepayers benefit from these incentive compensation programs. I&E and OCA provide no basis for distinguishing the Company's incentive compensation proposals in this case versus the fully litigated 2018 case. In fact, they fail to even mention it. Therefore, I&E's and OCA's proposed adjustments should be denied.

3. Act 40 Consolidated Tax Adjustment

OCA proposes a reduction in the Company's rate base balance by $35,000, based on its claim that the Company has not demonstrated that the remaining 50% of the Act 40 consolidated tax adjustment is being used for "general corporate purposes." (OCA St. No. 1, p. 47.)

As explained by Ms. Hazenstab in her rebuttal testimony (UGI Electric St. No. 2-R), OCA's position was rejected by the Commission and the Commonwealth Court and should be rejected again here. In particular, in the *UGI 2018 Rate Case Order*, the Commission held that the Company satisfied Act 40 by making the same presentation that UGI Electric has made in this case. The Commonwealth Court affirmed the Commission's ruling on appeal in *McCloskey v. Pa. PUC*, 225 A.3d 192 (Pa. Cmwlth. 2020) ("*McCloskey*"). Therefore, consistent with the showing made in UGI Electric's 2018 base rate case, 50% of the amount calculated in this proceeding will in fact be used for general

[1] *See Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket Nos. R-2017-2640058, pp. 71-74 (Order entered Oct. 25, 2018) ("*UGI 2018 Rate Case Order*").

corporate purposes, as the Company will be using this amount to support its lawful expenditures. Nothing presented by the OCA explains why the Commission should now, three years after *McCloskey*, depart from the Commission's and Commonwealth Court's precedent. Therefore, OCA's proposal should be denied.

B. COST OF COMMON EQUITY AND CAPITAL STRUCTURE

Both I&E and OCA propose that the Commission adopt returns on equity that are well below 9.0% and are significantly below the Commission's recent return on common equity determination in the Company's last fully-litigated base rate proceeding in 2018 (i.e., 9.85%) as well as the most recent Commission-approved Distribution System Improvement Charge ("DSIC") return on common equity for electric utilities of 9.55%. Specifically, I&E proposes a return on equity of 8.67%,[2] and OCA proposes a return on equity of 8.44%.[3] As explained by UGI Electric witness Moul (UGI Electric St. No. 9-R), OCA's and I&E's proposed returns on equity are flawed, and the Commission should adopt an allowed return on equity that is consistent with the analysis and recommendations of UGI Electric witness Moul (UGI Electric St. No. 9-R).

Furthermore, OCA proposes a hypothetical capital structure, rather than the Company's projected actual capital structure for the FPFTY. Such a proposal is improper and contrary to longstanding Commission practice and precedent, as explained by UGI Electric witness Moul (UGI Electric St. No. 9-R). As established in the several Commission orders cited in Mr. Moul's rebuttal testimony, the Commission will accept a utility's actual capital structure ratios so long as they are reasonable. Here, the Company's

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[2] *See* I&E St. No. 3, pp. 6, 25.
[3] *See* OCA St. No. 2, pp. 8, 10.

capital structure ratios (including the 54.59% common equity ratio) fall within the range of the proxy group and are fully consistent with the capital structures of other electric utilities in the Commonwealth. Thus, UGI Electric's actual projected capital structure should be used, and OCA's proposed hypothetical capital structure should be rejected.

C. COST AND REVENUE ALLOCATION

OCA opposes the Company's allocated cost of service study ("ACOSS"), which was prepared and presented by Mr. Taylor (UGI Electric St. No. 6). OSBA witness Knecht presents two alternative ACOSS: his first ACOSS applies the minimum system approach to both primary and secondary voltage systems (as proposed by UGI Electric), and his second ACOSS has "all primary voltage system costs . . . classified as demand-related." (OSBA St. No. 1, pp. 11-12.)

In rebuttal, Mr. Taylor identifies several flaws with OCA's position and explains why the Company's ACOSS should be adopted in this proceeding. (UGI Electric St. No. 6-R). In particular, the Commission previously rejected OCA's opposition to the use of the minimum system method in the *UGI 2018 Rate Case Order*, and nothing presented by OCA in this case warrants departing from that precedent. Further, OCA's position is inconsistent with all other Pennsylvania electric distribution companies that use the minimum system method. As for OSBA witness Knecht, Mr. Taylor addresses Mr. Knecht's proposed three minor adjustments to the Company's ACOSS, by accepting one and rejecting two, and responds to his alternative ACOSS, noting that, as acknowledged by Mr. Knecht, the alternative ACOSS produces a modest impact on the proposed revenue allocation. For these reasons, the Commission should adopt the Company's position on cost and revenue allocation.

D. RATE DESIGN

UGI Electric has proposed to increase its monthly residential customer charge from $9.50 to $13.50. The OCA and CEO oppose any increase to this charge on various grounds, while I&E recommends an increase of the charge to $12.00.

Mr. Taylor rebuts the parties' claims in his rebuttal testimony and demonstrates that the Company's proposed customer charge should be adopted (UGI Electric St. No. 6-R). UGI Electric's proposed $13.50 residential customer charge is substantially lower than the $15.86 residential customer charge of PPL Electric Utilities Corporation, whose service territory surrounds UGI Electric's service territory, and is substantially lower than Pennsylvania cooperatives' monthly customer charges, which range between $24.00 and $45.00. Also, contrary to the OCA's position, Mr. Taylor states that the principle of gradualism should be viewed with the entire electric bill in mind, not individual rate components. Further, Mr. Taylor explains that a lower customer charge is not more consistent with energy efficiency and conservation goals and would not benefit low-income customers. In fact, based on the average usage of both low-income customers and participants in the Company's Customer Assistance Program ("CAP"), the proposed customer charge of $13.50 would actually result in an annual bill decrease of $4.58 for the average low-income customer and an annual bill decrease of $15.24 for the average CAP customer. Thus, the Company's proposed monthly residential customer charge of $13.50 should be approved.

Q. What is the Company's overall position in rebuttal?

A. As explained in more detail in the Company's rebuttal testimony, the Commission should approve the Company's base rate increase and reject the proposed adjustments offered by the other parties to this proceeding (unless otherwise accepted in the Company's rebuttal). UGI Electric's proposals are based on sound and well-established ratemaking principles and will provide the Company with a fair opportunity to earn a return of and on its investments in the electric distribution system, and other investments that support providing safe and reliable electric service.

III. <u>MANAGEMENT PERFORMANCE AND RECOGNITION</u>

Q. OCA witness Colton argues that the Company has overstated its management performance and that its proposed return on equity adder for management performance should be rejected. (OCA St. No. 4, p. 54.) Please respond.

A. Mr. Colton argues that a few of the areas that I described in my direct testimony, and only a few, are over-stated and do not demonstrate exceptional management performance. I would note that Mr. Colton does not dispute UGI Electric's performance in the areas of electric reliability, consistent performance on long-term infrastructure improvement targets, and UGI Electric's significant community support. Performance in these areas alone clearly demonstrates excellent management performance.

Q. Mr. Colton also asserts that the Company's activities to enhance employee and customer safety do not justify an equity adder because they are standard industry practices and "not particularly innovative nor new." (OCA St. No. 4, pp. 54-56.) Do you agree with his position?

A. No. Mr. Colton's criticisms of UGI Electric's management performance effectiveness do not align with how the Commission reviews, considers, and awards utilities for engaging in such activities. UGI Electric has been, and continues to be, a trusted and reliable corporate citizen that provides safe and reliable electric service on which the public can rely. Moreover, Mr. Colton only highlights a few components of UGI Electric's safety program as being "not innovative or new" and appears to ignore the larger, comprehensive safety program discussed in Mr. Sorber's direct testimony. The importance of UGI Electric's safety efforts should not be downplayed or overlooked because Mr. Colton claims they are not new or innovative. Dedication to safety in a utility's day-to-day operations is paramount to any management effectiveness review.

Second, Mr. Sorber explained numerous components of the effective safety culture that UGI Electric maintains, including implementing the Company's new learning management system as well as the Intellishift Fleet Management system. Mr. Sorber also discussed how a well-defined and executed vegetation management program works to improve public safety, as well as reliability. In Mr. Colton's testimony, he singles out preventing would be failures, meeting with local first responders, and distributing safety information as "not being innovative or new." While these activities may not be new or innovative, their importance should not be ignored. These activities clearly evidence UGI Electric's dedication to safety. They also demonstrate the Company's commitment to being a strong community partner and a trusted and reliable corporate citizen. The Commission should consider the Company's safety program in totality in determining whether the Company should be awarded a management performance return on equity adder.

Q. Mr. Colton disputes that the Company's UGI Next Information Technology Enterprise ("UNITE") has caused an increase in electronic payments, alleging that UGI Electric's management decision-making was not a factor. (OCA St. No. 4, pp. 56-58.) Do you agree?

A. No. Mr. Colton states that "increasing electronic payments represents a societal-wide trend, not a UGI-specific customer response to management decisions." (OCA St. No. 4, p. 58.) To support his argument, Mr. Colton provides data from the 2022 Diary of Consumer Payment Choice reports that shows how the use of credit and debit cards has increased from 54% in 2019 to 57% in 2021, an increase of 3% over 2 years. (OCA St. No. 4, p. 56.) I reviewed the reports that Mr. Colton relies upon in making his management performance conclusions. In the same general time period as the consumer-specific data Mr. Colton relies on, UGI customers increased their use of electronic payments from 309,594 in November 2018 to 373,479 in November 2020 (i.e., an increase of 20.6%). Further, electronic payments continued to increase to 455,859 in November 2022, which equates to another 22% increase from 2020. These electronic payments would not have occurred without UGI Electric's foresight and investments in UNITE to serve its customer's interests. Clearly, the increase in electronic payments made by UGI customers since the implementation of UGI's customer billing system, and other customer portal enhancements made as part of the UNITE program, have significantly increased the number of electronic payments being made by UGI customers, and these increases are not solely due to a "societal wide trend," as alleged by Mr. Colton. The significant increase in customers opting for electronic payments, made possible by UGI Electric, is evidence that the Company correctly identified an investment that would benefit customers and implemented technology and policies to connect customers with that benefit.

Q. Relatedly, Mr. Colton disputes the claim that the UNITE investments are evidence of strong management due to "improved data quality," because "UGI falls well-short of collecting data that is essential to responding to the needs of its residential customers," and the Company "lacks basic data needed to support customer service and collections activities." (OCA St. No. 4, p. 58.) Is Mr. Colton correct?

A. No. Mr. Colton cites one data response – OCA-IV-42 – as evidence of the Company's "falling well short" of collecting data that he claims is essential to responding to customers' needs. His claimed shortfall in data collection is minor. Regarding the data categories that Mr. Colton sought in OCA-IV-42, UGI Electric provided all of the data for those categories. However, UGI Electric did not separate all of the requested data in each category by heating and non-heating customers. Additionally, the heating/non-heating level of data is not data that the Commission seeks from utilities in their annual Universal Service Reports. Further, the Company could not build its UNITE systems in anticipation of any and all possible data requests that may be received in a proceeding such as this one, as doing so would have required the Company to predict the everchanging sets of data requested by other parties. Clearly Mr. Colton's implicit assertion, that UGI Electric should have made such predictions as part of its UNITE implementation, is unreasonable. For these reasons, the Commission should disregard Mr. Colton's argument that the Company's IT systems do not support customer service and collections functions, because there is no evidence in this proceeding supporting that conclusion and it is simply not true.

Q. Mr. Colton also disputes UGI Electric's reliance on its voluntary Energy Efficiency and Conservation ("EE&C") Plan as evidence of strong management performance, given that the EE&C Plan allegedly "does not provide services to low-income customers." (OCA St. No. 4, p. 59.) Please respond.

A. Mr. Colton erroneously claims that UGI Electric's EE&C Plan lacks a low-income customer component, and the Company's response is detailed in the rebuttal testimony of Daniel V. Adamo (UGI Electric St. No. 11-R). The current EE&C Plan has a Residential Low-Income Program that offers additional and different measures than those offered under the standard Low-Income Usage Reduction Program ("LIURP") program, namely smart thermostats and EnergyStar heat pump water heaters. In addition, UGI Electric offers an appliance recycling program, a program to assist in converting from electric to natural gas (which would save home heating customers an anticipated $2,000 per year), as well as smart thermostat, appliance and HVAC equipment rebates that are available to all residential customers in the Company's service territory. While Mr. Colton does not recognize the programmatic benefits available to its low-income customers, it is indisputable that UGI Electric's EE&C Plan includes a low-income customer component that helps expand on the measures already offered through the Company's LIURP and, without it, low-income customers may not have access to EnergyStar heat pump water heaters and smart thermostats.

Q. Mr. Colton further finds the Company's LIURP budget to be lacking and, therefore, not evidence of strong management performance. (OCA St. No. 4, p. 59.) Please respond.

A. As detailed by UGI Electric witness Mr. Daniel V. Adamo (see UGI Electric St. No. 11-R), the Company's LIURP budget is not lacking. Instead, Mr. Colton's proposed increases to the Company's LIURP budget are based on misunderstandings, errors, and unsupported claims. As such, Mr. Colton's LIURP claims should be rejected. Therefore, Mr. Colton's opposition to the Company's return on equity adder for this reason lacks merit.

Q. Mr. Colton also disputes the Company's reliance on the amount of Low Income Home Energy Assistance Program ("LIHEAP") grants that the Company "provided," arguing that the Company does not provide LIHEAP grants from its own funds and therefore UGI Electric cannot claim credit for the provision of LIHEAP grants. (OCA St. No. 4, pp. 59-60.) Please respond.

A. Mr. Colton is correct that LIHEAP is a federal program administered locally by the Pennsylvania Department of Human Services. Although I agree that UGI Electric does not "provide" these grants, the Company undertakes extensive efforts to identify eligible customers and assist them in obtaining these grants, which cannot be overlooked. UGI Electric also provides educational information about the program and its eligibility requirements, and connects customers with resources to assist customers in the application process to obtain these grants. The results of these educational/outreach efforts are demonstrated by Mr. Adamo's rebuttal (UGI Electric St. No. 11-R), which documents a 302% increase in the number of LIHEAP grants received by UGI Electric's customers, as well as a 762% increase in total grant dollars distributed to customers, between 2019 and 2022.

Q. Mr. Colton argues that the Operation Share grants data from the 2021 program year is not representative because "from August 2020 through June 2021, UGI had temporarily raised the income guidelines for hardship grants from 200% to 250% of Poverty and had temporarily increased the maximum grant from $400 to $600." (OCA St. No. 4, pp. 60-61.) Please respond.

A. The Operation Share data speaks for itself, in that the Company's number of grants issued has increased since the onset of COVID, when the need for assistance to pay energy bills increased. The data upon which Mr. Colton relies demonstrates that the Company consistently increased the number of grants from program years 2020 through 2022. Mr. Colton is correct that the Company did modify eligibility requirements and maximum grant limits temporarily due to COVID, but Company management specifically decided to increase the customers benefitting from Operation Share at a time when there was significant customer need. The Company believes that its efforts to increase Operation Share grants to customers during the pandemic, is a strong management performance indicator. Further, comparing 2022 participation in Operation Share to pre-COVID participation also shows an increase in customers participating and funds provided. (*See* UGI Electric Exh. CRB-1R.) The data is clear that UGI Electric's activities have directly supported customers in need.

Q. I&E witness Patel also argues that UGI Electric's proposed return on common equity adder for management performance be denied. (I&E St. No. 3, pp. 62-65.) Could you please summarize his position?

A. I would note, first, that Mr. Patel appears to have a fundamental opposition to the concept of a management performance adder. He asserts that "there is no set criteria or measurement for claiming exemplary/superior management performance for a utility company that makes it eligible for an additional basis-point adder in the cost of equity claim." (I&E St. No. 3, p. 62.) Mr. Patel further contends that if UGI Electric "is effective at controlling operating and maintenance expenses due to prudent operation management policy," then those savings should be passed onto ratepayers, not "offset by the addition of basis points for management performance as ratepayers would have to fund the additional costs." According to Mr. Patel, "[t]his defeats the purpose of any cost cutting measures to benefit ratepayers." (*Id.*)

Turning to the claims made by UGI Electric in this case, Mr. Patel argues that the Company's actions cited in support of its proposal are akin to what is expected of a public utility, and that the activities used to support the management performance adder are ratepayer funded. Finally, Mr. Patel tries to distinguish the return on common equity adder awarded to Aqua Pennsylvania, Inc. ("Aqua") in its recent base rate case, by claiming that "[t]he situation in the Aqua proceeding . . . was very specific to Aqua rescuing troubled water and wastewater systems and preventing health and safety concerns regarding drinking water," which is a "scenario" that "does not apply to UGI Electric." (*Id.*, pp. 63-64.)

Q. Please respond to Mr. Patel's fundamental opposition to a performance management adder.

A. I am advised by counsel that I&E's position is inconsistent with Pennsylvania law and the Commission's consistent application of it in the area of management performance as set forth in 66 Pa. C.S. § 523. According to Section 523 of the Public Utility Code, the Commission has specific authority to consider management performance in setting base rates, including, "[a]ction or failure to act to encourage the development of cost-effective energy supply alternatives" as well as "other relevant and material evidence of efficiency, effectiveness and adequacy of service." 66 Pa. C.S. § 523. Therefore, the Commission should consider the Company's exceptional performance in management effectiveness, operating efficiencies, conservation encouragement, and other relevant or material evidence of efficiency, effectiveness and adequacy of service (as set forth in UGI Electric St. No. 1).

I note that Mr. Aaron Rothschild makes a similar assertion in his testimony, stating, "ratepayers should not be obligated to compensate shareholders for the Company's management doing its job." (OCA St. No. 2, p. 94.). To the extent the arguments of Mr. Patel and Mr. Rothschild are intended to make it impossible or nearly impossible for the Commission to award a management performance adder, those arguments are not supported by law and should be rejected.

Q. Has the Commission recently recognized UGI Electric's superior management performance efforts under Section 523 of the Public Utility Code?

A. Yes, it has. The Commission awarded a management incentive addition to UGI Electric's cost of equity in *UGI 2018 Rate Case Order*. In that proceeding, the Commission stated:

> [W]e are persuaded by the arguments of UGI that its management performance related to its implementation of a voluntary LTIIP, a fully voluntary EE&C Plan, programs focusing on enhancing customer satisfaction, and initiatives related to workforce safety and training is laudable and warrants consideration as a factor in our final cost of equity

> allowance. The unrebutted record evidence indicates that UGI has been consistently recognized for high customer satisfaction. Additionally, UGI has consistently exceeded its benchmark service reliability metrics . . .

Id. at 114.

Q. Does the Company have many of the same types of programs and attributes as those identified in the Commission's Order in *UGI 2018 Rate Case Order*?

A. Yes, it does. UGI Electric maintains its high standards for electric reliability, as well as its voluntary Long Term Infrastructure Improvement Plan ("LTIIP") and voluntary EE&C program. The Company has undertaken a variety of programs to improve customer service and enhance its safety commitments to employees and the public, including its efforts to coordinate and partner with the communities it serves. UGI Electric has demonstrated its support of customer service offerings, including its strong support of its low-income customers. These accomplishments highlighted in my direct testimony are the kind that this Commission has considered in the recent past as indicating a management performance adder is appropriate.

Q. Would you please respond to Mr. Patel's claims regarding UGI Electric's case?

A. Mr. Patel claims that many of the topics I presented in my direct testimony to support a management performance adder fall within categories that are required of every public utility company, but he provides no specific examples or comparisons. Without such clarity, it is difficult to ascertain which topics he is referencing. Nevertheless, I disagree with his overall claim. As I show above, the accomplishments detailed in my direct testimony are exactly the appropriate measures for recognizing an EDC's management performance. Accordingly, providing high standards of electric distribution system reliability, consistently meeting or exceeding targeted replacement of aged facilities, voluntarily implementing an EE&C Plan, continuing to enhance customer service offerings and IT systems to support those enhancements, implementing a robust safety culture through a diverse offering of programs, and supporting the communities that UGI Electric serves are hardly items that are simply “expected of a public utility,” as Mr. Patel argues. Also, it is important to understand that the Commission’s management performance evaluation as set forth in Section 523 is not influenced in any way by whether the Company achieved its management performance goals by using ratepayer or shareholder funds. The statute does not require management performance goals to be achieved with shareholder funds. Therefore, Mr. Patel’s argument that management performance results must be funded by shareholder funds does not undercut evidence of good management decisions that benefit the utility’s customers, and the Commission has never, to my knowledge, made a finding that ratepayer funded activities should be excluded from consideration in determining whether a management performance adder is appropriate.

Q. Do you agree with Mr. Patel’s arguments relying on the facts that supported a management performance adder for Aqua?

A. No, I do not agree. Mr. Patel admits that there is “no set criteria or measurement for claiming exemplary/superior management performance” (I&E St. No. 3, p. 62.) and then attempts to limit management performance adders to a narrow set of facts—those from the recent Aqua case. This approach is clearly incorrect, as UGI Electric itself was awarded a management performance adder in *UGI 2018 Rate Case Order*. The items discussed in my direct testimony and summarized here substantially support a management performance adder for a small EDC like UGI Electric, and the Commission should award a management performance adder in this proceeding.

IV. PUBLIC INPUT HEARINGS

Q. Did any members of the public participate in the public input hearings?

A. Yes. A total of six people testified at the public input hearings. Of those people who testified, four are customers of UGI Electric and two are not. Bill affordability was the primary issue raised at the public input hearings, although some witnesses also raised concerns regarding the availability of the Company's customer assistance programs. OCA witness Mr. DeAngelo repeats some of the concerns raised by witnesses at the public input hearing in his testimony. (*See* OCA St. No. 5, pp. 5-7.)

Q. Please address the concerns raised at the public input hearing regarding the affordability of rates.

A. UGI Electric understands that customers are concerned with the affordability of electric utility service. UGI Electric works to mitigate rising costs where it is able to do so. However, one of the most significant contributors increasing customer bills in recent years has been a steep increase in electric generation supply costs. While UGI Electric has little control over those costs, which are passed on to default service customers with no markup, the Company does note that its most recent supply pricing shows a decrease of 11%, which should provide customers with some relief.

Q. What actions does UGI Electric take to control costs ultimately borne by customers?

A. UGI Electric deploys many strategies in its effort to control costs. For example, numerous goods and services are procured through competitive bidding processes, salaries and wages are set at competitive market rates, and staffing is supplemented during peak outage events with outside temporary resources rather than full time crews kept on stand-by. However, the Company must undertake infrastructure replacement work and have a robust vegetation management program to continue providing safe and reliable service to customers. Moreover, the Company must pay competitive wages to secure a qualified workforce that will help ensure customers continue to receive good quality service. These are the primary drivers of the Company's need for a rate increase at this time; they are directly and intrinsically linked with UGI Electric's ability to continue providing safe and reliable service to customers.

Q. What efforts has UGI Electric made to support its customers?

A. UGI Electric has many customer assistance programs to help low-income and payment troubled customers afford electric service. The robust nature and adequacy of UGI Electric's customer service programs is addressed in the rebuttal testimony of Mr. Adamo, UGI Electric St. No. 11-R. In addition, the Company reached out directly to all four of the UGI Electric customers who testified at the public input hearing who agreed that the Company may contact them in order to determine if any qualified for UGI Electric's customer assistance programs.

V. <u>CONCLUSION</u>

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI ELECTRIC EXHIBIT CBR-1R

UGI Electric Operation Share Performance, 2018 to 2022*

Year	Type of Customer	# of Customers	# of Grants	Grant Dollars
2018	Total CAP + Non-CAP	240	247	$ 69,254
2019	Total CAP + Non-CAP	162	165	$ 51,483
2020	Total CAP + Non-CAP	85	98	$ 31,064
2021	Total CAP + Non-CAP	423	437	$ 171,586
2022	Total CAP + Non-CAP	307	311	$ 92,502

*UGI Electric notes that UGI Electric St. No. 1, page 15, line 3, incorrectly indicated that for program year 2022, Operation Share only had 287 grants for a total of more than $85,000. The data above corresponds to the information provided in CAUSE-PA-II-1 and CAUSE- PA-II-3.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2022-3037368, et. al

UGI Utilities, Inc. – Electric Division

Statement No. 2-R

Rebuttal Testimony of Tracy A. Hazenstab

Topics Addressed: **Updates To Filing**
Response To Adjustments To Operating Revenues And Expenses
Compliance With Act 40 Of 2016

Dated: May 25, 2023

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tracy A. Hazenstab. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Electric Statement No. 2, on January 27, 2023.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony provides updates to certain components of the Company's filing, based on the information provided during the discovery phase of this proceeding. In addition, my testimony responds to certain portions of the following direct testimony submitted by the Pennsylvania Public Utility Commission's ("Commission") Bureau of Investigation and Enforcement ("I&E") and the Office of Consumer Advocate ("OCA"): I&E Statement No. 1, the direct testimony of Vanessa Okum; I&E Statement No. 2, the direct testimony of Christopher Keller; I&E Statement No. 4, the direct testimony of Ethan Cline; and OCA Statement No. 1, the direct testimony of Dante Mugrace.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes. As discussed below, I am sponsoring the Company's final accounting exhibit, "UGI Electric Exhibit A – Fully Projected (REBUTTAL)," which reflects all the corrections and updates to the Company's claim to date.

Q. Please provide an overview of the other parties' revenue requirement adjustments.

A. I&E recommended a revenue requirement of $159,520,000, which represents an increase of $6,829,000 to the Company's present rate revenues of $152,691,000, which is a decrease of $4,596,000 to UGI Electric's revenue requirement of $164,116,000. I&E St. No. 1, p. 3. I&E's recommended revenue requirement includes a net decrease of $1,256,000 to UGI Electric's claimed operating expense, a total reduction of $77,000 to cash working capital, the use of the Company's plant in service, the use of the capital structure proposed by the Company, and a rate of return of 6.67%.

OCA recommended a revenue requirement increase of $3,540,663, which is $7,884,337 lower than UGI's proposed revenue requirement increase of $11,425,000. OCA St. No. 1, pg. 4. OCA's recommended revenue requirement includes a total reduction of $4,567,811 to operating expenses, a total reduction of $652,521 to rate base, a hypothetical common equity ratio of 44.75%, and a rate of return of 6.18%.

Q. Does the Company agree with the distribution revenue requirement proposed by the other parties?

A. No. As explained throughout this testimony and the other rebuttal testimony forming UGI Electric's rebuttal position, with the exception of certain updates to the Company's revised filing and the acceptance of some relatively minor operating expense and revenue adjustments, the Company believes that the various revenue, expense, and rate base adjustments proposed by the opposing parties are not reasonable and, therefore, should be rejected.

II. UPDATES AND CORRECTIONS TO THE COMPANY'S CLAIM

Q. Since the filing of your direct testimony, has the Company identified any rate base and revenue requirement components of its filing that should be updated?

A. Yes, the Company has identified parts of its initial filing that require revision. These include the following updates:

- Customer Deposit Balance: The Company is updating the period over which its average Customer Deposit balance is calculated within its lead/lag study to reflect the use of the 13-month average balance as of April 2023, which resulted in a net decrease in rate base of $154,000. This adjustment is discussed further in the rebuttal testimony of Vivian K. Ressler (UGI Electric St. No. 3-R). In addition, a revised Schedule C-7 is provided as an exhibit to my rebuttal testimony to reflect this adjustment.

- Materials and Supply Balance: The Company is updating the period over which its average Materials & Supplies balance is calculated within its lead/lag study to reflect the use of the 13-month average balance as of April 2023. Additionally, the Company updated the balance to reflect the distribution portion of the balance. These two updates resulted in a net increase to rate base of $109,000. These adjustments are discussed further in the rebuttal testimony of Vivian K. Ressler (UGI Electric St. No. 3-R). In addition, a revised Schedule C-8 is provided in UGI Electric Exhibit A – Fully Projected (REBUTTAL) to reflect this adjustment.

- Weighted Average Cost of Debt: The Company is updating the effective interest rate on the $225,000,000 Senior Unsecured Note, which was included in the original filing, with an interest rate of 4.551%. This adjustment increases the weighted average cost of debt from 4.35% to 4.44% and raises the Rate of Return to 8.19% from the original rate of return filed at 8.15%. This adjustment is discussed further in the rebuttal testimony of Paul R. Moul (UGI Electric St. No. 9-R). In addition, a revised Schedule B-6 (Composite Cost of Debt) and Schedule B-7 (Rate of Return) are provided in UGI Electric Exhibit A – Fully Projected (REBUTTAL) to reflect this revision.

- Salary and Wage Expense: The Company agrees to reduce its salary and wage expense claim by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for one unfilled position, as discussed in Section IV.A. of my rebuttal testimony and reflected in Schedule D-7. Additionally, due to this headcount reduction, the Company is reducing payroll tax expense in Schedule D-31 by $6,000 and benefits expense in Schedule B-4 by $12,000. These revised schedules are provided in UGI Electric Exhibit A – Fully Projected (REBUTTAL).

Each of these updates to the Company's rate base is reflected in UGI Electric Exhibit A – Fully Projected (REBUTTAL), which is the Company's final accounting exhibit. I am sponsoring this exhibit as a part of my rebuttal testimony.

Q. Since the filing of your direct testimony, has the Company identified any revenue components of its filing that should be updated?

A. Yes, as with the aforementioned rate base items, the Company also identified the following revenue requirement items that required revision for the fully projected future test year ending September 30, 2024 ("FPFTY"):

- Forfeited Discounts, Miscellaneous Revenues and Rent from Gas Properties: The Company revised its claim for these revenues to use a 3-year normalization of historical data from fiscal years 2019, 2021, and 2022. This adjustment is being made in response to an adjustment proposed by OCA witness Mr. Mugrace, and resulted in a revenue decrease of $20,000.

- Forfeited Discounts: The Company revised its claim for forfeited discounts to $559,000, an increase of $39,000. The Company's forfeited discount claim in the FPFTY is increased by the same percentage increase as the overall base rate increase, consistent with the recommendation of I&E witness Mr. Cline. In addition, a revised Schedule D-5B (Adjustments – Other Revenue Items) is provided in UGI Electric Exhibit A – Fully Projected (REBUTTAL) to reflect this revision.

As with the updates to the Company's rate base, each of these revisions to the Company's revenues are reflected in UGI Electric Exhibit A – Fully Projected (REBUTTAL).

Q. Based upon the adjustment analyses conducted by the Company, what do you conclude?

A. As set forth in the Company's final accounting exhibit, "UGI Electric Exhibit A - Fully Projected (REBUTTAL)," the overall effect of the updates and corrections to the Company's claim is that the Company has supported a revenue increase of $11,453,000 (as compared to the as-filed claim of $11,425,000 using the Company's proposed capital structure, revised weighted average cost of debt and proposed return on equity of 11.30%). While the Company is not requesting that the Commission authorize an increase greater than its as-filed amount, any adjustments proposed by the parties should be applied to the $11,453,000, which is the revenue increase supported by the evidence presented by the Company in this case.

III. OPERATING REVENUES ADJUSTMENTS

Q. Did any of the other parties propose adjustments to the Company's claimed operating revenues?

A. Yes. I&E witness Mr. Cline recommended an adjustment to the Company's revenues related to forfeited discounts. I&E St. No. 4 at 3-5. OCA witness Mr. Mugrace also recommended adjustments to the Company's revenues related to forfeited discounts. OCA St. No. 1 at 13-14; OCA Schedule DM-4. Mr. Mugrace further proposed adjustments to the Company's miscellaneous revenues and rent from electric properties. OCA St. No. 1 at 13-14; OCA Schedule DM-4. I will respond to each of these adjustments below.

Q. Please describe the bases for I&E's proposed adjustments to the Company's revenues related to forfeited discounts.

A. Mr. Cline recommends that UGI Electric's forfeited discount claim in the FPFTY be increased by the same percentage as the overall base rate increase granted by the Commission because "increasing revenue through a rate increase will cause revenues from forfeited discounts to increase over time." I&E St. No. 4 at 4-5.

Q. Does the Company agree with I&E's proposed adjustment?

A. Yes, the Company agrees that the forfeited discounts should be revised based on the revenue increase and the Company's final accounting exhibit UGI Electric Exhibit A – Fully Projected (REBUTTAL), which reflects a decrease to the revenue requirement in the amount of $39,000. As related to any final revenue determination made by the Commission that would change the overall revenue increase, a similar adjustment to forfeited discounts should be made.

Q. Please describe the bases for OCA's proposed adjustments to the Company's revenues related to forfeited discounts, miscellaneous revenues, and rent from electric properties.

A. OCA proposes to normalize the revenues associated with forfeited discounts, miscellaneous revenues and rent from electric properties over the three-year period of 2022-2024. OCA St. No. 1 at 14. The result of this proposal is to increase the Company's present rate revenues by $26,832. OCA St. No. 1 at 14. Mr. Mugrace claims that "[t]hese types of revenues do fluctuate and change from year to year, depending on customer actions or inactions, customer arrangements, agreements between and among various entities" and submits that it is appropriate to prospectively normalize them. OCA St. No. 1 at 14.

Q. Does the Company agree with OCA's proposed adjustments?

A. No, however, the Company is proposing a normalizing adjustment as described above and explained in more detail below.

Q. Please explain why not.

A. The Company is proposing to normalize forfeited discounts, miscellaneous revenues and rent from electric properties revenues based on the fiscal years of 2019, 2021 and 2022. This normalizing adjustment uses actual data for all three years of the normalization calculation, as opposed to Mr. Mugrace's calculation, which used one year of actual and two years of projected revenue. This adjustment will decrease revenue by $20,000.

Q. What is the total impact on the Company's rebuttal revenue requirement of the aforementioned adjustments to its operating revenues?

A. The impact of these adjustments is to decrease the Company's revenue requirement by $20,000. This adjustment is reflected on Schedule D-5B of UGI Electric Exhibit A – Fully Projected (REBUTTAL).

IV. <u>OPERATING EXPENSE ADJUSTMENTS</u>

A. PAYROLL EXPENSE

Q. Do any of the other parties recommend an adjustment to the Company's claimed payroll expenses?

A. Yes. OCA witness Mr. Mugrace makes two recommendations related to the Company's non-incentive compensation payroll expenses. I would note that Ms. Ressler addresses I&E's and OCA's adjustments to incentive compensation payroll expenses in her rebuttal testimony (UGI Electric St. No. 3-R).

Q. Please describe Mr. Mugrace's proposed adjustments to payroll expense.

A. Mr. Mugrace first proposes to decrease Distribution Expense related to payroll by $150,000. OCA St. No. 1 at 22; OCA Schedule DM-9. He asserts that these costs are related to two open positions that have not yet been authorized by the Company's Human Resources Department and, therefore, the timing of their employment is not known at this time. OCA St. No. 1 at 22 (citing the response to OCA-II-20). However, he does note that if the Company has further information, he will revisit this adjustment.

Second, Mr. Mugrace increases the Company's proposed overtime expenses for Distribution Expense by $23,333. OCA St. No. 1 at 22-23; Schedule DM-9. He asserts that these costs fluctuate and, therefore, recommends averaging overtime costs over a 3-year period using the HTY, FTY and FPFTY amounts. OCA St. No. 1 at 22-23.

Q. Does the Company agree with Mr. Mugrace's first adjustment to payroll expense?

A. It does in part.

Q. Please explain.

A. Of the two positions Mr. Mugrace recommends disallowing, one position was authorized and posted on May 10, 2023; the Company anticipates filling this position prior to the end of June. For this authorized position, the Company disagrees with Mr. Mugrace's payroll expense adjustment. However, the second position remains unauthorized and for this reason, the Company agrees with removing the associated claim and has reflected this **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** adjustment, as I noted above.

Q. Does the Company agree with Mr. Mugrace's second adjustment to payroll expense associated with overtime costs?

A. No.

Q. Please explain.

A. The Company's claim was based on projected workload for the FTY and FPFTY. There has been no change in these assumptions and thus the Company's claim remains supported.

B. RATE CASE EXPENSE

Q. Do any of the other parties propose adjustments to the Company's claimed rate case expense?

A. Yes. Both I&E witness Ms. Okum and OCA witness Mr. Mugrace propose adjustments to the Company's claimed rate case expense.

Q. Please summarize I&E's and OCA's proposed adjustments.

A. I&E witness Ms. Okum recommends that the Company's rate case expense be decreased by $77,400, based on the use of a 30-month normalization period. I&E St. No. 1 at 6-7. She asserts that the Company's historic filing frequency should be based on an average of its three most recent cases, and further asserts that the Company's pre-2018 filing frequency is not representative. I&E St. No. 1 at 7. Ms. Okum further cites to and relies upon recent Commission decisions, where the Commission has adopted I&E's reliance on historic filing frequency to normalize rate case expense. I&E St. No. 1 at 8-9.

OCA witness Mr. Mugrace recommends that the Company's rate case expense be decreased by $231,200, based on the use of a five-year normalization period. OCA St. No. 1 at 35-36. Mr. Mugrace claims that the Company is proposing to amortize rate case expense over a two-year period, and further asserts that the Company's historic filing frequency, inclusive of pre-2018 rate case filings, results in a five-year period. OCA St. No. 1 at 35.

Q. Does the Company agree with either I&E's or OCA's proposed adjustment to rate case expense?

A. No.

Q. Before responding to the specific periods used by I&E and OCA to normalize the Company's rate case expense, please respond to OCA witness Mr. Mugrace's claim that the Company is proposing to amortize rate case expense over a two-year period.

A. In my direct testimony, UGI Electric Statement No. 2, UGI Electric proposed to normalize rate case expense over a two-year period, based upon its projected rate case filing frequency going forward. The Company did not propose an amortization schedule in its initial filing.

Q. Has the Commission previously approved UGI Electric's proposed normalization period for rate case expense, based upon the Company's future expectations?

A. Yes. The Commission specifically approved the Company's projected three-year normalization period in *Pa. PUC, et al. v. UGI Utilities, Inc. - Electric Division*, Docket Nos. R-2017-2640058, et al. (Order entered Oct. 25, 2018) ("*UGI Electric 2018*"). UGI

Electric projected filing more frequent rate cases in that proceeding due to its projected acceleration of capital expenditures during the same normalization period.

Q. Does UGI Electric currently anticipate an accelerated frequency for rate cases in the future?

A. Yes, it does. Critically, after *UGI Electric 2018*, the Company filed its next base rate case in 2021. In that case, the Company projected that its anticipated investments would further accelerate and require a two-year rate case filing cycle in the future. Consistent with this projection, the Company filed the instant base rate case in 2023.

Q Does the Company anticipate investments that will require a rate case frequency of two years going forward?

A. Yes. Consistent with its prior projections in the 2021 base rate case, the Company continues to anticipate a two-year frequency for base rate cases.

Q. Why does the Company continue to anticipate a two year frequency for rate cases in the future?

A. The frequency of UGI Electric's past base rate cases is not a predictor of the frequency of future base rate cases. The Company's expectation that it will file another base rate case in two years is based upon an assessment of future capital requirements and the cost of other improvements as detailed in the Company's second Long-Term Infrastructure

Improvement Plan ("LTIIP") filing.[1] At the same time, all of the Company's operating expenses are subject to inflation, and the revenue requirements for plant additions that are not Distribution System Improvement Charge ("DSIC")-eligible will cause further pressure to file a rate case within two years after the rates in this case become effective. By way of further explanation, the Company is implementing a significantly accelerated replacement and betterment program as detailed in its Second LTIIP. This accelerated spend, in conjunction with other capital requirements and operating expenses, supports a two-year rate case cycle and a two-year normalization of rate case expenses.

Other factors supporting the Company's two-year normalization period include rising inflation, capital cost rates and higher risks associated with a rate of return that will reflect and be supportive of the Company's financial and risk profile. (*See* the rebuttal testimony of Paul R. Moul, UGI Gas St. No. 9-R). Additionally, the possibility of reaching the current five percent DSIC cap after the new rates established in this case become effective can be a factor that influences more frequent rate case filings. Thus, to the extent that the Company is subject to a DSIC maximum rate of five percent , the Company's earnings will suffer from attrition due to the DSIC cap. Such an occurrence can be a deciding factor in the relative frequency of rate case filings. Therefore, the Company's claimed rate case expense and associated normalization period are reasonable and should be adopted.

[1] *See* Petition of UGI Utilities, Inc. – Electric Division for Approval of its Second Long Term Infrastructure Improvement Plan, Docket No. P-2022-3032042 (Opinion and Order entered Aug. 25, 2022).

Q. Why is I&E's proposed 30-month normalization period not reflective of the Company's rate case frequency?

A. At a basic level, I&E's 30-month normalization period does not align with UGI Electric's practice of filing rate cases in January and having new rates effective in October of the same year, which is required in order to comply with the Commission's regulations specifying that the historic test year data cannot be more than 120 days older than the end of the HTY. I&E's mathematically derived normalization period clearly will not produce an appropriate amount of time for the Company to recover rate case expense.

Q. Why is OCA's proposed five-year normalization not reflective of the Company's rate case filing frequency?

A. OCA's proposed five-year normalization is clearly too long. Mapping OCA's normalization onto UGI Electric's recent experience, UGI Electric would have already had two base rate proceedings in the period of the single OCA proposed normalization. As previously described by UGI Electric, the Company is engaged in a period of intensive infrastructure replacement that will continue for the foreseeable future. Without some other source of rate relief (e.g., waiving the DSIC cap, formula rates, etc.) the Company will continue to require base rate adjustments at an accelerated rate.

Q. Are there any reasons why the Commission should differentiate between this case and other recently decided rate proceedings relied on by I&E?

A. I am advised by counsel that the Company also disagrees with I&E's legal analysis regarding Commission orders entered in other base rate cases for other utilities. It is my understanding that UGI Electric will further address I&E's reliance on these cases in its briefs.

C. CUSTOMER ACCOUNTS EXPENSES

Q. Do any of the parties recommend adjustments to the Company's expenses related to Customer Accounts Expense?

A. Yes. OCA witness Mr. Mugrace recommends adjustments to the Company's Meter Reading Expense, Miscellaneous Customer Accounts Expense and Customer Records/Collection Expense, in this category.

Q. Please describe Mr. Mugrace's recommended adjustments.

A. Mr. Mugrace asserts that the Company's Meter Reading Expense, Miscellaneous Customer Accounts Expense and Customer Records/Collection Expense fluctuate from year to year. OCA St. No. 1 at 29-31. Therefore, he recommends that these expenses be normalized using the three-year period of 2022-2024. OCA St. No. 1 at 29. This has the effect of: (a) reducing Meter Reading Expense by $61,000; (b) reducing Miscellaneous Customer Accounts Expense by $43,667; and (c) reducing Customer Records/Collection Expense by $403,333. OCA St. No. 1 at 29; Schedule DM-11.

Q. Does the Company agree with any of these proposed adjustments?

A. No, it does not.

Q. Please explain why not.

A. The Company does not agree with Mr. Mugrace's adjustment to Customer Records/Collection Expense. The majority of the expenses in this account are related to the Universal Service Program ("USP"). The USP is designed so that its costs can be recovered through a fully-reconcilable Section 1307 rider. In order to reflect the fully-reconcilable nature of a Section 1307 rider, the Company budgets the expenses for the program at the same level as the revenue, thereby making the program margin neutral in the budget and the revenue requirement calculation. A reduction of the expense in this account, without a corresponding reduction to revenue, would affect the fully-reconcilable nature of the rider. Additionally, the Company does not agree with Mr. Mugrace's adjustments to Meter Reading and Miscellaneous Customer Accounts Expenses. Taking a simple average of expenses does not consider the inflation and supply chain impacts that were outlined in the Direct Testimony of Eric W. Sorber, UGI Electric Statement No. 4 at 12–15. Based on current market conditions, the Company believes the costs presented in the FPFTY are justified.

D. CUSTOMER INFORMATION AND SERVICE ACCOUNT EXPENSES

Q. Do any of the parties recommend adjustments to the Company's expenses related to Customer Information and Service Account Expenses?

A. Yes. OCA witness Mr. Mugrace recommends adjustments to the Company's Miscellaneous Customer Information Expense (Account 910.00) and Customer Assistance Expenses (Account 908.00), in this category.

Q. Please describe Mr. Mugrace's recommended adjustment to the Company's Miscellaneous Customer Information Expense (Account 910.00).

A. Mr. Mugrace recommends that these expenses be normalized using the three-year period of 2022-2024. OCA St. No. 1 at 33. Mr. Mugrace claims that the Company's claimed increase in expenses is associated with its Energy Efficiency & Conservation ("EE&C") plan, but that these increases are not known and measurable at this time. OCA St. No. 1 at 33. The effect of his proposal to normalize this expense is to reduce the Company's claim by $69,333. OCA St. No. 1 at 33; OCA Schedule DM-13.

Q. Does the Company agree with this proposed adjustment?

A. No, it does not.

Q. Please explain why not.

A. The Company disagrees with Mr. Mugrace's adjustment to Miscellaneous Customer Information Expense. The majority of the expenses in this account are related to the EE&C. Similar to the USP described above, the EE&C plan is designed so that its costs can be recovered through a fully reconcilable Section 1307 rider. The Company budgets the expenses for the program at the same level as the revenue, thereby making the program margin neutral in the budget and the revenue requirement calculation. A reduction of the expense in this account, without a corresponding reduction to revenue, would affect the fully-reconcilable nature of the rider.

Q. Please describe Mr. Mugrace's recommended adjustment to the Company's Customer Assistance Expenses (Account 908.00).

A. Mr. Mugrace similarly recommends that these expenses be normalized using the three-year period of 2022-2024. OCA St. No. 1 at 33. The effect of his proposal to normalize this expense is to increase the Company's claim by $21,000. OCA St. No. 1 at 33; OCA Schedule DM-13.

Q. Does the Company agree with this proposed adjustment?

A. No.

Q. Please explain why not.

A. The Company does not agree with Mr. Mugrace's adjustments to Customer Assistance Expenses. Taking a simple average of expenses does not consider the inflation and supply chain impacts that were outlined in the Direct Testimony of Eric W. Sorber, UGI Electric Statement No. 4 at 12 – 15. Based on the current market conditions discussed by Mr. Sorber, the Company believes the costs presented in the FPFTY are justified.

E. TAX EXPENSES

Q. Do any of the parties recommend adjustments to the Company's claimed tax expense?

A. Yes. OCA witness Mr. Mugrace recommends adjustments to the Company's taxes other than income ("TOTI"), and federal and state income tax expense claim.

Q. Please describe Mr. Mugrace's recommended adjustment to the claim for TOTI.

A. Mr. Mugrace recommends that TOTI be reduced by $642,912. OCA St. No. 1 at 42; OCA Schedule DM-17. Mr. Mugrace explains that this adjustment is derivative of his other proposed adjustments to payroll expenses, employee headcount, incentive compensation and OCA's overall recommended revenue requirement. OCA St. No. 1 at 42.

Q. Does the Company agree with this proposed adjustment?

A. No, it does not.

Q. Please explain why not.

A. As noted previously, the Company agrees to reduce payroll expense by $75,000, which in turn lowers payroll tax expense by $6,000. Additionally, the Company agrees to increase the forfeited discount revenue by the percentage of the rate increase, which increases gross receipts tax by $2,000. However, the Company disagrees with the remaining $638,912 of Mr. Mugrace's adjustment as it is a derivative of his proposed adjustment to Incentive Compensation, which the Company does not accept. This position is further explained in the rebuttal testimony of Ms. Ressler (UGI Electric St. No. 3-R).

Q. Please describe Mr. Mugrace's recommended adjustment to the Company's claimed federal and state income tax expense.

A. Mr. Mugrace accepts the Company's methodology for calculating these expenses, which was explained by UGI Electric witness Mr. Darin T. Espigh (UGI Electric St. No. 8). OCA St. No. 1 at 43. However, he recommends that the Company's claim be adjusted to allow for only $1,848,728 in federal and $912,536 in state income tax expenses respectively based upon OCA's other proposed changes to rate base and operating income. OCA St. No. 43; OCA Schedule DM-18.

Q. Does the Company agree with this proposed adjustment?

A. No.

Q. Please explain why not.

A. The Company disagrees with the adjustments to the extent that the Company disagrees with their underlying rate base and operating income adjustments. As stated previously, the Company has agreed to I&E's recommendation for forfeited discounts and partially agrees with OCA's recommendation for payroll expense adjustments. These adjustments reduce income tax expense by $1,000. However, the Company does not agree with the remaining adjustments proposed by I&E and OCA, which impact income tax expense in the amount of $2,760,264. To the extent UGI Electric is not allowed the full revenue requirement requested in this proceeding associated with non-tax items, the Company does agree that federal and state taxes should be adjusted as needed to align with the approved amount.

F. CASH WORKING CAPITAL

Q. What was the Company's claim for cash working capital ("CWC") in its initial filing?

A. The Company claimed $11,447,000 in CWC in its filing.

Q. Has the Company identified any adjustments to its initial CWC claim?

A. The Company is adjusting its CWC claim to $11,437,000 based upon the adjustments explained in Section II of my rebuttal testimony and their impact to operations and maintenance ("O&M") expenses and interest payment components in the CWC.

Q. Did any party challenge the Company's methodology to calculate its CWC claim?

A. No.

Q. Did any party propose any adjustments to the Company's original CWC claim?

A. Yes. Both I&E and OCA have proposed adjustments to the Company's CWC, based upon their other proposed adjustments to the Company's O&M expenses. I&E St. No. 2 at 16-18; OCA St. No. 1 at 10-11.

Q. Does the Company agree with either I&E's or OCA's CWC adjustments?

A. The Company disagrees with their adjustments to CWC, to the extent that the Company disagrees with their underlying expense or tax adjustments.

Q. Please provide more detail on why the Company does not agree with the CWC adjustments proposed by I&E and OCA.

A. As previously stated, both I&E's and OCA's CWC adjustments are based solely on their respective recommended expense adjustments. As explained earlier in my testimony summarizing adjustments that the Company is making in rebuttal, consistent with the

Company's responses in discovery, I agree with Mr. Mugrace's proposal to reduce the CWC by $3,000 due to the reduction of payroll expense in the Company's initial claim. However, I do not agree with the remaining $425,333 of Mr. Mugrace's CWC adjustment based on my rejections of his O&M expense adjustments.

The Company does not agree with the CWC adjustment recommended by I&E Witness Mr. Keller as it is derivative of I&E's underlying expense and rate base adjustments, which the Company rejects. To the extent UGI Electric is not allowed the full revenue requirement requested in this proceeding, the Company does agree that CWC should be adjusted as needed to align with the approved amount.

V. <u>INTEREST SYNCHRONIZATION ADJUSTMENT TO INCOME TAX EXPENSE</u>

Q. What was the Company's original claim for income tax expense in this proceeding?

A. The Company's claim for income tax expense in this proceeding was $3,774,000, as reported on Schedule D-33 of UGI Electric Exhibit A (FPFTY). Income taxes are calculated using the procedures normally followed by the Commission, including the use of debt interest synchronization, the normalization method for accelerated depreciation used in the calculation of federal income taxes, and the flow through of accelerated depreciation benefits for state tax purposes. The Company's claimed interest expense deduction was $3,410,000 based on a rate base of $172,242,000 multiplied by the weighted cost of debt of 1.98% (45.41 % x 4.35 %). *See* UGI Electric A (FPFTY), Schedule B-7.

Q. Did any party challenge the Company's claim?

A. Yes. OCA witness Mr. Mugrace recommends an interest expense deduction of $4,123,939 based upon OCA's recommended adjustments to rate base and capital structure. OCA St. No. 1 at 44.

Q. Do you agree with Mr. Mugrace's proposed adjustment?

A. No. I note that UGI Electric witness Mr. Moul responds specifically to the OCA's proposed capital structure, cost of equity and overall rate of return in his rebuttal testimony (UGI Electric St. No. 9-R). For the reasons fully identified in Mr. Moul's rebuttal testimony, OCA witness Aaron L. Rothschild's adjustments (in OCA St. No. 2) to the Company's actual capital structure and cost of equity should be rejected and so should Mr. Mugrace's adoption of that recommendation in OCA's revenue requirement model. In addition, Mr. Mugrace proposed adjustments to the Company's filed rate base, which decrease the rate base balance by $651,521 to $171,589,479. *See* OCA Schedule DM-3. These rate base adjustments, and the reasons they should be rejected, are discussed in the rebuttal testimonies of UGI Electric witnesses Vivian K. Ressler (UGI Electric St. No. 3-R) and Vicky A. Schappell (UGI Electric St. No. 5-R).

Q. Are there other adjustments made by the Company as part of its Rebuttal Case?

A. As discussed earlier, the Company has reflected an adjustment to the average cost of long-term debt, which increases the rate from 4.35% to 4.44%. In addition, the Company has decreased its rate base claim by $56,000 to $172,186,000. These adjustments increase the interest deduction by $68,000 to $3,478,000 (based on a rate base of $172,186,000 multiplied by the weighted cost of debt of 2.02% (45.41% x 4.44%)). *See* UGI Electric Exhibit A – Fully Projected Future (REBUTTAL), Schedule B-7. The interest increase of $68,000 decreases the federal income taxes by $1,000.

VI. COMPLIANCE WITH ACT 40 OF 2017

Q. Did your direct testimony include a discussion of the requirements of Pennsylvania Act 40 of 2017 ("PA Act 40" or "Act 40")?

A. Yes, it did.

Q. Did any other parties address the PA Act 40 requirements?

A. Yes, OCA witness Mr. Mugrace addresses the PA Act 40 requirements. While Mr. Mugrace accepts the Company's satisfaction of Act 40's requirement that 50% of the hypothetical Consolidated Tax Adjustment ("CTA") is being used to support reliability or infrastructure related to the rate-base eligible capital investment, he argues that the Company has not demonstrated the remaining 50% is being used for "general corporate purposes." OCA St. No. 1 at 45-47. Mr. Mugrace asserts that "general corporate purposes" should mean only public utility purposes and uses that result in having some identifiable and quantifiable benefit to Pennsylvania and UGI Electric ratepayers. OCA St. No. 1 at 46-47. He also claims that UGI Electric has not identified how this amount will be used to benefit ratepayers, and insinuates, without any evidence, that the Company will use the money for the benefit of its stockholders. OCA St. No. 1 at 46-47. As such, he recommends that this hypothetical amount should be used as a source of non-investor supplied capital and reduces the Company's rate base balance by $35,000. OCA St. No. 1 at 47; *see also* OCA Schedule DM-3.

Q. Has the Commission previously rejected OCA witness Mr. Mugrace's proposals related to Act 40?

A. Yes. In *UGI Electric 2018* , the Commission specifically concluded that UGI Electric satisfied Act 40 by making the same presentation it has made in this case.

Consistent with the language of Section 1301.1, the Commission determined that UGI Electric had properly complied with the requirements of Act 40 by showing that the Company's *pro forma* capital additions for reliability or infrastructure projects in the FTY and FPFTY exceeded 50% of the amount of what would have been the CTA, and that the Company's general corporate purpose expense would also exceed 50% of the tax benefit resulting from the elimination of the CTA. Thereafter, in *McCloskey v. Pa. PUC*, 225 A.3d 192 (Pa. Cmwlth. 2020), the Commonwealth Court affirmed the Commission's determination.

Mr. Mugrace's proposals in this proceeding offer nothing new to the arguments previously rejected by the Commission and the Commonwealth Court. They should be rejected here as well.

Q. Is the Company using 50% of the amount calculated pursuant to Act 40 for general corporate purposes?

A. Yes. Consistent with the showing made in the 2018 UGI Electric base rate case, 50% of the amount calculated in this proceeding will in fact be used for general corporate purposes. The Company is using this amount to support its lawful expenditures. Mr. Mugrace attempts to improperly limit the definition of "general corporate purposes" to only "public utility purposes and uses that result in having some identifiable and quantifiable benefit to Pennsylvania and UGI ratepayers." OCA St. No. 1 at 47. Yet, in the same answer, he recognizes that general corporate purposes could broadly refer to any lawful expenditures by the public utility (e.g., "supporting capital expenditures necessary to execute utility business plans, paying off debt, funding construction projects, paying dividends, paying for maintenance and operating expenses, investing in utility plant in Pennsylvania, and providing a source of working capital."). It is disingenuous for Mr. Mugrace to propose to narrow the understanding of this term, which covers a broad swath of corporate actions.

Q. Can you provide any examples of categories of projects that this amount will be used to support?

A. Yes. While it is not practical to trace a hypothetical amount to specific projects, 50% of the Act 40 amount (*i.e.*, $35,000) will be used to pay for general operating expenses of the Company. As shown in UGI Electric Exhibit A – FPFTY, Schedule B-4, the Company's total budgeted O&M expense is $120,745,000. These expenses will be used to the benefit of ratepayers, including $217,000 in meter reading expenses, $9.712 million for the maintenance of overhead lines, and $1.275 million for various customer service expenses. Therefore, UGI Electric spends over 50% of the hypothetical CTA on general expenditures that are specifically for the purpose of providing utility service.

Q. Why else should Mr. Mugrace's adjustment be rejected?

A. Mr. Mugrace's adjustment should be rejected because, as I explained, UGI Electric has complied with Act 40's requirements to use 50% of the hypothetical CTA for general corporate purposes. Although Mr. Mugrace is attempting to frame his adjustment as an adjustment to rate base rather than as an adjustment to tax expense, the adjustment is still based on the incorrect theory that UGI Electric has not complied with the requirements of 66 Pa.C.S. §1301(b), and therefore it should be rejected.

Q. Do you have any additional concerns regarding the use of a CTA offset to rate base?

A. While it is unclear that placing the CTA as a deduction to rate base would result in a tax normalization violation, the IRS has taken the position on both sides of the issue, thereby raising the risk of an adverse IRS ruling on the issues. Therefore, adopting Mr. Mugrace's adjustment potentially jeopardizes the loss of $29.665 million of ADIT to the detriment of our customers and adversely impacts the cash position of the Company, as those taxes may become due immediately. That risk clearly outweighs the minor benefit for customers that would result from Mr. Mugrace's adjustment for tax benefits that are not the result of UGI Utilities' activities, but rather the activities of the Company's non-regulated affiliates.

VII. <u>CONCLUSION</u>

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI Electric Exhibit A – Fully Projected

(REBUTTAL)

Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)
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Fully Projected Future Period - 12 Months Ended September 30, 2024

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($ in Thousands)

Summary of Measure of Value and Revenue Increase

Line #	Description	[1] Function	[2] Reference Section	[3] Pro Forma Test Year Ended September 30, 2024 At Present Rates	[4] Increase	[5] Proposed Rates
RATE BASE						
1	Utility Plant		C-2	$ 275,001		$ 275,001
2	Accumulated Depreciation		C-3	(85,745)		(85,745)
3	Net Plant in service	L 1 + L 2		189,256	-	189,256
4	Working Capital		C-4	11,437		11,437
5	Accumulated Deferred Income Taxes		C-6	(29,665)		(29,665)
6	Customer Deposits		C-7	(1,103)		(1,103)
7	Materials & Supplies		C-8	2,261		2,261
8	TOTAL RATE BASE	Sum L 3 to L 7		$ 172,186	$ -	$ 172,186
	Operating Revenues					
9	Base Customer Charges		D-5	$ 44,106	$ 11,453	$ 55,559
10	Other Electric Revenue		D-5	107,482		107,482
11	Other Operating Revenues		D-5	1,123		1,123
12	Total Revenues	Sum L 9 to L 11		152,711	11,453	164,164
13	Operating Expenses		D-1	(145,361)	(929)	(146,290)
14	OIBIT	L 12 + L 13		7,350	10,524	17,874
15	Pro Forma Income Tax at Present Rates		D-33	(814)		
16	Pro Forma Income Tax on Revenue Increase		D-33		(2,957)	(3,772)
17	NET OPERATING INCOME	Sum L 14 to L 16		$ 6,535	$ 7,567	$ 14,103
18	RATE OF RETURN	L 17 / L 8		3.796%		8.190%
REVENUE INCREASE REQUIRED						
19	Rate of Return at Present Rates	L 18, Col 3		3.796%		
20	Rate of Return Required		B-7	8.190%		
21	Change in ROR	L 20 - L 19		4.394%		
22	Change in Operating Income	L 21 * L 8		$ 7,567		
23	Gross Revenue Conversion Factor		D-35	1.513583		
24	Change in Revenues	L 22 * L 23		$ 11,453		
25	Percent Increase -- Delivery Revenues	L 24 / L 9, C 3			25.97%	
26	Percent Increase -- Total Revenues	L 24 / L 12, C 3			7.50%	

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Balance Sheet

Line No	Description/(Account No)	[1] Budget TYE 9-30-24
	UTILITY PLANT (101 - 106, 108)	
1	Electric Utility Plant	$ 367,052
2	Other Utility Plant	
3	Total Plant In Service	367,052
4	Construction Work In Progress (107)	8,000
5	Total Utility Plant	375,052
6	Accumulated Provision for Depreciation - Electric (108)	(121,394)
7	Utility Acquisition Adjustment (114)	390
8	Accumulated Provision for Depreciation - Other (119)	-
9	Net Utility Plant	254,048
	OTHER PROPERTY INVESTMENTS	
10	Non-utility Property (121)	15
11	Accumulated Depreciation on NUP (122)	-
12	Investment in Associated & Subsidiary Companies (123.1)	-
13	Other Investments (124)	-
14	Total Other Property and Investments	15
	CURRENT AND ACCRUED ASSETS	
15	Cash & Other Temporary Investments(131-136)	566
16	Unbilled Revenues	-
17	Customer Accounts Receivable (142)	19,496
18	Other Accounts Receivable (143)	570
19	Accum Provision for Uncollectible (144)	(2,340)
20	Receivables from Associated Companies (145)	-
21	Accounts Receivable Assoc. Comp. (146)	404
22	Plant Materials & Operating Supplies (154)	3,100
23	Allowance Inventory (158.1)	682
24	Stores Expense - Undistributed (163)	183
25	Prepayments (165)	2,182
26	Accrued Utility Revenues (173)	4,000
27	Miscellaneous Current & Accrued Assets (174)	1,400
28	Derivative Instrument Assets (175)	-
29	Total Current and Accrued Assets	30,243
	DEFERRED DEBITS	
30	Unamortized Debt Expense (181)	20
31	Other Regulatory Assets (182.3)	33,146
32	Other Preliminary Survey & Investigation Charges (183.2)	-
33	Clearing Accounts (184)	-
34	Miscellaneous Deferred Debits (186)	1,166
35	Unamortized Loss on Reacquired Debt (189)	-
36	Accumulated Deferred Income Taxes (190)	16,000
37	Total Deferred Debits	50,332
38	TOTAL ASSETS AND OTHER DEBITS	$ 334,638

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Balance Sheet

Line No	Description/(Account No)	[1] Budget TYE 9-30-24
	PROPRIETARY CAPITAL	
39	Common Stock Issued (201)	$ 6,453
40	Preferred Stock Issued (204)	-
41	Premium on Capital Stock (207)	50,720
42	Capital Stock Expense (214)	-
43	Retained Earnings (215, 215.2, 216)	82,897
44	Accum Other Comprehensive Income (219)	(1,235)
45	Total Proprietary Capital	138,835
	LONG TERM DEBT	
46	Bonds (221)	-
47	Advances from Associated Companies (223)	-
48	Other Long-Term Debt (224)	90,828
49	Unamortized Premium on LTD (225)	-
50	Unamortized Discount on LTD (226)	-
51	Total Long-term Debt	90,828
	OTHER NON-CURRENT LIABILITIES	
52	Obligations under Capital Leases (227)	-
53	Advances from Associated Companies (223)	-
54	Other Long-Term Debt (224)	-
55	Unamortized Premium on LTD (225)	-
56	Unamortized Discount on LTD (226)	-
57	Accumulated Provision for Pension & Benefits (228.3)	8,592
58	Total Non-Current Liabilities	8,592
	CURRENT & ACCRUED LIABILITIES	
59	Notes Payable (231)	11,062
60	Accounts Payable (232)	11,000
61	Notes Payable to Assoc. Companies (233)	-
62	Accounts Payable to Assoc. Cos (234)	1,000
63	Customer Deposits (235)	947
64	Taxes Accrued (236)	219
65	Interest Accrued (237)	705
66	Tax Collections Payable (241)	-
67	Accrued Interest on Other Liabilities (237)	2,600
68	Tax Collections Payable (241)	-
69	Misc Current & Accrued Liabilities (242)	-
70	Total Current & Accrued Liabilities	27,533
	OTHER DEFERRED CREDITS	
71	Customer Advances for Construction (252)	-
72	Other Deferred Credits (253)	450
73	Other Regulatory Liabilities (254)	28,000
74	Deferred ITC (255)	-
75	Accumulated Deferred Income Taxes (282)	40,400
76	Accumulated Deferred Income Taxes (283)	-
77	Total Other Deferred Credits	68,850
78	TOTAL LIABILITIES & OTHER CREDITS	$ 334,638

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Statement of Net Utility Operating Income

		[1]	[2]
Line No	**Description**	**Budget TYE 9-30-24**	**Reference**
	Total Operating Revenues		
1	Total Sales Revenues	$ 144,200	B-3
2	Other Operating Revenues	1,103	B-3
3	Total Revenues	145,303	
	Total Operating Expenses		
4	Operation & Maintenance Expenses	120,733	B-4
5	Depreciation & Amortization Expense	9,075	D-3
6	Taxes Other Than Income Taxes	9,369	B-5
7	Total Operating Expenses	139,177	
8	Operating Income Before Income Taxes (OIBIT)	6,126	
	Income Taxes:		
9	State	170	B-5
10	Federal	644	B-5
11	Total Income Taxes	814	
12	**Net Utility Operating Income**	$ 5,311	

($ in Thousands)

Statement of Operating Revenues

Line No	Description	Account No		Budget TYE 9-30-24
				[1]
	Electric Operating Revenues			
1	Residential	440	$	111,376
2	Commercial & Industrial	442		32,040
3	Public Streets & Highway Lighting	444		749
4	Other Sales to Public Authorities	445		19
5	Sales for Resale	447		16
6	Sub-Total Electric Operating Revenues			144,200
	Other Operating Revenues			
7	Forfeited Discounts	450	$	520
8	Miscellaneous Service Revenues	451		16
9	Rent from Electric Properties	454		567
10	Interest on Over/(Under) Collections	456.1		-
11	Sub-Total Other Operating Revenues			1,103
12	**Total Operating Revenues**		$	145,303

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-24
	Other Power Supply Expenses		
1	Purchased Power	555.0	$ 79,973
2	Power Purchased for Storage Operations	555.1	-
3	System Control and Load Dispatching	556.0	-
4	Other Expenses	557.0	-
5	Load Dispatch - Reliability	561.1	-
6	Transmission of Electricty by Others	565.0	5,978
7	Gross Receipts Tax	408.1	-
8	Total Other Power Supply Expenses		85,951
	Transmission Expenses - Operation		
9	Operation Supervision and Engineering	560.0	-
10	Load Dispatch - Reliability	561.0	-
11	Load Dispatch - Monitor and Operate Trans. System	561.2	-
12	Load Dispatch - Transmission Service & Scheduling	561.3	-
13	Scheduling, System Control & Dispatch Service	561.4	-
14	Reliability Planning & Standards Development	561.5	-
15	Transmission Service Studies	561.6	-
16	Generation Interconnection Studies	561.7	-
17	Reliability Planning & Standards Development Services	561.8	-
18	Station Expenses	562.0	-
19	Operation of Energy Storage Equipment	562.1	-
20	Overhead Line Expense	563.0	-
21	Underground Line Expenses	564.0	-
22	Transmission of Electricty by Others	565.0	-
23	Miscellaneous Transmission Expenses	566.0	-
24	Rents	567.0	-
25	Operation Supplies and Expenses	567.1	-
26	Total Transmission Expenses - Operation		-
	Transmission Expenses - Maintenance		
27	Maintenance Supervision and Engineering	568.0	-
28	Maintenance of Structures	569.0	-
29	Maintenance of Computer Hadware	569.1	-
30	Maintenance of Computer Software	569.2	-
31	Maintenance of Communication Equipment	569.3	-
32	Maintenance of Miscellaneous Regional Trans Plant	569.4	-
33	Maintenance of Station equipment	570.0	-
34	Maintenance of Energy Storage Equipment	570.1	-
35	Maintenance of Overhead Lines	571.0	-
36	Maintenance of Underground Lines	572.0	-
37	Maintenance of Miscellaneous Transmission Plant	573.0	-
38	Maintenance of Transmission Plant	574.0	-
39	Total Transmission Expenses - Maintenance		-

($ in Thousands)

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-24
	Regional Market Expenses - Operation		
40	Operation Supervision	575.1	-
41	Day-Ahead and Real-Time Market Administration	575.2	-
42	Transmission Rights Market Administration	575.3	-
43	Capacity Market Administration	575.4	-
44	Ancillary Market Administration	575.5	-
45	Market Monitoring and Compliance	575.6	-
46	Market Facilitation, Monitoring and Compliance Serv	575.7	-
47	Rents	575.8	-
48	Total Region Market Expenses - Operation		-
	Regional Market Expenses - Maintenance		
49	Maintenance of Structures and Improvements	576.1	-
50	Maintenance of Computer Hardware	576.2	-
51	Maintenance of Computer Software	576.3	-
52	Maintenance of Communication Equipment	576.4	-
53	Maintenance of Misc Market Operation Plant	576.5	-
54	Total Region Market Expenses - Maintenance		-
	Distribution Expense - Operation		
55	Operation Supervision and Engineering	580.0	607
56	Load Dispatching	581.0	571
57	Line and Station Expenses	581.1	-
58	Station Expenses	582.0	96
59	Overhead Line Expenses	583.0	298
60	Underground Line Expenses	584.0	42
61	Operation of Energy Storage Equipment	584.1	-
62	Street Lighting and Signal System Expenses	585.0	31
63	Meter Expenses	586.0	782
64	Customer Installation Expenses	587.0	79
65	Miscellaneous Distribution Expenses	588.0	351
66	Rents	589.0	55
67	Total Distribution Expenses - Operation		2,912
	Distribution Expense - Maintenance		
68	Maintenance Supervision and Engineering	590.0	221
69	Maintenance of Structures	591.0	-
70	Maintenance of Station Equipment	592.0	208
71	Maintenance of Pipe Lines	592.1	-
72	Maintenance of Structures and Equipment	592.2	-
73	Maintenance of Overhead Lines	593.0	9,712
74	Maintenance of Underground Lines	594.0	61
75	Maintenance of Lines	594.1	-
76	Maintenance of Line Transformers	595.0	83
77	Maintenance of Street Lighting and Signal Systems	596.0	24
78	Maintenance of Meters	597.0	15
79	Maintenance of Miscellaneous Distribution Plant	598.0	23
80	Total Distribution Expenses - Maintenance		10,347
	Customer Accounts Expense - Operation		
81	Supervision	901.0	91
82	Meter Reading Expenses	902.0	217
83	Customer Records and Collection Expenses (USP)	903.0	9,082
84	Uncollectible Accounts	904.0	2,577
85	Miscellaneous Customer Accounts Expenses	905.0	73
86	Total Customer Accounts Expense - Operation		12,040

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Operation and Maintenance Expenses

Line No	Description	Account No		[1] Budget TYE 9-30-24
	Customer Service & Information Expense			
87	Customer Service and Informational Expenses	906.0		-
88	Supervision	907.0		17
89	Customer Assistance Expenses	908.0		12
90	Information and Instructional Advertising Expenses	909.0		-
91	Miscellaneous Customer Service & Informational Exps (EEC)	910.0		1,246
92	Total Customer Service & Informational Exps - Operations			1,275
	Sales Expense - Operation			
93	Supervision	911.0		-
94	Demonstrating and Selling Expenses	912.0		5
95	Advertising Expenses	913.0		-
96	Miscellaneous Sales Expenses	916.0		(5)
97	Sales Expenses	917.0		-
98	Total Sales Expenses - Operation			-
	Administrative & General - Operations			
99	Administrative and General Salaries	920.0		2,749
100	Office Supplies and Expenses	921.0		1,787
101	Administrative Expenses Transferred - Credit	922.0		-
102	Outside Services Employed	923.0		1,887
103	Property Insurance	924.0		31
104	Injuries and Damages	925.0		251
105	Employee Pensions and Benefits	926.0	*	819
106	Franchise Requirements	927.0		-
107	Regulatory Commission Expenses	928.0		357
108	Duplicate Charges - Credit	929.0		(74)
109	General Advertising Expenses	930.1		74
110	Miscellaneous General Expenses	930.2		259
111	Rents	931.0		2
112	Transportation Expenses	933.0		-
113	Total Administrative and General Expenses - Operation			8,139
	Administrative & General - Maintenance			
114	Maintenance of General Plant	935.0		69
115	Total Administrative and General Expenses - Maintenance			69
116	TOTAL OPERATION & MAINTENANCE EXPENSE			$ 120,733
117	Total Electric Operation Expenses			110,317
118	Total Electric Maintenance Expense			10,416
119	TOTAL OPERATION & MAINTENANCE EXPENSE			$ 120,733

* Acct. 926 decreased by $12 for headcount adjustment. Please see UGI Electric Statement No. 2-R.

($ in Thousands)

Detail of Taxes

Line No	Description	Reference	[1] Budget TYE 9-30-24
	Taxes Other Than Income Taxes		
	Non-revenue related:		
1	Pennsylvania - PURTA	D-31	$ 45
2	Gross Receipts Tax	D-31	8,508
3	PA and Local Use taxes	D-31	22
4	PUC Assessment	D-31	297
5	Subtotal		8,871
6	Payroll Taxes		
7	Social Security	D-31	463
8	SUTA	D-31	3
9	FUTA	D-31	31
10	Other		-
11	Subtotal		498
12	Total Taxes Other Than Income Taxes		$ 9,369
	Income Taxes		
13	State	D-33	$ 170
14	Federal	D-33	644
15	Total Income Taxes		$ 814

UGI Utilities, Inc. - Electric Division
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($ in Thousands)

Composite Cost of Debt

Line No	Series		Issue Date [1]	Maturity Date [2]	Amount Outstanding [3]	Percent to Total [4]	Effective Interest Rate [5]	Average Weighted Cost Rate [6] [4] * [5]
Medium Term Notes								
1	6.500%		8/14/2003	8/15/2033	$ 20,000	1.20%	6.56%	0.08%
2	6.133%		10/14/2004	10/15/2034	20,000	1.20%	6.19%	0.07%
Senior Unsecured Notes								
3	6.206%		9/15/2006	9/30/2036	100,000	5.98%	6.32%	0.38%
4	4.980%		3/26/2014	3/26/2044	175,000	10.46%	5.00%	0.52%
5	2.950%		6/30/2016	6/30/2026	100,000	5.98%	3.92%	0.23%
6	4.120%		9/30/2016	9/30/2046	200,000	11.96%	5.01%	0.60%
7	4.120%		10/31/2016	10/31/2046	100,000	5.98%	4.28%	0.26%
8	4.550%		2/1/2019	2/1/2049	150,000	8.97%	4.58%	0.41%
9	3.120%		3/19/2020	4/16/2050	150,000	8.97%	3.15%	0.28%
10	1.590%		6/15/2021	6/15/2026	100,000	5.98%	1.73%	0.10%
11	1.640%		9/15/2021	9/15/2026	75,000	4.48%	1.75%	0.08%
12	3.917%		7/12/2022	7/12/2027	82,813	4.95%	4.00%	0.20%
13	4.750%		7/15/2022	7/15/2032	90,000	5.38%	4.83%	0.26%
14	4.990%		9/15/2022	9/15/2052	85,000	5.08%	5.02%	0.26%
15	5.230%	*	10/31/2023	10/31/2053	225,000	13.45%	5.28%	0.71%
16	Total Long-Term Debt				$ 1,672,813	100.00%		4.44%
17	Total Long-Term Debt				$ 1,672,813	100.00%	4.44%	4.44%
18	Total Short-Term Debt				-	0.00%		0.00%
19	TOTAL				$ 1,672,813	100.00%		
20	Weighted Cost of Debt							4.44%

*Interest rate updated as referenced in UGI Electric Statement No. 2-R.

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Rate of Return

Line No	Description	[1] Capitalization Ratio	[2] Embedded Cost	[3] Statement Reference	[4] Return-%
1	Long-Term Debt	45.41%	4.44%	B-6	2.02%
2	Short-Term Debt	0.00%	0.00%	B-6	0.00%
3	Common Equity	54.59%	11.30%		6.17%
4	Total	100.00%			8.19%

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Measure of Value

Line #	Description	Reference Fully Projected [1]	Reference # of Pages [2]	Pro Forma Test Year Ended September 30, 2024 At Present Rates [3]	Adjustments [4]	Proposed Rates [5]
	MEASURE OF VALUE					
1	Utility Plant	C-2	5	$ 275,001		$ 275,001
2	Accumulated Depreciation	C-3	6	(85,745)		(85,745)
3	Net Plant in service			189,256	-	189,256
4	Working Capital	C-4	9	11,437		11,437
5	Accumulated Deferred Income Taxes	C-6	1	(29,665)		(29,665)
6	Customer Deposits	C-7	1	(1,103)		(1,103)
7	Materials & Supplies	C-8	1	2,261		2,261
8	TOTAL MEASURE OF VALUE			$ 172,186	$ -	$ 172,186

($ in Thousands)

Pro Forma Electric Plant in Service

Line No	Description	[1] Account No	[2] Pro Forma 9/30/2024
	INTANGIBLE PLANT		
1	Organization	301	$ 11
2	Franchise & Consent	302	5
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		16
	TRANSMISSION PLANT		
5	Land & Land Rights	350	$ -
6	Structures & Improvements	352	-
7	Station Equipment	353	-
8	Station Equipment - SCADA	353.2	-
9	Towers and Fixtures	354	-
10	Poles and Fixtures	355	-
11	Overhead Conductors and Devices	356	-
12	Underground Conduit	357	-
13	Underground Conductors and Devices	358	-
14	Roads and Trails	359	-
15	TOTAL TRANSMISSION		-
	DISTRIBUTION PLANT		
16	Land & Land Rights	360	313
17	Structures & Improvements	361	627
18	Station Equipment	362	11,568
19	Storage Battery Equipment	363	-
20	Poles, Towers and Fixtures	364	56,561
21	Overhead Conductors and Devices	365	82,806
22	Underground Conduit	366	8,780
23	Underground Conductors and Devices	367	15,566
24	Transformers	368.1	19,861
25	Transformer Installations	368.2	11,241
26	Services	369	16,709
27	Meters	370.1	3,094
28	Meter Installations	370.2	1,989
29	Electronic Meters	370.3	5,038
30	Installations on Customers' Premises	371.0	2,219
31	Installations on Customers' Premises - EV Charging Stations	371.1	-
32	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	348
33	Leased Property on Customers' Premises	372	-
34	Street Lighting and Signal Systems	373	2,615
35	TOTAL DISTRIBUTION		239,335
	GENERAL & COMMON PLANT		
36	Land & Land Rights	389	659
37	Structures & Improvements	390	10,646
38	Office Furniture & Equipment	391	18,441
39	Transportation Equipment	392	2,718
40	Stores Equipment	393	11
41	Tools & Garage Equipment	394	1,132
42	Laboratory Equipment	395	28
43	Power Operated Equipment	396	797
44	Communication Equipment	397	652
45	Miscellaneous Equipment	398	566
46	Other Tangible Property	399	-
47	TOTAL GENERAL & COMMON PLANT		35,650
48	Total Plant		$ 275,001

($ in Thousands)

Pro Forma Plant Adjustment Summary

Line #	Description	[1] Factor Or Reference	[2] Test Year 9/30/24 Budget	[3] Adjustments	[4] Pro Forma Test Year [2] + [3]
1	Intangible Plant	Sch C-2, Page 3	$ 16	$ -	$ 16
2	Transmission Plant	Sch C-2, Page 3	-	-	-
3	Distribution Plant	Sch C-2, Page 3	239,335	-	239,335
4	General & Common Plant	Sch C-2, Page 3	35,650	-	35,650
5	Other Plant		-	-	-
6	Total Utility Plant		$ 275,001	$ -	$ 275,001

($ in Thousands)

Pro Forma Year End Plant Balances

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2023	[3] Year Ended September 30, 2024	[4] Pro Forma Adjustment	[5] Balance
	INTANGIBLE PLANT					
1	Organization	301	$ 11	$ 11		$ 11
2	Franchise & Consent	302	5	5		5
3	Miscellaneous Intangible Plant	303		-		-
4	TOTAL INTANGIBLE		16	16	-	16
	TRANSMISSION PLANT					
5	Land & Land Rights	350		-		-
6	Structures & Improvements	352		-		-
7	Station Equipment	353		-		-
8	Station Equipment - SCADA	353.2		-		-
9	Towers and Fixtures	354		-		-
10	Poles and Fixtures	355		-		-
11	Overhead Conductors and Devices	356		-		-
12	Underground Conduit	357		-		-
13	Underground Conductors and Devices	358		-		-
14	Roads and Trails	359		-		-
15	TOTAL TRANSMISSION		-	-	-	-
	DISTRIBUTION PLANT					
16	Land & Land Rights	360	313	313		313
17	Structures & Improvements	361	627	627		627
18	Station Equipment	362	11,263	11,568		11,568
19	Storage Battery Equipment	363	-	-		-
20	Poles, Towers and Fixtures	364	55,047	56,561		56,561
21	Overhead Conductors and Devices	365	68,846	82,806		82,806
22	Underground Conduit	366	8,780	8,780		8,780
23	Underground Conductors and Devices	367	15,051	15,566		15,566
24	Transformers	368.1	18,263	19,861		19,861
25	Transformer Installations	368.2	11,219	11,241		11,241
26	Services	369	16,224	16,709		16,709
27	Meters	370.1	2,978	3,094		3,094
28	Meter Installations	370.2	1,980	1,989		1,989
29	Electronic Meters	370.3	5,038	5,038		5,038
30	Installations on Customers' Premises	371	2,219	2,219		2,219
31	Installations on Customers' Premises - EV Charging Stations	371.1	-	-		-
32	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	348	348		348
33	Leased Property on Customers' Premises	372	-	-		-
34	Street Lighting and Signal Systems	373	2,471	2,615		2,615
35	TOTAL DISTRIBUTION		220,667	239,335	-	239,335
	GENERAL & COMMON PLANT					
36	Land & Land Rights	389	659	659		659
37	Structures & Improvements	390	8,723	10,646		10,646
38	Office Furniture & Equipment	391	18,096	18,441		18,441
39	Transportation Equipment	392	1,826	2,718		2,718
40	Stores Equipment	393	11	11		11
41	Tools & Garage Equipment	394	1,156	1,132		1,132
42	Laboratory Equipment	395	55	28		28
43	Power Operated Equipment	396	598	797		797
44	Communication Equipment	397	692	652		652
45	Miscellaneous Equipment	398	442	566		566
46	Other Tangible Property	399		-		-
47	TOTAL GENERAL & COMMON PLANT		32,258	35,650	-	35,650
48	Total Plant		$ 252,941	$ 275,001	$ -	$ 275,001

($ in Thousands)

Additions to Plant

Line #	Description	[1] Account Number	[2] Year ended September 30, 2023	[3] 2024
	Plant Additions			
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	TRANSMISSION PLANT			
5	Land & Land Rights	350		
6	Structures & Improvements	352		
7	Station Equipment	353		
8	Station Equipment - SCADA	353.2		
9	Towers and Fixtures	354		
10	Poles and Fixtures	355		
11	Overhead Conductors and Devices	356		
12	Underground Conduit	357		
13	Underground Conductors and Devices	358		
14	Roads and Trails	359		
15	TOTAL TRANSMISSION		-	-
	DISTRIBUTION PLANT			
16	Land & Land Rights	360	5	-
17	Structures & Improvements	361	-	-
18	Station Equipment	362	285	308
19	Storage Battery Equipment	363	-	-
20	Poles, Towers and Fixtures	364	1,023	1,597
21	Overhead Conductors and Devices	365	15,749	14,695
22	Underground Conduit	366	-	-
23	Underground Conductors and Devices	367	316	540
24	Transformers	368.1	1,850	1,844
25	Transformer Installations	368.2	23	24
26	Services	369	496	511
27	Meters	370.1	96	398
28	Meter Installations	370.2	11	12
29	Electronic Meters	370.3	-	-
30	Installations on Customers' Premises	371	-	-
31	Installations on Customers' Premises - EV Charging Stations	371.1	-	-
32	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-	-
33	Leased Property on Customers' Premises	372	-	-
34	Street Lighting and Signal Systems	373	169	174
35	TOTAL DISTRIBUTION		20,023	20,103
	GENERAL & COMMON PLANT			
36	Land & Land Rights	389	-	-
37	Structures & Improvements	390	1,280	2,008
38	Office Furniture & Equipment	391	1,123	1,339
39	Transportation Equipment	392	193	892
40	Stores Equipment	393	-	-
41	Tools & Garage Equipment	394	-	-
42	Laboratory Equipment	395	-	-
43	Power Operated Equipment	396	467	199
44	Communication Equipment	397	-	-
45	Miscellaneous Equipment	398	135	124
46	Other Tangible Property	399	-	-
47	TOTAL GENERAL & COMMON PLANT		3,198	4,562
48	Total Additions		$ 23,221	$ 24,665

($ in Thousands)

Retirements

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2023	[3] 2024
INTANGIBLE PLANT				
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
TRANSMISSION PLANT				
5	Land & Land Rights	350		
6	Structures & Improvements	352		
7	Station Equipment	353		
8	Station Equipment - SCADA	353.2		
9	Towers and Fixtures	354		
10	Poles and Fixtures	355		
11	Overhead Conductors and Devices	356		
12	Underground Conduit	357		
13	Underground Conductors and Devices	358		
14	Roads and Trails	359		
15	TOTAL TRANSMISSION		-	-
DISTRIBUTION PLANT				
16	Land & Land Rights	360	-	-
17	Structures & Improvements	361	-	-
18	Station Equipment	362	3	3
19	Storage Battery Equipment	363	-	-
20	Poles, Towers and Fixtures	364	53	83
21	Overhead Conductors and Devices	365	787	735
22	Underground Conduit	366	-	-
23	Underground Conductors and Devices	367	15	25
24	Transformers	368.1	247	246
25	Transformer Installations	368.2	2	2
26	Services	369	25	26
27	Meters	370.1	68	282
28	Meter Installations	370.2	3	3
29	Electronic Meters	370.3	-	-
30	Installations on Customers' Premises	371	-	-
31	Installations on Customers' Premises - EV Charging Stations	371.1	-	-
32	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-	-
33	Leased Property on Customers' Premises	372	-	-
34	Street Lighting and Signal Systems	373	30	30
35	TOTAL DISTRIBUTION		1,233	1,435
GENERAL & COMMON PLANT				
36	Land & Land Rights	389	-	-
37	Structures & Improvements	390	189	85
38	Office Furniture & Equipment	391	2,306	994
39	Transportation Equipment	392	-	-
40	Stores Equipment	393	-	-
41	Tools & Garage Equipment	394	59	24
42	Laboratory Equipment	395	18	27
43	Power Operated Equipment	396	-	-
44	Communication Equipment	397	69	40
45	Miscellaneous Equipment	398	-	-
46	Other Tangible Property	399	-	-
47	TOTAL GENERAL & COMMON PLANT		2,641	1,170
48	Total Retirements		$ 3,874	$ 2,605

($ in Thousands)

Accumulated Provision for Depreciation

Line No	Description	[1] Account Number	[2] Pro Forma 9/30/2024
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	TRANSMISSION PLANT		
5	Land & Land Rights	350	-
6	Structures & Improvements	352	-
7	Station Equipment	353	-
8	Station Equipment - SCADA	353.2	-
9	Towers and Fixtures	354	-
10	Poles and Fixtures	355	-
11	Overhead Conductors and Devices	356	-
12	Underground Conduit	357	-
13	Underground Conductors and Devices	358	-
14	Roads and Trails	359	-
15	TOTAL TRANSMISSION		-
	DISTRIBUTION PLANT		
16	Land & Land Rights	360	-
17	Structures & Improvements	361	67
18	Station Equipment	362	1,555
19	Storage Battery Equipment	363	-
20	Poles, Towers and Fixtures	364	18,154
21	Overhead Conductors and Devices	365	14,476
22	Regulatory AFUDC	365.7	(116)
23	Underground Conduit	366	2,692
24	Underground Conductors and Devices	367	4,928
25	Transformers	368.1	8,267
26	Transformer Installations	368.2	6,688
27	Services	369	8,070
28	Meters	370.1	1,939
29	Meter Installations	370.2	825
30	Electronic Meters	370.3	4,275
31	Installations on Customers' Premises	371	1,088
32	Installations on Customers' Premises - EV Charging Stations	371.1	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	338
34	Leased Property on Customers' Premises	372	-
35	Street Lighting and Signal Systems	373	1,139
36	TOTAL DISTRIBUTION		74,384
	GENERAL & COMMON PLANT		
37	Land & Land Rights	389	11
38	Structures & Improvements	390	2,494
39	Office Furniture & Equipment	391	7,201
40	Transportation Equipment	392	612
41	Stores Equipment	393	6
42	Tools & Garage Equipment	394	498
43	Laboratory Equipment	395	21
44	Power Operated Equipment	396	87
45	Communication Equipment	397	274
46	Miscellaneous Equipment	398	157
47	Other Tangible Property	399	-
48	TOTAL GENERAL & COMMON PLANT		11,361
49	Total Accumulated Provision for Depreciation		$ 85,745

Summary of Accumulated Depreciation

		[1]	[2]	[3]	[4]
		Factor	Test Year Ended September 30, 2024		
Line #	Description	Or Reference	Amount	Pro Forma Adjustment	Balance
1	Intangible Plant	Sch C-3, Pg 3	$ -	$ -	$ -
2	Transmission Plant	Sch C-3, Pg 3	-	-	-
3	Distribution Plant	Sch C-3, Pg 3	74,384	-	74,384
4	General & Common Plant	Sch C-3, Pg 3	11,361	-	11,361
5	Other Plant		-	-	-
6	TOTAL ACC DEPR & AMORTIZATION		$ 85,745	$ -	$ 85,745

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Accumulated Depreciation by FERC Account

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2023	[3] Year Ended September 30, 2024	[4] Pro Forma Adjustment	[5] Balance
	INTANGIBLE PLANT					
1	Organization	301	$ -	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-	-
4	TOTAL INTANGIBLE		-	-	-	-
	TRANSMISSION PLANT					
5	Land & Land Rights	350	-	-	-	-
6	Structures & Improvements	352	-	-	-	-
7	Station Equipment	353	-	-	-	-
8	Station Equipment - SCADA	353.2	-	-	-	-
9	Towers and Fixtures	354	-	-	-	-
10	Poles and Fixtures	355	-	-	-	-
11	Overhead Conductors and Devices	356	-	-	-	-
12	Underground Conduit	357	-	-	-	-
13	Underground Conductors and Devices	358	-	-	-	-
14	Roads and Trails	359	-	-	-	-
15	TOTAL TRANSMISSION		-	-	-	-
	DISTRIBUTION PLANT					
16	Land & Land Rights	360	-	-	-	-
17	Structures & Improvements	361	52	67	-	67
18	Station Equipment	362	1,177	1,555	-	1,555
19	Storage Battery Equipment	363	-	-	-	-
20	Poles, Towers and Fixtures	364	16,932	18,154	-	18,154
21	Overhead Conductors and Devices	365	13,966	14,476	-	14,476
22	Regulatory AFUDC	365.7	(99)	(116)	-	(116)
23	Underground Conduit	366	2,552	2,692	-	2,692
24	Underground Conductors and Devices	367	4,511	4,928	-	4,928
25	Transformers	368.1	8,139	8,267	-	8,267
26	Transformer Installations	368.2	6,451	6,688	-	6,688
27	Services	369	7,799	8,070	-	8,070
28	Meters	370.1	2,055	1,939	-	1,939
29	Meter Installations	370.2	802	825	-	825
30	Electronic Meters	370.3	4,148	4,275	-	4,275
31	Installations on Customers' Premises	371	988	1,088	-	1,088
32	Installations on Customers' Premises - EV Charging Stations	371.1	-	-	-	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	336	338	-	338
34	Leased Property on Customers' Premises	372	-	-	-	-
35	Street Lighting and Signal Systems	373	1,058	1,139	-	1,139
36	TOTAL DISTRIBUTION		70,868	74,384	-	74,384
	GENERAL & COMMON PLANT					
37	Land & Land Rights	389	11	11	-	11
38	Structures & Improvements	390	2,100	2,494		2,494
39	Office Furniture & Equipment	391	6,239	7,201		7,201
40	Transportation Equipment	392	415	612		612
41	Stores Equipment	393	4	6	-	6
42	Tools & Garage Equipment	394	463	498	-	498
43	Laboratory Equipment	395	46	21	-	21
44	Power Operated Equipment	396	34	87	-	87
45	Communication Equipment	397	222	274	-	274
46	Miscellaneous Equipment	398	95	157	-	157
47	Other Tangible Property	399	-	-	-	-
48	TOTAL GENERAL & COMMON PLANT		9,628	11,361	-	11,361
49	Total Accumulated Provision for Depreciation		$ 80,496	$ 85,745	$ -	$ 85,745

($ in Thousands)

Cost of Removal

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2023	[3] 2024
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	TRANSMISSION PLANT			
5	Land & Land Rights	350	-	-
6	Structures & Improvements	352	-	-
7	Station Equipment	353	-	-
8	Station Equipment - SCADA	353.2	-	-
9	Towers and Fixtures	354	-	-
10	Poles and Fixtures	355	-	-
11	Overhead Conductors and Devices	356	-	-
12	Underground Conduit	357	-	-
13	Underground Conductors and Devices	358	-	-
14	Roads and Trails	359	-	-
15	TOTAL TRANSMISSION		-	-
	DISTRIBUTION PLANT			
16	Land & Land Rights	360	-	-
17	Structures & Improvements	361	-	-
18	Station Equipment	362	0	0
19	Storage Battery Equipment	363	-	-
20	Poles, Towers and Fixtures	364	80	124
21	Overhead Conductors and Devices	365	787	735
22	Regulatory AFUDC	365.7	-	-
23	Underground Conduit	366	-	-
24	Underground Conductors and Devices	367	3	5
25	Transformers	368.1	14	14
26	Transformer Installations	368.2	1	1
27	Services	369	43	45
28	Meters	370.1	-	-
29	Meter Installations	370.2	2	2
30	Electronic Meters	370.3	-	-
31	Installations on Customers' Premises	371	-	-
32	Installations on Customers' Premises - EV Charging Stations	371.1	-	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-	-
34	Leased Property on Customers' Premises	372	-	-
35	Street Lighting and Signal Systems	373	15	15
36	TOTAL DISTRIBUTION		946	942
	GENERAL & COMMON PLANT			
37	Land & Land Rights	389	-	-
38	Structures & Improvements	390	-	-
39	Office Furniture & Equipment	391	-	-
40	Transportation Equipment	392	-	-
41	Stores Equipment	393	-	-
42	Tools & Garage Equipment	394	-	-
43	Laboratory Equipment	395	-	-
44	Power Operated Equipment	396	-	-
45	Communication Equipment	397	-	-
46	Miscellaneous Equipment	398	-	-
47	Other Tangible Property	399	-	-
48	TOTAL GENERAL & COMMON PLANT		-	-
49	Total Cost of Removal		$ 946	$ 942

($ in Thousands)

Negative Net Salvage Amortization

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2023	[3] 2024
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	TRANSMISSION PLANT			
5	Land & Land Rights	350	-	-
6	Structures & Improvements	352	-	-
7	Station Equipment	353	-	-
8	Station Equipment - SCADA	353.2	-	-
9	Towers and Fixtures	354	-	-
10	Poles and Fixtures	355	-	-
11	Overhead Conductors and Devices	356	-	-
12	Underground Conduit	357	-	-
13	Underground Conductors and Devices	358	-	-
14	Roads and Trails	359	-	-
15	TOTAL TRANSMISSION		-	-
	DISTRIBUTION PLANT			
16	Land & Land Rights	360	-	-
17	Structures & Improvements	361	0	0
18	Station Equipment	362	9	8
19	Storage Battery Equipment	363	-	-
20	Poles, Towers and Fixtures	364	405	394
21	Overhead Conductors and Devices	365	255	392
22	Regulatory AFUDC	365.7	-	-
23	Underground Conduit	366	3	2
24	Underground Conductors and Devices	367	12	12
25	Transformers	368.1	6	9
26	Transformer Installations	368.2	27	24
27	Services	369	65	56
28	Meters	370.1	(49)	(81)
29	Meter Installations	370.2	4	3
30	Electronic Meters	370.3	0	0
31	Installations on Customers' Premises	371	16	15
32	Installations on Customers' Premises - EV Charging Stations	371.1	-	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-	-
34	Leased Property on Customers' Premises	372	-	-
35	Street Lighting and Signal Systems	373	17	18
36	TOTAL DISTRIBUTION		772	853
	GENERAL & COMMON PLANT			
37	Land & Land Rights	389	-	-
38	Structures & Improvements	390	0	0
39	Office Furniture & Equipment	391	-	-
40	Transportation Equipment	392	(2)	(2)
41	Stores Equipment	393	-	-
42	Tools & Garage Equipment	394	-	-
43	Laboratory Equipment	395	-	-
44	Power Operated Equipment	396	-	-
45	Communication Equipment	397	0	0
46	Miscellaneous Equipment	398	6	6
47	Other Tangible Property	399	-	-
48	TOTAL GENERAL & COMMON PLANT		4	4
49	Total Negative Net Salvage Amortization		$ 776	$ 857

($ in Thousands)

Salvage

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2023	[3] 2024
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	TRANSMISSION PLANT			
5	Land & Land Rights	350	-	-
6	Structures & Improvements	352	-	-
7	Station Equipment	353	-	-
8	Station Equipment - SCADA	353.2	-	-
9	Towers and Fixtures	354	-	-
10	Poles and Fixtures	355	-	-
11	Overhead Conductors and Devices	356	-	-
12	Underground Conduit	357	-	-
13	Underground Conductors and Devices	358	-	-
14	Roads and Trails	359	-	-
15	TOTAL TRANSMISSION		-	-
	DISTRIBUTION PLANT			
16	Land & Land Rights	360	-	-
17	Structures & Improvements	361	-	-
18	Station Equipment	362	(0)	(0)
19	Storage Battery Equipment	363	-	-
20	Poles, Towers and Fixtures	364	-	-
21	Overhead Conductors and Devices	365	-	-
22	Regulatory AFUDC	365.7	-	-
23	Underground Conduit	366	-	-
24	Underground Conductors and Devices	367	-	-
25	Transformers	368.1	-	-
26	Transformer Installations	368.2	-	-
27	Services	369	-	-
28	Meters	370.1	(39)	(160)
29	Meter Installations	370.2	-	-
30	Electronic Meters	370.3	-	-
31	Installations on Customers' Premises	371	-	-
32	Installations on Customers' Premises - EV Charging Stations	371.1	-	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-	-
34	Leased Property on Customers' Premises	372	-	-
35	Street Lighting and Signal Systems	373	-	-
36	TOTAL DISTRIBUTION		(39)	(160)
	GENERAL & COMMON PLANT			
37	Land & Land Rights	389	-	-
38	Structures & Improvements	390	-	-
39	Office Furniture & Equipment	391	-	-
40	Transportation Equipment	392	-	-
41	Stores Equipment	393	-	-
42	Tools & Garage Equipment	394	-	-
43	Laboratory Equipment	395	-	-
44	Power Operated Equipment	396	-	-
45	Communication Equipment	397	-	-
46	Miscellaneous Equipment	398	-	-
47	Other Tangible Property	399	-	-
48	TOTAL GENERAL & COMMON PLANT		-	-
49	Total Salvage		$ (39)	$ (160)

Working Capital

Line No	Description	[1] Fully Projected Future 9/30/2024	[2] Reference
1	Working Capital for O & M Expense	$ 9,445	C-4, Page 2
2	Interest Payments	(301)	C-4, Page 7
3	Tax Payment Lag Calculations	261	C-4, Page 8
4	Prepaid Expenses	2,032	C-4, Page 9
5	Total Cash Working Capital Requirements	$ 11,437	

($ in Thousands)

Summary of Working Capital

Line #	Description	[1] Reference	[2] Test Year Expenses	[3] Factor	[4] Number of (Lead) / Lag Days [2] * [3]	[5] Totals
WORKING CAPITAL REQUIREMENT						
1	REVENUE LAG DAYS	Page 3				59.56
2	EXPENSE LAG DAYS	Page 4				
3	Payroll	Sch D-7	$ 6,121	12.00	$ 73,452	
4	Purchased Power Costs	Sch D-6	91,176	33.30	3,035,752	
5	Other Expenses	L 19 - L 2 to L 4	26,559	30.76	816,942	
6	Total	Sum (L 3 to L 5)	$ 123,856		$ 3,926,146	
7	O & M Expense Lag Days	L6, C 4 / C 2				31.70
8	Net (Lead) Lag Days	L 1 - L 7				27.86
9	Operating Expenses Per Day	L 6, C 2 / 365				$ 339
10	Working Capital for O & M Expense	L 8 * L 9				$ 9,445
11	Interest Payments	Page 7				(301)
12	Tax Payment Lag Calculations	Page 8				261
13	Prepaid Expenses	Page 9				2,032
14	Total Working Capital Requirement	Sum (L 10 to L 13)				$ 11,437
15	Pro Forma O & M Expense		$ 127,095			
	Less:					
16	Uncollectible Expense		3,239			
17	Sub-Total		3,239			
18	Pro Forma Cash O&M Expense		$ 123,856			

($ in Thousands)

Revenue Lag

Line No.	Description	[1] Reference Or Factor	[2] Accounts Receivable Balance End of Month	[3] Total Monthly Sales	[4] A/R Turnover	[5] Days Lag
				Page 2	[3] / [2]	365 / [4]
1	Annual Number of Days					365
2	September, 2021		$ 11,849			
3	October		11,097	6,197		
4	November		9,723	7,951		
5	December, 2021		11,433	10,929		
6	January, 2022		14,407	12,474		
7	February		15,705	11,066		
8	March		16,494	10,190		
9	April		15,957	8,623		
10	May		14,986	8,280		
11	June		15,976	10,966		
12	July		17,542	14,900		
13	August		19,220	13,886		
14	September, 2022		18,672	9,911		
15	Total	Sum L 2 to L 14	$193,061			
16	Number of Months	13				
17	Average Acct Rec Balance	L 15 / L 16	$14,851			
18	Total Sales for Year	Sum L 3 to L 14		$ 125,373		
19	Acct Rec Turnover Ratio	L 18 / L 17			8.44	
20	Collection Lag Day Factor	L 1 / L 19				43.25
21	Meter Read Lag Factor					1.10
22	Midpoint Lag Factor		365 /	12 /	2 =	15.21
23	Total Revenue Lag Days	Sum L 20 to L 22				**59.56**

($ in Thousands)

Summary of Expense Lag Calculations

Line No.	Description	[1] Reference Or Factor	[2] Amount	[3] (Lead) / Lag Days	[4] Weighted Dollar Value [2] * [3]	[5] (Lead) / Lag Days [4] / [2]
PAYROLL						
1	Union Payrolls	Bi-Weekly	$ 1,321	12.00		
2	Exempt & Non-Exempt	Bi-Weekly	4,800	12.00		
3	Weighted for Union	L1, C2 * C3			$ 15,850	
4	Weighted for Other	L2, C2 * C3			57,601	
5	Payroll Lag	L 3 + L 4	$ 6,121		$ 73,451	
6	Payroll Lag Days	C 4 / C 2				12.00
PURCHASE POWER COSTS						
7	Payment Lag	Page 6	$ 62,613		$ 2,084,738	
8	Power Cost Lag Days	C 4 / C 2				33.30
OTHER O & M EXPENSES						
9	OCTOBER 2021	Page 5	$ 767		$ 15,119	
10	NOVEMBER 2021	Page 5	845		31,591	
11	DECEMBER 2021	Page 5	720		29,343	
12	JANUARY 2022	Page 5	1,005		31,292	
13	FEBRUARY 2022	Page 5	797		24,522	
14	MARCH 2022	Page 5	719		17,478	
15	APRIL 2022	Page 5	573		11,770	
16	MAY 2022	Page 5	613		16,801	
17	JUNE 2022	Page 5	1,218		27,473	
18	JULY 2022	Page 5	931		20,148	
19	AUGUST 2022	Page 5	1,314		46,926	
20	SEPTEMBER 2022	Page 5	2,031		82,279	
21	TOTAL		$ 11,532		$ 354,742	
22	Other O&M Expense Lag Days	C 4 / C 2				30.76

($ in Thousands)

General Disbursements Payment Lag Summary

Line #	Description	[1] Number of CDs	[2] Cash Disbursements	[3] Dollar-Days	[4] Expense Lag-Days [3] / [2]
OCTOBER 2021					
1	Total Disbursements for Month	913	$ 4,091		
2	Total Disbursements for Expenses	352	$ 767	$ 15,119	19.72
NOVEMBER 2021					
3	Total Disbursements for Month	672	$ 2,412		
4	Total Disbursements for Expenses	221	$ 845	$ 31,591	37.39
DECEMBER 2021					
5	Total Disbursements for Month	674	$ 2,824		
6	Total Disbursements for Expenses	209	$ 720	$ 29,343	40.76
JANUARY 2022					
7	Total Disbursements for Month	922	$ 3,219		
8	Total Disbursements for Expenses	325	$ 1,005	$ 31,292	31.15
FEBRUARY 2022					
9	Total Disbursements for Month	775	$ 2,732		
10	Total Disbursements for Expenses	229	$ 797	$ 24,522	30.78
MARCH 2022					
11	Total Disbursements for Month	983	$ 10,847		
12	Total Disbursements for Expenses	297	$ 719	$ 17,478	24.30
APRIL 2022					
13	Total Disbursements for Month	776	$ 2,479		
14	Total Disbursements for Expenses	231	$ 573	$ 11,770	20.54
MAY 2022					
15	Total Disbursements for Month	722	$ 2,621		
16	Total Disbursements for Expenses	209	$ 613	$ 16,801	27.43
JUNE 2022					
17	Total Disbursements for Month	996	$ 4,896		
18	Total Disbursements for Expenses	287	$ 1,218	$ 27,473	22.56
JULY 2022					
19	Total Disbursements for Month	830	$ 4,073		
20	Total Disbursements for Expenses	229	$ 931	$ 20,148	21.63
AUGUST 2022					
21	Total Disbursements for Month	1,127	$ 4,214		
22	Total Disbursements for Expenses	434	$ 1,314	$ 46,926	35.71
SEPTEMBER 2022					
23	Total Disbursements for Month	732	$ 4,129		
24	Total Disbursements for Expenses	202	$ 2,031	$ 82,279	40.50
TOTAL TWELVE TEST MONTHS					
25	Total Test Month Expense Disbursement	3,225	$ 11,532	$ 354,742	30.76

Purchase Power Cost Payment Lag Summary

Line #	Description	[1] Number of Invoices	[2] Amount of Invoice	[3] Dollar Days	[4] Total Payment Lag-Days
1	October 2021	5	$ 2,996	$ 106,020	35.39
2	November	5	3,317	108,740	32.78
3	December	7	5,193	181,364	34.93
4	January 2022	10	6,485	205,955	31.76
5	February	9	4,847	153,103	31.59
6	March	6	5,838	223,818	38.34
7	April	8	3,281	154,404	47.06
8	May	7	2,813	100,627	35.77
9	June	11	5,922	176,574	29.82
10	July	12	7,890	244,292	30.96
11	August	10	8,979	247,333	27.55
12	September 2022	6	5,052	182,509	36.13
13	Total		$ 62,613	$ 2,084,738	
14	Purchase Power Lag Days				33.30

Interest Payments

Line No.	Description	[1] Reference Or Factor	[2] # of Days	[3] # of Days	[4] Total
1	Measure of Value at September 30, 2024	Sch C-1			$ 172,186
2	Long-term Debt Ratio	Sch B-7			45.41%
3	Embedded Cost of Long-term Debt	Sch B-6			4.44%
4	Pro forma Interest Expense	L 1 * L 2 * L 3			$ 3,472
5	Daily Amount	L 4 / L 5 [2]	365		$ 10
6	Days to mid-point of interest payments			91.25	
7	Less: Revenue Lag Days	Page 3		59.56	
8	Interest Payment lag days	L 7 - L 6			(31.7)
9	Total Interest for Working Capital	L 5 * L 8			$ (301)

Tax Lag Day Calculations

Line #	Description	[1] Payment Dates	[2] Mid-Point of Service Period	[3] Lead (Lag) Payment Days	[4] Payment Amount	[5] Weighted Lead (Lag) Dollars	[6] Payment Lead (Lag) Days	[7] Revenue (Lag) Days	[8] Net Payment Lead (Lag) Days	[9] Total Dollar Days	[10] Working Capital Amount
		Fully Projected Future		[1] - [2]		[3] * [4]	[5] / [4]		[6] - [7]		365
1	**FEDERAL INCOME TAX**				$ 2,656						
2	First Payment	01/15/24	04/01/24	77.00	$ 664	51,128					
3	Second Payment	03/15/24	04/01/24	17.00	664	11,288					
4	Third Payment	06/15/24	04/01/24	(75.00)	664	(49,800)					
5	Fourth Payment	09/15/24	04/01/24	(167.00)	664	(110,888)					
6	Total				$ 2,656	$ (98,272)	(37.00)	(59.56)	22.56	$ 59,919	$ 164
7	**STATE INCOME TAX**				$ 1,117						
8	First Payment	12/15/23	04/01/24	108.00	$ 279	30,149					
9	Second Payment	03/15/24	04/01/24	17.00	279	4,746					
10	Third Payment	06/15/24	04/01/24	(75.00)	279	(20,937)					
11	Fourth Payment	09/15/24	04/01/24	(167.00)	279	(46,619)		c			
12	Total				$ 1,117	(32,661)	(29.25)	(59.56)	30.31	$ 33,845	$ 93
13	**PA PROPERTY TAX**				$ 22						
14	First Payment	04/30/24	04/01/24	(29.00)	$ 11	(313)					
15	Second Payment	08/31/24	04/01/24	(152.00)	11	(1,639)					
16	Total				$ 22	(1,952)	(90.50)	(59.56)	(30.94)	$ (667)	$ (2)
17	**PURTA**				$ 76						
18	Payment	05/01/24	04/01/24	(30.00)	$ 76	(2,269)	(30.00)	(59.56)	29.56	$ 2,235	$ 6
19	Total Working Capital For Other Taxes										$ 261

Prepaid Expenses

Line #	Description	[1]	[2] TOTAL	[3] Insurance	[4] PUC Assessment	[5] Gross Receipts Tax	[6] Subscriptions	[7] Miscellaneous	[8] Maintenance & Services
1	September, 2021		1,203	$ 449	$ 203	$ -	$ 30	$ 29	$ 492
2	October		1,244	426	203	-	46	24	545
3	November		1,241	412	178	-	102	21	530
4	December, 2021		1,131	348	152	-	61	12	559
5	January, 2022		1,226	290	127	-	61	50	699
6	February		1,090	231	101	-	55	30	673
7	March		4,791	173	76	3,798	49	27	668
8	April		4,117	121	51	3,238	44	21	643
9	May		3,515	66	25	2,783	39	27	575
10	June		2,305	12	-	1,635	33	21	604
11	July		1,964	620	-	772	12	12	548
12	August		1,193	577	-	-	22	41	553
13	September, 2022		1,399	522	223	-	1	35	618
14	TOTAL		$ 26,420	$ 4,246	$ 1,338	$ 12,225	$ 556	$ 351	$ 7,705
15	Percent to Electric			100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
16	Amount to Electric			$ 4,246	$ 1,338	$ 12,225	$ 556	$ 351	$ 7,705
17	Monthly Average	13		$ 327	$ 103	$ 940	$ 43	$ 27	$ 593
18	Rate Case Amount		$ 2,032						

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Accumulated Deferred Income Taxes

Line #	Description	[1] Amount Fully Projected	[2] Total
	Accumulated Deferred Income Tax		
1	Electric Utility Plant - a/c # 282	(30,062)	
2	Sub-total		(30,062)
3	ADIT on CIAC	2,177	
4	Sub-total		2,177
5	Federal ADIT		(27,885)
6	State Repair Regulatory Liability	(3,367)	(3,367)
7	Pro-Rata Adjustment	1,588	1,588
8	Balance At September 30, 2024		$ (29,665)

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Customer Deposits

Line #	Description	[1] Balance at End Of Month
1	April, 2022	$ 955
2	May	$ 949
3	June	$ 933
4	July	$ 941
5	August	$ 952
6	September	$ 984
7	October	$ 1,075
8	November	$ 1,173
9	December	$ 1,239
10	January, 2023	$ 1,269
11	February	$ 1,286
12	March	$ 1,299
13	April	$ 1,287
14	Total	$ 14,342
15	Number of Months	13
16	Average Monthly Balance	$ 1,103 *

*Please see UGI Electric Statement No. 3-R.

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Materials & Supplies

Line #	Month	[1] Materials and Supplies
1	April, 2022	$ 2,266
2	May	$ 2,381
3	June	$ 2,713
4	July	$ 2,758
5	August	$ 2,705
6	September	$ 2,626
7	October	$ 2,731
8	November	$ 2,744
9	December	$ 2,835
10	January, 2023	$ 3,032
11	February	$ 3,248
12	March	$ 3,318
13	April	$ 3,360
14	Total	$ 36,717
15	Number of Months	13
16	Average Monthly Balance	$ 2,824
17	Distribution Allocation	80.0500%
18	Average Monthly Balance - Distribution Only	$ 2,261 *

*Please see UGI Electric Statement No. 3-R.

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Summary of Revenue and Expenses
Pro Forma with Proposed Revenue Increase

Line #	Description	Factor Or Reference	[1] Pro Forma Test Year At Present Rates	[2] Rate Increase	[3] At Proposed Rates
	OPERATING REVENUES				
1	Customer & Distribution Revenue		$ 44,106	$ -	$ 44,106
2	Revenue - Cost of Purchased Power		107,483	-	107,483
3	Other Revenues		1,123	-	1,123
4	Revenue Increase			11,453	11,453
5	Total Operating Revenues		152,711	11,453	164,164
	OPERATING EXPENSES				
6	Other Power Supply Expenses		91,176		91,176
7	Transmission		-	-	-
8	Distribution		13,274	-	13,274
9	Customer Accounts		9,634	-	9,634
10	Uncollectible Expense	1.838%	3,239	211	3,449
11	Customer Information & Services		1,186	-	1,186
12	Sales		0	-	0
13	Administrative & General		8,586	-	8,586
14	Depreciation & Amortization		8,553	-	8,553
15	Taxes other than income taxes		9,714	718	10,432
16	Total Operating Expenses		145,361	929	146,290
17	Net Operating Income Before Income Tax		7,350	10,524	17,874
	Income Taxes				
18	Pro Forma Income Tax At Present Rates		814		814
19	Pro Forma Income Tax on Revenue Increase			2,957	2,957
20	Net Income (Loss)		$ 6,535	$ 7,567	$ 14,103

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Summary of Pro Forma Revenue and Expense
Adjustments with Proposed Revenue Increase

Line #	Description	[1] Factor Or Reference	[2] Test Year At Present Rates: Budget For Year End 09/30/24	[3] Test Year At Present Rates: Adjustments Sch D-3 Increase (Decrease)	[4] Test Year At Present Rates: Pro Forma Adjusted For Test Year 9/30/24	[5] Proposed Increase	[6] Pro Forma Test Year With Proposed Increase
	OPERATING REVENUES			-	[2] + [3]		[4] + [5]
1	Residential	440	$ 111,376	$ 5,890	$ 117,266		$ 117,266
2	Commercial & Industrial	442	32,040	1,489	33,529		33,529
3	Public Streets & Highway Lighting	444	749	9	758		758
4	Other Sales to Public Authorities	445	19	0	19		19
5	Sales for Resale	447	16	0	16		16
6	Forfeited Discounts	450	520	12	532		532
7	Miscellaneous Service Revenues	451	16	5	21		21
8	Rent from Electric Properties	454	567	3	570		570
9	Interest on Over/(Under)Collections	456	-		-		-
10	Rate Increase		-	-	-	11,453	11,453
11	Total Operating Revenues		145,303	7,408	152,711	11,453	164,164
	OPERATING EXPENSES						
12	Other Power Supply Expenses		85,951	5,225	91,176	-	91,176
13	Transmission		-	-	-		-
14	Distribution		13,259	15	13,274		13,274
15	Customer Accounts		9,463	171	9,634		9,634
16	Uncollectible Expense	1.838%	2,577	662	3,239	211	3,449
17	Customer Information & Services		1,275	(89)	1,186		1,186
18	Sales		-	0	0		0
19	Administrative & General		8,208	377	8,586		8,586
20	Depreciation & Amortization		9,075	(522)	8,553		8,553
21	Taxes other than income taxes		9,369	345	9,714	718	10,432
22	Total Operating Expenses		139,177	6,184	145,361	929	146,290
23	Net Operating Income - BIT		$ 6,126	$ 1,224	$ 7,350	$ 10,524	$ 17,874

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Summary of Pro Forma Adjustments

Line #	Description		[1] As Budgeted And Allocated	[2] Not Used D-4	[3] Revenues D-5	[4] Power Costs D-6	[5] Salaries & Wages D-7	[6] Not Used D-8	[7] Not Used D-9	[8] Rate Case Expenses D-10	[9] Uncollectibles Expense D-11	[10] COVID-19 Costs D-12	[11] Not Used D-13	[12] Sub-Total Adjustments	[13] Total Proforma
	OPERATING REVENUES														
	Customer & Distribution Revenue														
1	Residential	440	$ 28,459		$ 1,720									$ 1,720	$ 30,179
2	Commercial & Industrial	442	12,853		522									522	13,375
3	Public Streets & Highway Lighting	444	521		9									9	530
4	Other Sales to Public Authorities	445	17		0									0	17
5	Sales for Resale	447	4		0									0	4
	Non-Distribution and Operating Revenue													-	-
6	Residential	457	82,917		4,170									4,170	87,087
7	Commercial & Industrial	457	19,187		966									966	20,153
8	Public Streets & Highway Lighting	457	228		1									1	229
9	Other Sales to Public Authorities	489	2		0									0	2
10	Sales for Resale	489	12		-									-	12
11	Forfeited Discounts	450	520		12									12	532
12	Miscellaneous Service Revenues	451	16		5									5	21
13	Rent from Electric Properties	454	567		3									3	570
14	Interest on Over/(Under)Collections	456	-											-	-
15	Rate Increase		-											-	-
16	Total Operating Revenues		145,303		7,408	-	-	-	-	-	-	-	-	7,408	152,711
	OPERATING EXPENSES														-
17	Other Power Supply Expenses		85,951			-	-							-	85,951
18	Transmission		-			-	-							-	-
19	Distribution		13,259	-			15		-				-	15	13,274
20	Customer Accounts		9,463				9							9	9,472
21	Uncollectible Expense		2,577								662			662	3,239
22	Customer Information & Services		1,275				0							0	1,275
23	Sales		-				0							0	0
24	Administrative & General		8,208				9	-		(59)		-		(50)	8,158
25	Depreciation & Amortization		9,075											-	9,075
26	Taxes other than income taxes		9,369											-	9,369
														-	-
27	Total Operating Expenses		$ 139,177	$ -	$ -	$ -	$ 33	$ -	$ -	$ (59)	$ 662	$ -	$ -	$ 636	$ 139,813
28	Net Operating Income Before Income Tax		$ 6,126	$ -	$ 7,408	$ -	$ (33)	$ -	$ -	$ 59	$ (662)	$ -	$ -	$ 6,772	$ 12,898

($ in Thousands)

Summary of Pro Forma Adjustments

Line #	Description	[1] From Page 1 Sub-total	[2]	[3] Benefits Adjustments D-14	[4] Other Adjustments D-15	[5] Universal Service D-16	[6] GRT Adjustment D-17	[7] Power Supply Exp Adj D-18	[8] EE&C Program D-19	[9] Not Used D-20	[10] Depreciation D-21	[11] Taxes Other Than Income D-31	[12]	[13] TOTAL Adjusted
	OPERATING REVENUES													
	Customer & Distribution Revenue													
29	Residential	$ 30,179												$ 30,179
30	Commercial & Industrial	13,375												13,375
31	Public Streets & Highway Lighting	530												530
32	Other Sales to Public Authorities	17												17
33	Sales for Resale	4												4
	Non-Distribution and Operating Revenue													-
34	Residential	87,087												87,087
35	Commercial & Industrial	20,153												20,153
36	Public Streets & Highway Lighting	229												229
37	Other Sales to Public Authorities	2												2
38	Sales for Resale	12												12
39	Forfeited Discounts	532												532
40	Miscellaneous Service Revenues	21												21
41	Rent from Electric Properties	570												570
42	Interest on Over/(Under)Collections	-												-
43	Rate Increase	-												-
44	Total Operating Revenues	152,711	-	-	-	-	-	-	-	-	-	-	-	152,711
	OPERATING EXPENSES													
45	Other Power Supply Expenses	85,951					-	5,225						91,176
46	Transmission	-												-
47	Distribution	13,274			-									13,274
48	Customer Accounts	9,472			66	96								9,634
49	Uncollectible Expense	3,239												3,239
50	Customer Information & Services	1,275							(89)					1,186
51	Sales	0												0
52	Administrative & General	8,158		427										8,586
53	Depreciation & Amortization	9,075									(522)			8,553
54	Taxes other than income taxes	9,369					311					34		9,714
55	Total Operating Expenses	$ 139,813	$ -	$ 427	$ 66	$ 96	$ 311	$ 5,225	$ (89)	$ -	$ (522)	$ 34	$ -	$ 145,361
56	Net Operating Income Before Income Tax	$ 12,898	$ -	$ (427)	$ (66)	$ (96)	$ (311)	$ (5,225)	$ 89	$ -	$ 522	$ (34)	$ -	$ 7,350

($ in Thousands)

Adjustment - Revenue Adjustments

		[1]	[2]	[3]	[4]	[5]	[6]
				PRO FORMA ADJUSTMENTS			
Line #	Description	Reference Or Account Number	2024 Budget	Rev Adj Annualization	Other Adjustments	Total Proforma Adjustments	Proforma Adjusted At Present Rates
				D-5A	D-5B		
	Customer & Distribution Revenue						
1	Residential	440	$ 28,459	$ 1,720		$ 1,720	$ 30,179
2	Commercial & Industrial	442	12,853	522		522	13,375
3	Public Streets & Highway Lighting	444	521	9		9	530
4	Other Sales to Public Authorities	445	17	0		0	17
5	Sales for Resale	447	4	0		0	4
6	Cust Chg & Distrib Revenue		41,854	2,252	-	2,252	44,106
	Non-Distribution and Operating Revenue						
7	Residential	456.5	82,917	4,170		4,170	87,087
8	Commercial & Industrial	456.6	19,187	966		966	20,153
9	Public Streets & Highway Lighting	456.8	228	1		1	229
10	Other Sales to Public Authorities		2	0		0	2
11	Sales for Resale		12	-		-	12
12	Revenue for Cost of Electric		102,346	5,137	-	5,137	107,483
							-
13	Total Customer Revenue		144,200	7,388	-	7,388	151,588
14	Forfeited Discounts	450	520		12	12	532
15	Miscellaneous Service Revenues	451	16		5	5	21
16	Rent from Electric Properties	454	567		3	3	570
17	Interest on Over/(Under)Collections	456.1	-			-	-
18	TOTAL REVENUES		$ 145,303	$ 7,388	$ 20	$ 7,408	$ 152,711

($ in Thousands)

Adjustment - Test Year Revenue Changes

Line #	Description	[1] Factor Or Reference	[2] Budgeted Jurisdictional	[3] Revised Jurisdictional	[4] Adjustment [3] - [2]	[5] Total Adjustment
	TOTAL REVENUE					
1	Residential	440	$ 111,376	$ 117,265	$ 5,890	
2	Commercial & Industrial	442	32,041	33,529	1,489	
3	Public Streets & Highway Lighting	444	748	758	9	
4	Other Sales to Public Authorities	445	19	19	0	
5	Sales for Resale	447	16	16	0	
6	Total		$ 144,199	$ 151,588	$ 7,388	$ 7,388
	COSTS (GSR, STAS, EEC, USP, GRT)					
7	Residential		$ 82,917	$ 87,086	4,170	
8	Commercial & Industrial		19,187	20,154	966	
9	Public Streets & Highway Lighting		228	228	1	
10	Other Sales to Public Authorities		2	2	0	
11	Sales for Resale		12	12	0	
12	Total		$ 102,346	$ 107,482	$ 5,137	$ 5,137
	NET CUSTOMER & DISTRIBUTION					
13	Residential		$ 28,459	$ 30,179	$ 1,720	
14	Commercial & Industrial		12,853	13,376	522	
15	Public Streets & Highway Lighting		521	529	9	
16	Other Sales to Public Authorities		17	17	0	
17	Sales for Resale		4	4	0	
18	Total		$ 41,853	$ 44,105	$ 2,252	$ 2,252

Adjustment - Other Revenue Items

		[1]	[2]	[3]
Line #	Description	Factor Or Reference	Other Adjustments	Total
	OTHER REVENUES			
1	Miscellaneous Service Revenues	450	$ 5	
2	Forfeited Discounts	451	12	
3	Rent from Electric Properties	454	3	
4	Interest on Over/(Under)Collections	456.1	-	
5	Total Adjustments to Other Revenues			$ 20 *

Other Revenues increased. Please see UGI Electric Statement No. 2-R.

Adjustment - Power Costs

		[1]	[2]	[3]	[4]	[5]
			PRO FORMA ADJUSTMENTS			
Line #	Description	Budgeted Electric Costs	D-18 Costs	Other Costs	Electric Cost Pro Forma Adjustments	Pro Forma Electric Costs At Pres Rates
1	Budgeted Purchased Power Costs	$ 85,951	$ 5,225	$ -	$ 5,225	$ 91,176
2	Residential				-	-
3	Commercial & Industrial				-	-
4	Public Streets & Highway Lighting				-	-
5	Other Sales to Public Authorities				-	-
6	Sales for Resale				-	-
7	Company Use of Electricity				-	-
8	**Total Purchased Power Costs**	$ 85,951	$ 5,225	$ -	$ 5,225	$ 91,176

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment - Salaries & Wages

Line #	Description	[1] Budgeted Year 09/30/24	[2] Adjustment	[3] Payroll As Distributed	[4] Annualization Adjustment	[5] Total Pro Forma Payroll
	OPERATIONS					
1	Total Other Power Supply Expenses	$ -	$ -	$ -	$ -	$ -
2	Total Transmission Expenses - Operation	-	-	-	-	-
3	Total Regional Market Expenses - Operation	-	-	-	-	-
4	Total Distribution Expenses - Operation *	1,775	-	1,775	10	1,785
5	Total Customer Accounts Expense	1,677	-	1,677	9	1,686
6	Total Customer Service & Informational Expenses	28	-	28	0	28
7	Total Sales Expense	5	-	5	0	5
8	Total A&G - Operation	1,656		1,656	9	1,665
9	Total Operations	5,141	-	5,141	28	5,169
	MAINTENANCE					
10	Total Transmission Expenses - Maintenance	-	-	-	-	-
11	Total Regional Market Expenses - Maintenance	-	-	-	-	-
12	Total Distribution Expenses - Maintenance	914	-	914	5	919
13	Total A&G - Maintenance	33	-	33	0	33
14	Total Maintenance	947	-	947	5	952
15	Total Payroll to Expense	$ 6,088	$ -	$ 6,088	$ 33	$ 6,121
16	Percent Increase					0.541%

*The Company adjusted the original claim by $75. Please see UGI Electric Statement No. 2-R.

($ in Thousands)

Adjustment - Salaries & Wages

Line #	Description	[1] Reference Or Function	[2] Union	[3] Non-Exempt	[4] Exempt	[5] Pro Forma Total Payroll
1	Budgeted Payroll For TY 9-30-24		$ 1,311	$ 1,156	$ 3,621	$ 6,088
	Annualize for Wage Increase to 9-30-24					
2	Percent Increase		3.00%	4.00%	4.00%	
3	Union Increase At 1-1 Annualization Factor	1/1/24	25%			
4	Non-Exempt Annualization Factor	4/1/24		50%		
5	Exempt Annualization Factor	10/1/23			0%	
6	Increase for wage rate changes	L 1 * L 2 * Ls 3 to 5	10	23	0	$ 33
7	Annualized Salaries & Wages at 9-30-24 Rates	L 1 + L 6	$ 1,321	$ 1,179	$ 3,621	
8	Pro Forma Salaries & Wages for TY		$ 1,321	$ 1,179	$ 3,621	
9	Pro Forma Adjustment to S&W					$ 33
10	Annualization Factor	L 11 / L 1				0.541%

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment - Rate Case Expense

Line #	Description	[1] Reference	[2] Amount	[3] Total
	Rate Case Expenditures			
1	External Consultants		$ 228	
2	External Legal		500	
3	Miscellaneous Costs		41	
4	Sub-Total	L 1 to L 3		$ 769
	Total Expenditures for Rate Case Filing			
5	TOTAL COSTS	L 4		$ 769
6	Normalized over 2 years Line 4 / Line 5, Col [2]		2	$ 385
7	Rate Case Expense included in Budget			444
8	Pro Forma Adjustment	L 5 - L 6		$ (59)

($ in Thousands)

Adjustment - Uncollectibles

Line #	Description	[1] Reference Or Factor	[2] Uncollectible Expense	[3] Tariff Revenue	[4] Percent [2] / [3]	[5] Total [2] / [3]
	Adjustment #1:					
1	2020		(a) $ 2,028	$ 84,126	2.41%	
2	2021		(a) $ 1,330	$ 89,272	1.49%	
3	2022		$ 2,133	$ 125,374	1.70%	
4	Three Year Average Sum (Line 1 to Line 3) / 3	3	$ 1,830	$ 99,591		1.838%
5	2024 Budget				$ 2,239	
	Pro Forma Adjustment					
6	Adjusted Revenues	1.838%		$ 152,120		
7	Pro Forma at Present Rate Revenue	L6: [1] * [3]			2,796	
8	Total for Test Year					**$ 557**
	Adjustment #2: (b)					
9	Deferred Uncollectibles - Fiscal 2020			$ 1,013		
10	Less: recovery since last rate case			$ 338		
11	Balance of deferred uncollectibles for Fiscal 2020			$ 675		
12	Amortization per year			338		
13	Recovery of Fiscal 2020 deferred uncollectibles included in budget			$ 338		
14	Pro Forma Adjustment					**$ -**
	Adjustment #3: (c)					
15	Deferred Uncollectibles - Fiscal 2021			$ 315		
16	Amortize over 3 years			3		
17	Amortization per year (Line 15 / Line 16)			105		
18	Recovery of Fiscal 2021 deferred uncollectibles included in budget			-		
19	Pro Forma Adjustment					**$ 105**
20	Total Uncollectible Adjustment	L8 + L14 + L19				**$ 662**

(a) Includes $315 and $1,013 in 2021 and 2020 respectively, which were recorded as regulatory assets associated with COVID-19 in accordance with the May 13, 2020 Secretarial Letter at Docket No. M-2020-3019775. These amounts are the uncollectible accounts reserves needed in excess of the $1,015 uncollectible expense built into rates (from the 2018 Electric Rate Case at Docket No. R-2017-2640058).

(b) $1,013 was deferred and recorded as a regulatory asset for Fiscal 2020 associated with COVID-19 in accordance with the May 13, 2020 Secretarial Letter at Docket No. M-2020-3019775. As approved within the settlement to the 2021 UGI Electric Rate Case at Docket No. R-2021-3023618, this amount is being amortized over 3 years.

(c) Subsequent to the filing of the 2021 UGI Electric Rate Case at Docket No. R-2021-3023618, $315 was deferred and recorded as a regulatory asset for Fiscal 2021 associated with COVID-19 in accordance with the May 13, 2020 Secretarial Letter at Docket No. M-2020-3019775. The Company is proposing to amortize this amount over 3 years and is recording an adjustment to its budgeted bad debt expense for this Fiscal 2021 deferral amortization.

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment - Benefits Adjustments

		[1]	[2]	[3]
Line #	Description	Amount	Subtotal	Pro Forma Adjustment
Pension Expense Adjustment				
1	Total budgeted pension expense		$ 293	
2	Total cash contributions per revised estimate	$ 14,256		
3	Estimated Cash Contributions attributable to UGI Electric	1,272		
4	Less: estimated capitalized portion	(445)		
5	Pension cash contributions per updated estimates		827	
6	Total Adjustment			$ 534
7	Distribution Allocation Factor			80.05%
8	Pro Forma Adjustment			$ 427

Adjustment - Other Adjustments

		[1]	[2]
Line #	Description	Sub-Total	Total
	Customer Accounts Expense Adjustment		
1	Unrecovered Interest on Customer Deposits		$ 66

Adjustment - Universal Service

Line #	Description	[1] Amount
	Increase (Decrease) for Pro Forma TY Universal Service Expense	
		Pro Forma
1	Customer Assistance Plan Credit	$ 5,629
2	Administration Costs	158
3	LIURP	298
4	Hardship Program (Project Share)	5
5	Customer Assistance Plan Pre-program Arrearage	566
6	TOTAL	$ 6,656
7	Budget	$ 6,560
8	Total Adjustment	$ 96

Adjustment - Gross Receipts Tax

Line #	Description	[1] Amount	[2] Total
1	Revised Jurisdictional Revenue - Schedule D-5A, [3], Line 6	$ 151,588	
2	Other Operating Revenues	1,123	
3	Less: Uncollectible Expense	(3,239)	
4	Total		$ 149,472
5	Gross Receipts Tax Rate		5.90%
6	Revised Gross Receipts Tax		$ 8,819
7	Gross Receipts Tax Expense per Budget		$ 8,508
8	Pro Forma Adjustment		$ 311

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment - Power Supply Expense

Line #	Description	[1] Sub-Total	[2] Total
1	Power Supply Expense	$ 92,256	
2	Adjustment for Normalized & Annualized Use/Customer - See Exhibit SAE-4(b)	696	
3	Adjustment for Normalized & Annualized Use/Customer - See Exhibit SAE-4(c)	3,941	
4	Sub-Total	$ 96,893	
5	Adjustment for Gross Receipts Tax (1 - .059)	0.941	
6	Power Supply Expense As Adjusted	$ 91,176	
7	Power Supply Expense per Budget (net of Gross Receipts Tax) (Sch D-6, Col 1)	$ 85,951	
8	Pro Forma Adjustment		$ 5,225

Adjustment - Energy Efficiency and Conservation Programs

Line #	Description	[1] Amount	[2] Sub-Total
	Energy Efficiency and Conservation Programs		
1	2024 Original Program Costs	$ 1,241	
2	Adjusted Budget	1,152	
3	Additional Expense Adjustment (Line 2 - Line 1)		(89)
4	Total Adjustment		$ (89)

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment - Depreciation expense

Line #	Description	[1] Account Number	[2] Budgeted 9/30/24 Depreciation Expense	[3] Adjustment To Annualize At New Depre Study Rates	[4] Pro Forma Test Year Depreciation
	INTANGIBLE PLANT				
1	Organization	301	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-
4	TOTAL INTANGIBLE		-	-	-
	TRANSMISSION PLANT				
5	Land & Land Rights	350	-	-	-
6	Structures & Improvements	352	-	-	-
7	Station Equipment	353	-	-	-
8	Station Equipment - SCADA	353.2	-	-	-
9	Towers and Fixtures	354	-	-	-
10	Poles and Fixtures	355	-	-	-
11	Overhead Conductors and Devices	356	-	-	-
12	Underground Conduit	357	-	-	-
13	Underground Conductors and Devices	358	-	-	-
14	Roads and Trails	359	-	-	-
15	TOTAL TRANSMISSION		-	-	-
	DISTRIBUTION PLANT				
16	Land & Land Rights	360	-	-	-
17	Structures & Improvements	361	14	1	15
18	Station Equipment	362	271	99	370
19	Storage Battery Equipment	363	-	-	-
20	Poles, Towers and Fixtures	364	1,143	(114)	1,029
21	Overhead Conductors and Devices	365	1,634	366	2,001
22	Regulatory AFUDC	365.7	(14)	(2)	(16)
23	Underground Conduit	366	138	(2)	137
24	Underground Conductors and Devices	367	447	(14)	433
25	Transformers	368.1	359	69	428
26	Transformer Installations	368.2	225	(18)	207
27	Services	369	280	(1)	280
28	Meters	370.1	64	2	66
29	Meter Installations	370.2	25	(0)	25
30	Electronic Meters	370.3	134	(20)	115
31	Installations on Customers' Premises	371	94	(20)	74
32	Installations on Customers' Premises - EV Charging Stations	371.1	-	-	-
33	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	2	(1)	1
34	Leased Property on Customers' Premises	372	-	-	-
35	Street Lighting and Signal Systems	373	110	1	111
36	TOTAL DISTRIBUTION		4,927	347	5,275
	GENERAL & COMMON PLANT				
37	Land & Land Rights	389	-	-	-
38	Structures & Improvements	390	239	302	541
39	Office Furniture & Equipment	391	1,843	14	1,857
40	Transportation Equipment	392	183	107	290
41	Stores Equipment	393	1	(0)	1
42	Tools & Garage Equipment	394	63	(6)	57
43	Laboratory Equipment	395	14	(11)	2
44	Power Operated Equipment	396	72	(14)	58
45	Communication Equipment	397	117	(42)	75
46	Miscellaneous Equipment	398	56	6	61
47	Other Tangible Property	399	-	-	-
48	TOTAL GENERAL & COMMON PLANT		2,587	356	2,943
49	TOTAL DEPRECIATION		$ 7,515	$ 703	$ 8,218
50	CHARGED TO OTHER BUSINESS UNITS (IT-RELATED)		(42)	-	(42)
51	CHARGED TO CLEARING ACCOUNTS		$ (435)	$ (45)	$ (479)
52	NET SALVAGE AMORTIZATION		$ 782	$ 75	$ 857
53	TOTAL CLAIMED DEPRECIATION AND AMORTIZATION		$ 7,820	$ 733	$ 8,553

($ in Thousands)

Adjustment - Taxes Other Than Income Taxes

		[1]	[2]	[3]		[4]	[5]
Line #	Description	Account Number	Factor or Reference	Budget Amounts 9/30/24		Pro Forma Adjustments	Pro Forma Tax Expense 9/30/24
1	PURTA Taxes	408.1		$ 45		$ 31	$ 76
2	Gross Receipts Tax	408.1	D-17	8,508		311	8,819
3	PA & Local Use taxes	408.1		22		-	22
4	Social Security	408.1	D-32	463	*	3	466
5	FUTA	408.1	D-32	31		-	31
6	SUTA	408.1	D-32	3		-	3
7	PUC Assessment	408.1		297		-	297
8	Total			$ 9,369		$ 345	$ 9,714

* Decreased by $6,000 for headcount adjustment. Please see UGI Electric Statement No. 2-R.

($ in Thousands)

Adjustment - Payroll Taxes

Line #	Description	[1] Account Number	[2] Test Year 9/30/24 Present Rates	[3] Pro Forma Adjustments	[4] Increase in Payroll Taxes
1	Total Payroll Charged to Expense		$ 6,088	$ 33	
2	FICA Expense		463		
3	FICA Expense - Percent	L 2 / L 1	7.61%	7.61%	
4	Pro Forma FICA Expense on Pro Forma S&W	[4] L 1 * L 3			$ 3
5	FUTA Expense		31		
6	FUTA Expense - Percent	L 5 / L 1	0.51%	0.51%	
7	Pro Forma FUTA Expense on Pro Forma S&W	[4] L 1 * L 6			-
8	SUTA Expense		3		
9	SUTA Expense - Percent	L 8 / L 1	0.05%	0.05%	
10	Pro Forma SUTA Expense on Pro Forma S&W	[4] L 1 * L 9			-
11	Pro Forma Adjustment	Sum L 4 to L 10			$ 3

($ in Thousands)

Income Tax Calculation

Line #	Description	[1] Factor Or Reference	[2] Element Or Amount	[3] Pro Forma Test Year At Present Rates	[4] Revenue Increase	[5] Pro Forma Test Year At Proposed Rates [3] + [4]
1	Revenue			$ 152,711	$ 11,453	$ 164,164
2	Operating Expenses			(145,361)	(929)	(146,290)
3	OIBIT	L 1 + L 2		7,350	10,524	17,874
	Interest Expense					
4	Rate Base	Sch A-1	172,186			
5	Weighted Cost of Debt	Sch B-7	0.02020			
6	Synchronized Interest Expense	L 4 * L 5		(3,478)	-	(3,478)
7	Base Taxable Income	L 3 + L 6		3,872	10,524	14,396
8	Total Tax Depreciation	Sch D-34	$ 18,229			
9	Pro Forma Book Depreciation	Sch D-34	8,957			
10	State Tax Depreciation (Over) Under Book	L 9 - L 8		(9,273)		(9,273)
11	Other				-	-
12	State Taxable Income	Sum L 7 to L 11		$ (5,401)	$ 10,524	$ 5,124
13	State Income Tax (Expense)/Refund	L 12 * Rate [2]	8.99%	$ 486	$ (946)	$ (461)
14	Total Tax Depreciation	Sch D-34	$ 17,308			
15	Pro Forma Book Depreciation	Sch D-34	8,957			
16	Federal Tax Deducts (Over) Under Book	L 14 - L 13		(8,351)	-	(8,351)
17	Other				-	-
18	Federal Taxable Income	L 7 + sum L 13 to L 17		(3,994)	9,578	5,585
19	Federal Income Tax (Expense)/Refund	-L 18 * Rate [2]	21.00%	839	(2,011)	(1,173)
20	Total Tax Expense before Deferred Income Tax	L 13 + L 19		1,325	(2,957)	(1,634)
	Deferred Federal Income Taxes					
21	Total Straight Line Tax Depreciation	Sch D-34	$ 8,218			
22	Total Tax Depreciation	Sch D-34	16,526			
23	Federal Tax Deducts (Over) Under Book	L 22 - L 21		8,308	-	8,308
24	Deferred Federal Taxable Income	L 23		$ 8,308	$ -	$ 8,308
25	Federal Income Tax (Expense)/Refund	-L 24 * Rate [2]	Blended Rate [1]	(1,483)	-	(1,483)
	Deferred State Income Taxes					
26	Repairs			(694)		(694)
27	CIAC			38		38
28	State Deferred Income Tax (Expense)/Refund			(656)	-	(656)
29	Net Income Tax Expense	L20 + L 25 + L28		(814)	(2,957)	
	Other Tax Adjustments					
30	ITC			-		-
31	Combined Income Tax Expense	L 29 + L 30		$ (814)	$ (2,957)	$ -
32	Federal Income Tax Expense	L 19 + L 25 + L 30		$ (644)	$ (2,011)	$ (2,656)
33	State Income Tax Expense	L 13 + L 28		(170)	(946)	(1,117)
34	Total Income Tax Expense	L 32 + L 33		$ (814)	$ (2,957)	$ (3,773)

[1] Due to the 2018 Tax Cuts and Jobs Act, excess deferred income tax is now being flowed back to customers which results in a deferred tax rate other than 21%.

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024
($ in Thousands)

Tax Depreciation

Line #	Description	[1] Amount	[2] Amount	[3] Total
	Accelerated Tax Depreciation			
1	Electric Plant		$ 6,585	
2	Cost of Removal		782	
3	Repairs Tax Deduction		10,966	
4	Other Tax Basis Adjustments		(1,026)	
5	Total Federal Accelerated Tax Depreciation			$ 17,308
6	Adjustment for PA Tax Depreciation - Bonus Decoupling		922	
7	Total State Accelerated Tax Depreciation			$18,229
	Straight Line Tax Depreciation			
8	Electric Plant		$ 8,218	
9	Total Tax Depreciation			$ 8,218
	Book Depreciation			
10	Pro Forma Book Depreciation		$ 8,218	
11	Net Salvage Amortization		857	
12	Depreciation Charged to Clearing Accounts	(479)		
13	Estimated Percent of Clearing Charged to CWIP	25%		
14	Depreciation Charged to CWIP		(118)	
15	Book Depreciation for Tax Calculation			$ 8,957

($ in Thousands)

Gross Revenue Conversion Factor

Line #	Description	[1] Reference Or Factor	[2] Tax Rate	[3] Factor
GROSS REVENUE CONVERSION FACTOR				
1	GROSS REVENUE FACTOR			1.000000
2	UNCOLLECTIBLE EXPENSES			(0.018380)
3	NET REVENUES	Sum L 1 to L 2		0.981620
4	GROSS RECEIPTS TAX	[3] L 3 * Rate [2]	6.27%	(0.062700)
5	FACTOR AFTER GROSS RECEIPTS TAX			0.918920
6	STATE INCOME TAXES	[3] L 5 * Rate [2]	8.99%	(0.082611)
7	FACTOR AFTER STATE TAXES	L 5 + L 6		0.836309
8	FEDERAL INCOME TAXES	[3] L 7 * Rate [2]	21.00%	(0.175625)
9	NET OPERATING INCOME FACTOR	L 7 + L 8		0.660684
10	GROSS REVENUE CONVERSION FACTOR	1 / L 9		1.513583
11	Combined Income Tax Factor On Gross Revenues	-L 6 - L 8		25.824%
INCOME TAX FACTOR				
12	GROSS REVENUE FACTOR			1.000000
13	STATE INCOME TAXES	[3] L 10 * Rate [2]	8.9900%	(0.089900)
14	FACTOR AFTER STATE TAXES	L 10 + L 11		0.910100
15	FEDERAL INCOME TAXES	[3] L 12 * Rate [2]	21.00%	(0.191121)
16	NET OPERATING INCOME FACTOR	L 12 + L 13		0.718979
17	GROSS REVENUE CONVERSION FACTOR	1 / L 14		1.390861
18	Combined Income Tax Factor On Taxable Income	-L 11 - L 13		28.102%

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2022-3037368, et. al

UGI Utilities, Inc. – Electric Division

Statement No. 3-R

Rebuttal Testimony of Vivian K. Ressler

Topics Addressed:	**Updates And Corrections To Initial Filing** **Responses To Rate Base Adjustments** **Responses To Operating Expense Adjustments**

Dated: May 25, 2023

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vivian K. Ressler. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Electric Statement No. 3, on January 27, 2023.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony provides updates to certain components of the Company's filing, based on the information provided during the discovery phase of this proceeding. In addition, my testimony responds to certain portions of the following direct testimony submitted by the Bureau of Investigation and Enforcement ("I&E") and the Office of Consumer Advocate ("OCA"): I&E Statement No. 2, the direct testimony of Christopher Keller; and OCA Statement No. 1, the direct testimony of Dante Mugrace.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes, I am sponsoring UGI Electric Exhibits VKR-1R through 5R. These include CONFIDENTIAL UGI Electric Exhibits VKR-1R and 3R.

II. UPDATES AND CORRECTIONS TO THE COMPANY'S CLAIM

Q. Since the filing of your direct testimony, has the Company identified any rate base components of its filing that should be updated?

A. Yes, during the discovery phase of this proceeding, the Company identified parts of its initial filing that required revision. These include the following:

- The Company has updated the period over which its average Customer Deposit balance is calculated (UGI Electric Exhibit A - Fully Projected (REBUTTAL), Schedule C-7) to reflect the use of the 13-month average balance as of April 2023, which resulted in a net decrease in rate base of $154,000;
- The Company has updated the period over which its average Materials & Supplies balance is calculated (UGI Electric Exhibit A - Fully Projected (REBUTTAL), Schedule C-8) to reflect the use of the 13-month average balance as of April 2023. Additionally, the Company updated the average Materials & Supplies balance to reflect only the portion of the balance which is related to its Distribution business. The combination of these two updates resulted in a net increase in rate base of $109,000.

Each of these updates to the Company's rate base is reflected in UGI Electric Exhibit A (REBUTTAL), which is the Company's final accounting exhibit. UGI Electric witness Ms. Tracy A. Hazenstab sponsors this exhibit as a part of her rebuttal testimony (UGI Electric St. No. 2-R).

III. RATE BASE ADJUSTMENTS

A. UTILITY PLANT IN SERVICE

Q. Do any of the other parties propose adjustments to the Company's claimed utility plant in service as of the Fully Projected Future Test Year ("FPFTY")?

A. Yes. OCA witness Mr. Mugrace proposes adjustments to the Company's claim.

Q. Does the Company agree with the adjustments proposed by OCA?

A. No. In her rebuttal testimony, UGI Electric witness Ms. Vicky A. Schappell (UGI Electric St. No. 5-R) fully rebuts the adjustment advanced by OCA to the Company's claimed utility plant in service for the FPFTY, related to the Company's Data Center project. The Company manages its capital budget for any particular year, including the FPFTY, in total. In doing so, the Company will reprioritize projects and update associated projections as needed in order to achieve a result which has the greatest likelihood of being "on budget" for the year in total. Thus, the known and measurable amount is appropriately viewed in total and a selective disallowance of certain cost elements, as Mr. Mugrace suggests with the Data Center contingency costs, is inappropriate. As Ms. Schappell demonstrates, OCA's proposed adjustment is not appropriate. Therefore, as fully explained below, the derivative adjustments to other aspects of the Company's rate base and its operating expenses advanced by OCA should also be rejected.

B. ACCUMULATED DEPRECIATION

Q. Do any of the other parties propose an adjustment to the Company's claim for accumulated depreciation?

A. Yes. OCA witness Mr. Mugrace recommends that the Company's claim for accumulated depreciation be increased by $16,509. OCA St. No. 1 at 9-10. Mr. Mugrace's proposed adjustment is based upon his recommended adjustment to the Company's claimed FPFTY plant in service. OCA St. No. 1 at 9-10.

Q. Does the Company agree with the adjustment proposed by OCA?

A. No. The Company disagrees with OCA's proposed adjustment to accumulated depreciation, which is derivative of OCA's proposed adjustments to UGI Electric's utility plant in service claim, for the reasons explained in UGI Electric witness Ms. Schappell's rebuttal testimony (UGI Electric St. No. 5-R).

C. ACCUMULATED DEFERRED INCOME TAXES ("ADIT")

Q. Do any parties propose an adjustment to the Company's ADIT, Excess Deferred Federal Income Taxes ("EDFIT") or repairs allowance claim?

A. Yes. OCA witness Mr. Mugrace recommends an increase to the Company's ADIT claim of $4,662. OCA St. No. 1 at 12; *see also* OCA Schedule DM-8. Mr. Mugrace's adjustment is derived from his proposal to decrease the Company's claim for utility plant in service, which the Company rejects. OCA St. No. 1 at 12.

Q. Does the Company agree with the adjustment to ADIT that is proposed by OCA?

A. No. The Company disagrees with this adjustment, which is derivative of OCA's proposed adjustment to the Company's utility plant in service claim, for the reasons explained in UGI Electric witness Ms. Schappell's rebuttal testimony (UGI Electric St. No. 5-R).

IV. OPERATING EXPENSE ADJUSTMENTS

A. INCENTIVE COMPENSATION EXPENSE

Q. Do any parties propose adjustments to the Company's claim to recover costs related to incentive compensation plans?

A. Yes. OCA witness Mr. Mugrace proposes adjustments to several aspects of the Company's incentive compensation proposal, which taken together would decrease the Company's proposed total Incentive Compensation costs by $716,450. OCA St. No. 1 at 22; OCA Schedules DM-4 and DM-9. Similarly, I&E witness Mr. Keller recommends adjustments to several aspects of the Company's incentive compensation, which taken together would decrease the Company's proposed total incentive compensation costs by $725,800. I&E St. No. 2 at 2.

Q. Please identify the aspects of the Company's incentive compensation costs that OCA witness Mr. Mugrace and I&E witness Mr. Keller propose to adjust.

A. OCA witness Mr. Mugrace proposes the following adjustments to specific categories of incentive compensation that are included in the Company's overall claim for incentive compensation expense:

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]

[END CONFIDENTIAL]

I&E witness Mr. Keller proposes the following adjustments to specific categories of incentive compensation that are included in the Company's overall claim for incentive compensation expense:

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Please briefly summarize the incentive compensation plans to which OCA witness Mr. Mugrace and I&E witness Mr. Keller proposed adjustments.

A. A summary of the five plans that OCA and I&E address in their testimony is set forth below.

- <u>Restricted Stock Awards and Stock Options</u>
    - o Restricted stock awards and stock options are grants provided to employees which provide the recipient with the right to redeem the grants in the future for either (1)

company stock; (2) the right to purchase company stock at a price lower than market; or (3) cash. Awards typically vest over a three-year period and unvested awards are cancelled if an employee leaves the Company prior to the vesting date.

- Management Incentive Plan ("MIP")
  - The MIP is an annual incentive plan for full-time employees of UGI Utilities, Inc. ("UGIU") at levels below the executive level (as further defined in the Plan Document). The plan is designed to incentivize performance in the areas of (1) safety; (2) customer satisfaction; (3) financial performance; (4) business growth; (5) sustainability; (6) capital deployment; and (7) employee retention and engagement. A copy of the 2023 Management Incentive Plan and related goals was provided at CONFIDENTIAL Attachment I&E-RE-14-D (A).1.
- UGIU Executive Incentive Plan
  - The UGIU Executive Incentive Plan is an annual incentive plan for executives of UGIU. The plan includes financial, safety and diversity and inclusion goals. A copy of the 2023 UGIU Executive Incentive Plan goals was provided at CONFIDENTIAL Attachment OCA-II-25 and was included in PROPRIETARY I&E Exhibit No. 2, Schedule 2, page 9.
- UGI Corp. Executive and Non-Executive Incentive Plans
  - UGI Corp. (the ultimate parent of UGI Electric) offers annual incentive plans for its executives and certain non-executive employees. The plans include financial and safety goals and the executive plan also includes a diversity and inclusion goal. The costs of these plans are allocated to UGI Electric and other business units of UGI Corp. A copy of the 2023 UGI Corp. Executive and Non-Executive Incentive Plan goals is provided at CONFIDENTIAL UGI Electric Exhibit VKR-1R.
- Directors' Equity Compensation
  - Non-employee directors of UGI Corp. are provided with long-term equity awards in accordance with the director compensation program overseen by the Corporate Governance Committee and the Board of Directors as a whole. The Board of Directors uses market comparables to assess appropriate compensation for non-employee directors. Further details of the director compensation program can be found in the annual proxy statement of UGI Corp., an excerpt of which is included at UGI Electric Exhibit VKR-2R.

Q. Does the Company agree with any of the adjustments proposed by OCA and I&E to its claimed incentive compensation costs?

A. No, it does not. Both OCA and I&E attempt to evaluate individual aspects of the Company's incentive compensation program in isolation. These attempts to single out and remove specific aspects of the Company's compensation plan costs should be rejected for several reasons.

Q. Please explain.

A. As a general matter, OCA's and I&E's arguments should be rejected because they disregard the fact that UGI Electric is entitled to recover in rates all expenses reasonably necessary to provide electric service. In order to provide electric service to its customers, UGI Electric must be able to attract and retain qualified employees, managers, executives and directors. UGI Electric's ability to attract and retain qualified individuals into these positions is directly related to its ability to provide them with reasonable and competitive compensation. OCA's and I&E's attempts to disallow certain aspects of the Company's total compensation packages fundamentally undermines the Company's ability to attract qualified employees, managers, executives and directors, and would fail to produce just and reasonable rates.

Q. Why should the Commission reject Mr. Mugrace's and Mr. Keller's attempts to evaluate individual aspects of the Company's incentive compensation program in isolation?

A. Importantly, neither OCA witness Mr. Mugrace nor I&E witness Mr. Keller argue that UGI Electric's method of compensating its employees, <u>as a whole</u>, is unreasonable. Rather, the evidence of record demonstrates that UGI Electric compensates its employees consistent with industry standards and in a reasonable manner that permits the Company to attract and retain qualified employees in order to provide safe and reliable service to its customers. The other parties' attempts to single out specific aspects of the Company's overall compensation program—where the evidence demonstrates that the overall program is reasonable—is improper and should be rejected.

Incentive compensation programs work in conjunction with base compensation to incentivize, attract and retain a talented workforce. All else being equal, if the Company does not offer these compensation awards, alternative incentive compensation or higher base compensation (e.g., salary) would be necessary to allow the Company to continue to be competitive in attracting and retaining its workforce in a competitive job market.

Q. Has the Commission previously affirmed UGI Electric's incentive compensation programs?

A. Yes. Despite OCA's and I&E's attempts to cite other utilities' rate case orders, it is important to remember that the Commission concluded that UGI Electric's incentive compensation expense <u>as a whole</u> is recoverable in the Company's last fully-litigated base rate case. *Pa. PUC, et al. v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-

2640058, at pp. 73-74 (Order entered Oct. 25, 2018) ("*UGI Electric 2018*"). The same types of incentive compensation programs that were accepted by the Commission in that case are at issue in this proceeding. OCA and I&E have made no attempt to distinguish between the programs at issue in the 2018 base rate case and this case. Moreover, neither OCA nor I&E have offered any new reason why the same categories of expenses determined to be recoverable in the 2018 base rate case are not recoverable in this case.

Q. Has the Commission ruled on incentive compensation programs in other public utilities' claims?

A. Yes. The Commission has previously rejected proposed adjustments to other public utilities' claims for incentive compensation, including stock-based compensation. In PPL Electric Utilities Corp.'s ("PPL Electric") 2012 base rate proceeding, witnesses on behalf of I&E and the OCA recommended disallowance of half of PPL Electric's performance compensation expense claim, thereby requiring shareholders to share equally in the cost of its performance compensation plan. The Commission rejected that proposal stating:

> We find that, because PPL's incentive compensation plan is reasonable, prudently incurred, and is not excessive in amount, PPL is permitted full recovery of this expense. PPL correctly notes that many of the cases the OCA and I&E rely on are distinguishable from this case because, in those cases there was not adequate evidence that the incentive compensation expense was reasonable or that there was a benefit to ratepayers. Our decision to allow this incentive compensation expense is consistent with our prior decision approving incentive compensation programs that are focused on improving operational effectiveness.

Pa. PUC v. PPL Electric Utilities Corp., Docket No. R-2012-2290597, at p. 26 (Final Order entered December 28, 2012) (internal citations omitted).

The Commission again made it clear in the 2018 UGI Electric base rate proceeding that incentive compensation programs must be evaluated "as a whole," when determining whether the plan includes goals that benefit customers. *UGI Electric 2018*, at pp. 73-74. By breaking apart the Company's incentive compensation program into individual components, OCA and I&E once again, inappropriately and in contradiction of Commission precedent, try to single out individual aspects of the Company's total incentive compensation program. However, when viewed as a whole, the program clearly contains "both financial and operating metrics and goals which benefit customers," consistent with the Commission's order in the 2018 UGI Electric base rate proceeding. *Id.*, at p. 74.

Furthermore, the Commission again applied this reasoning in *Pa. PUC, et al v. Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc.*, Docket Nos. R-2021-3027385, R-2021-3027386, et al. (Order entered May 16, 2022) ("*Aqua PA 2021 Order*"). There, the Commission affirmed a utility's total incentive compensation package because:

> Aqua has provided evidence linking the stock-based incentive compensation program with benefits to customers and improved operational efficiency….
>
> We agree with the ALJ that the stock-based compensation benefits ratepayers. We find that the stock-based compensation is linked to performance objectives that benefit consumers, including controlling costs and compliance initiatives.

Aqua PA 2021 Order, at pp. 100-101.

Even though the Commission consistently approves incentive compensation claims, similar to UGI Electric's, OCA and I&E continue to try to disrupt that precedent and the Commission's wholistic review approach.

Q. Are I&E and OCA correct that a public utility must demonstrate that incentive compensation expenses that are reasonable and prudently incurred must benefit customers in order to recover those expenses?

A. No. A utility is not required to demonstrate that these programs benefit customers. Rather, they must show that an expense is reasonable, prudently incurred, and not excessive in amount.

In addition, even assuming OCA's and I&E's narrow views were proper, the Company's customers benefit from the achievement of the financial goals at both the parent and utility level that are the subject of the incentive compensation programs at issue. These financial goals ultimately improve the financial strength and profile of both the Company and its parent, UGI Corp. UGIU raises debt within its capital structure and a healthy business result allows the Company to achieve favorable credit ratings. Stronger credit ratings and a stronger financial profile provide UGI Electric with better access to capital at a lower cost; this lower cost of capital is part of UGI Electric's revenue requirement and is reflected in lower rates to customers. UGIU's credit ratings are also impacted by the financial performance and financial health of its parent company, UGI Corp. A financially stronger UGI Corp. helps UGI Electric support and maintain its own credit ratings. Contrary to OCA's and I&E's claims, the "financial goals" reflected in various portions of the Company's incentive compensation programs benefit customers by improving the Company's access to the capital needed to invest in infrastructure to provide safe and reliable electric service. For all of these reasons, all of I&E's and OCA's proposed disallowances related to UGI Electric's claimed incentive compensation expense should be denied.

Q. Are there any further specific arguments made by I&E or OCA with respect to the Company's incentive compensation expense claims that you would like to address?

A. Yes, there are two. First, I would like to respond to I&E witness Mr. Keller's reliance on the *Columbia 2021 Order* to support his proposed disallowance of the Company's claimed expense related to restricted stock awards and stock options. Second, I would like to respond to OCA witness Mr. Mugrace's argument that allowing recovery of UGI Electric's allocated portion of the Executive Bonus Plan may subsidize operations in other states.

Q. Please address I&E witness Mr. Keller's reliance on the *Columbia 2021 Order* in support of his proposed disallowance of stock options and restricted stock awards.

A. As an initial matter, I note that it is unclear where the block quote included on page 5 of Mr. Keller's direct testimony comes from. The cited passage does not appear in the Commission's final order at the cited Docket No. R-2020-3018835.

Moreover, as Mr. Keller concedes, that case is inapposite because the utility in *Columbia* voluntarily withdrew its claim for stock compensation as a part of the exceptions it filed in that case. I&E St. 2 at 5; *Columbia 2021 Order*, at p. 75. The *Columbia 2021 Order* recognizes that much. Critically, Columbia Gas of Pennsylvania, Inc.'s exceptions in that proceeding indicated that due to the "unique circumstances" presented by the COVID-19 Pandemic, "Columbia voluntarily is withdrawing and not taking Exception to several claims, including the stock compensation portion of its incentive compensation program . . ." *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835 (Columbia Exceptions dated Dec. 22, 2020). The unique circumstances present in the *Columbia 2021 Order* are not present here and UGI Electric has not voluntarily withdrawn this aspect of its claim. Therefore, reliance on the *Columbia 2021 Order* is flawed and should be disregarded.

Q. Are there any other reasons why I&E's reliance on the *Columbia 2021 Order* should be disregarded?

A. Yes. I&E witness Mr. Keller does not attempt to show that the Company's incentive compensation program is in any way similar to the incentive compensation program at issue in the *Columbia 2021 Order*. In addition, the other programs referenced in the *Columbia 2021 Order* are not a part of the record in this proceeding and, even if they were, would be irrelevant to the programs in place at UGI Electric. Therefore, it appears that I&E witness Mr. Keller's attempt to rely on the *Columbia 2021 Order* is little more than an improper attempt to deflect from the fact that the Commission has already determined that the costs of UGI Electric's incentive compensation programs <u>as a whole</u> are reasonable and prudent and, therefore, are recoverable.

Q. Please respond to OCA witness Mr. Mugrace's claim that the Executive Bonus Plan may result in Pennsylvania customers subsidizing actions in other states.

A. On page 21 of his direct testimony, Mr. Mugrace cites that the Executive Bonus Plan of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** rewards executives/management based on UGI Electric's parent company performance. The UGIU Executive Bonus Plan (which is the plan for which UGI Electric claimed **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of expense) does not have goals related to UGI Corp.'s performance. However, the UGI Corp. Executive Bonus Plan and the UGI Corp. Non-Executive Bonus Plan (for which UGI Electric claimed a total of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of expense) do reward executives and employees of UGI Corp. based on the performance of all business units under the ownership of UGI Corp.

The costs of UGI Corp. (including costs associated with incentive compensation paid to its executives and non-executive employees) are assigned to its business units using an allocation methodology that reasonably apportions costs based on the relative benefit of the service to each affected business unit. This same methodology is used to assign other salary and administrative costs in accordance with Commission approved affiliate interest agreements. As a result, the costs allocated to UGI Electric are reflective of the benefit that UGI Electric receives, and the allocation does not result in Pennsylvania customers subsidizing activities related to other states.

B. SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN ("SERP")

Q. Do any of the parties propose adjustments to the Company's claimed costs associated with the SERP?

A. Yes. OCA witness Mr. Mugrace proposes to disallow $25,000 related to the Company's SERP. OCA St. No. 1 at 23.

Q. Why does Mr. Mugrace propose to disallow these costs?

A. Mr. Mugrace argues these costs should be disallowed because they benefit executives rather than customers. OCA St. No. 1 at 23.

Q. Does the Company agree with OCA's proposed adjustment?

A. No.

Q. Please describe the Company's SERP.

A. The Company's SERP plan is designed to provide a retirement benefit for executive-level employees who are not eligible to receive the full typical Company contribution within its pension or 401(k) program. Current (not retired) executives who earn more than the cap for the regular pension or 401(k) plan are eligible for the SERP.

Q. Why should the Commission also reject Mr. Mugrace's recommended disallowance of the costs of the Company's SERP?

A. A SERP is a typical benefit of an executive benefit package, and the Company includes this benefit for its executives in order to be competitive for talent at that level. The SERP works together with other portions of the Company's pay and benefits program to provide a complete compensation package. If the SERP were excluded, the Company would need to increase base salary or other compensation in order to remain competitive for talented executives.

C. ADMINISTRATIVE & GENERAL ("A&G") SALARIES

Q. Do any of the parties propose adjustments to the Company's claim for A&G salaries expense?

A. Yes. OCA witness Mr. Mugrace proposes a reduction to this expense category.

Q. Please summarize Mr. Mugrace's proposed adjustment.

A. Mr. Mugrace recommends that $178,000 be disallowed from this expense category, which he asserts is related to bonus compensation. OCA St. No. 1 at 40. He further argues that costs are related to personnel of UGI Corp., Shared Executives, and Shared Service Center, and that the Company did not provide reasons for including such costs that relate to ratepayer benefits or customer service initiatives. OCA St. No. 1 at 40. He also claimed that "[t]here is no information as to whether these bonus payments related to business goals, financial goals, or operational goals in the areas of safety, reliability, customer satisfaction or the provision of safe and reliable utility service." OCA St. No. 1 at 40.

Q. Does the Company agree with OCA's proposed adjustment?

A. No.

Q. Please explain why not.

A. The amounts referenced by Mr. Mugrace in this section of his testimony are duplicative of amounts which he has already addressed (and for which he recommended disallowance) in the Incentive Compensation section of his testimony. Specifically, within OCA St. No. 1 at 17, Mr. Mugrace lists the following amounts (among others):

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

These are incentive compensation amounts that are allocated to UGI Electric from UGI Corp. and are the same amounts that are listed in a response to OCA-IX-6 (which requested amounts allocated from UGI Corp.) and cited in the A&G Salaries section of Mr. Mugrace's testimony. *See* CONFIDENTIAL UGI Electric Exhibit VKR-3R, which highlights these same amounts within two different data request responses. Due to such duplication, this adjustment should be rejected.

Q. Are there any other reasons to reject Mr. Mugrace's A&G Salaries adjustment for $178,000?

A. Yes. Putting aside the clear duplication error described above, the incentive compensation allocated from UGI Corp. provides the same benefits to customers described earlier in my testimony. The incentive compensation under these plans includes non-financial performance measures based on safety and diversity and inclusion, in addition to financial performance goals. Customers benefit from the following incentivized actions: (1) safety is at the core of providing safe and reliable utility service; (2) diversity allows the Company and its customers to benefit from diverse viewpoints and opinions; and (3) strong financial performance benefits customers by either reducing the Company's proposed revenue requirement in its base rate proceedings or enabling the Company to file less frequent base rate cases. Finally, these programs also work in conjunction with base compensation and benefits to incentivize and retain a talented workforce.

D. PENSION EXPENSE

Q. Do any of the parties propose adjustments to the Company's claimed Pension Expense?

A. Yes. OCA witness Mr. Mugrace recommends "normalizing the actual pension expense over a three-year period 2020-2022." OCA St. No. 1 at 36-37. Mr. Mugrace argues that "[t]his adjustment reduces the contribution and the proposed adjustment from $427,000 to $179,000, (after the allocation factors shown on Attachment OCA-II-30 (B)) a difference of $248,500." OCA St. No. 1 at 37; *see also* OCA Schedule DM-15.

Q. Does the Company agree with Mr. Mugrace's proposed adjustment?

A. No.

Q. Why does the Company disagree with Mr. Mugrace's proposed adjustment?

A. Mr. Mugrace's adjustment to the Company's claimed pension expense should be rejected by the Commission for two reasons. First, Mr. Mugrace's adjustment results from an apparent misunderstanding of the basis for the Company's claim to recover pension <u>costs</u>, which is its cash contribution to the pension fund. Second, his adjustment is inconsistent with established ratemaking practice in Pennsylvania, which allows public utilities to claim expense based on the cash contribution to their pension funds.

Q. Please explain why it appears that Mr. Mugrace misunderstands the basis for the Company's claim.

A. The Company made its claim based on the portion of total plan cash contributions that related to UGI Electric (distribution). Mr. Mugrace's adjustment appears to be predicated on a normalized amount of the <u>difference</u> between GAAP pension expense (per the Company's budget) and pension cash contributions properly based on a recent actuarial report. If accepted, his adjustment would result in a claim that is based on neither GAAP expense nor cash contributions and is not connected to the Company's cost for providing pension benefits.

Q. Is there discussion in your original testimony which clarifies the basis of the Company's pension claim?

A. Yes. In UGI Electric - Statement No. 3, page 18, lines 8 – 24, I discuss the calculation of the Company's benefits adjustments on Schedule D-14 within Exhibit A (Fully Projected), and specifically state that "the company claims pension costs within its rates on a cash basis."

Q. Have you prepared an exhibit that helps to explain the basis for the Company's claim?

A. Yes. UGI Electric Exhibit VKR-4R shows how the Company calculated its claim. Within Schedule D-14 to Exhibit A – Revenue Requirement (Fully Projected) in the initial filing, the Company calculated an adjustment of $427,000 to adjust from the pension expense in the budget of $293,000 ($235,000 of which relates to Electric Distribution) to the claimed cash contribution of $662,000. An alternative presentation would have shown two separate adjustments – the first to eliminate the expense in the budget and the second to record the claimed cash contribution of $662,000. This two-adjustment methodology is shown at UGI Electric Exhibit VKR-4R. However, both methodologies result from using the same amount of the actuary-determined $662,000 cash contribution claim within the Company's revenue requirement claim.

Q. Why is it relevant that the Company's claim for pension cost be based on cash contribution, not on pension expense?

A. UGI Electric, consistent with long-standing Commission precedent and like most public utilities within the state of Pennsylvania, has consistently based its pension cost on an actuary-determined cash contribution. If the Company were to change its method of recovery from period to period, it ultimately would not recover an appropriate amount of cost over the life of the pension plan. Therefore, Mr. Mugrace's recommendation to modify the Company's method of recovery should be rejected as inappropriate.

Q. You also testified that Mr. Mugrace's adjustment is inconsistent with established ratemaking practice in Pennsylvania. Please explain.

A. I am advised by counsel that, where a utility's claim to recover pension cost is based upon its actual cash contributions to the pension fund, it is generally inappropriate for those actual cash contributions to be normalized. It is my understanding that UGI Electric will further address this legal issue in its briefs.

Q. What would a normalization adjustment have been if it were calculated based on the Company's claim (i.e., on cash contributions)?

A. As shown at UGI Electric Exhibit VKR-5R, if the Company's pension claim had been normalized for the period 2020–2022, the amount of the claim would have been $521,000, or a reduction of $141,000 from the Company's actual claim. While I do not agree with Mr. Mugrace's suggestion to normalize the Company's claim for the reasons stated above, if his suggestion to normalize is upheld, the amount of the adjustment should be based on the Company's claim rather than on Mr. Mugrace's misguided calculation of the difference between expense and cash.

E. UNCOLLECTIBLES EXPENSE

Q. Do any of the parties propose adjustments to the Company's uncollectibles expense claim?

A. Yes. OCA witness Mr. Mugrace proposes an adjustment to this expense category.

Q. Please describe Mr. Mugrace's proposed adjustment.

A. Mr. Mugrace recommends that the Company's uncollectibles expense be reduced by $168,047. OCA St. No. 1 at 31-32; OCA Schedule DM-12. He explains that this adjustment is based upon his recommended revenue requirement. OCA St. No. 1 at 31-32.

Q. Does the Company agree with OCA's proposed adjustment?

A. No.

Q. Please explain why not.

A. Mr. Mugrace's adjustment is based on his recommended revenue requirement. As discussed herein and within the testimony of other UGI Electric witnesses, the Company does not agree with OCA's adjusted revenue requirement. Therefore, the Company also does not agree with his derivative uncollectible expense adjustment.

F. OTHER ADVERTISING EXPENSES

Q. Do any of the other parties propose any adjustments to the Company's claimed advertising expenses?

A. Yes. Both OCA witness Mr. Mugrace and I&E witness Mr. Keller propose to reduce the Company's claimed advertising expenses in their direct testimony.

Q. Please describe the adjustments to advertising expenses proposed by OCA and I&E.

A. OCA witness Mr. Mugrace recommends that the Company's claimed Other Advertising Expenses and Other Media Expenses be reduced by $83,252. OCA St. No. 1 at 38-39. Mr. Mugrace asserts that these costs are associated with expenditures related to community-based sponsorship. OCA St. No. 1 at 38-39. He further asserts that these sponsorships mainly benefit the Company, and not its customers, by contributing to the Company's advocacy on policy issues before State and Governmental agencies. OCA St. No. 1 at 39.

I&E witness Mr. Keller recommends that the Company's claim for Other Advertising Expense be reduced by $67,000. I&E St. No. 2 at 12, 15. Mr. Keller explains that his recommendation is designed to decrease the Company's Other Advertising Expense to the HTY amount, because "the increase to the FPFTY claim is primarily for event sponsorships, builder meetings, tradeshows, and arena signage." I&E St. No. 2 at 13. He further argues that these types of advertising are goodwill/promotional advertising that do not benefit customers. I&E St. No. 2 at 14.

Q. Does the Company agree with OCA's and I&E's recommendations to reduce Other Advertising Expenses?

A. No.

Q. Please explain why not.

A. As a general matter, OCA and I&E propose too narrow of a standard for determining whether these expenses can be recovered in rates. I am advised by counsel that a public utility is not required to show that these types of advertisements benefit customers; rather, they must be reasonable, prudent and meet <u>one of</u> the criteria listed in 66 Pa.C.S. § 1316(a). Importantly, a public utility can show that its advertising expenses are recoverable if those advertisements provide information regarding, safety, rate changes, means of reducing usage or bills, load management or energy conservation, or if the advertising is for the promotion of community service or economic development.

Q. Please explain how UGI Electric uses sponsorships and related advertising to achieve these objectives.

A. UGI Electric uses sponsorships and related advertising as a means of connecting with the communities in which it provides services. As UGI Electric and its employees develop a presence in the community, customers can connect with the Company and receive information about billing, customer programs, safety, or utility services. At certain events, the Company can present information about careers in utilities, leading to opportunities for recruiting of employees. These opportunities ensure that the Company's potential customer base remains aware of the Company and the services it provides, and serve as an attraction for potential customers and potential employees.

The amounts within the Company's claim for advertising expense also include costs for chambers of commerce and economic development alliances, which promote economic development. The Company participates in these organizations because of its interest in growing its customer base, which benefits all customers as fixed costs are then spread over a larger number of customers. However, the costs included in the claim are not related to advocacy of policy issues with governmental agencies. Such costs (which the Company classifies as lobbying costs) are excluded from the Company's revenue claim.

G. ASSOCIATION DUES

Q. Do any of the other parties oppose the Company's claim for recovery of certain association dues?

A. Yes. OCA witness Mr. Mugrace proposes to disallow $7,000 in association dues from the Company's claim, which are related to the Company's membership in the Energy Association of Pennsylvania ("EAP"). OCA St. No. 1 at 38. He argues that these expenses should not be recovered in rates because EAP is an association that promotes interests of regulated electric and gas companies, and that the Company has not provided a breakdown of what is included in this amount. OCA St. No. 1 at 38.

Q. Does the Company agree with the adjustment proposed by OCA?

A. No.

Q. Please explain why it is appropriate for the Company to recover its association dues related to its membership in EAP.

A. The Company's membership in EAP provides opportunities to connect with other public utilities in the state of Pennsylvania. These opportunities allow the Company's professionals to discuss best practices related to operations, safety and other matters specific to the utility industry. It is appropriate for the Company to recover the cost of this membership as it is a cost that is reasonably incurred to support the provision of safe and reliable electric utility service to its customers. Moreover, the Company's claim specifically excludes amounts identified by EAP as those related to any lobbying efforts.

H. ENVIRONMENTAL, SOCIAL AND GOVERNANCE ("ESG") COSTS

Q. Do any parties propose an adjustment to the Company's claim to recover certain ESG costs?

A. Yes. OCA witness Mr. Mugrace recommends disallowance of $11,000 related to ESG costs incurred in the FPFTY. OCA St. No. 1 at 39-40. He argues that ESG goals "mainly relate to corporate social goals of maximizing profits on behalf of the Company's shareholders and advocating for certain environmental goals." OCA St. No. 1 at 39. He further argues that "[t]hese types of costs should not be recovered from ratepayers as they do not support the safe and reliable utility service requirements, but rather the costs are akin to sponsorships and civic related activities." OCA St. No. 1 at 40. He goes on to state that "[r]atepayers should not be responsible for how… an organization manages its risk or corporate philanthropy." OCA St. No. 1 at 40.

Q. Does the Company agree with Mr. Mugrace's proposal to disallow these costs?

A. No.

Q. Please explain why not.

A. Mr. Mugrace's characterization of ESG goals is misguided. Customers benefit from ESG initiatives in many ways, including but not limited to efforts to reduce greenhouse gas emissions. Programs such as UGI Electric's EE&C program, which is available to all UGI Electric customers, bring direct benefits to the customers and communities that UGI Electric serves. Robust ESG programs, such as the one being implemented at UGI Electric, have the potential to increase transparency, improve corporate governance, and nourish a corporate culture that will ultimately deliver a better quality of customer service experience to UGI Electric customers and the communities the Company serves.

Q. What role does the Company's ESG initiatives play in ensuring the financial health of UGI Electric?

A. ESG goals are important to the investor community, which secures the future success of this Company and enables the continued provision of safe and reliable service to customers by funding capital investment.

ESG is a "hot topic" in the investment community. Investors are interested in a Company's ESG strategy and often request this information prior to investing in a company's stock. The New York Stock Exchange (where the stock of UGI Corp. is traded) has developed an ESG Resource Center website for its members and investors. UGI Corp. has published four annual reports on ESG and plans to issue its fifth ESG report in June

2023. In December 2022, UGI Corp. received a rating of AAA from rating agency MSCI ("Morgan Stanley Capital International"), which indicates that UGI is among the leading companies worldwide for action across ESG matters. In response to investor demand for ESG information, on March 21, 2022, the United States Securities and Exchange Commission ("SEC") proposed enhanced and standardized climate-related disclosures from its registrants. While the complete guidance for these disclosures is not expected to be published until later in 2023, the Company has begun its preparation for these requirements based on currently-available information, and a portion of the ESG costs claimed in the UGI Electric case will be used to prepare for and/or comply with this SEC proposal.

Customers benefit from ESG goals and policies because of the resulting reduction in emissions and because such policies make the Company's stock more attractive to investors. As investors choose to invest in the Company, capital becomes available to fund improvements, such as infrastructure upgrades and expansion, leading to safer, more reliable, and environmentally-friendly electric service.

I. DEPRECIATION EXPENSE

Q. Do any of the other parties propose an adjustment to the Company's claimed depreciation expense?

A. Yes. OCA witness Mr. Mugrace recommends that the Company's claimed depreciation expense be decreased by $16,590 based upon OCA's proposed adjustment to utility plant in service at the end of the FPFTY. OCA St. No. 41; OCA Schedule DM-16.

Q. Does the Company agree with OCA's proposed adjustment to depreciation expense?

A. No. The Company disagrees with these adjustments, which are derivative of OCA's proposed adjustment to the Company's utility plant in service claim. The proposed utility plant in service adjustments should be rejected for the reasons explained in UGI Electric witness Ms. Schappell's rebuttal testimony (UGI Electric St. No. 5-R).

V. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI Electric Exhibit VKR-1R
(No Public Version Available)

UGI Electric Exhibit VKR-2R

UGI Utilities – Electric Division

Explanation of Director Compensation

From UGI Corporation Notice of Annual Meeting and Proxy Statement

Filed with the SEC on December 14, 2022

COMPENSATION OF DIRECTORS

DETERMINATION OF NON-EMPLOYEE DIRECTOR COMPENSATION

Our Board of Directors plays a critical role to guide our strategic direction and create and sustain long-term value for our shareholders, with intense focus on corporate governance best practices. In order to attract and retain highly qualified, skilled, diverse and experienced public company directors to effectively guide the Company and address the risks and responsibilities associated with a company of size and complexity similar to UGI, it is necessary to provide a competitive director compensation program. Our non-employee Directors are compensated based upon their service as a Director as well as their respective roles on Board Committees. Our employee Directors receive no separate compensation for their service as Directors.

Our director compensation is overseen by the Corporate Governance Committee, which makes recommendations to our Board of Directors on the structure of our non-employee director compensation program and the appropriate amount of compensation. Our Board of Directors is responsible for approval of our non-employee director compensation program and the compensation paid to our non-employee Directors. In establishing director compensation, our Corporate Governance Committee and our Board of Directors rely on market comparables and assess the vital strategic skills and qualifications of the Board to fulfill our Company's short- and long-term goals.

The Corporate Governance Committee retained Pay Governance as its independent compensation consultant to assist with the review of our non-employee director compensation and incentive programs for Fiscal 2022. In connection therewith, Committee member and chair retainers, the number of Board and Committee meetings, stock-based compensation, share ownership requirements and total cash and equity compensation were reviewed.

For our non-employee Directors, other than our Board Chair, we referenced market data provided to us by Pay Governance that compared our non-employee director compensation to similarly-sized companies in the General Industry (weighted 75%) and Energy Services (weighted 25%) sectors. This methodology is consistent with the methodology used to benchmark the compensation of our named executive officers. We seek to position our non-employee director compensation (other than the Board Chair) within 10% of the median total compensation of the directors included in the databases referenced by Pay Governance. See COMPENSATION DISCUSSION AND ANALYSIS – Determination of Competitive Compensation for additional information on the methodology used to benchmark the compensation of our named executive officers.

DETERMINATION OF BOARD CHAIR COMPENSATION

As discussed in greater detail below, the Corporate Governance Committee and Board of Directors (with the Board Chair recusing himself from discussions and decisions regarding incremental Chair compensation) rely on market data as well as a number of other factors in determining independent Chair compensation. The size and complexity of the Company's business, including that we operate domestic and international LPG businesses, a domestic natural gas and electric utility business, and domestic and international midstream businesses, drives the need for our Board Chair to dedicate a significant amount of time to Company-related matters. In addition, we believe that our Board Chair's duties and responsibilities are significantly more strategic and expansive than those of a typical board chair.

Our Board of Directors considers it to be a best practice from a corporate governance standpoint to have an independent chair of the board of directors. Because a significant majority of the companies included in the Energy Services Database have an executive chair of their board of directors rather than an independent chair, as independence is defined under New York Stock Exchange rules, we do not believe that sufficient comparable data exists to appropriately determine compensation for UGI's independent Chair using the methodology applied to our director compensation generally. As a result, for UGI Board Chair compensation, Pay Governance referenced a comparator group selected from the General Industry Database based on: (i) a combination of median revenue and market capitalization similar to those of the Company and (ii) a representation of a variety of industries that reflect a cross-section of operations that are reflective of the Company's complexity. The median revenue of the comparator group was $6.7 billion (UGI's revenue for the same Fiscal 2020 period was $6.6 billion) and the median market capitalization of the comparator group was $10 billion as of May 31, 2021 (UGI's market capitalization as of May 31, 2021 was $9.6 billion).

Consistent with the aforementioned methodology, the following is the comparator group referenced for purposes of determining the Fiscal 2022 compensation of our Board Chair:

Alliance Data System
American Water Works
Big Lots, Inc.
Campbell Soup
CDK Global, Inc.
Conagra Brands, Inc.
Crane Co.
Discover Financial
Dover Corporation
Encompass Health
Hanesbrand Inc.
Hawaiian Electric
Invesco Ltd.
Lincoln National
NiSource Inc.
Nordstrom, Inc.
NRG Energy, Inc.
Perrigo Company plc
Reliance Steel
Stanley Black & Decker
The AES Corporation
The Chemours Company
The Williams Cos.
Tractor Supply
Unum

In addition to referencing the above general industry comparator group, the Corporate Governance Committee and Board of Directors (with the Board Chair recusing himself from the discussion and decision regarding incremental Chair compensation) considered a number of other factors in determining the compensation for the Board's independent Chair within a range of 10% of the $440,000 Fiscal 2022 median total compensation of the comparator group. These factors include the significant time commitment spent by the Board Chair on Company-related matters in light of the size and complexity of the Company's business, including domestic and international LPG businesses, a domestic natural gas and electric utility business, and domestic and international midstream businesses. Furthermore, UGI's Board Chair role involves a variety of significant strategic responsibilities that drive value for our shareholders, including merger and acquisition activities, business transformation projects, capital project investment reviews, chief executive officer succession planning, regular discussions with management regarding the Company's strategic direction and communications, and direct engagement with the Company's investors. We view the role of UGI's Board Chair as a highly strategic role with duties and responsibilities over and above traditional Chair activities, which would include chairing meetings, setting meeting agendas and facilitating discussions with other directors on the board in between meetings.

By comparison, use of an alternative methodology referencing a comparator group comprised of companies with independent chairs and in UGI's two-digit GICS utilities classification would result in comparing UGI's revenue of $6.6 billion to a median revenue for the comparator group of only $1.5 billion and UGI's market capitalization of $9.6 billion to a median market capitalization for the comparator group of only $3.8 billion. The median chair compensation for this comparator group is approximately $300,000. We do not believe, for purposes of benchmarking, that this is a relevant comparison. In addition, and as further support that UGI's two-digit GICS classification does not generate a relevant comparator group, more than 75% of UGI's earnings were derived from its non-regulated non-utility businesses in Fiscal 2022. Accordingly, we believe that the general industry comparator group utilized by the Company in determining Chair compensation more appropriately reflects the size, complexity and composition of the Company's business.

ELEMENTS OF NON-EMPLOYEE DIRECTOR COMPENSATION

ELEMENTS OF NON-EMPLOYEE DIRECTOR COMPENSATION

For Fiscal 2022, our non-employee director compensation program consisted of: (i) annual cash retainers for Board service and for service as the chair or member of one of the standing Board Committees and (ii) long-term equity awards granted on an annual basis to non-employee Directors immediately following the Company's Annual Meeting of Shareholders, or following their initial appointment to the Board for new directors. Our non-employee Directors did not receive any Board or committee meeting fees in Fiscal 2022.

- ***Annual cash retainers***

In Fiscal 2022, the Company paid its non-employee Directors an annual base retainer of $102,500 for Board service and paid an additional annual retainer of $12,500 to members of the Audit Committee, other than the chair of the Committee. The Company also paid an annual retainer to the chair of each of the Committees, other than the Executive Committee, as follows:

Audit Committee Chair	$25,000
Compensation and Management Development Committee Chair	$20,000
Safety, Environmental and Regulatory Compliance Committee Chair	$15,000
Corporate Governance Committee Chair	$15,000
Pension Committee Chair	$15,000

In addition, the Company paid Mr. Hermance an additional cash retainer of $68,500 for his service as independent Chair for Fiscal 2022.

- ***Annual Long-Term Equity Awards***

Each non-employee Director continuing to serve as a Director after the adjournment of the 2022 Annual Meeting of Shareholders received long-term equity grants consisting of 2,300 UGI stock units and 6,050 UGI stock options. Mr. Hermance received an additional 1,810 UGI stock units and 4,760 UGI stock options in Fiscal 2022 for his service as Chair of the Board. Our philosophy is to pay a higher percentage of total compensation in equity, rather than cash, to more closely align the interests of our non-employee Directors with those of our shareholders. In addition, all non-employee Directors are required to own Company common stock, together with stock units, in an aggregate amount equal to five times the Director's base annual cash retainer. As of September 30, 2022, Mr. Hermance, the Chair of our Board, owned 465,000 shares of UGI common stock and 49,469 UGI stock units, which equated to a value of $16,632,782 (approximately 36 times Mr. Hermance's total compensation for Fiscal 2022).

The UGI stock units and stock options were granted under the UGI Corporation 2021 Incentive Award Plan (the "2021 Plan"). Each stock unit represents the right to receive a share of stock and dividend equivalents when the Director ends his or her service on the Board. Stock units earn dividend equivalents on each record date for the payment of a dividend by the Company on its shares. Accrued dividend equivalents are converted to additional stock units annually, on the last date of the calendar year, based on the closing stock price for the Company's shares on the last trading day of the year. All stock units and dividend equivalents are fully vested when credited to the Director's account. Account balances become payable 65% in shares and 35% in cash, based on the value of a share, upon retirement or termination of service, unless a deferral election to defer payout of the stock units was made pursuant to the UGI Corporation 2009 Deferral Plan. In the case of a change in control of the Company, the stock units and dividend equivalents will be paid in cash based on the fair market value of the Company's common stock on the date of the change in control.

For UGI stock options, the option exercise price is not less than 100% of the fair market value of the common stock on the effective date of the grant. The term of each option is generally 10 years, which is the maximum allowable term. The options are fully vested on the effective date of the grant. All options are nontransferable and generally exercisable only while the Director is serving on the Board, with exceptions for exercise following disability, death or retirement. If termination of service occurs due to disability, the option term is shortened to the earlier of the third anniversary of the date of such termination of service or the original expiration date. In the event of death, the option term will be shortened to the earlier of the expiration of the 12-month period following the

Director’s death or the original expiration date. If termination of service occurs due to retirement, as defined in the 2021 Plan, the option remains exercisable through its original expiration date.

UGI Electric Exhibit VKR-3R
(No Public Version Available)

UGI Electric Exhibit VKR-4R

UGI Utilities, Inc. - Electric Division
Calculation of Pension Claim
For the Fully Projected Future Test Year Ended September 30, 2024
$ Amounts in '000s

Claim as shown at Schedule D-14 in Exhibit A - Revenue Requirement (Fully Projected):

Total budgeted pension expense	$ 293	A		
Distribution Allocation Factor	80.05%	B		
UGI Electric Pension Expense	$ 235	A*B=C		
Pension cash contributions per updated estimates	$ 827	D		
Distribution Allocation Factor	80.05%	B		
UGI Electric Pension Cash Contribution	$ 662	D*B=E		**UGI Electric Pension Claim**
Pro Forma Adjustment - Pension	$ 427	E-C		

Alternative Method of Showing Adjustment(s) for Pension:

Total budgeted pension expense	$ 293	A			
Distribution Allocation Factor	80.05%	B			
UGI Electric Pension Expense	$ 235	A*B=C			
Adjustment #1 to remove budgeted pension expense			$ (235)	F	
Pension cash contributions per updated estimates	$ 827	D			
Distribution Allocation Factor	80.05%	B			
UGI Electric Pension Cash Contribution	$ 662	D*B=E			**UGI Electric Pension Claim**
Adjustment #2 to claim pension cash contribution			$ 662	G	
Pro Forma Adjustment - Pension			$ 427	F+G	

UGI Electric Exhibit VKR-5R

UGI Utilities, Inc. - Electric Division
Pension Claim Normalization Calculation
Amounts from Attachment OCA-II-30 (B)
Dollar Amounts in Thousands

Item		2018	2019	2020	2021	2022	2023	2024	Avg. for Selected Period	Calculated Normalization Adjustment
Distribution rate	A	*76.48%*	*77.48%*	*75.61%*	*80.05%*	*80.05%*	*80.05%*	*80.05%*		
Cash contribution	B	$ 13,439	$ 11,467	$ 12,606	$ 12,176	$ 11,364	$ 14,256	$ 14,256		
Cash contribution attributable to UGI Electric	C	$ 1,164	$ 1,074	$ 1,023	$ 1,030	$ 1,011	$ 1,272	$ 1,272		
Capitalized portion	D	$ (407)	$ (376)	$ (358)	$ (361)	$ (354)	$ (445)	$ (445)		
UGI Electric Pension Cash Contribution	C+D = E	$ 757	$ 698	$ 665	$ 669	$ 657	$ 827	$ 827		
UGI Electric Pension Cash Contribution - non-capitalized, Distribution portion	E * A	$ 579	$ 541	$ 503	$ 536	$ 526	$ 662	$ 662	$ 521	$ (141)

The normalization period selected by Mr. Mugrace is highlighted above.

The pension normalization adjustment shown is based on normalization of the Company's claim for cash contributions (which is not the amount that Mr. Mugrace proposed).

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2022-3037368, et al.

UGI Utilities, Inc. – Electric Division

Statement No. 4-R

Rebuttal Testimony of
Eric W. Sorber

Topics Addressed:	**Vegetation Management** **Major Storm Expense** **Outside Contractor Expenses** **Battery Storage Project**

Dated May 25, 2023

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Eric W. Sorber. My business address is One UGI Center, Wilkes Barre, Pennsylvania 18711.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Electric Statement No. 4, on January 27, 2023.

Q. What is the purpose of your testimony?

A. My rebuttal testimony responds to certain portions of the following direct testimony submitted by other parties: OCA Statement No. 1, the direct testimony of Dante Mugrace; and OCA Statement No. 5, the direct testimony of Morgan N. DeAngelo.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes, as part of my rebuttal testimony I am sponsoring UGI Electric Exhibits EWS-1R through EWS-3R.

II. VEGETATION MANAGEMENT

Q. What was OCA's response to the Company's proposed vegetation management program expense?

A. In OCA Statement No. 1, Mr. Mugrace claimed that the planned vegetation management expense proposed by UGI Electric should be reduced by $1,431,151 to a level of approximately $2,500,626. (OCA St. No. 1 at 24-25.) This adjustment is based on Mr.

Mugrace's use of a five-year historic average for 2018 through 2022. (OCA St. No. 1 at 24.)

Q. Do you agree with Mr. Mugrace's analysis?

A. No, I do not. Utilizing a five-year historic average significantly understates the Company's actual vegetation management expenses for the FPFTY because:

- A five-year average does not consider or reflect that the Company has significantly accelerated its vegetation management activities and expenses over the five-year period; and
- A five-year backward-looking analysis does not account for planned increases to vegetation management expense in the FTY or FPFTY.

Q. How has UGI Electric accelerated spending related to vegetation management?

A. The Company began its accelerated vegetation management activities in 2018. Table 1, below, shows UGI Electric's actual and budgeted vegetation management activities since 2018.

Table 1: Annual Distribution Vegetation Management Expense, 2018-2024

FY2018 Actual	FY2019 Actual	FY2020 Actual	FY2021 Actual	FY2022 Actual	FY2023 (FTY) Budget	FY2024 (FPFTY) Budget
$2,011,036	$2,189,747	$1,858,722	$3,238,551	$3,205,072	$3,807,997	$3,931,777

As shown in Table 1, in 2018, the Company spent just over $2.0 million, and has increased substantially in the last two fiscal years to more than $3.2 million—an increase of approximately $1.2 million, or 59%.

The Company's vegetation expenses are clearly increasing over time. Mr. Mugrace does not dispute this fact; nor does he make any argument that the amount claimed in the FPFTY is unreasonable or will not be expended. On these facts, the use of a five-year historic average will simply result in the Company's inability to recover its reasonable and prudent vegetation management costs in rates. This will compromise its ability to provide safe and reliable service to its customers. In some instances where an expense is highly variable (moving up and down substantially over time) some type of averaging approach may make sense. As shown above, however, the Company's vegetation management activities and associated expenses have steadily increased over time and the use of a five-year historic average is neither reasonable nor appropriate, particularly when dealing with vegetation management, which is critical to the provision of safe and reliable service to customers.

Q. Why has UGI Electric accelerated spending related to vegetation management?

A. As stated in the Executive Summary of the Commission's 2021 Electric Service Reliability Report: "Trees, and especially [off-right-of-way] trees, are again the leading cause of outages and customer minutes interrupted in Pennsylvania."[1] That has certainly been UGI Electric's experience. In particular, off-right-of-way trees, which are the most difficult and expensive to access and maintain, are the primary culprit with respect to outages and damage to electric infrastructure. In addressing this critical safety and reliability issue, the Company's vegetation expenses have been increasing for several reasons. The primary reason is that the Company has increased resource hours working on the entire scope of

[1] https://www.puc.pa.gov/General/publications_reports/pdf/Electric_Service_Reliability2021.pdf.

vegetation management activities across the system. A continued acceleration will eventually reduce the average system trim cycle from over 6 years, prior to 2018, to an optimum goal of approximately 4 to 5 years, aligning with industry best practices. These additional resource hours have been achieved by adding full-time equivalent ("FTE") employees to the Company's primary vegetation contractor, working overtime hours and via supplemental vegetation work, utilizing line-mile bid contracts and other third-party vegetation contractors. This workforce is focused on reducing annual vegetation trim cycles and removing vegetation including danger trees on and off right-of-way to address risk to our facilities, so that UGI Electric can continue providing safe and reliable service under the Public Utility Code. The Company's service territory has experienced the mass decline of certain prominent vegetation species, like ash and hemlock, due to non-native invasive insects, such as the emerald ash borer and the hemlock woolly adelgid. The increased mortality of these large trees has created an elevated and ongoing danger tree risk that is expected to continue and potentially increase because of emerging issues from new invasive species, such as the spotted lanternfly.

These danger tree factors present an ongoing reliability challenge with respect to maintaining current benchmark reliability performance metrics. UGI Electric, like other utilities, focuses on addressing this vegetation challenge through a combination of capital-based Long Term Infrastructure Improvement Plan ("LTIIP") projects and increased vegetation management. Increased vegetation management activity translates to more tree removals, more trimming mileage, and more off-cycle vegetation management work. As related specifically to off-right-of-way trees, UGI Electric continues to engage additional property owners to obtain required authorizations in order to remove identified danger trees presenting risks to distribution system overhead wires.

Indeed, UGI Electric has already reduced the number of years between trim cycles on 15 of its 50 overhead distribution circuits, increased the number of danger tree removals as documented in UGI Electric Exhibit EWS-1R, and accelerated targeted removals and "hot-spotting" to address poor performing circuit elements and Customers Experiencing Multiple Interruptions ("CEMI"); each driving incremental costs. For example, in FY2022 and FY2023 YTD, the Company completed targeted vegetation trimming and removals on 7 of the top 10 CEMI areas. In addition, the Company also recently completed work to widen the right-of-way along more than a mile of 3-phase line, which is at the start of a circuit that serves nearly 900 customers. This expanded the width of the right-of-way from 20' to 60' and removed over 2,000 trees that threatened reliability. *See* UGI Electric Exhibit EWS-2R.

Q. Why else is Mr. Mugrace's proposed backward-looking five-year average approach not appropriate to establish the level of vegetation management expense in this proceeding?

A. In addition to failing to recognize the acceleration of the vegetation management program that the Company has undertaken over the past several years as discussed above, Mr. Mugrace's backward-looking approach also does not consider labor cost increases or planned additional work that extends through the FPFTY period. UGI Electric vegetation contractor labor rates, based on the 2021 contract that extends through 2024, will be 30%

higher in the FPFTY as compared to 2018. The Company also has additional incremental contract work planned for the FPFTY.

Q. Are there any other flaws with Mr. Murgrace's use of a five-year average?

A. Yes. Mr. Mugrace's five-year average encompasses 2020, where COVID-19 materially impacted the Company's vegetation management spend. In 2020, vegetation management spend fell to an amount of $1,858,722, a reduction from the two prior years. It is clear that the 2020 data is an outlier. Further, using 2018 and 2019 data is also clearly non-representative of the Company's existing program. Using that data to arrive at a future number would not even provide the Company with enough funds to cover the <u>actual</u> expense of the vegetation management program for FY2021 and FY2022, no less address the known increases to costs identified in my testimony.

Q. How do the Company's plans for the FTY and FPFTY compare with the past two years?

A. As seen in Table 1, the Company's vegetation management budget is $3.8 million for the FTY and $3.9 million for the FPFTY. These amounts reflect an increase from the FY2022 (HTY) and FY2021 level of $3.2 million. The additional increase in vegetation management expense between the past two years and the FTY is driven primarily by dedicated resource hours focused on distribution vegetation management activities in-line with budget. The Company is using both (1) baseline vegetation management crew resources and (2) incremental vegetation work contracts in place with two additional vegetation contractors. The additional contractors include a seven-person manual crew that has focused on difficult right-of-way tracts including CEMI areas and a mechanized vegetation contractor that utilizes specialized equipment to efficiently remove large quantities of trees. Funding for these incremental resources to date is nearly $300,000. Table 2 shows the to-date, FY2023 actual and projected spending related to vegetation management broken out by month, with the remaining budget split across the remaining months:

Table 2: Actual and Forecasted Distribution Vegetation Maintenance Expense For FY2023

Month	Spend	
Oct	$ 420,087	
Nov	$ 259,723	
Dec	$ 291,316	
Jan	$ 303,421	
Feb	$ 261,360	
Mar	$ 349,630	
Apr	$ 291,501	
May	$ 321,000	(1)
Jun	$ 321,000	(1)
Jul	$ 321,000	(1)
Aug	$ 321,000	(1)
Sep	$ 381,000	(2)
Total	$ 3,842,039	

Note (1) – Through April is actual, May forward is forecasted baseline resource spend for balance of year
Note (2) - Includes baseline resource spend plus additional planned third-party contractor

As can be calculated from Table 2, the actual year-to-date through April vegetation management spend has averaged $311,005 per month as baseline resource spend. With a minor increase in summer monthly spend projections at $321,000 per month and just one month of planned additional third-party contractor spend in September, Table 2 clearly shows that the Company is on track to fully spend the budget amount of $3.8 million for FY2023. I would note that, based on the year-to-date actuals shown in Table 2 and using

Mr. Mugrace's proposed annual vegetation management expense budget of $2,500,626, UGI Electric would have a mere $323,587 left in its budget for the remaining five months of the year, or just $64,717 per month. Those five months are the busiest and most critical season from a vegetation management perspective. The remaining OCA budget would only allow UGI Electric to cover a single month of the Company's anticipated summer vegetation work and, if the Company were to plan for that spend limit, crew layoffs would be required.

Q. For the FPFTY, how do the Company's plans compare to the activities you have identified for the FTY?

A. For the FPFTY, the Company is planning to utilize incremental line-mile vegetation bid work as was the case in FY2021 and FY2022 to supplement the baseline vegetation crews to achieve the budgeted amount of $3.9 million. The FPFTY budget amount includes a 4% increase in labor rates year over year as required under the current vegetation management contract for base resources. Thus, given that UGI Electric is fully on track to meet or slightly exceed its vegetation management distribution budget in the FTY, the Company's claimed vegetation management expense of $3.9 million for the FPFTY is fully supported.

Q. Do you have any concluding comments on vegetation management expense?

A. Yes. Vegetation management is a critical tool in combating customer outages and supporting safety and reliability across the distribution system. The Company is not immune from the industrywide increase in both the cost and amount of vegetation management work which needs to be completed to maintain and/or improve reliability performance. The Company will continue to increase resources in this area as appropriate. The Commission should not reduce the Company's vegetation expense budget by accepting OCA's proposed five-year average expense method in this area when there is a clear need for UGI Electric to continue undertaking this work and where the amount and cost of needed work continues to expand. Thus, OCA's adjustment should be rejected.

III. MAJOR STORM EXPENSE

Q. Please describe the adjustment proposed by OCA to the Company's Major Storm Expense.

A. Mr. Mugrace proposed an adjustment to the Company's claim based on a five-year average. In doing so, he has arrived at a Maintenance Expense of $561,000 and a Mutual Assistance Expense of $241,000, for a total of $802,000 in Major Storm Expense. (OCA St. No. 1 at 25.) This is an overall $42,000 increase to the Company's claim.

Q. What is UGI Electric's response to the proposed adjustment?

A. UGI Electric can accept Mr. Mugrace's adjustment for this expense item. It is worth noting here that a multi-year average of Major Storm Expense is a reasonable approach to establishing ratemaking recovery for this expense considering the Company has little control over the causation of these expenses. This differs from vegetation management expense, where the Company plans in advance for the use of its resources and has actively engaged in an accelerated approach to vegetation management planning over the last five years. To the contrary, Mr. Mugrace's testimony suggests that the same methodology should be used for these two categories of expense, when the facts surrounding the cost build up are distinguishable.

IV. OUTSIDE CONTRACTOR EXPENSE

Q. Please describe the OCA's adjustments to Outside Contractor Expense.

A. The OCA proposes to use a three-year average to normalize the contractor labor costs of five categories of operations and maintenance expenses:

FERC Account	UGI Claim	OCA Allowance	Adjustment
583 Overhead Lines Expense	$163,000	$92,000	$71,000
588 Miscellaneous Distribution Expense	$7,000	$3,000	$4,000
595 Maintenance of Line Transformers	$66,000	$41,667	$24,333
596 Maintenance of Street Light	$7,000	$4,333	$2,667
598 Maintenance of Misc. Distribution Plant	$5,000	$3,667	$1,333
Total	$248,000	$144,667	$103,333

The total adjustments proposed by OCA reflect a decrease of $103,333, or a reduction of approximately 41% from the Company's total claimed amount of $248,000. (OCA St. No. 1 at 26-27.) Mr. Mugrace states that his review of these costs shows that they fluctuate over time, and are volatile in nature and unpredictable, and thus he believes that a three-year average is appropriate. (OCA St. No. 1 at 26.)

Q. Do you agree with the OCA's recommended adjustments?

A. No, I do not. Of this adjustment amount, a majority—$71,000—is related to FERC Account 583. However, the use of a three-year average for this account is entirely inappropriate.

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Q. Why would a three-year average be inappropriate for FERC Account 583 – Overhead Line Expenses?

A. Contractor labor charged to this account consists of three primary activities which support the Company's ongoing and long-term inspection and maintenance ("I&M") programs. These programs are generally performed annually with consistent requirements outlining the scope of work. The first requirement is the Company's Overhead I&M program, which covers half the distribution system annually and is completed by a third-party contractor. The second is the Company's annual pole inspection and treatment program, which includes work to inspect and treat approximately 4,000 poles annually. This program is also performed by a third-party contractor. The last is the Company's distribution disconnect and air-break I&M program. This program is performed on a five-year cycle which includes an off-year at the end of the cycle—and FY2023 is the off-year. Thus, the expense amount for FY2023 does not reflect a normalized cost for this disconnect and air-break I&M program. This work is performed by the Company's contractor of choice and includes some flagging expense. The historical charges for these programs are captured in FERC Account 583 across several Line-Item categories, as identified in UGI Electric's discovery response to OCA-II-34 (i.e., the response referenced by Mr. Mugrace on page 26 of his direct testimony), and taken as a whole, represent the historical spend for these programs annually. Looking at the budgets for FY2023 and FY2024, the contracted program dollars that were included in FERC Account 583 for all programs were budgeted in a single Line-Item category. UGI Electric Exhibit EWS-3R shows historic expense information for FERC Account 583, which provides further clarification of baseline costs associated with all contractor labor and demonstrates annual spending for these programs that far exceeds OCA's recommendation.

Q. Can you quantify a normalized expense amount for FERC Account 583 – Overhead Line Expenses and compare that to OCA's recommended $71,000 downward adjustment?

A. Yes. In particular, in recognizing the 5-year cycle (4 on years, 1 off year) impact of the cost which flow to this account and using the data presented in UGI Exhibit EWS-3R, the "4 on years" can be assessed by using an average of the "on years" contained on that exhibit: $257,487 (2020 expenses), $316,038 (2021 expenses) and $293,618 (2022 expenses), or $289,048 per year. The "1 off year" can be assessed at the stated FY2023 value of $149,000. Thus, using the average "on year" spend of $289,048 for 4 years plus one year at $149,000 is $261,038 per year on a normalized basis ((4 x $289,048 plus 1 x $149,000) / 5). As compared to Mr. Mugrace's recommended $92,000, the corrected normalized expense level should be $169,038 higher.

Q. Given this analysis, what is the Company's recommendation related to FERC contracted labor accounts?

A. The Company's analysis demonstrates that Mr. Mugrace should be recognizing an amount of $169,038 as an offset to his total recommended adjustments of $103,333 for these FERC contractor labor accounts in order to properly normalize these expenses. As a result, the Company is recommending that none of Mr. Mugrace's adjustments should be made. To be clear, the Company is not recommending that the Company's claim in this area should be increased at this time, either.

V. BATTERY STORAGE PROJECT

Q. Please summarize the OCA's testimony regarding the battery storage project that UGI Electric proposed in the 2021 base rate case and that was described in your direct testimony.

A. OCA witness Mr. DeAngelo states that UGI Electric should continue to look for reliability solutions for the customers that would have been impacted by the Company's battery storage project. (OCA St. No. 5 at 4.) He also testifies that because the Company redirected the $1.5 million battery storage project budget to other reliability projects, UGI Electric now does not have funding available for a reliability project to serve the customers of Ruckle Hill Road. (OCA St. No. 5 at 4.) Mr. DeAngelo recommends that the Company prioritize finding a reliability solution for these customers and provide a status report at the end of the FPFTY that includes any information or developments made towards the battery storage project. (OCA St. No. 5 at 4-5.) He also recommends that UGI Electric identify where the $1.5 million for the battery storage project was reallocated. (OCA St. No. 5 at 5.)

Q. Has the Company continued to explore potential solutions for the reliability challenges associated with Ruckle Hill Road?

A. Yes. After exploring the battery storage project and determining it was not feasible at this time based on existing technology on the market, UGI Electric has continued to monitor the operational reliability of Ruckle Hill Road and explore alternative solutions for the reliability challenges identified. In the interim, the Company has already undertaken additional targeted vegetation work that is expected to provide short-term relief and the Ruckle Hill Road customers have benefitted in part from the installation of a redundant primary distribution circuit across the Susquehanna River which provides a second source of supply to that segment of the UGI Electric distribution system. The Company is working to develop a long-term approach toward addressing reliability for this location. In order to address Mr. DeAngelo's concern related to reporting on solutions, the Company is willing to report on identified long-term approaches as part of its November 2024 Annual Asset Optimization Plan ("AAOP") filing (i.e., the first AAOP filing after the end of the FPFTY).

Q. In addressing Mr. DeAngelo's requests that the Company provide an explanation regarding the reallocation of the $1.5 million of rate base associated with the battery storage project, how did the Company reallocate the budget associated with the battery storage project?

A. The $1.5 million planned for the battery storage project was absorbed into the Company's Distribution Replacement and Betterment budget and allocated to other capital projects focused on reliability and end of life replacements. In FY2022, UGI Electric placed in service $13.134 million associated with Distribution Replacement and Betterment, exceeding a budget of $12.815 million. *See* UGI Electric Exhibit VAS-2. The budgeted amount of $12.815 million included the $1.5 million for the battery storage project, as proposed in the Company's last rate case. This clearly demonstrates the related reallocation of those amounts to other capital projects in general and addresses Mr. DeAngelo's concern.

Q. If the Company identifies an alternative solution to improve reliability on the Ruckle Hill Road circuit, how will it fund that project?

A. UGI Electric would treat a reliability solution for Ruckle Hill Road in a manner similar to other planned large scale reliability projects and build it into its budget planning process. In addition, the Company does have budget allocated annually to prioritizing projects associated with Worst Performing Feeders. Thus, UGI Electric has avenues available for funding a project to improve reliability on Ruckle Hill Road.

VI. <u>CONCLUSION</u>

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI ELECTRIC EXHIBIT EWS-1R

UGI Utilities, Inc. - Electric Division

UGI ELECTRIC EXHIBIT EWS-2R

UGI Utilities Inc. – Electric Division

Right-of-Way Widening Project

UGI ELECTRIC EXHIBIT EWS-3R

UGI Utilities Inc. - Electric Division
Historic and Budgeted FERC Account 583 Contractor Labor Expense

Account	Description	Line Item	UGI Electric I&M Program	FY2020		FY2021		FY2022	FY2023		FY2024	
583	Overhead Lines Expense	Plant Contractor Labor: Pipeline	Air-Break and Disconnect I&M	$ 107,779		$ 68,000		$ 58,711	$ 149,000	(2)	$ 163,000	(2)
583	Overhead Lines Expense	Plant Contractor Labor: Traffic Control	Air-Break and Disconnect I&M - Flagging	$ 20,398	(3)	$ 7,674		$ 14,991				
583	Overhead Lines Expense	Plant Contractor Labor: Engineering	Overhead Visual & Infrared Inspections					$ 79,000				
583	Overhead Lines Expense	Plant Contractor Labor: Other	Overhead Visual & Infrared Inspections	$ 56,477		$ 47,085		$ 87,306				
583	Overhead Lines Expense	Plant Contractor Labor: Other	Overhead Visual & Infrared Inspections			$ 120,426	(1)					
583	Overhead Lines Expense	Plant Contractor Labor: Other	Pole Inspection & Treatment Program	$ 72,829		$ 72,853		$ 53,610				
			Total	$ 257,483		$ 316,038		$ 293,618	$ 149,000		$ 163,000	

(1) - This expense was for contractor labor but incorrectly posted as a material charge in FERC 583.
(2) - Contractor labor for I&M programs were budgeted to a single Line Item in FY2023 and FY2024.
(3) - The portion of flagging costs specific to this inspection program were estimated for FY2020.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2022-3037368, et al.

UGI Utilities, Inc. – Electric Division

Statement No. 5-R

Rebuttal Testimony of
Vicky A. Schappell

Topics Addressed: **Adjustments To Utility Plant In Service**

Dated: May 25, 2023

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vicky A. Schappell. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Electric Statement No. 5, on January 27, 2023.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to certain portions of the direct testimony submitted by the Pennsylvania Public Utility Commission's ("Commission") Bureau of Investigation and Enforcement ("I&E") and the Office of Consumer Advocate ("OCA"). Specifically, I respond to the direct testimony of Esyan A. Sakaya, I&E Statement No. 5, and the direct testimony of Dante Mugrace, OCA Statement No. 1.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes. Attached to my testimony is CONFIDENTIAL UGI Electric Exhibit VAS-1R.

II. UTILITY PLANT IN SERVICE

Q. Did any parties propose adjustments to the Company's claimed utility plant in service in their direct testimony?

A. Yes. OCA witness Mr. Mugrace recommended an adjustment to the Company's claimed plant in service for the fully projected future test year ending September 30, 2024 ("FPFTY"). I&E witness Mr. Sakaya accepted the Company's claimed utility plant in service.

Q. Please describe the plant in service adjustment related to the Company's Data Center proposed by Mr. Mugrace on pages 6-9 of OCA St. No. 1.

A. OCA witness Mr. Mugrace recommends removing from base rates the contingency costs attributable to UGI Electric that are associated with the proposed Data Center project. OCA St. No. 1 at 8-9. Accordingly, Mr. Mugrace makes an adjustment to remove $218,806.00 associated with the allocation of the contingency costs from UGI Electric's plant in service balance. OCA St. No. 1 at 9. Mr. Mugrace argues that the contingency costs are not known and measurable, and that as a result they should not be included in the Company's FPFTY claim. OCA St. No. 1 at 9. As a result of the adjustment to plant in service, Mr. Mugrace also makes resulting adjustments to the Company's claimed accumulated depreciation, accumulated deferred income taxes, and depreciation expense. OCA St. No. 1 at 9-10; 12; 41. These adjustments are addressed by UGI Electric witness Vivian Ressler. *See* UGI Electric St. No. 3-R at 2-4 and 29-30.

Q. Does the Company agree with Mr. Mugrace's proposed adjustment to disallow the contingency costs associated with the Data Center?

A. No, it does not agree.

Q. What are contingency costs?

A. A project contingency for construction is a specific amount of money, usually a percentage of the total cost, that is identified at the outset of the project as part of its budget to address unforeseen additional costs arising during the construction process. Construction contingencies arise for a variety of reasons, including issues with materials, equipment, labor or supplies, such as price increases or limited supply availability; weather impacts and subcontractor changes; unforeseen change order impacts; or other general cost changes pursuant to contract terms and conditions. This category of costs is a means to cover the expenditures that have not been specifically foreseen by parties within the scope of the project, but are likely to occur based on past experiences with similar types of projects. Contingency costs are commonly added to large or complex projects as an element of project management that allows the Company to balance the project's schedule, quality commitments and cost in a manner which accurately reflects real-world conditions.

Q. Mr. Mugrace describes the contingency costs as "insurance against other unforeseen costs" in OCA St. No. 1 at 9. Do you agree?

A. No, that is not an accurate description of the function of contingency costs in a project budget. On all complex projects, there are situations where changes in planned activities, materials or labor costs will occur, and those changes may cause deviations from the original project scope or timeline. Including contingency costs allows the Company to accommodate these changes and provides flexibility in order for a project to stay on budget and on track so that it has the greatest likelihood of being placed in service timely.

Q. Mr. Mugrace claims that contingency costs should not be included in rate base because they are not known and measurable. Do you agree?

A. No, I do not agree with Mr. Mugrace. Any contingency costs used during the construction of the Data Center would be included in the cost of the asset placed in service. To the extent that the contingency is not used on the Data Center, the costs will be reallocated back into the budget. As described in my direct testimony, the Company manages its capital budget for any particular year, including the FPFTY, in total. In doing so, the Company will reprioritize projects and update associated projections as needed in order to achieve a result which has the greatest likelihood of being "on budget" for the year in total. UGI Electric has consistently met or exceeded its capital budget projections. *See* UGI Electric Exhibit VAS-2. Thus, the known and measurable amount is appropriately viewed in total, and a selective disallowance of certain cost elements (as Mr. Mugrace suggests here with the Data Center contingency costs) is inappropriate.

Q. Mr. Mugrace also notes that the Company has indicated that some costs may be accrued after November 2023 (*i.e.*, the in-service date of the Data Center), but has not identified those costs. What is the Company's response?

A. All of the major identified construction costs anticipated on the project will be incurred by November 2023, however, some additional costs are likely to be incurred after the in-service date. For instance, there is a timing lag that will result in certain costs being carried over after the November 2023 anticipated in service date. The anticipated costs after the November 2023 in service date primarily relate to the network and equipment costs that cannot be incurred until after the occupancy permit is issued. CONFIDENTIAL UGI Electric Exhibit VAS-1R provides a summary of the costs, by category, that will occur both prior to and after the Data Center is placed in service.

III. <u>CONCLUSION</u>

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI Electric Exhibit VAS-1R

(No Public Version Available)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2022-3037368, et al.

UGI Utilities, Inc. – Electric Division

Statement No. 6-R

Rebuttal Testimony of
John D. Taylor, Managing Partner
Atrium Economics, LLC

Topics Addressed:	**Cost of Service** **Residential Customer Charge** **Revenue Targets by Class**

Dated: May 25, 2023

Table of Contents

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. My business address is 10 Hospital Center Commons, Suite 400 Hilton Head Island SC 29926.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Electric Statement No. 6, on January 27, 2023.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to certain portions of the following direct testimony submitted by other parties. I will also explain updates to the Company's allocated cost of service study ("ACOSS"). The areas addressed include the following – with reference to the direct testimony of the other parties addressed:

Proposed Revenue Targets by Class

- Office of Consumer Advocate ("OCA") Statement No. 3 – direct testimony of Karl R. Pavlovic ("OCA witness Pavlovic")
- Bureau of Investigation and Enforcement ("I&E") Statement No. 4 – direct testimony of Ethan H. Cline ("I&E witness Cline")
- Office of Small Business Advocate ("OSBA") Statement No. 1 – direct testimony of Robert D. Knecht ("OSBA witness Knecht")

Allocated Cost of Service Study Methodology

- OCA witness Pavlovic
- OSBA witness Knecht

Customer Charge Levels

- OSBA witness Knecht
- I&E witness Cline
- OCA witness Pavlovic
- OCA Statement No. 4 – direct testimony of Roger D. Colton ("OCA witness Colton")
- Commission on Economic Opportunity ("CEO") Statement No. 1 – direct testimony of Jennifer Warabak ("CEO witness Warabak")

Low Income Customer Impact

- OCA witness Colton

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes, I am sponsoring UGI Electric Exhibit D Cost of Service Study (REBUTTAL).

II. PROPOSED REVENUE TARGETS BY CLASS

Q. Please summarize the other parties' positions concerning the proposed revenue targets for each of the rate classes.

A. OCA witness Pavlovic recommends the Pennsylvania Public Utility Commission ("Commission" or "PUC") reject the Company's ACOSS results as a guide for revenue allocation and "accept the results of UGI's ACOSS without minimum size classification as a guide for revenue allocation."[1] I will address OCA witness Pavlovic's proposed edits to the ACOSS later in this rebuttal testimony.

OSBA witness Knecht states that the "Company's proposal is consistent with its ACOSS methodology and generally reasonable."[2] OSBA witness Knecht does suggest some refinements to the Company's ACOSS, which reinforce the Company's ACOSS

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[1] OCA Statement No. 3 at 3.
[2] OSBA Statement No. 1 at 15.

results but do produce slightly different proposed revenue targets by class. As claimed by OSBA witness Knecht, "[t]he only modification that [he] propose[s] to the Company's revenue allocation approach is to make the balance of progress toward cost-based rates more even across the rate classes."[3] Additionally, OSBA witness Knecht presents alternative ACOSS results reflecting his refinements to the Company's ACOSS that are addressed later in this testimony.

I&E witness Cline does not opine on the revenue targets by class at the proposed revenue requirement but does recommend a scale back methodology to apply to the residential customer charge if the Commission grants less than the full requested increase.

Q. Can you please provide a summary of the parties' positions on revenue targets by class?

A. Yes, below in Table 1, I present the revenue increases by class proposed by the parties. As can be seen in Table 1, there is a strong alignment between the Company's position and OSBA's position. However, there is a divergence between the proposed proportionate increase presented by OCA witness Pavlovic based on the OCA's position that an ACOSS should be conducted without recognizing that a portion of Accounts 364, 365, 366, 367 and 368 are customer-related.

[3] OSBA Statement No. 1 at 17.

Table 1 – Revenue Targets by Class as Proposed ($000)

Customer Class	UGI Direct	OSBA Direct	OSBA Direct Alt.	OCA Direct
Residential	$ 49,701	$ 49,823	$ 49,751	$ 46,639
General Service	3,433	3,313	2,982	3,163
General Service-4	5,084	5,084	5,484	6,538
Flood Control Power	24	22	25	22
Large Power	6,617	6,617	6,617	8,301
Lighting	1,262	1,261	1,261	1,457
Total	**$ 66,120**	**$ 66,121**	**$ 66,121**	**$ 66,120**

Q. Do you agree with OCA witness Pavlovic's recommendation to move the class relative rates of return approximately 60 percent towards parity?

A. No, I do not. OCA witness Pavlovic's recommendation "to move the class relative rates of return approximately 60 percent towards 1.00 or parity,"[4] with exception of the Flood Control Power ("FCP") class, is informed by the ACOSS that conflicts with well-established Commission principles and practices. As explained in my direct testimony and this rebuttal testimony, the Company's revenues should be allocated amongst the customer classes reflecting the results of the ACOSS I prepared. The resulting movement of classes towards the overall system rate of return that I recommend is consistent with regulatory practice and precedent, including the *Lloyd* decision[5] and the Commission's Order on remand approving settlement of that case.[6] Further, OCA witness Pavlovic does not opine on why the Commission should diverge from the traditional base rate setting process, under which rates are based on the cost of service and generally accepted rate design principles. I would note that most recently, the Commission explicitly accepted the ACOSS that I

[4] OCA Statement No. 3 at 20.

[5] *Lloyd v. Pa. PUC*, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006) ("*Lloyd*"), *appeal denied*, 916 A.2d 1104 (2007).

[6] *See Pa. PUC v. PPL Elec. Utils. Corp.*, Docket Nos. R-00049255, *et al.* (Order on Remand entered July 25, 2007).

presented in the Company's 2018 base rate case proceeding (Docket No. R-2017-2640058), based on the same ACOSS methodology presented in this case, and explicitly rejected the OCA's similar proposals in that case.

Q. What position are you taking with respect to OSBA witness Knecht's proposed revenue increase targets by class?

A. As further explained in the ACOSS section of this testimony, OSBA witness Knecht provides some valid refinements of the specification of the ACOSS model and uses those refinements in his ACOSS to inform his revenue increase targets by class. The Company's proposed revenue targets by class presented later in this testimony are in alignment with OSBA witness Knecht's.

Additionally, as discussed in the ACOSS section of this testimony, OSBA witness Knecht provided an alternative ACOSS that supports additional revenue allocation options shown in Table 1. While the results of this alternative option align with the Company's proposed revenue distribution, I recommend utilizing the Company's proposed revenue increase targets by class.

Q. How do you respond to I&E witness Cline's scale back suggestions?

A. I agree with the approach of proportionately adjusting the revenue increase if the Commission grants less than the requested increase (termed a "scale back"). Moreover, I&E witness Cline suggests that the proposed residential customer charge must be included in the scale back. I disagree with I&E witness Cline's recommendation to scale back the customer charge as the Company's proposed residential customer charge is lower than what is required to recover customer-related costs.

Q. Have you prepared new proposed revenue targets by class reflecting the rebuttal version of the ACOSS model?

A. Later in this testimony, I present the Company's adjusted rebuttal ACOSS and describe the changes made. However, revenue targets proposed based on the rebuttal ACOSS remain the same as in the Company's direct case. The rebuttal ACOSS results reinforce the conclusions from the Company's direct case, namely that the Residential, GS-1, and Flood Control Power rate classes are being charged rates that recover less than their indicated costs of service and that the other rate classes provide for recovery of more than the indicated costs of serving these other rate classes.[7] As such, the revenue apportionment aligns with the Company's direct case, where there is a percentage increase to Residential, GS-1, and Flood Control Power and no increase to the other classes.

III. <u>ALLOCATED CLASS COST OF SERVICE STUDY</u>

Q. Do any of the intervenors' witnesses contest your ACOSS?

A. Yes. In general, OCA witness Pavlovic recommends relying on ACOSS results provided as a response to a discovery request (i.e., Attachment OCA-XI-1.1). Through this discovery request the OCA asked for a version of the ACOSS model with a demand only classification and allocation for Distribution plant Accounts 364-368 (i.e., allocates distribution plant Accounts 364-368 using non-coincidental peak demand with none of

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[7] UGI Electric Statement No. 6 at 18.

these costs allocated on customer count or classified as customer related). OSBA witness Knecht replicated the Company's ACOSS results[8] recommending minor revisions and further modifying the ACOSS to reflect alternative allocation methods that will be addressed below.

Q. Has the OCA presented the same or similar criticism of the ACOSS methodology in other proceedings before the Commission?

A. Yes. In this proceeding the OCA presents a materially similar position to the recommendations in UGI Electric's last litigated base rate case (R-2017-2640058).[9] Most importantly, as I noted in my direct testimony, the Commission explicitly adopted UGI Electric's ACOSS and rejected the alternative proposed by the OCA in that proceeding. Specifically, the Commission stated the following in its Final Order:

> Additionally, as UGI and the OSBA both highlighted, the Commission has affirmed the use of the "minimum system method" as the accepted approach to classify and allocate distribution system costs in several proceedings. See 2012 PPL Order, supra; see also, Pa. PUC v. PPL Electric Utilities Corp., Docket No. R-2010-2161694, 11 (Order entered December 21, 2010) (2010 PPL Order). Further, we find that UGI's ACOSS is consistent with the NARUC Manual and more accurately reflects cost-causation principles than the ACOSS methodology proposed by the OCA.[10] In short, the Commission has already considered and rejected the OCA's arguments. Thus, consistent with Commission precedent, upstream distribution plant should be classified as customer and demand related, with a minimum system study utilized to develop the classification.

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[8] OSBA Statement No. 1 at 7.

[9] Consequently, in UGI Electric's last base rate case (Docket No. R-2021-3023618) the OCA similarly critiqued the ACOSS for accounting for customer-related costs within these same distribution accounts. In that proceeding, I provided rebuttal testimony further demonstrating the cost-causative support for relying on the minimum system study to determine the customer-related portion and reflecting that within the ACOSS. See Rebuttal Testimony of John Taylor in Docket No. R-2021-3023618.

[10] *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket Nos. R-2017-2640058, *et al.*, p. 160 (Order entered Oct. 25, 2018).

A. OCA's Position

Q. Please summarize OCA witness Pavlovic's proposed ACOSS.

A. Mr. Pavlovic critiques the classification of upstream distribution plant between a customer component and demand component by referring to the Company's proposed methodology as an ACOSS error[11]. He disagrees with the use of the minimum system approach to identify and allocate the portion of those costs required to serve a customer with minimal or no load. He recommends relying on the ACOSS without minimum size classification of the upstream distribution plant claiming that the number of customers is neither a cause nor a driver of distribution costs.[12]

Q. With OCA witness Pavlovic's rejection of the minimum system for classification and allocation of distribution plant, what are the impacts on a class basis from his use of a 100 percent demand classification and allocation of distribution plant?

A. The impact of OCA witness Pavlovic's 100% demand classification of poles, conductors, and transformers is the allocation of more distribution costs to larger customers who may not even use any of the smaller facilities allocated to them through his method. There are substantial economies of scale for all sizes of transformers, overhead and underground conductor, and poles. In each case, the cost per kilovolt-ampere ("kVA") of industrial transformers is below the cost for every size of the residential transformer. Some industrial transformers may be even lower in cost per kVA than the lowest cost, single phase transformers used for residential customers. Using a demand allocation factor alone implicitly makes the incorrect assumption that the cost of transformer capacity is the same

[11] OCA Statement No. 3 at 7-8.
[12] OCA Statement No. 3 at 15.

for all classes; it is not. By allocating the cost of transformers only on demand, all the economies of scale of transformer costs are unfairly and incorrectly allocated to the residential class.

By classifying plant between customer and demand, the residential class receives a higher weighting of transformer costs consistent with cost causation, since the unit costs per kVA for residential transformers is higher, and they use many more transformers than other classes of customers. Similar economies of scale occur for other distribution accounts, with the result being that without the minimum system component, costs are significantly under-allocated to the residential class and over-allocated to larger customers with higher demands who use far less of the distribution assets than residential customers. For conductor, larger customers are typically located closer to substations than residential customers and therefore require fewer miles of conductor. The demand allocator significantly over-allocates distribution lines to larger customers, which does not consider the lower unit cost per kVA of line capacity to serve these customers. In summary, absent the use of the minimum system, the distribution costs to serve smaller customers are under-allocated and similar costs to serve larger load customers are over-allocated.

Q. What authoritative sources does OCA witness Pavlovic rely on to support his position?

A. In support of his position OCA witness Pavlovic points to The National Association of Regulatory Utility Commissioners ("NARUC") Cost Allocation Manual ("1992 Manual")[13] and Professor James Bonbright's 1988 Principles of Public Utility Rates.[14]

[13] OCA Statement No. 3 at 12.
[14] OCA Statement No. 3 at 10.

Q. Can you please address the information provided by these authoritative sources relating to determining the appropriateness of classifying upstream distribution as customer related and demand related?

A. Yes. I address them below.

NARUC 1992 Cost Allocation Manual

OCA witness Pavlovic points to the 1992 Manual by emphasizing the definition of the customer components of distribution facilities and construes the Manual as being wrong for "the unsupported assertion that "[t]hus, the number of poles, conductors, transformers, services and meters are directly related to the number of customers on the utility's system."[15] However, the key conclusion to draw from the 1992 Manual is "[w]hen the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs."[16] In fact, the 1992 Manual does not even mention the sole allocation of upstream distribution facilities as demand-related as an alternative for classifying and allocating distribution plant.

Bonbright's Principles of Public Utility Rates

OCA witness Pavlovic misconstrues principles defined in the Principles of Public Utility Rates[17] and omits a key sentence from his quotation above: "Alternatively, they [distribution system customer costs] are calculated by the 'zero-intercept' method whereby

[15] OCA Statement No. 3 at 12.

[16] National Association of Regulatory Utility Commissioners, "Electric Utility Cost Allocation Manual," 1992, at 90.

[17] Principles of Public Utility Rates, Second Edition, James C. Bonbright, Albert L. Danielson, David R. Kamerschen, Public Utility Reports, Inc., 1988, at 491.

regression equations are run relating cost to various sizes of equipment and eventually solving for the cost of a zero-sized system." Thus, the portion quoted by OCA witness Pavlovic refers to the zero-intercept method, which I have not proposed to use in this proceeding, nor has any other witness proposed to use in this proceeding. It is obvious that as the system expands, new poles, wires, and transformers must be added to attach the customers at the periphery of the system or even within system boundaries when land use options change. In addition, Professor Bonbright states:

> [C]ustomer costs incurred to serve a customer are invariant with respect to consumption. They are the costs incurred to serve a customer even if the customer does not use the service at all. The most obvious examples of these customer costs are the expenses associated with local connection facilities, metering equipment and meter reading, billing and accounting, <u>and a portion of the distribution system</u>. [18]

Finally, Professor Bonbright states that "in actual practice the vast majority of utilities utilized some form of minimum system to classify costs, which is in line with FERC accounts."[19]

Q. Are there other authoritative sources that support the recognition of the customer component of upstream distribution facilities?

A. Yes. Dr. James Suelflow writes in his treatise, Public Utility Accounting: Theory and Practice, published by the Institute of Public Utilities at Michigan State University, that "distribution transformers and primary and secondary lines including conductors and

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[18] *Id.* at 401.

[19] *Id.* at 492 (emphasis added).

devices (account 365 "Distribution Plant") and poles and towers (account 364 "Distribution"), all contain capacity and customer costs."[20]

Dr. Suelflow recognizes that costs are more closely related to customers the closer one approaches the ultimate customer premises. This is not a new concept. Writing in 1900, Henry L. Doherty formulated a three-part rate consisting of a customer charge, demand charge and energy charge. In the original paper, "Equitable, Uniform and Competitive Rates," Doherty defined the minimum costs associated with "readiness to serve," and specifically included not only the components of the basic customer costs, but the cost of poles and conductors, with 50% classified to the customer component and 50% to the demand component. His analysis also included overhead loaders in the cost-per-customer.

Q. Is the minimum system study consistently used by Pennsylvania Electric Distribution Companies ("EDCs")?

A. Yes. As I have noted above, the Commission explicitly adopted UGI Electric's ACOSS in the Company's last litigated base rate proceeding, noting the use of the "minimum system method" as the accepted approach to classify and allocate distribution system costs in several proceedings. I also testified on behalf of PPL Electric Utilities Corporation ("PPL Electric") in its 2015 electric base distribution rate case (Docket No. R-2015-2469275). The minimum system approach was utilized in that proceeding, in PPL Electric's 2012 proceeding (Docket No. R-2012-2290597), and in PPL Electric's 2010 proceeding (Docket No. R-2010-2161694). I also have reviewed the direct testimony of Howard Gorman on

[20] Public Utility Accounting: Theory and Practice, Dr. James Suelflow, Institute of Public Utilities, Michigan State University, at 241.

behalf of Duquesne Light Company ("Duquesne Light") in its 2018 base rate case (Docket No. R-2018-3000124), and the minimum system approach was used in Duquesne Light's allocated class cost of service study. Further, Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company all have utilized minimum system concepts to determine the portion of upstream distribution facilities that are customer and demand related.[21] In fact, every Pennsylvania electric utility classifies a portion of these upstream distribution facilities as partially customer related.

Q. How do you respond to OCA witness Pavlovic's statement[22] that PECO Energy does not utilize the minimum system method?

A. While PECO's most recent rate proceeding (Docket No R-2021-3024601) was settled, PECO proposed utilizing the allocation method similar to one proposed by OSBA witness Knecht in his alternative scenario, which includes a customer component of the secondary distribution system. While the PECO method is slightly different from that used by the other electric utilities, OCA witness Pavlovic accurately describes the use of the minimum size method across Pennsylvania, "in Pennsylvania the minimum size method is still widely used by electric utilities."[23] Most importantly, all electric utilities in Pennsylvania

[21] *See* the Direct Testimony of Thomas J Dolezal at page 11 - Docket R-2016-2537349 (Metropolitan Edison Company). *See also* the Direct Testimony of Thomas J Dolezal at page 12 – Docket R-2016-2537352 (FE - Pennsylvania Electric Company); Direct Testimony of Thomas J Dolezal at page 11-12 – Docket R-2016-2537355 (Pennsylvania Power); Direct Testimony of Thomas J Dolezal at page 13 – Docket R-2016-2537359 (FE - West Penn Power Company); the Direct Testimony of Jiang Ding at page 17 – Docket R-2018-3000164 (PECO).

[22] OCA Statement No. 3 at 9.

[23] OCA Statement No. 3 at 9.

recognize a portion of distribution facilities upstream from the customer service as both customer related and demand related.

Q. OCA witness Pavlovic states that nowadays the minimum size method is used less by major electric utilities. Do you have information regarding the use of a minimum system or zero intercept approach to classifying electric and gas distribution system costs?

A. Yes, the results of my research are presented in Table 2, below. Based on my current experience with client engagements in multiple state jurisdictions and research, electric utilities in 23 states have adopted to varying degrees a customer component of the distribution system.

Table 2 - Survey of Cost Classification of Electric Distribution

		Customer Component of Distribution			
State	**Electric Utility**	**Recognized**	**Method**	**Docket/Case Number**	**Year**
AZ	Tucson Electric Power Co.	Yes	Minimum System	D-E-01933A-15-0322	2015
CT	The CT Light & Power Co	Yes	Minimum System	D-17-10-46	2017
FL	Tampa Electric Company	Yes	Min.Distribution System	20210034-EI	2022
GA	Georgia Power Co.	Yes	Minimum System	D-42516	2019
HI	Hawaii Electric Light Co	Yes	Minimum System	D-2018-0368	2018
ID	Idaho Power Company	Yes	Unspecified	IPC-E-l1-08	2011
KS	Evergy Kansas Central Inc.	Yes	Minimum System	D-18-WSEE-328-RTS	2018
ME	Central Maine Power Co.	Yes	Minimum System	D-2018-00194	2018
MN	Minnesota Power Entrprs Inc.	Yes	Minimum System	D-E-015/GR-16-664	2016
MS	Mississippi Power Co.	Yes	Zero Intercept	2019-UN-0219	2019
MO	Evergy Missouri Metro	Yes	Minimum System	C-ER-2022-0129	2022
MT	MDU Resources Group, Inc.	Yes	Minimum System	2022.11.099	2022
NH	Unitil Energy Systems Inc.	Yes	Minimum System	D-DE-16-384	2016
NY	Consolidated Edison Co. of NY	Yes	Minimum System	C-16-E-0060	2016
NC	Duke Energy Carolinas, LLC	Yes	Minimum System	E-7, Sub 1214	2019
ND	Northern States Power Co.	Yes	Both	C-PU-20-441	2020
OH	Duke Energy Ohio	Yes	Minimum System	21-887-EL-AIR	2022
OK	Oklahoma Gas and Electric Co.	Yes	Zero Intercept	Ca-PUD201500273	2015
PA	PPL Electric Utilities Corp.	Yes	Minimum System	D-R-2015-2469275	2015
SC	Duke Energy Progress LLC	Yes	Minimum System	D-2018-318-E	2018
SD	Xcel Energy	Yes	Minimum System	EL14-058	2014
VA	Virginia Electric and Power Co.	Yes	Unspecified	C-PUE-2009-00019	2009
WI	Wisconsin Electric Power Co.	Yes	Minimum System	D-05-UR-107	2014

Q. Has OCA witness Pavlovic provided any evidence that distribution costs do not vary with the number of customers?

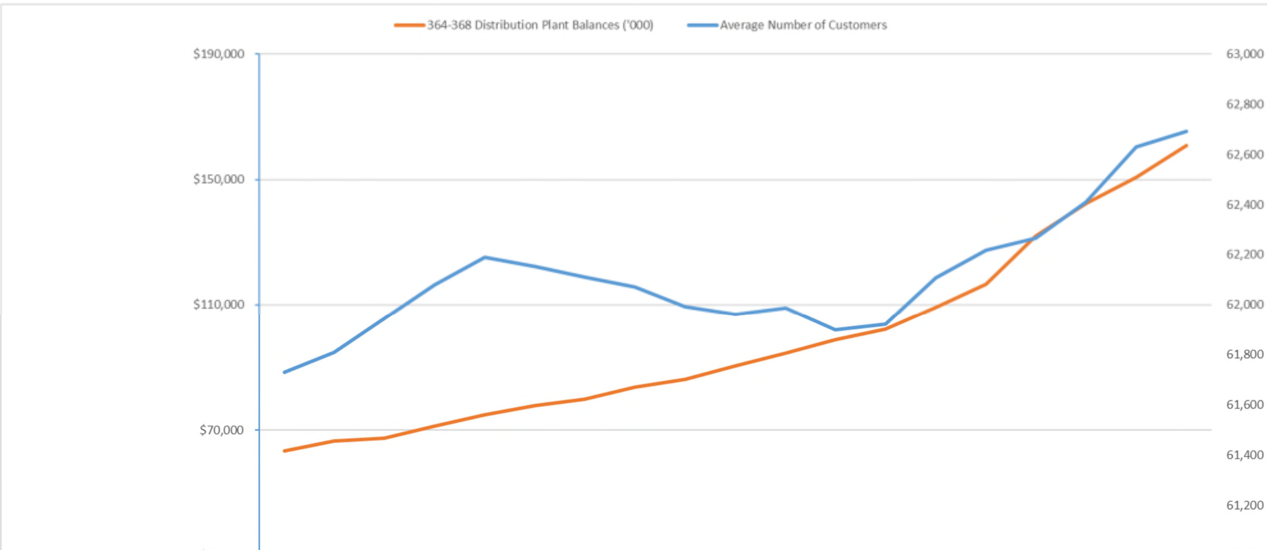
A. No. OCA witness Pavlovic relies on the Company's "Planning Principles and Practices" document provided in response to data request OCA-III-4. This document simply contains planning and procedure protocols and reliability guidelines of the Company's distribution system; however, it does not provide any guidance as to how costs should be allocated to each customer class to set revenue targets and rates. In his reference to the Company's "Planning, Principles and Practices" document, OCA witness Pavlovic emphasizes that system expansion is based on the loads, which is in fact a function of new customers and omits emphasizing a phrase in the same sentence that the planning group in fact considers "new residential developments."[24] Thus, customer growth does factor in the planning process. Further, while the "Planning, Principles and Practices" document may not specifically identify the need to extend distribution facilities actually to attach and serve a customer, all distribution planners and engineers understand the simple law of physics that the use of electricity by a customer requires that customer to be attached to the circuits which are providing the electricity.

Q. Is there further evidence to support the connection between distribution plant investments and customer growth?

[24] OCA Statement No. 3 at 11.

A. Yes. Table 3 below illustrates a historical correlation (84% between the two measures) between customer growth and distribution plant investment balances specifically for FERC Accounts 364, 365, 366, 367, and 368.

Table 3 – Correlation of Average Number of Customers and Distribution Plant Investments



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
364-368 Distribution Plant Balances ('000)	$63,354	$66,541	$67,460	$71,209	$74,857	$77,881	$79,885	$83,667	$86,229	$90,376	$94,487	$98,686	$102,23	$109,17	$116,57	$131,88	$142,37	$150,64	$160,87
Average Number of Customers	61,730	61,808	61,944	62,080	62,189	62,152	62,112	62,071	61,993	61,961	61,988	61,899	61,923	62,107	62,219	62,267	62,410	62,630	62,692

B. <u>OSBA's Position</u>

Q. How do you respond to OSBA witness Knecht's reliance on the PUC's statement in the Columbia decision that cost of service methodologies should be reviewed on a case-by-case basis?

A. While the PUC did state that, the consistent use and reliance on a certain methodology should be considered. Counsel has informed me that while administrative agencies in Pennsylvania are not strictly bound by stare decisis, they must render consistent decisions unless there are **<u>new</u>** facts that justify deviation from the prior rulings. Nothing presented in this case warrants deviating from using the minimum system method for distribution facilities. My direct testimony and this rebuttal testimony provide evidence of why the Company's proposed allocation method is appropriate and in alignment with cost causation principles.

Q. Please summarize OSBA's proposed adjustments to the Company's ACOSS.

A. As mentioned above OSBA witness Knecht replicated the Company's proposed ACOSS presented as RDK WP1 and proposed three minor modifications as presented in RDK WP-2.[25] He then prepares an alternative ACOSS scenario, which is based on all primary voltage system costs being classified as demand-related and presented the results in RDK WP3.

Q. Please summarize OSBA's proposed adjustments to the Company's ACOSS.

A. OSBA witness Knecht identifies the need for three minor adjustments and modifications to the Company's ACOSS[26]:

1. Modify the factor for the working capital balance allocation based on the assumption that "revenue lag for non- residential customers is only marginally longer than the lag in payments, implying that the non-residential classes contribute little to the need for working capital".[27]
2. Exclude all uncollectible and universal service charges from the customer charge cost basis by classifying them as demand-related.
3. Correction of INT_REV_REQ Pre-tax functionalization factor.

[25] OSBA Statement No. 1 at 12.
[26] OSBA Statement No. 1 at 12.
[27] OSBA Statement No. 1 at 12.

Q. How do you respond to each of these modifications?

A. An evaluation was not completed to determine working capital requirements for each rate class, and his proposed change would have immaterial impacts to the overall results of the ACOSS. As such we have not reflected OSBA witness Knecht's modifications of the working capital allocation factor in the ACOSS Rebuttal model presented as UGI Electric Exhibit D Cost of Service Study (REBUTTAL). With respect to the classification of uncollectible and universal service charges as demand-related, I am inclined to disagree with such modification. As described in my direct testimony, the next method of dealing with these costs is to include them as customer-related costs and take them into consideration when evaluating the appropriate level of costs to consider when setting a customer charge (see Table 6 on page 26 of UGI Electric Statement No. 6). Lastly, the ACOSS Rebuttal corrects the INT_REV_REQ Pre-tax functionalization factor which has an immaterial impact on the overall results.

Q. Please discuss the alternative ACOSS presented by OSBA witness Knecht.

A. As an alternative to the ACOSS proposed by the Company and most recently approved by the Commission, OSBA witness Knecht presents an allocation scenario based on all primary voltage system costs as being classified as demand-related. OSBA witness Knecht continues to support the existence of scale economies in the secondary voltage system, but less so in the primary voltage system. Thus, he recommends applying customer-demand classification only for the secondary voltage system but uses a 100 percent demand approach for the primary voltage system. As a result, the alternative scenario shifts cost allocation to larger customer classes as shown in Table 4.

Table 4 - OSBA's Cost of Service Proposed Allocation Scenarios

Customer Class	OSBA's Proposed Cost to Serve	OSBA's Proposed Alternative Cost to Serve	Difference
Residential	$ 133,159	$ 130,029	$ (3,130)
GS-1	7,434	6,764	(670)
GS-4	13,311	14,521	1,210
Flood Control Power	24	40	16
Large Power	8,983	11,495	2,512
Lighting	1,205	1,267	61
Total System	**$ 164,117**	**$ 164,117**	**$ 0**

Q. How do you respond to OSBA witness Knecht's proposed alternative scenario?

A. While OSBA witness Knecht agrees with the fact that the economies of scale exist for distribution system,[28] he also argues that it is less so on the primary voltage system. The allocation of primary distribution system based on 100 percent demand factor completely removes economies of scale from the system utilization, which was addressed above in this testimony. Additionally, as pointed out by OSBA witness Knecht in his testimony at page 18, while the alternative scenario results in cost shifts, it has a modest impact on the proposed revenue allocation under the alternative scenario. The results of the OSBA's two proposals are shown in Table 4 above.

IV. <u>REBUTTAL VERSION OF ACOSS MODEL</u>

Q. What updates were made in the rebuttal version of the ACOSS model?

A. The rebuttal version of the ACOSS presented as UGI Electric Exhibit D – Allocated Cost of Service Study (REBUTTAL) incorporates the following updates:

[28] OSBA Statement No. 1 at 10.

1. An update to the meter study to reflect a more accurate count of meters for each rate class.
2. An update to the non-coincident peak allocation to reflect the non-coincident peaks more accurately at each voltage level.

Given the Company's rebuttal version of the revenue requirement is only approximately ten thousand dollars above the direct version, the rebuttal version of the ACOSS relies on the direct filed revenue requirement.

Q. How do the results of the Rebuttal ACOSS model compare to the ACOSS initially proposed in the Company's direct case?

A. Table 5 below compares the results of the Rebuttal ACOSS with the Direct Case ACOSS:

Table 5 - Compare Rebuttal ACOSS to the Direct Case ACOSS

Customer Classes	UGI's Direct Cost to Serve	UGI's Rebuttal Cost to Serve	Difference
Residential	$ 131,771	$ 132,116	$ 345
General Service	7,386	7,425	39
General Service-4	13,161	13,273	112
Flood Control Power	24	24	0
Large Power	9,469	8,962	(507)
Lighting	1,203	1,215	11
Subtotal	**$ 163,014**	**$ 163,014**	**$ -**
Other Revenues	$ 1,102	$ 1,102	$ -
Total System	**$ 164,116**	**$ 164,116**	**$ -**

Q. Please summarize the results of the Company's rebuttal version of the ACOSS.

A. The Residential rate class is still far below the cost to serve, GS-1 and FCP classes are contributing revenues below their cost to serve, and GS-4, Large Power, and Lighting are all contributing revenues above their cost to serve. Table 6 provides a summary of the revenue deficiencies and surpluses for each rate class. The rebuttal version of the Company's ACOSS is provided as UGI Electric Exhibit D – Allocated Cost of Service Study (REBUTTAL).

Table 6 - Results of the Rebuttal ACOSS Model

Customer Classes	Current Revenues	Cost to Serve	Class Revenue (Deficiency)/ Excess	Percentage Change to Cost to Serve	Current Rate of Return
Residential	$ 117,080	$ 132,116	$ (15,036)	12.84%	-0.29%
General Service	6,647	7,425	$ (778)	11.70%	2.98%
General Service-4	14,321	13,273	$ 1,048	-7.32%	16.40%
Flood Control Power	19	24	$ (5)	25.42%	4.21%
Large Power	11,680	8,962	$ 2,718	-23.27%	28.73%
Lighting	1,843	1,215	$ 628	-34.09%	37.44%
Subtotal	**$ 151,589**	**$ 163,014**	**$ (11,425)**	7.54%	x
Other Revenues	$ 1,102	$ 1,102	$ -		
Total System	**$ 152,691**	**$ 164,116**	**$ (11,425)**	7.48%	3.77%

V. CUSTOMER CHARGE LEVELS

Q. What are the parties' positions concerning the proposed customer charge levels?

A. OSBA witness Knecht disagrees with the Company's proposed customer charge levels for GS-1 and GS-4.[29] OSBA witness Knecht proposes higher customer charges for GS-1 and GS-4 of $17.00 and $18.00, respectively. He did not provide a position on the Company's proposed Residential customer charge.

I&E witness Cline recommends a $12.00 per month customer charge for Residential and GS-5 classes, which is lower that the Company's proposed customer charge of $13.50. I&E witness Cline also recommends that the Company's proposed Residential class

[29] OSBA Statement No. 1 at 21-22.

customer charge of $12.00 be included in the scale back of rates if the Commission grants less than the full requested increase.[30]

OCA witness Pavlovic recommends that the Residential customer charge remain at its current level of $9.50. OCA witness Pavlovic takes issue with the Company's proposed Residential class customer charge of $13.50 for the following reasons[31]:

1. An increase of 42% "represents significant and unacceptable rate shock to no ratemaking benefit";

2. "[N]o residential customer chooses either to take service or to take a given amount of service based on the customer charge. Thus, the ratemaking principle of efficiency, to which UGI subscribes, provides no basis to set the customer charge at one level or another"; and

3. "Placing all of the increase in the volumetric distribution charge will provide Residential customers with both (1) an increased incentive to engage in conservation and (2) the ability to exercise control over a larger portion of their monthly electric distribution bill."

OCA witness Colton explores the relationship between income and electric usage and concludes that the "UGI proposal to substantially increase its fixed monthly customer charge makes these low-income responses to inability-to-pay less efficacious."[32]

Similar to OCA witness Pavlovic, CEO witness Warabak opposes any increase in the fixed monthly customer charge.[33] CEO witness Warabak contends that higher fixed customer charges "discourage conservation and leave a customer with less ability to

[30] I&E Statement No. 3 at 8.
[31] OCA Statement No. 3 at 23-24
[32] OCA Statement No. 4 at 24.
[33] CEO Statement No. 1 at 4.

conserve energy and less ability to reduce their bill."[34] She also avers that "the Company's proposed request ignores the interests of its low-income customers" and that the proposed increase in the customer charge has a "negative impact" that "would be particularly harsh on the Company's low-income customers."[35]

Q. How do you respond to the testimonies of OSBA witness Knecht and I&E witness Cline?

A. The Company agrees with OSBA witness Knecht's proposed customer charge levels for GS-1 and GS-4. I do take exception to I&E witness Cline's proposal to scale back the recommended Residential class customer charge of $12.00 if the Commission grants less than the full requested increase. Given the substantial support for UGI Electric's proposed Residential customer charge of $13.50 provided in my direct testimony and this rebuttal testimony, the Residential customer charge should not be subject to any scale back if the Commission grants less than the Company's full requested base rate increase. My direct testimony shows the total Residential customer related costs of $22.47, well above the Company's proposal. Further, while the I&E believes the $12.00 Residential customer charge is more appropriate than $13.50, they provide no evidence or support for why the customer charge should be lower than their recommended $12.00. As such, I recommend the Commission reject their proposal to scale back the Residential customer charge.

Q. What is the nature of the critiques with respect to how the proposed $13.50 monthly Residential customer charge will impact low-income customers?

[34] CEO Statement No. 1 at 3.
[35] CEO Statement No. 1 at 5.

A. Present in this proceeding, and a common critique of increasing a customer charge, is the supposition that an increase in the customer charge disproportionately impacts low-income customers, as they are typically low usage customers. As I will discuss below, this is not a correct characterization of low-income customers who are indeed higher-use customers. All else equal, increasing a monthly customer charge will increase the bill more for low-use customers than it will for high-use customers. Further, although I do not dispute that low-income families at times struggle to balance the requirements of utility bills, the impact of an increase in the customer charge on UGI Electric's low-income customers in particular is a matter of disagreement between OCA witness Colton and me.

Q. How is the issue of gradualism related to the appropriateness of the monthly residential customer charge level?

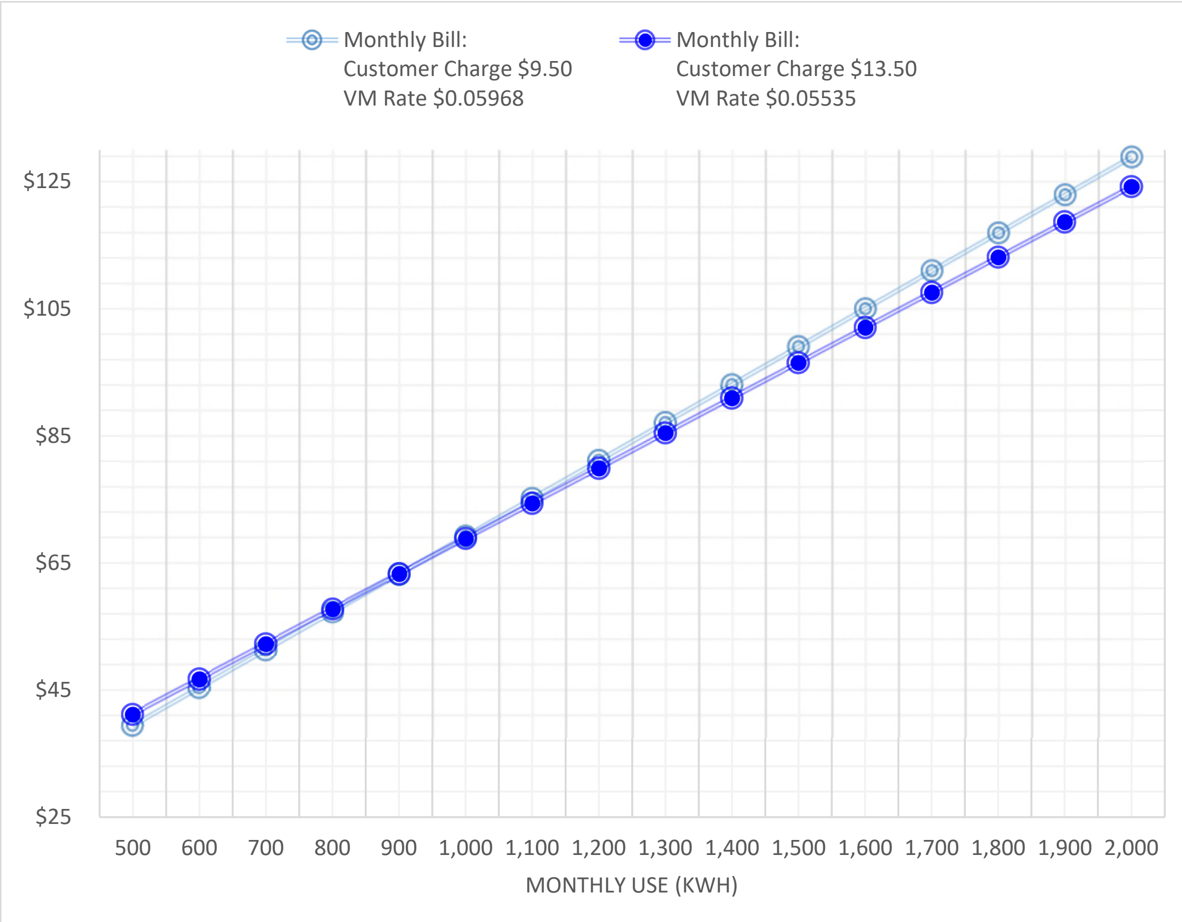
A. OCA witness Pavlovic would like us to believe that the only charge for electricity service is the customer charge and that an increase of $9.50 to $13.50 (representing a 42 percent increase) is out of alignment with gradualism. It is necessary when looking at concepts of gradualism to review the entire bill of a customer not just a single component because customers pay their entire bill, not only single rate components. Only customers with zero usage would see a 42% difference between a customer charge of $9.50 and $13.50. Most customers would see a much lower percentage difference given any revenues not recovered in the customer charge must be recovered in the volumetric energy charge. Decreasing the proposed customer charge from $13.50 to $9.50 will result in a corresponding increase in the variable per kWh distribution charge.

Q. Have you conducted an analysis of the difference between a $9.50 monthly residential customer charge and a $13.50 a month charge on low-income customers?

A. Yes, I have. For illustrative purposes, I have used two scenarios: (1) the lowest residential customer charge suggested by a party in this proceeding, *i.e.*, the current level at $9.50[36]; and (2) the Company's proposed residential customer charge of $13.50. Decreasing the proposed customer charge from $13.50 to $9.50 at proposed rates will result in a corresponding increase to the variable per kWh distribution charge. For example, assuming the Company's proposed residential revenue target, a customer charge of $13.50 will result in a distribution charge of $0.05535 per kWh as opposed to $0.05968 per kWh under a $9.50 monthly customer charge. As illustrated in Table 7 below, customers with monthly average usage of approximately 900 kWh will have a lower bill with a higher customer charge as compared to the lower one under the given scenario.

[36] OCA Statement No. 3 at 25.

Table 7 – Monthly Bill Impact Comparison



Additionally, UGI Electric witness Adamo's rebuttal testimony indicates that the average Customer Assistance Program ("CAP") participant has a monthly average kWh usage of 1,229 kWh and low-income customers' monthly average kWh is 1,036 kWh. Therefore, there is an annual <u>decrease</u> of $5.85 for the average low-income customer and an annual <u>decrease</u> of $15.86 for the average CAP customer, resulting from a change in the customer charge from $9.50 to $13.50 (as shown in Table 6 below). The outcome of the $13.50 charge over the $9.50 charge is a <u>lower bill</u> for the average low-income customer and the average CAP participant. Thus, the OCA should support the Company's proposed customer charge of $13.50 due to the favorable impact on low-income customers.

Table 6 – Bill Impact of Customer Charge[37]

Low-Income Customer Usage		
Customer Charge	$ 9.50	$ 13.50
Variable Charge	$ 0.05968	$ 0.05535
Average Monthly Usage	1,036	1,036
Usage Charge	$ 61.85	$ 57.36
Total Distribution Charges	$ 71.35	$ 70.86
Monthly Difference		$ (0.49)
Annual Difference		$ (5.85)

CAP Participant Usage		
Customer Charge	$ 9.50	$ 13.50
Variable Charge	$ 0.05968	$ 0.05535
Average Monthly Usage	1,229	1,229
Usage Charge	$ 73.34	$ 68.02
Total Distribution Charges	$ 82.84	$ 81.52
Monthly Difference		$ (1.32)
Annual Difference		$ (15.86)

As such, the conclusion that an increase in the customer charge from $9.50 to $13.50 is harmful to low-income customers is erroneous.

Further, a volumetrically weighted rate design conveys improper price signals to customers because it recovers fixed costs through the volumetric components of the utility's rate structure. When this undesirable situation exists, it can: (1) increase revenue variability due to factors beyond the utility’s ability to influence; (2) fail to account for cost differences between and within customer classes; (3) promote inefficient use of the utility’s system; and (4) needlessly inflate bills in the winter months (for heating customers) or summer months (for cooling customers). The important policy point in this discussion is that it makes no economic sense to send the wrong economic price signals to all customers

[37] Average Monthly Usage obtained from the Company’s response to data request CAUSE-PA-I-14.

in order to supposedly benefit a few customers. It is far more efficient to address the issues of low-income customers directly through programs and assistance, such as the Company's CAP.

Q. How do you respond to OCA witness Pavlovic's statement that "[n]o residential customer chooses either to take service or to take a given amount of service based on the customer charge. Thus, the ratemaking principle of efficiency, to which UGI subscribes, provides no basis to set the customer charge at one level or another"?[38]

A. This is an illogical conclusion. As demonstrated above, the customer charge level directly impacts the volumetric charge level, so the customer charge cannot be reviewed in isolation. One cannot simply ignore that the customer and volumetric charges are inextricably linked and related. The ratemaking principle of efficiency relates to ensuring price signals are properly aligned between consumer and producer; such that rates discourage wasteful use of service while promoting all justified types and amounts of use. As James Bonbright stated, "rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between the private and social costs incurred and benefits received."[39]

Q. How do you respond to OCA witness Pavlovic's claim that a lower customer charge is more consistent with energy conservation and efficiency goals?

[38] OCA Statement No. 3 at 24.

[39] James Bonbright, *et al.*, Principles of Public Utility Rates, Public Utilities Reports, Inc. 2nd Edition, 1988, at 385.

A. OCA witness Pavlovic provides no basis or support for his conclusion. He makes claims based on price elasticity (how consumers respond to changes in prices) with no basis as to why he believes they will respond in the manner he believes nor why his preferred response is best. These arguments suffer from an unreasonably narrow definition of conservation in their discussions and look to value only this singular consideration in rate design recommendations. Secondly, OCA witness Pavlovic overgeneralizes his premises when reaching conclusions. OCA witness Pavlovic's premise is that a higher percentage of cost recovery in a fixed charge leads to less conservation, and thus the increase in a customer charge from $9.50 to $13.50 will result in less conservation. In short, he introduces two overgeneralizations: (1) he assumes the only reason for conservation is price signals; and (2) he assumes that customers will respond to a change of this degree (i.e., a change of $4.00 monthly) without consideration of total bill impact.

Q. What definition of conservation should be utilized in the context of setting distribution rates?

A. Conservation is the act of preserving, guarding, and protecting wise use. In this case, it is the wise use of distribution facility resources. The issue under consideration is much broader than simply a concept of reducing usage, where numerous principles and considerations must be made as to the correct level of fixed monthly customer charge. Certain costs of operating a distribution utility are incurred regardless of the level of electricity consumed; they are incurred simply to attach a customer and meet their peak demands. By charging customers on a variable basis for these fixed costs, customers can spend time and resources on reducing their bills; however, this does not reduce the costs incurred by the utility. This is not an efficient use of our resources as a society. Although the consumer spent time and resources to "save" money, it does not reduce fixed distribution utility costs incurred by the utility to provide service, *i.e.*, any bill savings under a lower customer charge would exceed the actual savings of the resources used to provide service. Those costs are simply charged to other customers or result in unrecovered costs. This is a zero-sum game; the gain to one customer by reducing how much they pay for fixed costs is the loss of either another customer or the utility itself.

Q. How do utility consumers respond to price signals and changes in rates?

A. They respond in very complicated and inconsistent ways. First, any reduction in usage is not just a function of price signals. Energy efficiency gains and reduction in usage to date are based on a several items, including, but not limited to: (1) capital investment in appliances (partially due to rebate and tax policies and federal efficiency mandates); (2) the thermal envelope of housing; (3) fuel switching; and (4) other societal/cultural responses that will not go away with the customer charge increase. Second, the conclusion that a change from $9.50 to $13.50 will reduce consumers' desire to reduce usage is based on an incorrect interpretation of price elasticity. Utility customers have mixed abilities to respond to prices based on numerous contributing factors, including heating fuel, ambient temperatures, alternative fuel options, family size, access to capital, etc. They also have mixed desires to respond to prices, given that they face plenty of competing concerns and may choose not to spend time and effort on managing their energy use. A paper by the Electric Power Research Institute ("EPRI") provides clarifying insight into the complexity of price elasticity.

> Consumers may be practically capable of responding to price changes, but do not do so for a number of reasons. First and most importantly, as demonstrated above, the lack of exhibited price response could be because the consumer has not been subject to a price change that exceeds its price threshold. Electricity price changes are generally limited to single digit amounts at any one time to protect consumers from the consequences. As a result, the price changes that are implemented do not meet the response threshold requirement. But, when faced with a large price change, they may indeed exhibit a response because it exceeds the threshold.[40]

This quote clearly states that single digit price changes may not reach the response threshold to elicit changes in usage. EPRI goes on to state why this would be the case for some consumers.

> Additionally, many consumers may treat electricity as a necessity, for which there is no apparent substitute, at least in the near-term. Therefore their consumption is driven primarily by other factors, such as income, weather, and lifestyle. Still others may simply be unwilling to devote time and effort to managing electricity usage closely, even though they are aware that opportunities to respond are available and that the net savings are tangible. Others may pay so little attention to electricity consumption and bills that they do not realize that a price change has occurred.[41]

Q. Do you agree with CEO witness Warabak's recommendation to deny the Company's proposed increase for the Residential customer charge?

A. No. For the reasons explained in response to OCA witness Pavlovic, CEO witness Warabak's argument that the proposed increase in the customer charge will discourage energy efficiency and conservation is without merit.

Q. Are there other insights relating to the appropriateness of the Residential customer charge that you would like to share?

[40] Electric Power Research Institute. 2008. *Price Elasticity of Demand for Electricity: A Primer and Synthesis*, at 14.
[41] *Id.*

A. Yes. Customers of the Pennsylvania electric distribution service cooperatives that are exempt from the Commission's ratemaking jurisdiction are owned by and operated for the benefit of customers. Table 8, below, shows the residential customer charge component of Pennsylvania electric cooperatives' electric rates.

Table 8 - PA Electric Cooperatives' Monthly Customer Charge

Northwestern Rural Electric Cooperative Association, Inc.	$45.00
United Electric Cooperative, Inc.	$45.00
Claverack Rural Electric Cooperative, Inc.	$41.00
Adams Electric Cooperative, Inc.	$40.00
Sullivan County Rural Electric Cooperative, Inc.	$40.00
REA Energy Cooperative, Inc.	$37.50
Central Electric Cooperative, Inc.	$33.00
Warren Electric Cooperative, Inc.	$32.00
Tri-County Rural Electric Cooperative, Inc.	$30.00
Valley Rural Electric Cooperative, Inc.	$30.00
Bedford Rural Electric Cooperative, Inc.	$29.00
Somerset Rural Electric Cooperative, Inc.	$28.70
New Enterprise Rural Electric Cooperative, Inc.	$24.00

All the cooperatives have monthly customer charges significantly above the Company's proposed level. This is very instructive because it reveals what the citizens of Pennsylvania who own and operate their own utilities view as an appropriate customer charge. It is also very instructive to consider that UGI Electric's service territory is surrounded by PPL Electric's service territory with a monthly residential customer charge of $15.86. The Company's proposed $13.50 customer charge is well below cooperative utilities' monthly fixed charges and PPL Electric's current customer charge.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368

UGI UTILITIES, INC. – ELECTRIC DIVISION

EXHIBIT D (REBUTTAL)

COST OF SERVICE ALLOCATION STUDY
FULLY PROJECTED FUTURE TEST YEAR
ENDED SEPTEMBER 30, 2024

Witness: John D. Taylor

ATRIUM ECONOMICS
CENTERED ON ENERGY

Contents

I. INTRODUCTION

The purpose of this document is to discuss the development and results of the Cost of Service Study ("COSS") model and related schedules prepared for UGI Utilities, Inc. ("UGI" or the "Company") based on the Fully Projected Future Test Year ended September 30, 2024 ("FPFTY").

The document is organized into three sections. The first section discusses the purpose of cost allocation and includes an overview of Atrium's COSS model used to develop the cost allocation study. The second section, UGI Cost of Service Procedures, includes details of the methodologies adopted in the development of the study. The last section exhibits the results of the cost of service allocation.

1. Purpose of Cost Allocation

The purpose of COSS is to determine the cost of service responsibilities of each customer class upon which the base rates may be established. The revenue requirement studies provide the overall level of costs of providing service, while the COSS is used to change the basic rate structures and/or the relative overall cost responsibility of each customer class. Based on the functionalization and classification of costs and allocation methodologies used in the COSS, the revenue requirement by customer class is determined and used in designing the Company's proposed base rates. In other words, the COSS measures each class's contribution to the Company's overall cost of service. Comparing the costs to serve any customer class with that class's rate revenues provides a measure of the return realized from that class and their associated revenue-to-cost ratio. This allows for a comparison across classes to ascertain the presence and extent of interclass subsidization (i.e., when one class pays more than its cost to serve and another pays less than its cost to serve).

2. COSS Procedures

Cost of service studies utilize a three-step process: functionalization, classification, and allocation.

In the first step, the functionalization sets off with assigning Federal Energy Regulatory Commission ("FERC") plant accounts and associated investment balances to appropriate cost of service functions. UGI's primary functional cost categories associated with electric distribution services include Primary Distribution, Secondary Distribution, and Customer Accounts and Services. The expenses related to particular property investments or groups of investments can often follow the same functionalization and are allocated based on the ratios of electric plant assigned to each function. These plant ratios can be used to functionalize most other cost items.

In the second step, classification, each functional cost category is further separated by cost causation. There are three basic cost-defining characteristics of electric services: demand, energy/commodity, and customer.

- Demand (Capacity) related costs are associated with the peak usage of the utility system. These costs are necessary to maintain the system at a level sufficient to satisfy the greatest demand that all the customers could place upon the system.
- Energy/Commodity-related costs are variable costs that vary with the quantity of electricity used. These costs reflect the number of units consumed or supplied during a period of time.

- Customer-related costs are associated with serving customers regardless of their usage or demand characteristics. They are allocated directly to the customers of a particular class of service.

The last step is to allocate these cost components among customer classes. An analysis of the utility's records may indicate specific costs that should be assigned directly to a particular customer class, including plant investments and associated expenses. All the remaining costs that cannot be directly attributable to a specific group of customers are allocated using allocation factors.

3. Atrium Economics Cost of Service Study Model Overview

The Cost of Service Study is submitted in support of the direct testimony of John D. Taylor in Exhibit D. The COSS model presented in this proceeding is an excel based model that allows the user to modify various inputs and assumptions.

COSS Model Capabilities

The Atrium Economics' COSS model provides a large range of analytical capabilities including:

- Unbundling of operations into functions: (i.e. production/supply, storage, transmission, distribution, metering, and billing services.)
- Classification and allocation of costs into customer classes.
- Reports on Rate of Return, Revenue Requirement, and Revenue-to-Cost ratio for each function and rate class.
- Development of unit costs of each functional classification for each rate class.
- Specification of the individual rate of return targets for each function or customer class.
- Provides detailed analyses of working capital, income taxes, depreciation reserve, and depreciation expenses.
- Use of detailed analysis of labor expenses by account to facilitate the analyses of administrative and general expenses and overhead costs.
- Facilitation of direct assignment of plant investment, expenses, and revenue dollars to individual functions, classifications, or customer classes.

Follows Traditional 3-Step Allocation

The Atrium COSS Model follows the standard three-step analysis process:1) functionalization of rate base and expenses into various functional categories; 2) classification of functionalized components into demand, energy/commodity, and customer cost categories; and 3) allocation of each component among the customer classes.

As part of the functionalization process, accounts for common costs that are not specifically related to the primary functions, such as general plant and administrative and general expenses, are automatically allocated to the proper function based on internally defined allocation factors. All components of the utility's total cost of service are grouped into one of the functions.

The Atrium COSS Model provides unbundled functionalized and classified cost information by customer class; develops unbundled revenue requirements by functional classification for each customer class; and calculates unit costs by function for customer, energy/commodity, and demand categories. Accounting costs are reported by the FERC account level, and the allocation of A&G expenses, general taxes, and income taxes are clearly reported.

Revenue requirements are calculated from the allocated rate base and expenses and are adjusted to reflect the user-determined target rate of return and statutory tax adjustments. The actual revenues collected are compared to the calculated cost-based revenue requirements to determine class-specific, revenue-to-cost ratios to assist in revenue allocation and pricing activities.

Unit Cost Output Functionality

The COSS model calculates the unit cost of each functional classification separately for each rate class based on the user-specified billing determinants. These unit cost data are among the most important outputs from an embedded cost of service analysis. They are defined as the average cost of providing service to customers per measure of service (i.e., per kilowatt hour, per kilowatt of daily demand, and per customer). Unit costs are a key consideration in developing prices for bundled, unbundled, and re-bundled services.

Acceptance by Utility Regulatory Commissions

The format and presentation of the model's outputs have been used in many rate case proceedings and conform to standard utility commission requirements. Where necessary the COSS model outputs can be easily modified to meet specific jurisdictional filing requirements.

II. UGI's COST OF SERVICE PROCEDURES

1. Functionalization

The following functional cost categories were identified for purposes of UGI's cost allocation:

- Purchased Power
- Distribution
- PA PUC Direct Customer

UGI's assigned functional categories are presented on Schedule 1.

2. Classification

The following classification categories were identified for purposes of UGI's cost allocation:

- Energy/Commodity
- Demand
- Customer

UGI's assigned classification categories are presented on Schedule 1.

3. Functional Split & Minimum System Study

To properly classify all distribution costs as either customer-related, demand-related or a combination of these two factors, UGI's distribution capital and operating costs are functionalized into their primary and secondary voltage level components using a primary secondary split study. Once functionalized, the plant is then classified into the demand and customer components based on a "minimum size system" study. These studies are based on historical electric distribution plant data and the results are applied to distribution plant for the fully projected future test year.

The cost allocation methodology utilized in the minimum system studies is based on the specific design and operating characteristics of the Company's distribution system. It provides a more accurate and consistent measure of class cost responsibility than other approaches for providing distribution service to its customers.

UGI's Functional Split & Minimum System Study is presented as Schedule 2.

4. Allocation

The allocation step involves assigning classified costs to the customer classes based on cost causation. Therefore, the allocation of costs is usually based on some measure of class loads or class service characteristics. The External and Internal Allocation Factors are utilized to allocate costs among various customer classes. UGI's assigned Allocation Factors are presented on Schedule 1.

4.1. Customer Classes and Tariff Schedules

The following customer classes were identified for purposes of cost allocation:

- Residential
- General Service
- General Service-4
- Flood Control Power ("FCP")
- Large Power
- Lighting

4.2. External Allocation Factors

UGI's External Allocation Factors are presented on Schedule 3. The External Allocation Factors are developed based on the special studies conducted using various detailed data.

ENERGY/COMMODITY AND REVENUE ALLCOATION FACTORS

Costs classified as "Energy/Commodity" are allocated among customer classes based on the megawatt-hour (MWh) sales volumes for the test year.

<u>ENERGY</u> – Factor developed to directly assign MWh sales to the specific class in the FPFTY, based on sales customers' volumes.

<u>DISTREV</u> – Factor developed to directly assign associated current distribution base rate revenues to the customer classes in the FPFTY.

<u>PWRREV</u> – Developed to allocate Purchased Power revenue across customer classes based on current Rider GDR revenues by customer classes in the FPFTY.

<u>DSICREV</u> – Factor developed to allocate Distribution System Improvement Charge (DSIC) revenue to customer classes.

STASREV – Factor to allocate State Tax Adjustment Surcharge (STAS) revenue to customer classes. The STAS is applicable to the net monthly rates and minimum charges in UGI's electric tariff.

USPREV – Factor developed to allocate Universal Service Program (USP) revenue to the Residential customer class. The USP was established to recover costs related to the Company's Universal Service and Conservation Programs, excluding internal administrative costs.

EECREV – Factor developed to allocated Energy Efficiency & Conservation (EEC) revenue to customer classes based on UGI's Rider E revenue. Rider E recovers costs related to the Company's Phase III EEC Plan for 2019-2024.

CUSTOMER ALLOCATION FACTORS

Customer-related costs are generally allocated based on the number of customers within each class of service, with appropriate weighting to recognize specific service characteristics.

CUST – Factor based on the average number of customers per customer class in the FPFTY.

PRI_CUST – Factor based on the average number of customers using the primary system per customer class in the FPFTY.

SEC_CUST – Average number of customers using the secondary system (excludes customers using primary system only) per customer class.

METERS – Factor based on the weighted customer unit cost of meters used to serve customers in different rate classes. The analysis relies upon the Company's records, which provide an inventory of each type and size of meter for a specific rate schedule. The average meter current replacement cost (including labor and overhead) was linked to the meter records dataset to develop the total current cost of the investment for each customer class. Then the relative customer class unit cost was developed and multiplied by the forecasted customer count for each customer class.

SERV – The analysis relies upon the data contained in the Company's property records which provide an inventory of average footage and count of service wires by customer type. Additionally, current unit costs per foot by service wire type and design (underground or overhead) were provided by UGI. The method employed to develop the service allocator was similar to that used for the meter allocator.

UNCOL – Uncollectible Accounts - This factor is based on the statistics related to the three-year average (2020 – 2022) of uncollectible accounts by rate class.

DEPCUST – Customer Deposits – Factor based on statistics of customer deposits by rate class from fiscal year 2022.

FORTDISC – Forfeited Deposits – This factor is based on the statistics related to the three-year average (2020 – 2022) of forfeited discounts by rate class.

LIGHT – Direct assignment for the Lighting customer class only.

CUSTPREMIS – This factor was developed to assign FERC Account 371 – Installation on Customer Premises to applicable customer classes. 50% of this allocation was based on customer count, and 50% was based on the primary demand allocator PRI_DEM, described below.

DEMAND ALLOCATION FACTORS

PRI_DEM – This factor analyzes each rate class's monthly contribution to the sum of the monthly maximum demands for all classes. The monthly demand is computed by taking a class's maximum non-coincident peak ("NCP") demand across all twelve months. This factor looks only at customers who utilize energy flowing through the primary distribution system.

SEC_DEM – This factor employs the same method described above for the PRI_DEM allocator. However, it only looks at customers who utilize energy flowing through the secondary distribution system.

4.3. Internal Allocation Factors

Internal Allocation Factors are developed within the COSS model based on the cost ratios of allocated costs. The Internal Allocation Factors are provided in Schedule 5 and described below.

INT_D361-364 – Account 361 – 364 – The factor is based on the allocation of plant accounts 361 through 364 by customer class.

INT_D364 – Account 364 – The factor is based on the allocation of plant account 364 by customer class.

INT_D365 – Account 365 - The factor is based on the allocation of plant account 365 by customer class.

INT_D367 – Account 367 - The factor is based on the allocation of plant account 367 by customer class.

INT_D368 – Account 368 - The factor is based on the allocation of plant account 368 by customer class.

INT_DISTPLT – Distribution Plant Total – The factor is based on the allocated total Distribution plant balance by customer class.

INT_GENPLT – General Plant Total – The factor is based on the allocated total General plant balance by customer class.

INT_TOTPLT – Production Plant Total - The factor is based on the allocated total plant balance by customer class.

INT_RATEBASE – Total Rate Base – The factor is based on the derived rate base by customer class.

INT_DISTOPS – Distribution Operations Expense – The factor is based on the distribution operations expense accounts 581 - 587 by customer class.

INT_DMAINT – Distribution Maintenance Expense – The factor is based on the distribution maintenance expense accounts 591 - 597 by customer class.

INT_DISTOM – Distribution Operations & Maintenance Expense – The factor is based on the total distribution operations and maintenance expense by customer class.

INT_LABOR – Operations and Maintenance Labor – The factor is based on the labor-related operations and maintenance expense by customer class.

INT_REV_REQ Pre-Tax – Pre-Tax Revenue Requirement – The factor is based on the pre-tax revenue requirement by customer class.

UGI Utilities, Inc. - Electric Division
Electric Class Cost of Service Study
Fully Projected Future Test Year September 30, 2024
Schedule 1 - Account Balances and Allocation Methods
($ in thousands)

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
1	**RATE BASE**								
2	**Plant in Service**								
3	**Intangible Plant**								
4	Organization	301	11	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
5	Franchise & Consent	302	5	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
6	Miscellaneous Intangible Plant	303	0	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
7	Subtotal - Intangible Plant		16						
8	**Distribution Plant**								
9	Land & Land Rights	360	313	INT_D361_364	INT_D361_364	INT_D361_364	INT_D361_364	INT_D361_364	INT_D361_364
10	Structures & Improvements	361	627		DISTR	DEM	PRI_DEM		
11	Station Equipment	362	11,568		DISTR	DEM	PRI_DEM		
12	Storage Battery Equipment	363	0		DISTR	DEM	PRI_DEM		
13	Poles, Towers and Fixtures - PRI DEM	364	16,548		DISTR	DEM	PRI_DEM		
14	Poles, Towers and Fixtures - PRI CUS	364	15,455		DISTR	CUS			PRI_CUST
15	Poles, Towers and Fixtures - SEC DEM	364	9,219		DISTR	DEM	SEC_DEM		
16	Poles, Towers and Fixtures - SEC CUS	364	15,340		DISTR	CUS			SEC_CUST
17	Overhead Conductors and Devices - PRI DEM	365	25,626		DISTR	DEM	PRI_DEM		
18	Overhead Conductors and Devices - PRI CUS	365	33,621		DISTR	CUS			PRI_CUST
19	Overhead Conductors and Devices - SEC DEM	365	7,356		DISTR	DEM	SEC_DEM		
20	Overhead Conductors and Devices - SEC CUS	365	16,204		DISTR	CUS			SEC_CUST
21	Underground Conduit	366	8,780	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367
22	Underground Conductors and Devices - PRI DEM	367	7,404		DISTR	DEM	PRI_DEM		
23	Underground Conductors and Devices - PRI CUS	367	5,924		DISTR	CUS			PRI_CUST
24	Underground Conductors and Devices - SEC DEM	367	430		DISTR	DEM	SEC_DEM		
25	Underground Conductors and Devices - SEC CUS	367	1,808		DISTR	CUS			SEC_CUST
26	Transformers and Transformer Installations - SEC DEM	368.1	11,841		DISTR	DEM	SEC_DEM		
27	Transformers and Transformer Installations - SEC CUS	368.2	19,261		DISTR	CUS			SEC_CUST
28	Services	369	16,709		DRCUS	CUS			SERV
29	Meters	370.1	3,094		DRCUS	CUS			METERS
30	Meter Installations	370.2	1,989		DRCUS	CUS			METERS
31	Electronic Meters	370.3	5,038		DRCUS	CUS			METERS
32	Installations on Customers' Premises	371.0	2,219		DISTR	CUS			CUSTPREMIS
33	Installations on Customers' Premises - EV Charging Stations	371.1	0		DISTR	CUS			CUST
34	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	348		DISTR	CUS			LIGHT
35	Street Lighting and Signal Systems	373	2,615		DISTR	CUS			LIGHT
36	Subtotal - Distribution Plant		239,335						
37	**General Plant**								
38	Land & Land Rights	389	659	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
39	Structures & Improvements	390	10,646	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
40	Office Furniture & Equipment	391	18,441	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
41	Transportation Equipment	392	2,718	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
42	Stores Equipment	393	11	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
43	Tools & Garage Equipment	394	1,132	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
44	Laboratory Equipment	395	28	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
45	Power Operated Equipment	396	797	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
46	Communication Equipment	397	652	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
47	Miscellaneous Equipment	398	566	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
48	Other Tangible Property	399	0	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
49	Subtotal - General Plant		35,650						
50	**Total Plant in Service**		275,001						

UGI Utilities, Inc. - Electric Division
Electric Class Cost of Service Study
Fully Projected Future Test Year September 30, 2024
Schedule 1 - Account Balances and Allocation Methods
($ in thousands)

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
51	**Accumulated Depreciation & Amortization**								
52	**Intangible Plant**								
53	Organization	301.0	0	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
54	Franchise & Consent	302.0	0	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
55	Miscellaneous Intangible Plant	303.0	0	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
56	Subtotal - Intangible Plant		-						
57	**Distribution Plant**								
58	Land & Land Rights	360.0	0	INT_D361_364	INT_D361_364	INT_D361_364	INT_D361_364	INT_D361_364	INT_D361_364
59	Structures & Improvements	361.0	(67)	0	DISTR	DEM	PRI_DEM	0	
60	Station Equipment	362.0	(1,555)	0	DISTR	DEM	PRI_DEM	0	
61	Storage Battery Equipment	363.0	0	0	DISTR	DEM	PRI_DEM	0	
62	Poles, Towers and Fixtures	364.0	(18,154)	INT_D364	INT_D364	INT_D364	INT_D364	INT_D364	INT_D364
63	Overhead Conductors and Devices	365.0	(14,476)	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365
64	REG AFUDC	365.7	116	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365
65	Underground Conduit	366.0	(2,692)	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367
66	Underground Conductors and Devices	367.0	(4,928)	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367
67	Transformers	368.1	(8,267)	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368
68	Transformer Installations	368.2	(6,688)	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368
69	Services	369.0	(8,070)	0	DRCUS	CUS	0	0	SERV
70	Meters	370.1	(1,939)	0	DRCUS	CUS	0	0	METERS
71	Meter Installations	370.2	(825)	0	DRCUS	CUS	0	0	METERS
72	Electronic Meters	370.3	(4,275)	0	DRCUS	CUS	0	0	METERS
73	Installations on Customers' Premises	371.0	(1,088)	0	DISTR	CUS	0	0	CUSTPREMIS
74	Installations on Customers' Premises - EV Charging Stations	371.1	0	0	DISTR	CUS	0	0	CUST
75	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	(338)	0	DISTR	CUS	0	0	LIGHT
76	Street Lighting and Signal Systems	373.0	(1,139)	0	DISTR	CUS	0	0	LIGHT
77	Subtotal - Distribution Plant		(74,384)						
78	**General Plant**								
79	Land & Land Rights	389.0	(11)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
80	Structures & Improvements	390.0	(2,494)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
81	Office Furniture & Equipment	391.0	(7,201)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
82	Transportation Equipment	392.0	(612)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
83	Stores Equipment	393.0	(6)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
84	Tools & Garage Equipment	394.0	(498)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
85	Laboratory Equipment	395.0	(21)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
86	Power Operated Equipment	396.0	(87)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
87	Communication Equipment	397.0	(274)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
88	Miscellaneous Equipment	398.0	(157)	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
89	Other Tangible Property	399.0	0	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
90	Subtotal - General Plant		(11,361)						
91	**Total Accumulated Depreciation & Amortization**		(85,745)						
92	**Other Rate Base Items**								
93	Working Capital	Sch. A-1	11,447	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
94	Accumulated Deferred Income Taxes	Sch. A-1	(29,665)	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
95	Customer Deposits	Sch. A-1	(949)		DRCUS	CUS			DEPCUST
96	Materials & Supplies	Sch. A-1	2,152	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
97	**Total Other Rate Base Items**		(17,015)						
98	**TOTAL RATE BASE**		172,242						

UGI Utilities, Inc. - Electric Division
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Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
99	**OPERATION AND MAINTENANCE EXPENSE**								
100	**Generation Production, Transmission, and Distribution Expense**								
101	**Other Power Generation Expense**								
102	Purchased Power	555	85,198		PRPWR	ENG		PWRREV	
103	Transmission of Electricty by Others	565	5,978		PRPWR	ENG		PWRREV	
104	Subtotal - Other Power Generation Expense		91,176						
105	**Distribution Operation Expenses**								
106	Operation Supervision and Engineering	580.0	609	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS
107	Load Dispatching	581.0	574	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT
108	Line and Station Expenses	581.1	0	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT
109	Station Expenses	582.0	96		DISTR	DEM	PRI_DEM		
110	Overhead Line Expenses	583.0	298	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365
111	Underground Line Expenses	584.0	42	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367
112	Operation of Energy Storage Equipment	584.1	0	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT
113	Street Lighting and Signal System Expenses	585.0	31		DISTR	CUS			LIGHT
114	Meter Expenses	586.0	785		DISTR	CUS			METERS
115	Customer Installation Expenses	587.0	79		DISTR	CUS			SERV
116	Miscellaneous Distribution Expenses	588.0	352	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS
117	Rents	589.0	55	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS	INT_DISTOPS
118	Subtotal - Distribution Operation Expenses		2,922						
119	**Distribution Maintenance Expenses**								
120	Maintenance Supervision and Engineering	590	222	INT_DMAINT	INT_DMAINT	INT_DMAINT	INT_DMAINT	INT_DMAINT	INT_DMAINT
121	Maintenance of Structures	591	0		DISTR	DEM	PRI_DEM		
122	Maintenance of Station Equipment	592.0	208		DISTR	DEM	PRI_DEM		
123	Maintenance of Pipe Lines	592.1	0	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT	INT_DISTPLT
124	Maintenance of Structures and Equipment	592.2	0		DISTR	DEM	PRI_DEM		
125	Maintenance of Overhead Lines	593	9,715	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365
126	Maintenance of Underground Lines	594.0	61	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367
127	Maintenance of Lines	594.1	0	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367
128	Maintenance of Line Transformers	595	83	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368
129	Maintenance of Street Lighting and Signal Systems	596	24		DISTR	CUS			LIGHT
130	Maintenance of Meters	597	15		DISTR	CUS			METERS
131	Maintenance of Miscellaneous Distribution Plant	598	23	INT_DMAINT	INT_DMAINT	INT_DMAINT	INT_DMAINT	INT_DMAINT	INT_DMAINT
132	Subtotal - Distribution Maintenance Expenses		10,352						
133	**Total Generation Production, Transmission, and Distribution Expense**		104,450						
134	**Customer Accounts, Service, and Sales Expense**								
135	**Customer Account**								
136	Supervision	901	91		DRCUS	CUS			CUST
137	Meter Reading Expenses	902	218		DRCUS	CUS			CUST
138	Customer Records and Collection Expenses	903.0	2,529		DRCUS	CUS			CUST
139	Customer Records and Collection Expenses (USP)	903.0	6,656		DRCUS	CUS			USPREV
140	Uncollectible Accounts	904	3,239		DRCUS	CUS			UNCOL
141	Miscellaneous Customer Accounts Expenses	905	139		DRCUS	CUS			CUST
142	Subtotal - Customer Account		12,873						
143	**Customer Service & Information Expenses**								
144	Customer Service and Informational Expenses	906	0		DRCUS	CUS			CUST
145	Supervision	907	17		DRCUS	CUS			CUST
146	Customer Assistance Expenses	908	12		DRCUS	CUS			CUST
147	Information and Instructional Advertising Expenses	909	0		DRCUS	CUS			CUST
148	Miscellaneous Customer Service & Informational Exps (EEC)	910	1,157		DRCUS	CUS			EECREV
149	Subtotal - Customer Service & Information Expenses		1,186						

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150	**Sales Expenses**								
151	Supervision	911	0		DRCUS	CUS			CUST
152	Demonstrating and Selling Expenses	912	5		DRCUS	CUS			CUST
153	Advertising Expenses	913	0		DRCUS	CUS			CUST
154	Miscellaneous Sales Expenses	916	(5)		DRCUS	CUS			CUST
155	Sales Expenses	917	0		DRCUS	CUS			CUST
156	Subtotal - Sales Expenses		0						
157	**Total Customer Accounts, Service, and Sales Expense**		14,059						
158	**Administrative and General Expenses**								
159	Administrative and General Salaries	920.0	2,757	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
160	Office Supplies and Expenses	921.0	1,787	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
161	Administrative Expenses Transferred - Credit	922.0	0	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
162	Outside Services Employed	923.0	1,887	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
163	Property Insurance	924.0	31	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
164	Injuries and Damages	925.0	251	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
165	Employee Pensions and Benefits	926.0	1,259	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
166	Franchise Requirements	927.0	0	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM
167	Regulatory Commission Expenses	928.0	298	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM
168	Duplicate Charges - Credit	929.0	(74)	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM
169	General Advertising Expenses	930.1	74	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
170	Miscellaneous General Expenses	930.2	259	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
171	Rents	931.0	2	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
172	Transportation Expenses	933.0	0	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM	INT_DISTOM
173	Maintenance of General Plant	935.0	69	INT_GENPLT	INT_GENPLT	INT_GENPLT	INT_GENPLT	INT_GENPLT	INT_GENPLT
174	**Total Administrative and General Expenses**		8,598						
175	**TOTAL OPERATION AND MAINTENANCE EXPENSE**		127,107						
176	**Adjustments, Depreciation and Amortization Expense**								
177	**Depreciation Expense**								
178	Organization	301	0	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
179	Franchise & Consent	302	0	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
180	Miscellaneous Intangible Plant	303	0	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
181	Subtotal - Depreciation Expense		-						
182	**Distribution Plant**								
183	Land & Land Rights	360	0	INT_D361_364	INT_D361_364	INT_D361_364	INT_D361_364	INT_D361_364	INT_D361_364
184	Structures & Improvements	361	15	0	DISTR	DEM	PRI_DEM	0	
185	Station Equipment	362	370	0	DISTR	DEM	PRI_DEM	0	
186	Storage Battery Equipment	363	0	0	DISTR	DEM	PRI_DEM	0	
187	Poles, Towers and Fixtures	364	1,029	INT_D364	INT_D364	INT_D364	INT_D364	INT_D364	INT_D364
188	Overhead Conductors and Devices	365	2,001	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365
189	REG AFUDC	365.7	(16)	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365	INT_D365
190	Underground Conduit	366	137	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367
191	Underground Conductors and Devices	367	433	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367	INT_D367
192	Transformers	368.1	428	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368
193	Transformer Installations	368.2	207	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368	INT_D368
194	Services	369	280	0	DRCUS	CUS	0	0	SERV
195	Meters	370.1	66	0	DRCUS	CUS	0	0	METERS
196	Meter Installations	370.2	25	0	DRCUS	CUS	0	0	METERS
197	Electronic Meters	370.3	115	0	DRCUS	CUS	0	0	METERS
198	Installations on Customers' Premises	371.0	74	0	DISTR	CUS	0	0	CUSTPREMIS
199	Installations on Customers' Premises - EV Charging Stations	371.1	0	0	DISTR	CUS	0	0	CUST
200	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	1	0	DISTR	CUS	0	0	LIGHT
201	Street Lighting and Signal Systems	373	111	0	DISTR	CUS	0	0	LIGHT
202	Subtotal - Distribution Plant		5,275						

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Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Commodity Allocation Factor	Customer Allocation Factor
203	**General Plant**								
204	Land & Land Rights	389	0	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
205	Structures & Improvements	390	541	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
206	Office Furniture & Equipment	391	1,857	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
207	Transportation Equipment	392	290	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
208	Stores Equipment	393	1	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
209	Tools & Garage Equipment	394	57	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
210	Laboratory Equipment	395	2	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
211	Power Operated Equipment	396	58	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
212	Communication Equipment	397	75	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
213	Miscellaneous Equipment	398	61	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
214	Other Tangible Property	399	0	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
215	Subtotal - General Plant		2,943						
216	**Amortization Expense**								
217	Amortization Expense & Depreciation Adjustments		336	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
218	Subtotal - Amortization Expense		336						
219	**Total Adjustments, Depreciation and Amortization Expense**		8,553						
220	**Taxes**								
221	**Taxes Other Than Income Taxes**								
222	PURTA & Property Taxes		76	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
223	Gross Receipts Tax		3,101	INT_REV_REQ Pre-tax	INT_REV_REQ Pre-	INT_REV_REQ Pre-tax	INT_REV_REQ Pre-t	INT_REV_REQ Pre-	INT_REV_REQ Pre-tax
224	GRT - Purchased Power		5,717		PRPWR	ENG		PWRREV	
225	Payroll related		507	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR	INT_LABOR
226	Real estate		297	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
227	PA Local Use and Miscellaneous		22	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT	INT_TOTPLT
228	Subtotal - Taxes Other Than Income Taxes		9,718						
229	**Income Taxes**								
230	State Income Tax expense		(483)	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE
231	Federal Income Tax expense		1,306	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE
232	Subtotal - Income Taxes		823						
233	**Total Taxes**		10,542						
234	**REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**								
235	**Test Year Expenses at Current Rates**		146,201						
236	**Return on Rate Base**		14,038	INT_RATEBASE					
237	**Gross Up Items**								
238	Federal Income Tax		2,007	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE
239	State Income Tax		944	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE	INT_RATEBASE
240	Gross Receipts Tax		716	INT_REV_REQ Pre-tax	INT_REV_REQ Pre-	INT_REV_REQ Pre-tax	INT_REV_REQ Pre-t	INT_REV_REQ Pre-	INT_REV_REQ Pre-tax
241	Uncollectible		210		DRCUS	CUS			UNCOL
242	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		**164,116**						

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243	**INTERNAL ALLOCATION FACTORS**								
244	INT_D361_364		68,756						
245	INT_D364		56,561						
246	INT_D365		82,806						
247	INT_D367		15,566						
248	INT_D368		31,102						
249	INT_DISTPLT		239,335						
250	INT_GENPLT		35,650						
251	INT_TOTPLT		274,985						
252	INT_RATEBASE		172,242						
253	INT_DISTOPS		1,905						
254	INT_DMAINT		10,107						
255	INT_DISTOM		13,274						
256	INT_LABOR		4,498						
257	INT_REV_REQ Pre-tax		150,598						
258	*last line for internals*								
259	**Operating Revenue**			**Revenue/Margin Allocation Factor**					
260	Total Customer and Distribution Revenue	440-447	44,268	DISTREV					
261	Purchased Power Revenue		96,893	PWRREV					
262	Purchased Power GRT Revenue		0	PWRREV					
263	USP Rider		6,656	USPREV					
264	EEC Rider		1,152	EECREV					
265	Forfeited Discounts	450	520	FORTDISC					
266	Miscellaneous Service Revenues	451	16	UNCOL					
267	Rent from Electric Properties	454	567	INT_D364					
268	Interest on Undercollection - Refunded	456	0	UNCOL					
269	STAS Revenue		15	STASREV					
270	DSIC Revenue		2,604	DSICREV					
271	Rounding of Rev Req and POR		(1)	DISTREV					
272	**Total Operating Revenue**		152,691						
273	**NET INCOME AT CURRENT RATES**		6,490						
	REVENUE DEFICIENCY (EXCESS)		11,425						

UGI Utilities, Inc. - Electric Division
Subfunctionalization/Classification of Distribution Plant
Schedule 2 - Functional Split & Minimum System Study

		FUNCTIONALIZATION		PRIMARY SPLIT		SECONDARY SPLIT	
DIST. ACCT. NO.	DESCRIPTION	PRIMARY % OF ACCOUNT TOTAL	SECONDARY % OF ACCOUNT TOTAL	CUSTOMER COMPONENT % OF	DEMAND COMPONENT % OF	CUSTOMER COMPONENT % OF	DEMAND COMPONENT % OF
364	POLES, TOWERS AND FIXTURES	56.58%	43.42%	48.29%	51.71%	62.46%	37.54%
365	OVERHEAD CONDUCTORS AND DEVICES	71.55%	28.45%	56.75%	43.25%	68.78%	31.22%
367	UNDERGROUND CONDUCTORS	85.62%	14.38%	44.45%	55.55%	80.78%	19.22%
368	TRANSFORMERS	0.00%	100.00%	NA	NA	61.93%	38.07%

UGI Electric
Minimum Size System Study

Primary

			Minimum Size			Expand to Total Account				
Account	Minimum Size (Asset Description)	Unit	Total Installed Cost	Total Installed Units	Average Unit Cost	Total Units	Total Customer Component	Account Total	% Customer	% Demand
364	30 Foot Wood Pole	Pole			$ 945.22	25,400	$ 24,008,311	$ 49,713,744	48.29%	51.71%
365	365100 O/H COND. & DEV - 2 ACSR 15KV BARE WIRE	Feet	$ 3,968,789	1,511,533	$ 2.63	17,278,644	$ 45,368,048	$ 79,947,090	56.75%	43.25%
367	367100 URD COND & DEV: #2 CBL 15KV (C/C)	Feet	$ 770,645	131,655	$ 5.85	1,516,176	$ 8,874,962	$ 19,968,149	44.45%	55.55%

Secondary

			Minimum Size			Expand to Total Account				
Account	Minimum Size (Asset Description)	Unit	Total Installed Cost	Total Installed Units	Average Unit Cost	Total Units	Total Customer Component	Account Total	% Customer	% Demand
364	30 Foot Wood Pole	Pole			$ 945.22	25,210	$ 23,829,202	$ 38,149,969	62.46%	37.54%
365	365100 O/H COND. & DEV - 2 ALUM TRIPLEX WIRE	Feet	$ 1,954,587	239,918	$ 8.15	2,683,883	$ 21,865,317	$ 31,790,918	68.78%	31.22%
367	367100 URD COND & DEV: COND SEC #350 MCM AA	Feet	$ 1,725,729	195,122	$ 8.84	306,197	$ 2,708,117	$ 3,352,480	80.78%	19.22%
368 - OH					$ 1,840.94	22,368	$ 41,178,044	$ 63,692,769	64.65%	35.35%
368 - PAD					$ 5,063.97	1,234	$ 6,248,942	$ 12,890,912	48.48%	51.52%
368							$ 47,426,985	$ 76,583,681	61.93%	38.07%

Minimum Size (Asset Description)	Unit	Total Installed Cost	Total Installed Units	Average Unit Cost	Non-Load Adjustment Factor	Min Sys Avg. Unit Cost
7.5-15 KVA	OH	$ 4,794,199	2,938			$ -
10 KVA	OH	5,300,168	2,435			$ -
15 KVA	OH	7,502,457	3,826			$ -
Average		$ 17,596,824	9,199	$ 1,912.91	96.24%	$ 1,840.94
25 KVA	UG	$ 1,498,139	287	$ 5,220.00	97.01%	$ 5,063.97

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Class Allocation Factors

Line No.	Name	Description	Total	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
	DEMAND ALLOCATORS								
1	NCPs @ Primary								
2		NCPs @ Primary	245,500	152,649	7,548	33,011	352	50,496	1,443
3		Adjustment Factor		100%	100%	100%	100%	100%	100%
4	PRI_DEM	Primary Demand Allocator	245,500	152,649	7,548	33,011	352	50,496	1,443
5			100%	62.18%	3.07%	13.45%	0.14%	20.57%	0.59%
6	NCPs @ Secondary								
7		NCPs @ Secondary	206,853	149,544	7,395	31,619	-	16,881	1,414
8		Adjustment Factor		100%	100%	100%	100%	100%	100%
9	SEC_DEM	Secondary Demand Allocator	206,853	149,544	7,395	31,619	-	16,881	1,414
10			100%	72.29%	3.57%	15.29%	0.00%	8.16%	0.68%
11	**CUSTOMER ALLOCATORS**								
12	Customer Count								
13	CUST	2023 Forecasted Customer Count	62,937	54,998	5,331	2,330	7	211	60
14			100%	87.39%	8.47%	3.70%	0.01%	0.34%	0.10%
15	Number of Customers Using Primary System								
16	PRI_CUST	2023 Forecasted Customer Count	62,937	54,998	5,331	2,330	7	211	60
17			100%	87.39%	8.47%	3.70%	0.01%	0.34%	0.10%
18	Number of Customers Using Secondary System								
19	SEC_CUST	2023 Forecasted Customer Count	62,882	54,996	5,331	2,320	-	175	60
20			100%	87.46%	8.48%	3.69%	0.00%	0.28%	0.10%
21	Allocation of Meter Investments								
22		Average Cost per Meter		$ 139	$ 161	$ 303	$ 309	$ 313	$ -
23		Relative Weighting Factor		1.00	1.15	2.17	2.21	2.25	-
24		2023 Forecasted Customer Count		54,998	5,331	2,330	7	211	60
25		Weighted Meter Count	66,695	54,998	6,152	5,056	16	474	-
26	METERS		100%	82.46%	9.22%	7.58%	0.02%	0.71%	0.00%
27	Allocation of Services								
28		Service Cost per Service	$ 250	$ 68.46	$ 58.98	$ 59.56	$ -	$ 63.26	$ -
29		Relative Weighting Factor		1.00	0.86	0.87	-	0.92	-
30	SERV	Weighted Customers	61,813	54,998	4,593	2,027	-	195	-
31			100%	88.97%	7.43%	3.28%	0.00%	0.32%	0.00%
32	Uncollectible								
33	UNCOL	Uncollectibles	$ 1,448,134	$ 1,380,411	$ 26,726	$ 24,971	$ -	$ 11,873	$ 4,153
34			100%	95.32%	1.85%	1.72%	0.00%	0.82%	0.29%
35	Customer Deposits								
36	DEPCUST	Customer Deposits	$ 983,808	$ 630,284	$ 70,267	$ 228,408	$ -	$ 50,282	$ 4,568
37			100%	64.07%	7.14%	23.22%	0.00%	5.11%	0.46%

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Class Allocation Factors

Line No.	Name	Description	Total	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
38	Forfeited Discounts								
39	FORTDISC	Forfeited Discounts	$ 395,644	$ 250,380	$ 36,968	$ 60,780	$ -	$ 43,173	$ 4,342
40			100%	63.28%	9.34%	15.36%	0.00%	10.91%	1.10%
41	Direct Assignment of Lighting								
42	LIGHT		1	-	-	-	-	-	1
43			100%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
44	Account 371 - Installation on Customer Premises								
45	CUSTPREMIS	Non-residential - 50% customer count and 50% demand	25%	-	5.77%	8.57%	0.08%	10.45%	0.34%
46		Installation on Customer Premises	100%	0.00%	22.89%	34.00%	0.31%	41.45%	1.35%
47	**ENERGY ALLOCATORS**								
48	MWh Sales								
49	ENERGY	MWh Sales	1,055,931	610,230	33,026	115,648	763	289,197	7,066
50			100%	57.79%	3.13%	10.95%	0.07%	27.39%	0.67%
51	**REVENUE ALLOCATORS**								
52	Distribution Revenue								
53	DISTREV	Total Revenue	44,267,882	30,111,450	2,545,379	4,687,856	17,185	5,713,469	1,192,542
54			100%	68.02%	5.75%	10.59%	0.04%	12.91%	2.69%
55	Total Purchased Power Revenue								
56	PWRREV	Total Purchased Power Revenue	96,893,373	78,084,084	3,928,239	9,236,799	-	5,063,150	581,102
57			100%	80.59%	4.05%	9.53%	0.00%	5.23%	0.60%
58	Total DSIC Revenue								
59	DSICREV		2,603,825	1,856,384	129,412	242,026	910	315,027	60,067
60		Total DSIC Revenue	39%	27.89%	1.94%	3.64%	0.01%	4.73%	0.90%
61	Total STAS Revenue								
62	STASREV		15,157	11,707	665	1,432	2	1,168	184
63		Total STAS Revenue	1%	1.02%	0.06%	0.12%	0.00%	0.10%	0.02%
64	Total USP Revenue								
65	USPREV		6,656,204	6,656,204	-	-	-	-	-
66		Total USP Revenue	100%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
67	Total EEC Revenue								
68	EECREV	Total EEC Revenue	1,152,420	360,036	42,855	152,656	1,008	587,071	8,795
69			100%	31.24%	3.72%	13.25%	0.09%	50.94%	0.76%

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Subfunctionalization/Classification Of Distribution Plant

Line No.	DIST. ACCT. NO.	DESCRIPTION	FUNCTIONALIZATION PRIMARY % OF ACCOUNT TOTAL	FUNCTIONALIZATION SECONDARY % OF ACCOUNT TOTAL	PRIMARY SPLIT CUSTOMER COMPONENT % OF	PRIMARY SPLIT DEMAND COMPONENT % OF	SECONDARY SPLIT CUSTOMER COMPONENT % OF	SECONDARY SPLIT DEMAND COMPONENT % OF
1	364	POLES, TOWERS AND FIXTURES	56.58%	43.42%	48.29%	51.71%	62.46%	37.54%
2	365	OVERHEAD CONDUCTORS AND DEVICES	71.55%	28.45%	56.75%	43.25%	68.78%	31.22%
3	367	UNDERGROUND CONDUCTORS	85.62%	14.38%	44.45%	55.55%	80.78%	19.22%
4	368	Transformers	0.00%	100.00%			61.93%	38.07%
5		Poles, Towers and Fixtures - PRI DEM	29.26%					
6		Poles, Towers and Fixtures - PRI CUS	27.32%					
7		Poles, Towers and Fixtures - SEC DEM	16.30%					
8		Poles, Towers and Fixtures - SEC CUS	27.12%					
9		Overhead Conductors and Devices - PRI DEM	30.95%					
10		Overhead Conductors and Devices - PRI CUS	40.60%					
11		Overhead Conductors and Devices - SEC DEM	8.88%					
12		Overhead Conductors and Devices - SEC CUS	19.57%					
13		Underground Conductors and Devices - PRI DEM	47.57%					
14		Underground Conductors and Devices - PRI CUS	38.06%					
15		Underground Conductors and Devices - SEC DEM	2.76%					
16		Underground Conductors and Devices - SEC CUS	11.61%					
17		Transformers and Transformer Installations - SEC DEM	38.07%					
18		Transformers and Transformer Installations - SEC CUS	61.93%					

Notes:
1. Account 366 Underground Conduit is split the same for customer and demand percentages as Account 367 Underground Conductor

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Billing Determinants

Line No.		Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting	Total
1	Year End Book Report Customer Count	54,998	5,331	2,330	7	211	60	62,937
2	Sales-KWH	610,229,801	33,025,595	115,648,153	763,235	289,197,391	7,066,465	1,055,930,640
3	Distribution Revenue	30,111,450	2,545,379	4,687,856	17,185	5,713,469	1,192,542	44,267,882
4	STAS Revenue	11,707	665	1,432	2	1,168	184	15,157
5	GSR Revenue	78,084,084	3,928,239	9,236,799	-	5,063,150	581,102	96,893,373
6	USP Revenue	6,656,204	-	-	-	-	-	6,656,204
7	EEC Revenue	360,036	42,855	152,656	1,008	587,071	8,795	1,152,420
8	DSIC Revenue	1,856,384	129,412	242,026	910	315,027	60,067	2,603,825
9	Total Revenue - Sum from Above	117,079,865	6,646,549	14,320,768	19,104	11,679,885	1,842,691	151,588,862
10	Total Revenue - From Revenue Proof	117,079,865	6,646,549	14,320,768	19,104	11,679,885	1,842,691	151,588,862

Primary and Secondary Split

Line No.		Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting	Total
1	Year End Book Report Customer Count	54,998	5,331	2,330	7	211	60	62,937
2	Primary Customers	2		10	7	36	-	55
3	Secondary Customers	54,996	5,331	2,320	-	175	60	62,882

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Allocation Of Demand

Line No.		Residential	General Service	General Service-4	FCP	Large Power	Lighting	Total	Loss Factors from Generation
1	**NCP (kW) at Generation**	159,264	7,875	34,441	368	52,684	1,506	256,138	1.0000
2	**NCP at Primary**	152,649	7,548	33,011	352	50,496	1,443	245,500	1.0433
3	**NCP at Secondary**	149,544	7,395	31,619	-	16,881	1,414	240,505	1.0650
4									
5	**NCP (kW) at Primary**			735	352	33,264		34,351	
6	**NCP (kW) at Secondary**	149,544	7,395	31,619	-	16,881	1,414	206,853	
7	**Total**	149,544	7,395	32,354	352	50,145	1,414	241,204	

Rate	**R**	**GS**	**GS-4**	**FCP**	**LP**	**Lighting**	**Total**
NCP (kW) at Meter	149,544	7,395	32,354	352	50,145	1,414	241,204

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Allocation of Meter Costs

Line No.		Total	Residential	General Service	General Service-4	Flood Control Power	Large Power
1	Total Meter Costs	$ 9,444,298	$ 7,794,052	$ 883,826	$ 696,938	$ 2,162	$ 67,320
2	Count of Meters	63,906	55,889	5,492	2,303	7	215
3	Average Cost per Meter		$ 139	$ 161	$ 303	$ 309	$ 313
4	Relative Weighting Factor		1.00	1.15	2.17	2.21	2.25

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Allocation of Services

Line No.	Customer Class	Commerical Customer Count	Industrial Customer Count	Weighted Average Service Cost	Relative Weighting
1	Residential	NA	NA	$ 68.46	1.000
2	General Service	5,303	11	$ 58.98	0.862
3	General Service-4	2,181	87	$ 59.56	0.870
4	Large Power	153	57	$ 63.26	0.924

Line No.	Customer Group	Total Services in Study	Total Service Cost in Study	Average Service Cost	Relative Weighting
1	Commerical	3,989	$ 235,151	$ 58.95	0.861
2	Industrial	69	$ 5,167	$ 74.89	1.094
3	Residential	40,369	$ 2,763,689	$ 68.46	1.000
4	Total	44,427	$ 3,004,007	67.62	

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Average and Excess Method

Line No.		Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting	Total
1	**Sales-KWH**	610,229,801	33,025,595	115,648,153	763,235	289,197,391	7,066,465	1,055,930,640
2	**Average Demand**	69,661	3,770	13,202	87	33,013	807	120,540
3	**Class NCP**	149,544	7,395	32,354	352	50,145	1,414	241,204
4	**Class Excess**	79,883	3,625	19,152	265	17,132	607	120,664
5	**Average Allocator Component**	37.27%	2.02%	7.06%	0.05%	17.66%	0.43%	64%
6	**Excess Allocator Component**	22.01%	1.09%	4.76%	0.05%	7.38%	0.21%	36%
7	**Average and Excess Allocator**	59.28%	3.11%	11.83%	0.10%	25.05%	0.64%	100%

8	**System Load Factor**	64.49%

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Allocation of Customer Deposits

Line No.	Customer Class	Customer Deposits
1	Residential	$ 630,284
2	General Service	$ 70,267
3	General Service-4	$ 228,408
4	Large Power	$ 50,282
5	Lighting	$ 4,568
6	Total	$ 983,808

UGI Utilities, Inc. – Electric Division
Schedule 3 - External Allocation Factors
Allocation of Forfeited Discounts

Line No.	Customer Class	Average 2020 - 2022	2022	2021	2020
1	Residential	$ 250,380	$ 355,503	$ 234,538	$ 161,100
2	General Service	$ 36,968	$ 52,139	$ 41,163	$ 17,603
3	General Service-4	$ 60,780	$ 83,115	$ 70,523	$ 28,702
4	Large Power	$ 43,173	$ 55,846	$ 56,017	$ 17,655
5	Lighting	$ 4,342	$ 5,136	$ 5,433	$ 2,457
6	Total	$ 395,644	$ 551,738	$ 407,674	$ 227,518

UGI Utilities, Inc. – Electric Division

Schedule 3 - External Allocation Factors

Allocation of Uncollectibles

Line No.	Customer Class	Average 2020 - 2022	2020	2021	2022
1	Residential	$ 1,380,411	$ 1,165,815	$ 1,188,195	$ 1,787,224
2	General Service	$ 26,726	$ 23,022	$ 27,504	$ 29,654
3	General Service-4	$ 24,971	$ 17,954	$ 23,227	$ 33,731
4	Large Power	$ 11,873	$ 48,225	$ 1,523	$ (14,130)
5	Lighting	$ 4,153	$ 4,328	$ 1,990	$ 6,139
6		$ 1,448,134	$ 1,259,344	$ 1,242,440	$ 1,842,618

UGI Utilities, Inc. - Electric Division
Electric Class Cost of Service Study
Fully Projected Future Test Year September 30, 2024
Schedule 4 - Internal Allocation Factors

Line	Allocator Code	Total	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
1	**ALLOCATION FACTOR BASIS ($ in thousands)**							
2	INT_D361_364	$ 68,756	$ 51,458	$ 3,823	$ 6,412	$ 43	$ 6,759	$ 261
3	INT_D364	$ 56,561	$ 43,875	$ 3,448	$ 4,772	$ 25	$ 4,250	$ 190
4	INT_D365	$ 82,806	$ 64,803	$ 5,272	$ 6,413	$ 41	$ 6,029	$ 248
5	INT_D367	$ 15,566	$ 11,672	$ 898	$ 1,347	$ 11	$ 1,583	$ 54
6	INT_D368	$ 31,102	$ 25,406	$ 2,056	$ 2,521	$ -	$ 1,020	$ 99
7	INT_DISTPLT	$ 239,335	$ 183,370	$ 15,256	$ 19,552	$ 111	$ 17,359	$ 3,688
8	INT_GENPLT	$ 35,650	$ 29,957	$ 2,015	$ 1,970	$ 11	$ 1,349	$ 348
9	INT_TOTPLT	$ 274,985	$ 213,328	$ 17,272	$ 21,521	$ 121	$ 18,708	$ 4,035
10	INT_RATEBASE	$ 172,242	$ 133,618	$ 10,543	$ 13,466	$ 82	$ 12,537	$ 1,995
11	INT_DISTOPS	$ 1,905	$ 1,482	$ 139	$ 149	$ 1	$ 93	$ 41
12	INT_DMAINT	$ 10,107	$ 7,859	$ 635	$ 794	$ 5	$ 759	$ 55
13	INT_DISTOM	$ 13,274	$ 10,322	$ 864	$ 1,041	$ 6	$ 921	$ 120
14	INT_LABOR	$ 4,498	$ 3,780	$ 254	$ 249	$ 1	$ 170	$ 44
15	INT_REV_REQ Pre-tax	$ 150,598	$ 122,045	$ 6,839	$ 12,324	$ 21	$ 8,261	$ 1,108
16	**ALLOCATION FACTOR (%)**							
17	INT_D361_364	100.0%	74.8%	5.6%	9.3%	0.1%	9.8%	0.4%
18	INT_D364	100.0%	77.6%	6.1%	8.4%	0.0%	7.5%	0.3%
19	INT_D365	100.0%	78.3%	6.4%	7.7%	0.0%	7.3%	0.3%
20	INT_D367	100.0%	75.0%	5.8%	8.7%	0.1%	10.2%	0.3%
21	INT_D368	100.0%	81.7%	6.6%	8.1%	0.0%	3.3%	0.3%
22	INT_DISTPLT	100.0%	76.6%	6.4%	8.2%	0.0%	7.3%	1.5%
23	INT_GENPLT	100.0%	84.0%	5.7%	5.5%	0.0%	3.8%	1.0%
24	INT_TOTPLT	100.0%	77.6%	6.3%	7.8%	0.0%	6.8%	1.5%
25	INT_RATEBASE	100.0%	77.6%	6.1%	7.8%	0.0%	7.3%	1.2%
26	INT_DISTOPS	100.0%	77.8%	7.3%	7.8%	0.0%	4.9%	2.2%
27	INT_DMAINT	100.0%	77.8%	6.3%	7.9%	0.1%	7.5%	0.5%
28	INT_DISTOM	100.0%	77.8%	6.5%	7.8%	0.0%	6.9%	0.9%
29	INT_LABOR	100.0%	84.0%	5.7%	5.5%	0.0%	3.8%	1.0%
30	INT_REV_REQ Pre-tax	100.0%	81.0%	4.5%	8.2%	0.0%	5.5%	0.7%

UGI Utilities, Inc. - Electric Division
Electric Class Cost of Service Study
Fully Projected Future Test Year September 30, 2024
Schedule 5 - Comparison of Cost of Service with Revenues under Present and Proposed Rates
($ in thousands)

		Pro Forma Cost of Service		Pro Forma Revenues Under Present Rates		Pro Forma Revenues Under Proposed Rates		Revenue Increase	
Line	**Service Classification**	**Amount**	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**
1	Residential	$ 132,116	81.0%	$ 117,080	77.2%	$ 127,785	78.4%	$ 10,705	9.1%
2	General Service	7,425	4.6%	6,647	4.4%	7,361	4.5%	714	10.7%
3	General Service-4	13,273	8.1%	14,321	9.4%	14,321	8.8%	-	0.0%
4	Flood Control Power	24	0.0%	19	0.0%	24	0.0%	5	27.7%
5	Large Power	8,962	5.5%	11,680	7.7%	11,680	7.2%	-	0.0%
6	Lighting	1,215	0.7%	1,843	1.2%	1,843	1.1%	-	0.0%
7	**Total System**	**$ 163,014**	100%	**$ 151,589**	100%	**$ 163,014**	100%	**$ 11,425**	7.5%
8	Other Revenues	$ 1,102		$ 1,102		$ 1,102		-	0.0%
9	Total	**164,116**		**152,691**		**164,116**		**11,425**	7.5%

		Pro Forma Cost of Service		Pro Forma Revenues w/o Purchase Power Under Present Rates		Pro Forma Revenues w/o Purchase Power Under Proposed Rates		Revenue Increase	
10	**Service Classification**	**Amount**	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**
11	Residential	$ 54,032	81.7%	$ 38,996	71.3%	$ 49,701	75.2%	$ 10,705	27.5%
12	General Service	3,496	5.3%	2,718	5.0%	3,433	5.2%	714	26.3%
13	General Service-4	4,036	6.1%	5,084	9.3%	5,084	7.7%	-	0.0%
14	Flood Control Power	24	0.0%	19	0.0%	24	0.0%	5	27.7%
15	Large Power	3,899	5.9%	6,617	12.1%	6,617	10.0%	-	0.0%
16	Lighting	633	1.0%	1,262	2.3%	1,262	1.9%	-	0.0%
17	**Total System**	**$ 66,120**	100.0%	**$ 54,695**	100.0%	**$ 66,120**	100.0%	**$ 11,425**	20.9%
18	Other Revenues	$ 1,102		$ 1,102		$ 1,102		-	0.0%
19	Total	**67,223**		**55,798**		**67,223**		**11,425**	20.5%

UGI Utilities, Inc. - Electric Division
Electric Class Cost of Service Study
Fully Projected Future Test Year September 30, 2024
Schedule 6 - Summary of Cost of Service and Rate of Return Under Present and Proposed Rates
($ in thousands)

Line No.	Revenue Requirement Summary	Total System	Total Check	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
1	**Rate Base**								
2	Plant in Service	$ 275,001	-	$ 213,341	$ 17,273	$ 21,522	$ 121	$ 18,709	$ 4,035
3	Accumulated Reserve	(85,745)	-	(66,790)	(5,639)	(6,529)	(31)	(4,965)	(1,789)
4	Other Rate Base Items	(17,015)	-	(12,932)	(1,090)	(1,527)	(7)	(1,206)	(251)
5	**Total Rate Base**	**$ 172,242**	**-**	**$ 133,618**	**$ 10,543**	**$ 13,466**	**$ 82**	**$ 12,537**	**$ 1,995**
6	**Revenue at Current Rates**								
7	Total Distribution Margin	$ 44,268	-	$ 30,111	$ 2,545	$ 4,688	$ 17	$ 5,713	$ 1,193
8	STAS Revenue	15	-	12	1	1	0	1	0
9	DSIC Revenue	2,604	-	1,856	129	242	1	315	60
10	USP Rider	6,656	-	6,656	-	-	-	-	-
11	EEC Rider	1,152	-	360	43	153	1	587	9
12	**Total Base and Rider Revenue**	**$ 54,695**	-	**$ 38,996**	**$ 2,718**	**$ 5,084**	**$ 19**	**$ 6,617**	**$ 1,262**
13	Forfeited Discounts	$ 520	-	$ 329	$ 49	$ 80	$ -	$ 57	$ 6
14	Miscellaneous Revenues	582	-	455	35	48	0	43	2
15	**Total Base, Rider, and Other Revenue**	**$ 55,798**	-	**$ 39,780**	**$ 2,802**	**$ 5,212**	**$ 19**	**$ 6,716**	**$ 1,269**
16	Purchased Power Revenue	$ 96,893	-	$ 78,084	$ 3,928	$ 9,237	$ -	$ 5,063	$ 581
17	**Total Current Revenue**	**$ 152,691**	-	**$ 117,864**	**$ 6,730**	**$ 14,449**	**$ 19**	**$ 11,779**	**$ 1,850**
18	**Total Base, Rider, and Purchased Power Revenue**	**$ 151,589**	-	**$ 117,080**	**$ 6,647**	**$ 14,321**	**$ 19**	**$ 11,680**	**$ 1,843**
19	**Expenses at Current Rates**								
20	O&M and A&G Expenses	$ 35,930	-	$ 30,259	$ 1,710	$ 1,844	$ 10	$ 1,882	$ 225
21	Purchased Power Expense	91,176	-	73,477	3,696	8,692	-	4,764	547
22	Depreciation and Amortization Expense	8,553	-	6,688	520	632	4	547	162
23	Purchased Power GRT Expense	5,717	-	4,607	232	545	-	299	34
24	Taxes Other Than Income	901	-	1,055	63	(40)	0	(147)	(32)
25	Gross Receipts Tax	3,101	-	2,211	154	288	1	375	72
26	Income Taxes	823	-	(49)	40	280	0	457	95
27	**Total Expenses at Current Rates**	**$ 146,201**	-	**$ 118,248**	**$ 6,416**	**$ 12,241**	**$ 16**	**$ 8,178**	**$ 1,103**
28	**Operating Income - Current**	$ 6,490	-	$ (384)	$ 314	$ 2,208	$ 3	$ 3,602	$ 747
29	Current Rate of Return	3.77%	-	-0.29%	2.98%	16.40%	4.21%	28.73%	37.44%
30	Relative Rate of Return	1.00		(0.08)	0.79	4.35	1.12	7.62	9.94
31	Current Revenue to Cost Ratio	0.93		0.89	0.90	1.08	0.80	1.30	1.51
32	Current Parity Ratio	1.00		0.95	0.96	1.16	0.86	1.40	1.63
33	**Current Revenue at Equal Rates of Return**								
34	Current Rate of Return	3.77%	-	3.77%	3.77%	3.77%	3.77%	3.77%	3.77%
35	Current Operating Income at Equal ROR	$ 6,490	-	$ 5,035	$ 397	$ 507	$ 3	$ 472	$ 75
36	Income Taxes - Equal ROR	823	-	639	50	64	0	60	10
37	Gross Receipts Tax	3,101	-	2,535	164	190	1	182	29
38	Other Expenses - Equal ROR	142,277	-	116,086	6,222	11,672	14	7,346	937
39	**Total Margin @ Equal Rates of Return**	**$ 152,691**	**-**	**$ 124,294**	**$ 6,833**	**$ 12,434**	**$ 19**	**$ 8,061**	**$ 1,051**
40	Present (Subsidies)/Excesses	-	-	(6,430)	(103)	2,015	0	3,719	799
41	**Revenue Requirement at Equal Rates of Return**								
42	Required Return	8.15%	-	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%
43	Required Operating Income	$ 14,038	$ -	$ 10,890	$ 859	$ 1,097	$ 7	$ 1,022	$ 163

UGI Utilities, Inc. - Electric Division
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Schedule 6 - Summary of Cost of Service and Rate of Return Under Present and Proposed Rates
($ in thousands)

Line No.	Revenue Requirement Summary	Total System	Total Check	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
44	**Expenses at Required Return**								
45	O&M and A&G Expenses	$ 35,930	$ -	$ 30,259	$ 1,710	$ 1,844	$ 10	$ 1,882	$ 225
46	Purchased Power Expense	91,176	-	73,477	3,696	8,692	-	4,764	547
47	Depreciation and Amortization Expense	8,553	-	6,688	520	632	4	547	162
48	Purchased Power GRT Expense	5,717	-	4,607	232	545	-	299	34
49	Taxes Other Than Income	901	-	731	53	59	0	46	11
50	Gross Receipts Tax	3,101	-	2,535	164	190	1	182	29
51	Income Taxes	823	-	639	50	64	0	60	10
52	Gross Up - Income Taxes	2,951	-	2,289	181	231	1	215	34
53	Gross Up - Gross Receipts	716	-	586	38	44	0	42	7
54	Gross Up - Uncollectibles	210		200	4	4	-	2	1
55	**Total Expenses - Required**	**$ 150,079**	-	**$ 122,010**	**$ 6,649**	**$ 12,303**	**$ 18**	**$ 8,039**	**$ 1,060**
56	**Total Revenue Requirement at Equal Return**	**$ 164,116**	-	**$ 132,900**	**$ 7,508**	**$ 13,401**	**$ 24**	**$ 9,061**	**$ 1,222**
57	Current Miscellaneous Revenue	1,102	-	784	83	128	0	99	8
58	**Total Revenue @ Equal Rates of Return**	**$ 163,014**	-	**$ 132,116**	**$ 7,425**	**$ 13,273**	**$ 24**	**$ 8,962**	**$ 1,215**
59	**Revenue (Deficiency)/Surplus**	**$ (11,425)**	-	**$ (15,036)**	**$ (778)**	**$ 1,048**	**$ (5)**	**$ 2,718**	**$ 628**
60	Proposed Margin Increase	$ 11,425		$ 10,705	$ 714	$ -	$ 5	$ -	$ -
61	Total Base and Miscellaneous Revenue as Proposed	$ 67,223	-	$ 50,485	$ 3,516	$ 5,212	$ 25	$ 6,716	$ 1,269
62	Purchased Power Revenue	96,893	-	78,084	3,928	9,237	-	5,063	581
63	**Total Revenue as Proposed**	**$ 164,116**	-	**$ 128,569**	**$ 7,444**	**$ 14,449**	**$ 25**	**$ 11,779**	**$ 1,850**
64	**Total Base Revenue as Proposed**	**$ 66,120**	-	**$ 49,701**	**$ 3,433**	**$ 5,084**	**$ 24**	**$ 6,617**	**$ 1,262**
65	**Total Base and Purchased Power Revenue as Proposed**	**$ 163,014**	-	**$ 127,785**	**$ 7,361**	**$ 14,321**	**$ 24**	**$ 11,680**	**$ 1,843**
66	Proposed (Subsidies)/Excesses	$ -	-	$ (4,331)	$ (64)	$ 1,048	$ 0	$ 2,718	$ 628
67	Proposed Percentage Change	7.54%		9.14%	10.75%	0.00%	27.69%	0.00%	0.00%
68	Proposed Margin Percentage Change	20.89%		27.45%	26.28%	0.00%	27.69%	0.00%	0.00%
69	Gross Receipts Tax	$ 3,817	$ -	$ 2,869	$ 198	$ 294	$ 1	$ 382	$ 73
70	Income Prior to Taxes	17,812	-	9,737	1,030	2,380	9	3,857	798
71	Income Taxes	3,774	-	2,063	218	504	2	817	169
72	Operating Income	$ 14,038	-	$ 7,674	$ 812	$ 1,876	$ 7	$ 3,040	$ 629
73	Proposed Return	8.15%	-	5.74%	7.70%	13.93%	8.51%	24.25%	31.51%
74	Relative Rate of Return	1.00		0.70	0.95	1.71	1.04	2.98	3.87
75	Proposed Revenue to Cost Ratio	1.00		0.97	0.99	1.08	1.02	1.30	1.51
76	Proposed Parity Ratio	1.00		0.97	0.99	1.08	1.02	1.30	1.51

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Schedule 7 - Cost of Service Allocation Study Detail by Account
($ in thousands)

Line No.	Account Description	FERC Account	Account Balance	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
1	**RATE BASE**								
2	**Plant in Service**								
3	**Intangible Plant**								
4	Organization	301	11	9	1	1	0	0	0
5	Franchise & Consent	302	5	4	0	0	0	0	0
6	Miscellaneous Intangible Plant	303	-	-	-	-	-	-	-
7	Subtotal - Intangible Plant		16	13	1	1	0	1	0
8	**Distribution Plant**			-	-	-	-	-	-
9	Land & Land Rights	360	313	234	17	29	0	31	1
10	Structures & Improvements	361	627	390	19	84	1	129	4
11	Station Equipment	362	11,568	7,193	356	1,555	17	2,379	68
12	Storage Battery Equipment	363	-	-	-	-	-	-	-
13	Poles, Towers and Fixtures - PRI DEM	364	16,548	10,289	509	2,225	24	3,404	97
14	Poles, Towers and Fixtures - PRI CUS	364	15,455	13,505	1,309	572	2	52	15
15	Poles, Towers and Fixtures - SEC DEM	364	9,219	6,665	330	1,409	-	752	63
16	Poles, Towers and Fixtures - SEC CUS	364	15,340	13,416	1,300	566	-	43	15
17	Overhead Conductors and Devices - PRI DEM	365	25,626	15,934	788	3,446	37	5,271	151
18	Overhead Conductors and Devices - PRI CUS	365	33,621	29,380	2,848	1,245	4	113	32
19	Overhead Conductors and Devices - SEC DEM	365	7,356	5,318	263	1,124	-	600	50
20	Overhead Conductors and Devices - SEC CUS	365	16,204	14,172	1,374	598	-	45	15
21	Underground Conduit	366	8,780	6,584	507	760	6	893	30
22	Underground Conductors and Devices - PRI DEM	367	7,404	4,604	228	996	11	1,523	44
23	Underground Conductors and Devices - PRI CUS	367	5,924	5,177	502	219	1	20	6
24	Underground Conductors and Devices - SEC DEM	367	430	311	15	66	-	35	3
25	Underground Conductors and Devices - SEC CUS	367	1,808	1,581	153	67	-	5	2
26	Transformers and Transformer Installations - SEC DEM	368.1	11,841	8,560	423	1,810	-	966	81
27	Transformers and Transformer Installations - SEC CUS	368.2	19,261	16,845	1,633	711	-	54	18
28	Services	369	16,709	14,867	1,242	548	-	53	-
29	Meters	370.1	3,094	2,551	285	235	1	22	-
30	Meter Installations	370.2	1,989	1,640	183	151	0	14	-
31	Electronic Meters	370.3	5,038	4,154	465	382	1	36	-
32	Installations on Customers' Premises	371	2,219	-	508	754	7	920	30
33	Installations on Customers' Premises - EV Charging Stations	371.1	-	-	-	-	-	-	-
34	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	348	-	-	-	-	-	348
35	Street Lighting and Signal Systems	373	2,615	-	-	-	-	-	2,615
36	Subtotal - Distribution Plant		239,335	183,370	15,256	19,552	111	17,359	3,688
37	**General Plant**			-	-	-	-	-	-
38	Land & Land Rights	389	659	554	37	36	0	25	6
39	Structures & Improvements	390	10,646	8,946	602	588	3	403	104
40	Office Furniture & Equipment	391	18,441	15,496	1,042	1,019	5	698	180
41	Transportation Equipment	392	2,718	2,284	154	150	1	103	26
42	Stores Equipment	393	11	9	1	1	0	0	0
43	Tools & Garage Equipment	394	1,132	951	64	63	0	43	11
44	Laboratory Equipment	395	28	24	2	2	0	1	0
45	Power Operated Equipment	396	797	670	45	44	0	30	8
46	Communication Equipment	397	652	548	37	36	0	25	6
47	Miscellaneous Equipment	398	566	476	32	31	0	21	6
48	Other Tangible Property	399	-	-	-	-	-	-	-
49	Subtotal - General Plant		35,650	29,957	2,015	1,970	11	1,349	348
50	**Total Plant in Service**		275,001	213,341	17,273	21,522	121	18,709	4,035

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Line No.	Account Description	FERC Account	Account Balance	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
51	**Accumulated Depreciation & Amortization**			-	-	-	-	-	-
52	**Intangible Plant**			-	-	-	-	-	-
53	Organization	301	-	-	-	-	-	-	-
54	Franchise & Consent	302	-	-	-	-	-	-	-
55	Miscellaneous Intangible Plant	303	-	-	-	-	-	-	-
56	Subtotal - Intangible Plant		-	-	-	-	-	-	-
57	**Distribution Plant**			-	-	-	-	-	-
58	Land & Land Rights	360	-	-	-	-	-	-	-
59	Structures & Improvements	361	(67)	(42)	(2)	(9)	(0)	(14)	(0)
60	Station Equipment	362	(1,555)	(967)	(48)	(209)	(2)	(320)	(9)
61	Storage Battery Equipment	363	-	-	-	-	-	-	-
62	Poles, Towers and Fixtures	364	(18,154)	(14,082)	(1,107)	(1,532)	(8)	(1,364)	(61)
63	Overhead Conductors and Devices	365	(14,476)	(11,329)	(922)	(1,121)	(7)	(1,054)	(43)
64	REG AFUDC	365.7	116	91	7	9	0	8	0
65	Underground Conduit	366	(2,692)	(2,019)	(155)	(233)	(2)	(274)	(9)
66	Underground Conductors and Devices	367	(4,928)	(3,695)	(284)	(427)	(4)	(501)	(17)
67	Transformers	368.1	(8,267)	(6,753)	(547)	(670)	-	(271)	(26)
68	Transformer Installations	368.2	(6,688)	(5,463)	(442)	(542)	-	(219)	(21)
69	Services	369	(8,070)	(7,180)	(600)	(265)	-	(25)	-
70	Meters	370.1	(1,939)	(1,599)	(179)	(147)	(0)	(14)	-
71	Meter Installations	370.2	(825)	(680)	(76)	(63)	(0)	(6)	-
72	Electronic Meters	370.3	(4,275)	(3,525)	(394)	(324)	(1)	(30)	-
73	Installations on Customers' Premises	371	(1,088)	-	(249)	(370)	(3)	(451)	(15)
74	Installations on Customers' Premises - EV Charging Stations	371.1	-	-	-	-	-	-	-
75	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	(338)	-	-	-	-	-	(338)
76	Street Lighting and Signal Systems	373	(1,139)	-	-	-	-	-	(1,139)
77	Subtotal - Distribution Plant		(74,384)	(57,244)	(4,997)	(5,902)	(28)	(4,535)	(1,679)
78	**General Plant**								
79	Land & Land Rights	389	(11)	(9)	(1)	(1)	(0)	(0)	(0)
80	Structures & Improvements	390	(2,494)	(2,096)	(141)	(138)	(1)	(94)	(24)
81	Office Furniture & Equipment	391	(7,201)	(6,051)	(407)	(398)	(2)	(273)	(70)
82	Transportation Equipment	392	(612)	(514)	(35)	(34)	(0)	(23)	(6)
83	Stores Equipment	393	(6)	(5)	(0)	(0)	(0)	(0)	(0)
84	Tools & Garage Equipment	394	(498)	(419)	(28)	(28)	(0)	(19)	(5)
85	Laboratory Equipment	395	(21)	(18)	(1)	(1)	(0)	(1)	(0)
86	Power Operated Equipment	396	(87)	(73)	(5)	(5)	(0)	(3)	(1)
87	Communication Equipment	397	(274)	(230)	(15)	(15)	(0)	(10)	(3)
88	Miscellaneous Equipment	398	(157)	(132)	(9)	(9)	(0)	(6)	(2)
89	Other Tangible Property	399	-	-	-	-	-	-	-
90	Subtotal - General Plant		(11,361)	(9,547)	(642)	(628)	(3)	(430)	(111)
91	**Total Accumulated Depreciation & Amortization**		(85,745)	(66,790)	(5,639)	(6,529)	(31)	(4,965)	(1,789)
92	Other Rate Base Items								
93	Working Capital	Sch. A-1	11,447	8,880	719	896	5	779	168
94	Accumulated Deferred Income Taxes	Sch. A-1	(29,665)	(23,013)	(1,863)	(2,322)	(13)	(2,018)	(435)
95	Customer Deposits	Sch. A-1	(949)	(608)	(68)	(220)	-	(49)	(4)
96	Materials & Supplies	Sch. A-1	2,152	1,808	122	119	1	81	21
97	Total Other Rate Base Items		(17,015)	(12,932)	(1,090)	(1,527)	(7)	(1,206)	(251)
98	**TOTAL RATE BASE**		172,242	133,618	10,543	13,466	82	12,537	1,995

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Schedule 7 - Cost of Service Allocation Study Detail by Account
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Line No.	Account Description	FERC Account	Account Balance	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
99	**OPERATION AND MAINTENANCE EXPENSE**			-	-	-	-	-	-
100	Generation Production, Transmission, and Distribution Expense			-	-	-	-	-	-
101	**Other Power Generation Expense**			-	-	-	-	-	-
102	Purchased Power	555	85,198	68,659	3,454	8,122	-	4,452	511
103	Transmission of Electricty by Others	565	5,978	4,818	242	570	-	312	36
104	Subtotal - Other Power Generation Expense		91,176	73,477	3,696	8,692	-	4,764	547
105	**Distribution Operation Expenses**			-	-	-	-	-	-
106	Operation Supervision and Engineering	580	609	474	45	48	0	30	13
107	Load Dispatching	581	574	440	37	47	0	42	9
108	Line and Station Expenses	581.1	-	-	-	-	-	-	-
109	Station Expenses	582	96	60	3	13	0	20	1
110	Overhead Line Expenses	583	298	233	19	23	0	22	1
111	Underground Line Expenses	584	42	32	2	4	0	4	0
112	Operation of Energy Storage Equipment	584.1	-	-	-	-	-	-	-
113	Street Lighting and Signal System Expenses	585	31	-	-	-	-	-	31
114	Meter Expenses	586	785	647	72	59	0	6	-
115	Customer Installation Expenses	587	79	71	6	3	-	0	-
116	Miscellaneous Distribution Expenses	588	352	274	26	27	0	17	8
117	Rents	589	55	43	4	4	0	3	1
118	Subtotal - Distribution Operation Expenses		2,922	2,273	214	228	1	143	64
119	**Distribution Maintenance Expenses**			-	-	-	-	-	-
120	Maintenance Supervision and Engineering	590	222	173	14	17	0	17	1
121	Maintenance of Structures	591	-	-	-	-	-	-	-
122	Maintenance of Station Equipment	592	208	130	6	28	0	43	1
123	Maintenance of Pipe Lines	592.1	-	-	-	-	-	-	-
124	Maintenance of Structures and Equipment	592.2	-	-	-	-	-	-	-
125	Maintenance of Overhead Lines	593	9,715	7,603	619	752	5	707	29
126	Maintenance of Underground Lines	594	61	46	4	5	0	6	0
127	Maintenance of Lines	594.1	-	-	-	-	-	-	-
128	Maintenance of Line Transformers	595	83	68	5	7	-	3	0
129	Maintenance of Street Lighting and Signal Systems	596	24	-	-	-	-	-	24
130	Maintenance of Meters	597	15	12	1	1	0	0	-
131	Maintenance of Miscellaneous Distribution Plant	598	23	18	1	2	0	2	0
132	Subtotal - Distribution Maintenance Expenses		10,352	8,049	651	813	5	778	56
133	**Total Generation Production, Transmission, and Distribution Expense**		104,450	83,799	4,561	9,733	6	5,685	667
134	**Customer Accounts, Service, and Sales Expense**								
135	**Customer Account**								
136	Supervision	901	91	80	8	3	0	0	0
137	Meter Reading Expenses	902	218	191	18	8	0	1	0
138	Customer Records and Collection Expenses	903	2,529	2,210	214	94	0	8	2
139	Customer Records and Collection Expenses (USP)	903	6,656	6,656	-	-	-	-	-
140	Uncollectible Accounts	904	3,239	3,087	60	56	-	27	9
141	Miscellaneous Customer Accounts Expenses	905	139	122	12	5	0	0	0
142	Subtotal - Customer Account		12,873	12,346	312	166	0	37	12
143	**Customer Service & Information Expenses**			-	-	-	-	-	-
144	Customer Service and Informational Expenses	906	-	-	-	-	-	-	-
145	Supervision	907	17	15	1	1	0	0	0
146	Customer Assistance Expenses	908	12	11	1	0	0	0	0
147	Information and Instructional Advertising Expenses	909	-	-	-	-	-	-	-
148	Miscellaneous Customer Service & Informational Exps (EEC)	910	1,157	361	43	153	1	589	9
149	Subtotal - Customer Service & Information Expenses		1,186	387	45	154	1	590	9

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Schedule 7 - Cost of Service Allocation Study Detail by Account
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Line No.	Account Description	FERC Account	Account Balance	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
150	**Sales Expenses**			-	-	-	-	-	-
151	Supervision	911	-	-	-	-	-	-	-
152	Demonstrating and Selling Expenses	912	5	4	0	0	0	0	0
153	Advertising Expenses	913	-	-	-	-	-	-	-
154	Miscellaneous Sales Expenses	916	(5)	(4)	(0)	(0)	(0)	(0)	(0)
155	Sales Expenses	917	-	-	-	-	-	-	-
156	Subtotal - Sales Expenses		0	0	0	0	0	0	0
157	**Total Customer Accounts, Service, and Sales Expense**		14,059	12,733	357	320	1	626	21
				-	-	-	-	-	-
158	**Administrative and General Expenses**			-	-	-	-	-	-
159	Administrative and General Salaries	920	2,757	2,317	156	152	1	104	27
160	Office Supplies and Expenses	921	1,787	1,501	101	99	1	68	17
161	Administrative Expenses Transferred - Credit	922	-	-	-	-	-	-	-
162	Outside Services Employed	923	1,887	1,586	107	104	1	71	18
163	Property Insurance	924	31	24	2	2	0	2	0
164	Injuries and Damages	925	251	211	14	14	0	9	2
165	Employee Pensions and Benefits	926	1,259	1,058	71	70	0	48	12
166	Franchise Requirements	927	-	-	-	-	-	-	-
167	Regulatory Commission Expenses	928	298	232	19	23	0	21	3
168	Duplicate Charges - Credit	929	(74)	(58)	(5)	(6)	(0)	(5)	(1)
169	General Advertising Expenses	930.1	74	57	5	6	0	5	1
170	Miscellaneous General Expenses	930.2	259	217	15	14	0	10	3
171	Rents	931	2	1	0	0	0	0	0
172	Transportation Expenses	933	-	-	-	-	-	-	-
173	Maintenance of General Plant	935	69	58	4	4	0	3	1
174	Total Administrative and General Expenses		8,598	7,204	489	483	3	336	84
				-	-	-	-	-	-
175	**TOTAL OPERATION AND MAINTENANCE EXPENSE**		127,107	103,735	5,407	10,536	10	6,647	772
176	**Adjustments, Depreciation and Amortization Expense**			-	-	-	-	-	-
177	Depreciation Expense			-	-	-	-	-	-
178	Organization	301	-	-	-	-	-	-	-
179	Franchise & Consent	302	-	-	-	-	-	-	-
180	Miscellaneous Intangible Plant	303	-	-	-	-	-	-	-
181	Subtotal - Depreciation Expense		-	-	-	-	-	-	-
182	**Distribution Plant**			-	-	-	-	-	-
183	Land & Land Rights	360	-	-	-	-	-	-	-
184	Structures & Improvements	361	15	9	0	2	0	3	0
185	Station Equipment	362	370	230	11	50	1	76	2
186	Storage Battery Equipment	363	-	-	-	-	-	-	-
187	Poles, Towers and Fixtures	364	1,029	798	63	87	0	77	3
188	Overhead Conductors and Devices	365	2,001	1,566	127	155	1	146	6
189	REG AFUDC	365.7	(16)	(13)	(1)	(1)	(0)	(1)	(0)
190	Underground Conduit	366	137	103	8	12	0	14	0
191	Underground Conductors and Devices	367	433	325	25	37	0	44	1
192	Transformers	368.1	428	349	28	35	-	14	1
193	Transformer Installations	368.2	207	169	14	17	-	7	1
194	Services	369	280	249	21	9	-	1	-
195	Meters	370.1	66	54	6	5	0	0	-
196	Meter Installations	370.2	25	21	2	2	0	0	-
197	Electronic Meters	370.3	115	95	11	9	0	1	-
198	Installations on Customers' Premises	371	74	-	17	25	0	31	1
199	Installations on Customers' Premises - EV Charging Stations	371.1	-	-	-	-	-	-	-
200	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	1	-	-	-	-	-	1
201	Street Lighting and Signal Systems	373	111	-	-	-	-	-	111
202	Subtotal - Distribution Plant		5,275	3,955	332	443	3	413	129

UGI Utilities, Inc. - Electric Division
Electric Class Cost of Service Study
Fully Projected Future Test Year September 30, 2024
Schedule 7 - Cost of Service Allocation Study Detail by Account
($ in thousands)

Line No.	Account Description	FERC Account	Account Balance	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
203	**General Plant**			-	-	-	-	-	-
204	Land & Land Rights	389	-	-	-	-	-	-	-
205	Structures & Improvements	390	541	455	31	30	0	20	5
206	Office Furniture & Equipment	391	1,857	1,561	105	103	1	70	18
207	Transportation Equipment	392	290	243	16	16	0	11	3
208	Stores Equipment	393	1	1	0	0	0	0	0
209	Tools & Garage Equipment	394	57	48	3	3	0	2	1
210	Laboratory Equipment	395	2	2	0	0	0	0	0
211	Power Operated Equipment	396	58	49	3	3	0	2	1
212	Communication Equipment	397	75	63	4	4	0	3	1
213	Miscellaneous Equipment	398	61	52	3	3	0	2	1
214	Other Tangible Property	399	-	-	-	-	-	-	-
215	Subtotal - General Plant		2,943	2,473	166	163	1	111	29
216	**Amortization Expense**			-	-	-	-	-	-
217	Amortization Expense & Depreciation Adjustments		336	260	21	26	0	23	5
218	Subtotal - Amortization Expense		336	260	21	26	0	23	5
				-	-	-	-	-	-
219	**Total Adjustments, Depreciation and Amortization Expense**		8,553	6,688	520	632	4	547	162
220	**Taxes**			-	-	-	-	-	-
221	**Taxes Other Than Income Taxes**			-	-	-	-	-	-
222	PURTA & Property Taxes		76	59	5	6	0	5	1
223	Gross Receipts Tax		3,101	2,535	164	190	1	182	29
224	GRT - Purchased Power		5,717	4,607	232	545	-	299	34
225	Payroll related		507	426	29	28	0	19	5
226	Real estate		297	230	19	23	0	20	4
227	PA Local Use and Miscellaneous		22	17	1	2	0	1	0
228	Subtotal - Taxes Other Than Income Taxes		9,718	7,873	449	793	1	527	74
229	**Income Taxes**			-	-	-	-	-	-
230	State Income Tax expense		(483)	(374)	(30)	(38)	(0)	(35)	(6)
231	Federal Income Tax expense		1,306	1,013	80	102	1	95	15
232	Subtotal - Income Taxes		823	639	50	64	0	60	10
233	**Total Taxes**		10,542	8,512	500	858	2	587	84
234	**REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**			-	-	-	-	-	-
235	Test Year Expenses at Current Rates		146,201	118,935	6,426	12,025	16	7,781	1,018
236	Return on Rate Base		14,038	10,890	859	1,097	7	1,022	163
237	**Gross Up Items**			-	-	-	-	-	-
238	Federal Income Tax		2,007	1,557	123	157	1	146	23
239	State Income Tax		944	732	58	74	0	69	11
240	Gross Receipts Tax		716	586	38	44	0	42	7
241	Uncollectible		210	200	4	4	-	2	1
242	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		**164,116**	**132,900**	**7,508**	**13,401**	**24**	**9,061**	**1,222**

UGI Utilities, Inc. - Electric Division
Electric Class Cost of Service Study
Fully Projected Future Test Year September 30, 2024
Schedule 8 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
($ in thousands)

Line	Description		TOTAL	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
1	**Functional Rate Base**								
2	**Purchased Power**								
3	Demand	Product_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Energy	Product_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Customer	Product_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Subtotal		$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	**Distribution**								
8	Demand	Dist_Dem	$ 68,346	$ 44,319	$ 2,191	$ 9,521	$ 72	$ 11,822	$ 419
9	Energy	Dist_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Customer	Dist_Cust	$ 85,254	$ 72,133	$ 7,272	$ 3,567	$ 9	$ 696	$ 1,577
11	Subtotal		$ 153,599	$ 116,452	$ 9,464	$ 13,088	$ 81	$ 12,519	$ 1,996
12	**PA PUC Direct Customer**								
13	Demand	DirCust_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Energy	DirCust_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Customer	DirCust_Cust	$ 18,642	$ 17,166	$ 1,079	$ 378	$ 1	$ 18	$ (1)
16	Subtotal		$ 18,642	$ 17,166	$ 1,079	$ 378	$ 1	$ 18	$ (1)
17	**Total**								
18	Demand		$ 68,346	$ 44,319	$ 2,191	$ 9,521	$ 72	$ 11,822	$ 419
19	Energy		$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Customer		$ 103,896	$ 89,299	$ 8,352	$ 3,944	$ 10	$ 715	$ 1,576
21	**TOTAL RATE BASE**		$ 172,242	$ 133,618	$ 10,543	$ 13,466	$ 82	$ 12,537	$ 1,995

UGI Utilities, Inc. - Electric Division
Electric Class Cost of Service Study
Fully Projected Future Test Year September 30, 2024
Schedule 8 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
($ in thousands)

Line	Description		TOTAL	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
22	**Functional Revenue Requirement**								
23	**Purchased Power**								
24	Demand	Product_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Energy	Product_Energy	$ 96,893	$ 78,084	$ 3,928	$ 9,237	$ -	$ 5,063	$ 581
26	Customer	Product_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Subtotal		$ 96,893	$ 78,084	$ 3,928	$ 9,237	$ -	$ 5,063	$ 581
28	**Distribution**								
29	Demand	Dist_Dem	$ 17,800	$ 11,507	$ 569	$ 2,473	$ 19	$ 3,122	$ 109
30	Energy	Dist_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31	Customer	Dist_Cust	$ 26,476	$ 22,335	$ 2,260	$ 1,181	$ 3	$ 189	$ 507
32	Subtotal		$ 44,276	$ 33,842	$ 2,829	$ 3,655	$ 22	$ 3,311	$ 616
33	**PA PUC Direct Customer**								
34	Demand	DirCust_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	Energy	DirCust_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36	Customer	DirCust_Cust	$ 22,947	$ 20,974	$ 750	$ 509	$ 2	$ 687	$ 25
37	Subtotal		$ 22,947	$ 20,974	$ 750	$ 509	$ 2	$ 687	$ 25
38	**Total**								
39	Demand		$ 17,800	$ 11,507	$ 569	$ 2,473	$ 19	$ 3,122	$ 109
40	Energy		$ 96,893	$ 78,084	$ 3,928	$ 9,237	$ -	$ 5,063	$ 581
41	Customer		$ 49,424	$ 43,309	$ 3,011	$ 1,691	$ 5	$ 876	$ 532
42	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		$ 164,116	$ 132,900	$ 7,508	$ 13,401	$ 24	$ 9,061	$ 1,222
43	Demand		10.85%	8.66%	7.58%	18.46%	79.74%	34.45%	8.90%
44	Energy		59.04%	58.75%	52.32%	68.93%	0.00%	55.88%	47.55%
45	Customer		30.11%	32.59%	40.10%	12.62%	20.26%	9.67%	43.55%

UGI Utilities, Inc. - Electric Division
Electric Class Cost of Service Study
Fully Projected Future Test Year September 30, 2024
Schedule 8 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
($ in thousands)

Line	Description		TOTAL	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
46	**Unit Costs (in $)**								
47	**Purchased Power**								
48	Demand	Product_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49	Energy	Product_Energy	$ 91.76	$ 127.96	$ 118.94	$ 79.87	$ -	$ 17.51	$ 82.23
50	Customer	Product_Cust	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51	**Distribution**								
52	Demand	Dist_Dem	$ 7.17	$ 6.41	$ 6.41	$ 6.52	$ -	$ 15.41	$ 6.41
53	Energy	Dist_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54	Customer	Dist_Cust	$ 35.06	$ 33.84	$ 35.33	$ 42.25	$ 36.14	$ 74.76	$ 704.70
55	**PA PUC Direct Customer**								
56	Demand	DirCust_Dem	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	Energy	DirCust_Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	Customer	DirCust_Cust	$ 30.38	$ 31.78	$ 11.73	$ 18.21	$ 22.26	$ 271.32	$ 34.57
59	**Total**								
60	Energy		$ 91.76	$ 127.96	$ 118.94	$ 79.87	$ -	$ 17.51	$ 82.23
61	Customer (per cust month)		$ 65.44	$ 65.62	$ 47.06	$ 60.46	$ 58.40	$ 346.08	$ 739.28
62	Demand & Customer (per cust month)		$ 89.01	$ 83.06	$ 55.96	$ 148.92	$ 288.29	$ 1,579.04	$ 890.39
63	Demand (per kwh)					$ 5.62		$ 5.96	
64	**BILLING DETERMINANTS**								
65	Demand (Peak Day Demand * 12)	SEC_DEM	2,482,231	1,794,525	88,735	379,428	0	202,577	16,967
66	Energy	ENERGY	1,055,931	610,230	33,026	115,648	763	289,197	7,066
67	Customers (Number of Bills)	CUST	755,244	659,976	63,972	27,960	84	2,532	720
68	Demand					440,278		523,763	

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368

UGI Utilities, Inc. – Electric Division

Statement No. 9R

Rebuttal Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

Topics Addressed:	**Capital Structure**
	Cost of Equity
	Rate of Return

Dated: May 25, 2023

REBUTTAL TESTIMONY OF PAUL R. MOUL

INTRODUCTION AND SUMMARY

Q. Please state your name, occupation and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Electric Statement No. 9, on January 27, 2023.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the direct testimony submitted by Aaron L. Rothschild, a witness appearing on behalf of the Office of Consumer Advocate ("OCA"), and D.C. Patel, a witness appearing on behalf of the Bureau of Investigation and Enforcement ("I&E"). If I fail to address each and every issue in the testimony of these witnesses, it does not imply my agreement with those issues.

Q. What are the key aspects of the rate of return issue that the Pennsylvania Public Utility Commission ("Commission") should consider when deciding this issue in this case?

A. The issues involve the Company's cost of equity and the capital structure. I&E's witness, Mr. Patel, has accepted the Company's proposed capital structure ratios. OCA's witness, Mr. Rothschild, has opposed the actual capital structure and instead proposed a hypothetical capital structure. All the witnesses have accepted the embedded cost of debt for UGI Electric.

The equity returns proposed by the I&E and OCA witnesses are entirely too low to reflect the risks of UGI Electric and its prospective cost of equity and are completely inconsistent with recent Commission determinations of the cost of equity and in particular the Company's last litigated electric rate case in 2018. Aside from technical issues that I will discuss later in my rebuttal testimony, the Commission should take into consideration its recent decisions and adopt a rate of return that will reflect and be supportive of the Company's financial and risk profile. As I explain below, the opposing parties' recommendations fail to adequately consider this point, simply ignore well-reasoned Commission decisions on this issue and thereby very substantially understate the required cost of common equity in this proceeding.

Q. Please summarize the key points of your rebuttal testimony.

A. My key points are:

- The recommended equity returns proposed by Messrs. Patel and Rothschild fail to adequately reflect higher interest rates that have transpired since the Company's last Electric Division rate case. In that case, the Commission set the Company's cost of equity at 9.85%. Today, the return should be higher for reasons I will explain below. Instead, Messrs. Patel and Rothschild are erroneously moving in the other direction. Some of the flawed analysis by opposing witness can be traced to the failure by Mr. Patel to give any weight to CAPM and Mr. Rothschild's defective CAPM analysis. These omissions by the opposing witnesses rest with the failure to follow the Commission's lead established in the Aqua rate case decision.
- The Commission has recognized that additional methods should also be considered when establishing the cost of equity. This is especially important because of monetary policy by the FOMC and relatively high inflation points to a higher cost of equity than formerly. Moreover, the DCF model is slow to respond to changes in bond yields, mandating use of alternative methods, such as CAPM and Risk Premium. Both the I&E and OCA witnesses have

inadequately addressed this issue.

- Capital Structure Ratios – Mr. Rothschild's use of a hypothetical capital structure, rather than the Company's projected actual capital structure for the FPFTY, is factually wrong and contrary to long-standing Commission practice and precedent. I will detail the Commission recent findings on capital structure below.
- Comparable Companies – Mr. Patel has made erroneous deletions from my electric company barometer group by eliminating AVANGRID, Consolidated Edison, Exelon Corporation and NextEra Energy.
- Discounted Cash Flow ("DCF") – most of DCF results by the opposing parties are clearly too low to provide a reliable measure of the cost of equity. This can be traced to the formulaic approach taken by Mr. Patel in applying this model (see pages 26-27 of I&E Statement No. 3). It is troublesome that Mr. Patel only devotes two pages out of 67 pages of his direct testimony to substantiate his recommended cost of equity. Regarding Mr. Rothschild, he fails to adequately reflect investor expectations of growth. He errs when he gives insufficient weight to analysts' growth rate forecasts of earnings per share growth that are consistently used by Mr. Patel, me, and the Commission.
- The DCF proposal by Mr. Rothschild provides an inappropriate measure of investor expected returns. Analysts' projections of future growth are the only reasonable evidence of the DCF growth rate and the retention growth rate that he used is entirely inappropriate and has never been adopted in Pennsylvania.
- A multistage DCF model, as proposed by Mr. Rothschild is unnecessary for this case. The only thing that the multistage DCF model does is to show that his sustainable growth DCF result is much too low.

- DCF Leverage Adjustment – Mr. Patel has not refuted the accuracy of my leverage adjustments to the DCF and beta component of the Capital Asset Pricing Model ("CAPM"). Mr. Rothschild draws erroneous conclusions concerning my leverage adjustment.
- CAPM – A reasonable application of the CAPM mandates using 30-year Treasury bond yields, leverage adjusted betas, and size adjustment. With these elements the CAPM indicates an equity cost rate that is above 12% following the approach used by Mr. Patel. Indeed, Mr. Patel has proposed an 11.55% CAPM result in this case, even without these considerations. However, he fails to reflect his CAPM result in his cost of equity recommendation. Without the results of the CAPM, Mr. Patel fails to adequately incorporate the current level of high interest rates. And, Mr. Patel fails to incorporate CAPM results that the Commission used in its recent Aqua rate case decision.

Q. How should the rate of return set by the Commission support the Company's financial profile?

A. The Commission should set the Company's return on equity at a level that will attract investment in the Company to ensure the Company's financial ability to render safe and reliable service. Applying this principle, the Commission should reject the proposals by Messrs. Patel and Rothschild to cut the Company's return on common equity to 8.76% and 8.44%, respectively. These proposed equity returns would be viewed by investors as unsupportive of the Company's financial condition. Indeed, in my memory, the Commission has not set a return on equity on an original cost rate base that was less than 9% for an investor-owned utility in the past 40-years. The I&E and OCA witnesses provide no explanation why 8.76% or 8.44% would be reasonable now when the Commission approved 10.24% in the last PECO gas rate case in 2021, and the Aqua Pennsylvania rate case where 10.00% was approved in 2022. There have been dramatic increases in inflation and interest rates since those decisions, prompting the Federal Open Market Committee ("FOMC") to increase the federal funds ("Fed Funds") rate to combat inflation. Indeed, the Fed Funds rate has been increased ten times, its fastest rate increase cycle in 40 years. This fact has not been adequately incorporated into the cost of equity proposals of Messrs. Rothschild and Patel. Indeed, with the upward move in interest rates, an equity return above 10% is clearly warranted today given the fact the Commission set the Company's return at 9.85% just four years ago. Rather, based on the factors listed below, and for technical reasons set forth later in my rebuttal testimony, the Commission should adopt a substantially higher equity return today for UGI Electric.

Q. Are there additional issues that the Commission should consider when setting the Company's return?

A. Yes. The investment community would be very concerned if the Commission were to adopt the position of the OCA in this case. If it were to do so, investors would view Pennsylvania regulation as less supportive of the Company at a time of high levels of capital investment and increasing capital cost rates. Over the next five years, UGI Electric expects capital expenditures to be $131.59 million, which represents 72% of the Company's existing Utility Plant In Service. Indeed, Mr. Patel shows on page 39 of I&E Statement No. 3 that future capex for UGI Electric will increase by 19.2% (($131.59 million ÷ $110.38 million) -1) from historical experience. If the Commission were to reduce the authorized return as proposed by I&E and OCA, Pennsylvania's regulatory support would certainly be placed into question by the investment community, particularly in the context of higher capital costs due to high inflation. Although cost allocations, rate design issues, and regulatory policies relative to the cost of service are important considerations, the return on equity used by the Commission to set rates, embodies in a single numerical value a clear signal of regulatory support (or lack thereof) for the financial strength of the utilities that it regulates. In a single figure, the return on equity utilized to set rates provides a common and widely understood benchmark that can be compared from one company to another and is the basis by which returns on all financial assets (stocks – both utility and non-regulated, bonds, money market instruments, and so forth) can be measured. So, while varying degrees of sophistication are required to interpret the meaning of specific Commission policies on technical matters, the return on equity figure is universally understood and communicates to investors the types of returns that they can reasonably expect from an investment in utilities operating in Pennsylvania.

Q. Should the Commission consider the future trend in capital costs when deciding the return on equity in this case?

A. Yes. The Commission should recognize that accommodative policy by the FOMC has ended and higher interest rates have occurred and will prevail in the future. High inflation also has been a driving factor. Indeed, the rate of inflation spiked upward to 9.1% in June 2022, and as of April 2023, it was 4.9%. High levels of inflation have an impact on the level of economic activity, the cost of capital – particularly the interest cost of debt – and the need for more cautious financial practices, such as a prudent level of borrowing. Today's inflation is substantially higher than the target rate of 2%, which is the FOMC policy goal. Contributing to "sky high" inflation is pandemic-related supply side issues, strong consumer demand, and tight labor markets. Supply disruptions have also significantly impacted the consumer sector of the economy, which developed during the pandemic. While short-term interest rates were at historically low levels during much of the pandemic, interest rates began to rise and have continued at high levels throughout 2022 and 2023. This was revealed by a series of Fed Funds increases including 0.25% announced on March 16, 2022, 0.50% announced on May 4, 2022, 0.75% increases announced on June 15, 2022, July 27, 2022, September 21, 2022, and November 2, 2022, 0.50% announced on December 14, 2022, and 0.25% increases each announced on February 1, 2023, March 22, 2023, and May 3, 2023. In total, the Fed Funds rate has increased by 5.00% since the beginning of 2022. I will describe the forecasts of interest rates below.

Q. Is there additional evidence that suggests that the cost of capital has been increasing?

A. Yes. To gain a consensus view of future interest rates, I tabulated the forecasts of yields on 10-year Treasury notes published by a variety of well recognized and investor-influencing sources. I chose the 10-year Treasury note because it is available on a consistent basis across all sources. The comparisons are:

	2023	2024	2025	2026	2027
Blue Chip	3.60%	3.70%	3.50%	3.60%	3.60%
EIA	3.15%	3.05%	3.11%	3.15%	3.15%
CBO	3.90%	3.80%	3.80%	3.80%	3.80%

The Blue Chip (December 2022), EIA (March 2023), and CBO (February 2023) reflect the general consensus is that interest rates will remain at elevated levels in the future. The high levels of interest rates represent one key factor that adds to the risk of common equity. The Commission should take into account the forecast of interest rates when it sets the cost of equity for UGI Electric.

Q. Given the situation of current interest rates, what equity return would be indicated today based on the Commission finding in the Company's last fully litigated Electric rate case?

A. Interest rates have increased. The yield on A-rated public utility bond was 4.17% in April 2018 at the time of the Company's last fully litigated Electric Division rate case. In April 2023, that rate was 5.13%, a 0.96% (5.13% - 4.17%) increase. The Commission determined on October 4, 2018 in UGI Electric's most recent base rate case (Docket No. R-2017-2640058) that the Company's cost of equity was 9.85%. Recognizing higher interest rates since that time would increase the cost of equity to 10.81% (9.85% + 0.96%) today.

Q. Mr. Rothschild likewise acknowledges that interest rates have increased. Can you show how this increase would affect the Company's cost of equity?

A. Yes. Significantly, Mr. Rothschild himself does not seem to believe that the cost of equity has remained the same (see page 20 of OCA Statement No. 2). There, he states that he moved up his cost of equity by 127 basis points between two rate cases in Connecticut. Applying the same 127 basis points determined by Mr. Rothschild here, the cost of equity would now be 11.12% (9.85% + 1.27%) for UGI Electric using as a base the Commission determined cost of equity in the Company's last fully litigated rate case.

Q. Are there other aspects of Mr. Rothschild's testimony where he is inconsistent in his approach?

A. Yes. Specific instances include:

- Mr. Rothschild states that his recommended ROE is "market-based" and "forward-looking" (p. 5.), yet he criticizes forecasts as unreliable (p. 19).
- He claims that he uses primarily current, forward-looking market data (e.g., stock prices, bond yields, stock option prices) and then criticizes me for relying on historical data (betas in my CAPM are based on past 5 years of data) and non-market data (p. 13). Yet, he used historical data himself (p. 13), which conflicts with his own criticism of historical data. Indeed, Mr. Rothschild used

book value data extensively in his analysis. First, he calculates a return on book value as part of his Retention Growth Rate (see page 58 of OCA Statement No. 2). Second, he also employs book value per share growth rates in his non-constant DCF (see page 60 of OCA Statement No. 2). (see OCA Statement No. 2 at pages 58-59). .

- Despite his preference for forward-looking data, he claims that using analyst's forecasts would be speculative (p. 18). He also states that his market-based cost of equity recommendation is not based on future stock prices because he cannot "predict the future" and "capital markets are unpredictable" (p. 19).
- His retention method relies on historic data in part, yet he previously criticized my use of historic data (p. 51).
- He states that he uses an analytical approach focused on market data while my testimony is too focused on non-market data. Yet he uses book value data in his analysis, e.g. growth rate and book value per share. Also, he uses historical data for risk free rate of return for CAPM. (pp. 58-60)
- Although he criticizes analyst forecasts as speculative and unreliable (p. 19), he admits to using them (p. 19). Specifically, he admits to relying on Value Line and Zacks analyst forecasts in his DCF analysis despite his own criticisms of the data. (compare p. 19 with pp. 55-58).
- He admits that rising interest rates generally mean higher cost of equity for utility companies, (p. 23) but then states that the cost of equity has remained about the same (p. 20).
- He claims that UGI's authorized ROE in this proceeding does not need to be consistent with the authorized ROE in other proceedings because those proceedings are "historical data" and not "current market data" (p. 17). He

emphasizes his position that rates should be set using his market-based method, and not historical data (p. 17). This contradicts his criticism of forecasts as being unreliable (p. 19).

Q. How is the remainder of your testimony organized?

A. I will cover the issues of (i) capital structure, (ii) updated cost of debt, (iii) the composition of the proxy (i.e., barometer) group, (iv) the weight to be given to the DCF method, (v) the DCF growth rate, (vi) the leverage adjustment to the DCF and CAPM methods, (vii) the CAPM method, (viii) the Risk Premium analysis, (ix) Comparable Earnings, and (x) management performance as part of the return on equity consideration.

CAPITAL STRUCTURE RATIOS

Q. Is there a difference in the proposed capital structure ratios utilized by the rate of return witnesses in this case?

A. Yes. Mr. Rothschild is alone in advocating a hypothetical capital structure for UGI Electric. Mr. Patel has followed long-standing Commission precedent and accepted the Company's proposed capital structure, as it falls within the range of capital structures of the proxy group. Mr. Rothschild's position is clearly contrary to long-standing Commission policy and practice concerning capital structure ratios which is to accept the projected equity ratio if it is within the range of equity ratios of the barometer group companies. This practice was reiterated and followed in the Gas Division rate case of PECO Energy Company at Docket No. R-2020-3018929 (Order entered June 22, 2021), where a 53.38% common equity ratio was accepted. In the Commission’s Columbia decision at Docket No. R-2020-3018835 (Order entered February 19, 2021), the Commission accepted an equity ratio of 54.19% for Columbia (Columbia Order, p. 118). The Commission also accepted a 53.95% common equity ratio in the Aqua Pennsylvania case at Docket No. R-2021-3027385 (Order Entered

May 16, 2022). In a York Water case in 1984, the Commission observed that generally hypothetical capital structure ratios usurp the prerogative of management unless it can be demonstrated that management has acted imprudently and the resulting actual capital structure ratios are atypical (1984 Pa. PUC LEXIS 61, *85, 58 Pa. PUC 155, 187 (Pa. P.U.C. January 26, 1984)). Essentially, the Commission will accept a utility's actual capital structure ratios as long as they are reasonable. This is the case for UGI Electric in this case as the data provided below will support.

Q. Is there any basis to deviate from the Company's actual capital structure to set the rate of return in this case?

A. No. As Mr. Patel explained (see pages 11-14 of I&E Statement No. 3), the Company's actual capital structure ratios (including the 54.59% common equity ratio) falls within the range of the proxy group. This is sufficient to meet the Commission's standard that makes the actual UGI Electric capital structure appropriate in this case.

Q. Does Mr. Rothschild provide clear justification for rejecting the Company's actual capital structure and substituting a different capital structure?

A. No. Mr. Rothschild has not substantiated his position regarding the selection of hypothetical capital structure ratios. Indeed, to follow Mr. Rothschild's proposal here would do real harm to UGI Utilities. I say this because the Company's actual capital structure supports its credit quality ratings from Moody's and Fitch. Additional debt in the capital structure as proposed by Mr. Rothschild could prompt an unfavorable credit quality evaluation for UGI Utilities. Aside from the hypothetical nature of his capital structure ratios, Mr. Rothschild's approach represents a generic capital structure that would apply to any and all electric utilities. And with his hypothetical capital structure, he is effectively driving down the 8.44% return on equity that he proposes to 7.69% (6.18% - 1.98% = 4.20% ÷ .5459), an illogical proposal. As pointed out previously, returns of 8.44% or 7.69% are outside of any reasonable range.

Q. Mr. Rothschild has used historical data to support his position on capital structure. Does this position conform with Commission practice?

A. No. Mr. Rothschild proposes to use historical common equity ratios employed by the members of his barometer group (see OCA Statement No. 2 at page 43). This position does not conform with the Commission's use of the FPFTY and, hence, his proposal should be rejected. The Company has submitted a well-documented proposal with reasonable projections for the FPFTY.

Q. Is there other evidence demonstrating the reasonableness of UGI Electric's proposed capital structure?

A. Yes. As a preliminary matter, I would note that each of the companies listed on page 5 of Exhibit ALR-5 are holding companies many of which have both regulated and unregulated subsidiaries. In these instances, the parent company capital structure may not be reflective an appropriate utility capital structure. It is perhaps in part for this reason that the Commission looks at the range of results rather than the average result when evaluating a utility's actual capital structure. As a check on the holding company results, I also reviewed the actual capital structures of the electric utility subsidiaries for my Electric Group, as shown in the table below.

Company	Weighted Average Public Utility subsidiary Common Equity Ratio
AVANGRID, Inc.	57.19%
Consolidated Edison, Inc.	47.83%
Dominion Energy	52.96%
Duke Energy Corporation	53.36%
Eversource Energy	53.79%
Exelon Corporation	52.50%
FirstEnergy, Corp.	54.97%
NextEra Energy, Inc.	60.64%
PPL Corporation	55.13%
Public Service Enterprise Group	54.88%
Average	54.33%

The average common equity ratios for the public utility subsidiaries provide an average of 54.33%, with a range of 47.83% to 60.64%. Hence, the common equity ratio of 54.59% for UGI Electric is clearly within the range of reasonableness. This provides additional support for the use of the Company's actual capital structure in this case.

Q. As shown on Rebuttal Exhibit PRM-1, your data covers most of the regulated electric utilities in Pennsylvania. Do you have additional and later data focusing specifically on Pennsylvania electric utilities.

A. Yes. That data is shown on Rebuttal Exhibit PRM-2. Duquesne Light is included there but is not contained in my Electric Group because it is privately owned. As revealed by the data shown on Rebuttal Exhibit PRM-2, the average common equity ratio is 51.91% for the Pennsylvania electric utilities. The range of the common equity ratios for the Pennsylvania electric utilities is 48.76% to 56.04%. These capital structure ratios are considered directly by investors that purchase the debt of these utilities. And, they are the ones reviewed by the rating agencies that opine on the creditworthiness of these utilities. UGI Electric falls within this range, and is therefore reasonable and should be accepted.

COST OF DEBT

Q. Have you updated the Company's cost of debt?

A. Yes. Schedule B-6 provides the Company's updated cost of debt updated for the FPFTY. It reflects the higher forecast interest rate on the new issue of Senior Notes that will be issued on later in the year. I described the fundamentals associated with higher interest rates previously. The coupon rate on this new issue is now projected to be 5.23%, an increase from the 4.551% originally forecasted. As shown on Schedule B-6, the embedded cost of long-term debt is 4.44% for the FPFTY. This change increased the embedded cost of long-term debt by 0.09% (4.44% - 4.35%) from my direct testimony. With this update, the overall rate of return moves to 8.19% as shown on Schedule B-7. Company witness Hazenstab has adjusted the revenue requirements for this change.

PROXY GROUP

Q. Mr. Patel excluded four companies from your Electric Group in his testimony (see page 10 of I&E Statement No. 3). Are these exclusions warranted?

A. No. Mr. Patel drops AVANGRID, Consolidated Edison, Exelon Corporation, and NextEra Energy.

Q. As one basis for exclusion, Mr. Patel used the percentage of revenues devoted to utility operations as a criterion for screening companies. Is this a correct criterion?

A. Not in my opinion. Revenues should not be the focus for screening the companies for membership in the Barometer Group. I In spite of this fact, the ALJ in the Company's last rate case removed two companies from my proxy group because they failed to meet the 50% revenue threshold. As shown below, no exclusions are warranted in this case because all my companies have revenues above 50% threshold. Moreover, in its Quarterly Earnings Report, the Commission uses assets as the screening criteria.

Q. How do the percentages of utility revenues, income, and assets compare for the companies contained in your Electric Group?

A. Those results are shown below:

Company		Regulated Revenues	Regulated Earnings	Regulated Assets
AVANGRID, Inc (AGR)		82%	85%	66%
Consolidated Edison Inc (ED)		93%	92%	89%
Dominion Energy, Inc. (D)		79%	72%	67%
Duke Energy Corporation (DUK)		98%	95%	96%
Eversource Energy (ES)		78%	83%	78%
Exelon Corp (EXC)	(1)	77%	116%	103%
FirstEnergy Corp (FE)		102%	137%	97%
NextEra Energy Inc (NEE)		83%	90%	54%
PPL Corp (PPL)	(2)	99%	NMF	89%
Public Service Enterprise Group Inc (PEG)		73%	NMF	76%
Average		86%	96%	81%

(1) Excluding generation business subsequently divested
(2) Excluding Discontinued Operations

As shown above, the percentage of utility revenues, earnings and assets equals or exceeds the 50% threshold for all members of my Electric Group. As such, these data show that no elimination to my Electric Group is appropriate for this criterion, especially Exelon.

Q. Is Mr. Patel also removed AVANGRID, Consolidated Edison, and NextEra Energy due to acquisition activity and other reasons? Is this elimination warranted?

A. No. He has excluded two companies because he says they are involved in merger/acquisition activities. As to AVANGRID, there is no reason to exclude it because it is attempting to acquire PNM Resources. In the circumstance of most merger and acquisition ("M&A") transactions, only the target company should be excluded in the barometer group selection process. It is the target company in a takeover whose stock price usually does not reflect its underlying fundamentals, and not the acquiring company. This is revealed by the premium offered by AVANGRID to acquire the stock of PNM in the M&A transaction. That premium was 10% over the share price of PNM on the day prior to the announced acquisition and 19.3% premium over the 30-day average price. In this situation, the acquiring company, i.e., AVANGRID, is not so affected and it continues to be an appropriate member of the Electric Group. In addition, this transaction has been pending since October 2020, and the merger has been rejected by the New Mexico Public Regulation Commission. It seems doubtful that the transaction will actually be completed. Further, the removal of Consolidated Edison is not well supported. Consolidated Edison is in the process of selling its renewable generation portfolio, which will make it a more utility focused company. Finally, as to his deregulated utility market criteria, a significant number of Mr. Patel's companies operate predominately in fully regulated integrated utility markets (*e.g*. American Electric Power, Dominion Energy, Duke, Entergy, Portland General Electric, and Xcel), which would disqualify them for membership in the barometer group under his criteria #6. As a consequence, there is no reason to exclude NextEra Energy.

DCF APPLICATION BY I&E

Q. The DCF model has been used by Mr. Patel, Mr. Rothschild and you as one method to measure the cost of equity. What is your position concerning the usefulness of the DCF method?

A. While the results of a DCF analysis should certainly be given weight, the use of more than one method provides a superior foundation for the cost of equity determination. Since all cost of equity methods contain certain unrealistic and overly restrictive assumptions, the use of more than one method will capture the multiplicity of factors that motivate investors to commit capital to an enterprise (i.e., current income, capital appreciation, preservation of capital, level of risk bearing). I am aware that the Commission usually expresses its cost of equity determination in the context of the DCF model. But the Commission also considers other methods as well. In its order entered on December 28, 2012, in Docket No. R-2012-2290597, the Commission stated:

> Sole reliance on one methodology without checking the validity of the results of that methodology with other cost of equity analyses does not always lend itself to responsible ratemaking. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived equity return calculation.[1]

Similarly, in the recent Aqua Pennsylvania decision, the Commission observed:

> In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence

[1] Pennsylvania Public Utility Commission v. PPL Electric Utilities, R-2012-2290597, meeting held December 5, 2012, at 80.

> based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination.[2]

The Commission has acknowledged the usefulness of other methods, such as CAPM, as a means of establishing a range of reasonable returns. Indeed, it is clear that the Commission has been guided by the results of other models and other factors aside from DCF when setting the DSIC return. The Commission's selection of the rate of return on equity for use in the DSIC is usually set well above the cost of equity indicated by the DCF model alone.

Indeed, the influence of other methods must have an impact on the Commission's attitude toward the DCF model because the Commission's selection of the rate of return on equity for use in the DSIC is usually set well above the cost of equity indicated by the DCF model alone. For example, in the Quarterly Earnings Report at Docket No. M-2023-3040145, the Commission set the DSIC return at 9.55% for the Electric Companies, while the DCF returns were 9.39% using current stock prices and 9.40% using 52-week average stock prices. It is clear that the Commission has been guided by the results of other models and other factors aside from DCF when setting the DSIC return. As an apparent input on the reasonableness of the DCF result, the CAPM result was 11.22% for the Electric Company Barometer Group as calculated in the Commission's Quarterly Earnings Report.

In this case, Mr. Patel essentially ignores the results of the CAPM, calling his CAPM results a basis for comparison purposes only (see page 32 of I&E Statement No. 3). Unlike Mr. Patel, Mr. Rothschild acknowledges (see page 9 of OCA Statement No. 2) that the CAPM serves as a check on the DCF because it

[2] Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc., R-2021-3027385, order entered May 16, 2022, at 154-55.

incorporates the impact of inflation and interest rates on the cost of equity. The use of multiple methods provides a more comprehensive and reliable basis to establish a reasonable equity return for UGI Electric. In his testimony, Mr. Patel shows that the average DCF result is too low by reference to his CAPM results. In this situation, the Commission should consider moving to within the top half of the range of DCF returns submitted in this case due to this understatement. This process would preserve use of DCF, but also accommodate the tendency of the DCF model to understate the required return in this market. Mr. Patel's DCF return range is from 6.67% for IDACORP to 10.88% for CMS Energy. Since Mr. Patel's CAPM result is 11.55%, then it stands to reason that the top half of the range of DCF results should be emphasized in this case, because the average DCF by itself is too low. Hence if DCF is to be used exclusively, as argued by Mr. Patel, then the proper DCF return should be at least 9.82% which is within the top half of the range, i.e., 8.76% + 10.88% = 19.64% ÷ 2.

Indeed, the CAPM and RP methods reflect directly the changes in interest rates and are an important indicator of higher equity cost rates. Although he claims (see page 32 of I&E Statement No. 3) that DCF sufficiently considers inflationary trends, there is no input that Mr. Patel has pointed to that substantiates his position. The CAPM and RP methods directly reflect the effect of rising interest rates and are an important indicator of higher equity cost rates. There is no interest rate input in the DCF formulation, so we do not know how or if the DCF is responsive to rising interest rates. We know that CAPM and RP reflects directly changes in interest rates and those models are more responsive in this regard than DCF.

Q. Has the National Association of Regulatory Utility Commissioners ("NARUC") taken a position on the use of multiple methods to measure the cost of equity?

A. Yes. The NARUC has published a paper entitled "Cost of Capital and Capital Markets

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Primer for Utility Regulators." In it, the NARUC said:

> The goal of all cost of equity models is to capture the realities of the capital marketplace and each model does so from a different perspective. Because these financial models are simplifications of the real world, the ROE results are estimates rather than exact discernments of ultimate truth. Ideally, the model results will corroborate each other but may not in practice. Different estimates resulting from different models can usefully frame, bracket, or define a range or zone of estimates.
>
> Investors, investment bankers, and corporate financial professionals use multiple models when evaluating the cost of equity. Likewise, it is desirable for regulators to also use multiple models when evaluating the cost of equity.

Q. What form of the DCF model has been employed in this case?

A. The constant growth form of the DCF model has been used by Mr. Patel, Mr. Rothschild, and me.

Q. Are there limitations to the application of the DCF that indicates that it should not be used alone to establish the equity return, which Mr. Patel seems to support especially in times of rising or falling interest rates?

A. My point is that all models have their strengths and weaknesses, and it is important to rely on more than one model in determining the cost of common equity. There are many assumptions associated with the specification of the DCF. These are:

- The form of the model. A choice must be made whether to employ the continuous or discrete form of the model.
- Whether a finite or infinite form of the model realistically represents investor's horizon.
- Whether compounding of the quarterly dividend should be employed.
- The timing of the dividend payments regarding the interval from the ex-dividend date and the stock measurement date needs to be addressed.
- A choice is necessary relative to a representative price that would reasonably represent the rate effective period, e.g., 12-month average, 6-month average, 13-week average, spot, etc.
- Assumptions concerning the structure of returns which under the DCF assumes that the price-earnings multiple, dividend payout ratio, and earned return will be constant.
- Whether single or multiple growth rates better reflect investor expectations.

- Choices concerning the use of historical or forecast growth rates.
- From a historical perspective, whether 10-years, 5-years, or some other historical period is representative of investor expectations.
- Choice among variables to measure growth, e.g., earnings per share, dividends per share, book value per share, cash flow per share, retention growth, price growth, etc.
- Choice of investor influencing growth rates that are available from I/B/E/S First Call, Zacks, Morningstar and Value Line.
- Whether the growth rate if measured by the formula "b x r" should be modified for external growth, i.e., "sv."
- The potential misspecification of the rate of return applicable to book value when taken directly from DCF if the market price diverges from book value.

Many of the assumptions, especially the constant price-earnings multiple, constant payout rate, and constant earned return, are particularly unrealistic.

Q. Mr. Patel presents a revenue requirements calculation showing the difference associated with using the DCF and CAPM results (see page 33 of I&E Statement No. 3.) What does this comparison reveal?

A. This comparison is not relevant to this case. Neither the Company nor I&E are arguing for an equity return of 11.55% shown by the CAPM result and used in his table shown on page 33. The Commission has used the DCF and CAPM models to establish a range, and the authorized return would fall within that range. If any insight can be made with these inputs, it would be between the midpoint of the range, i.e., 10.16% (11.55% + 8.76% = 20.31% ÷ 2) and the lower end of the range, i.e., 8.76%. That gap is 140 basis points. That produces a $1.985 million difference in revenue requirements, not the $3.971 million Mr. Patel reports.

Q. Do the DCF results proposed by Mr. Patel provide a reasonable representation of the cost of equity?

A. Not in my opinion. I&E Witness Patel concludes that the DCF cost of equity is 8.76% and the CAPM cost rate is 11.55% (I&E Statement No. 3, pages 27 and 31). The Commission has stated that it would consider other methods when the other methods showed that the DCF method understated the cost of equity. (Columbia Order, page

131.) It should be noted that I&E's DCF result in this case is also too low for two reasons. First, there have been significant increases in interest rates and inflation since the pandemic, indicating a higher cost of equity today. Second, I&E's own CAPM result of 11.55% illustrates its DCF result is too low, in contrast to the lower CAPM return in the Columbia case.

Focusing on the DCF approach, the principal purpose of assembling a barometer group is to avoid relying on data for a single company that may not be representative and to thereby smooth out any abnormalities. That said, when some of the DCF results for companies in the I&E barometer group are unreasonable on their face, the reliability of the method being used, or the witness' application of that method, must be questioned. As indicated below, the DCF results shown below fall into this category:

Company	Average: 52 wk & Spot Yield	+	Growth	=	Total
IDACORP, Inc.	3.14%	+	3.53%	=	6.67%
PPL Corporation	3.42%	+	3.50%	=	6.92%
Public Service Enterprise	3.64%	+	3.57%	=	7.21%
Portland General Electric	3.90%	+	3.90%	=	7.80%

It is a fundamental tenet of finance that the cost of equity must be higher than the cost of debt by a meaningful margin to compensate for the higher risk associated with a common equity investment. As noted above, the DCF return for these companies fail to provide a sufficient spread over the yield of on A-rated public utility bonds. Hence, any DCF return below 8% is clearly unreasonable and should be rejected.

Q. Please summarize the DCF growth rate analysis performed by Mr. Patel.

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A. As shown on page 27 of I&E Statement No. 3, Mr. Patel proposes a growth rate based on his review of analysts' projected earnings growth rates. His growth rate (i.e., 5.15%) is somewhat below the 6.00% growth rate that I determined. Referring to Mr. Patel's growth rates, the 3.50% growth rate for PPL Corporation, 3.53% for IDACORP, 3.57% for Public Service Enterprise Group and 3.90% for Portland General Electric appear to be outliers. The range of growth rates for other companies is 4.70% (i.e., First Energy) to 7.76% (i.e., CMS Energy). The reason for those low growth rates is attributed to the low Yahoo growth rates. Indeed, looking at the Value Line data presented on Schedule 6 of I&E Exhibit No. 3, that growth rate averages 5.91%. Applying the resulting DCF return would be 9.56% (3.65% + 5.91%).

DCF APPLICATION BY OCA

Q. Please summarize Mr. Rothschild's DCF methodology.

A. In his DCF analyses, Mr. Rothschild uses the Value Line dividend yields for the average period LTM and March 31, 2023 -- i.e., average of spot and twelve-month average yields (see page 56 of OCA Statement No. 2). He arrives at a dividend yield of 3.69% for both periods. He employs the Retention Growth Rate as his first DCF approach. As part of his retention growth analysis, Mr. Rothschild relies upon historical returns for his proxy group (see Source [C] on page 1 of Exhibit ALR-3).

Q. At page 13 of OCA Statement No. 2, Mr. Rothschild asserts that he uses an analytical approach focused primarily of market data. He further alleges that your analysis is too focused on non-market data. Is this an accurate description of the evidence in this case?

A. No. Both Mr. Rothschild and I have considered both historical and forecast data for this case. And, we both have used book value data and market data in our analysis. For example, the dividend yield component of the DCF and the risk-free rate of return component of the CAPM are recent averages of historical data. No other approach here is possible. Forecasts have been employed by both of us for the growth component of the DCF and the market risk premium of the CAPM. I have looked at book value measures of historical data, just like Mr. Rothschild as revealed on page 60 of OCA Statement No. 2 (see additional examples at Source [C] of page 1 of Exhibit ALR-3, page 8 of Exhibit ALR-3, page 1 of Exhibit ALR-4, and page 2 of Exhibit ALR-5). His extensive use of history strongly indicates that Mr. Rothschild’s analysis is in no way superior to my analysis.

Q. At page 59 of OCA Statement No. 2, Mr. Rothschild claims that it is inappropriate to strictly rely upon EPS growth rates on either a historical or forecast basis. Do you agree?

A. No. As noted above, to properly reflect investor expectations within the limitations of the DCF model, earnings per share growth, which is the basis for the capital gains yield and the source of dividend payments, must be given greatest weight. The reason that earnings per share growth is the primary determinant of investor expectations rests with the fact that the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). It is also important to recognize that analysts' forecasts significantly influence investor growth expectations and include review of historic growth rates. Therefore, Mr. Rothschild’s reliance on historic rates of growth in earnings, dividends and book value is duplicative of the analyst review and should be rejected. Mr. Rothschild presents DPS (dividends per share) and BPS (book value per share) growth rates in addition to EPS (earnings per share) growth. Mr. Rothschild is incorrect to believe that DPS and BPS have any role in the DCF model. The theory of the model rests on the assumption that there will be a constant price-earnings multiple, and therefore the price of stock will increase at the same rate as earnings growth – that is, EPS growth is the metric that drives the DCF analysis. Moreover, with the constant payout ratio assumption of the DCF, dividend growth will equal earnings growth in the long-term. Finally, with a consistent market-to-book ratio assumption of the DCF, book value per share will equal the other variables of growth, i.e., earnings per share and dividends per share. It is therefore not surprising that Professor Myron Gordon[3] found that EPS forecast are the best measure of growth in the DCF. I cited to his work on this matter above.

Q. In his direct testimony, Mr. Rothschild relies heavily on retention growth in his constant growth DCF analysis. Please discuss the limitations of this approach.

A. Retention growth, along with external financing growth, is another means of describing book value per share growth. Other factors also contribute to earnings growth that is not accounted for by the retention growth formula, such as sales of new common stock that Mr. Rothschild has included in his DCF growth rate analysis, reacquisition of common stock previously issued, changes in financial leverage, acquisition of new business opportunities, profitable liquidation of assets, and repositioning of existing assets. In my view, book value per share growth, or its surrogate retention growth, does not represent the proper financial variable to be considered when selecting the DCF growth component. This shows how the return expected of 10.30% translates into a much lower DCF result for his Comparison Group (see page 1 of Exhibit ALR-3).

[3]The Company has previously adjusted its interest rates on long-term debt in its rebuttal testimony to reflect changing market conditions. In its 2021 Electric Base Rate Case proceeding at Docket No. R-2021-3023618. UGI Electric lowered its interest rate, which had the effect of reducing its overall rate of return in that proceeding. UGI Electric St. No. 5-R, p. 9.

	Year Ending 3/31/2023	As of 3/31/2023
Return on Equity (Line 2c)	10.30%	10.30%
Dividend Yield on Book Value (Line 2b)	-7.25%	-7.03%
Dividend Yield on Market Value (Lines 1 & 6)	3.77%	3.77%
Result	6.82%	7.04%
New financing growth (Line 4)	1.30%	1.22%
Average DCF return	8.12%	8.26%

It should be noted that the Commission has not previously adopted a retention growth approach in the DCF analysis. A key component of retention growth is the analyst's assumed return on book common equity. Mr. Rothschild does not and cannot explain why an investor expected return of 10.30% should be reduced to 8.12% or 8.26% in this case, particularly since rates are set on book value (net original cost). As shown above, the retention approach advocated by Mr. Rothschild is clearly inconsistent with the traditional form of the DCF model used by the Commission.

Q. What DCF results would be obtained by relying on forecasts of earnings per share growth stated by Mr. Rothschild that is typically considered by the Commission?

A. Mr. Rothschild himself relied on forecast by analysts published by Zacks (see page 58 of OCA Statement No. 2), but fails to use these forecasts directly. This violates the process used by investors that I will discuss below, which results in a mis-specified

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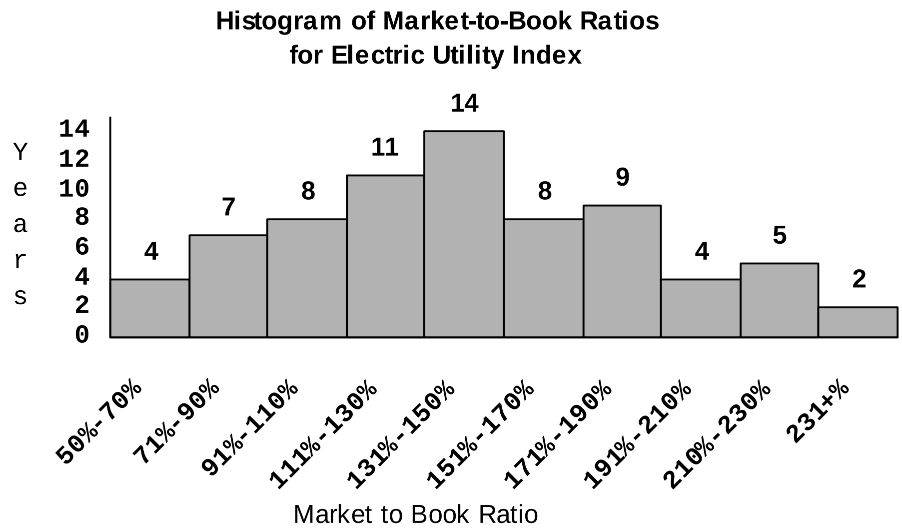
cost of equity determination by Mr. Rothschild. Mr. Rothschild declined to use directly the earnings per share forecast growth rate of 6.20% by Zacks (see page 3 of Exhibit ALR-5). Had he done so, the resulting DCF return would be 10.00% ((3.69% (1 + 0.5 (0.062%) + 6.20%) with the Zacks growth rate. This provides a far more reasonable DCF result than the DCF returns advocated by Mr. Rothschild (see OCA Statement No. 2 at page 10). As I describe in my pre-filed direct testimony, forecast earnings growth is the only valid measure of growth for DCF purposes.

Q. Do the DCF results proposed by Mr. Rothschild provide a reasonable representation of the cost of equity?

A. Not in my opinion. It is a fundamental tenet of finance that the cost of equity must be higher than the cost of debt by a meaningful margin to compensate for the higher risk associated with a common equity investment. As such, none of his returns can come close to meeting this standard.

Q. One of the features of Mr. Rothschild's direct testimony is his contention that when stock prices are considerably higher than their book value then the return that investors expect to receive on their market prices is less than whatever is anticipated on book value (Appendix A of OCA Statement No. 2). Please respond.

A. Mr. Rothschild makes this assertion in Appendix A of his direct testimony. That is to say, when a company has a market-to-book ratio above 1, it is over earning, in Mr. Rothschild's view. But such a claim is unwarranted given the evidence of the history of market-to-book ratios I provide below. The Commission has stated that it does not believe that its rate case decisions can ensure any particular market-to-book ratios (*PUC vs. The York Water Co.*, 62 Pa.PUC 459, Order Entered November 25, 1986). Moreover, if this assertion were correct then it leads to the inevitable conclusion that if investors expected to earn their required return, then stock prices would revert to their book value. However, the market for stocks shows that Mr. Rothschild's assertion is baseless. In the long history of market-to-book ratios for electric utilities since 1945, M/B ratios equal to 1.0 are unusual and ratios of greater than 1.0 are quite common. That data is shown below.



These data show that it is unusual for market prices to gravitate to book value. Indeed, in only about 11% of the years studied did electric utility stock prices approximate book value. In 74% of the years, electric utilities stock prices exceeded book value and sometimes by a substantial amount. The average market-to-book ratio over the past 72 years is 143%.

Q. Mr. Rothschild also uses what he identifies as "Constant Growth – Option-Implied Growth" model of the DCF. What value do the results of the model provide?

A. Very little to none. Mr. Rothschild provides virtually no explanation for this model and only divulges the result on page 2 of Exhibit ALR-3. The only value provided by this model is that it shows his "normal" constant growth DCF produces unreasonably low results.

Q. Mr. Rothschild submits an alternative calculation as his additional method to measure the cost of equity. Is this data useful in this case?

A. Only to show that his constant-growth DCF model results are unrealistic. As a preliminary matter, his alternative constant growth – options implied growth was 8.47% and 9.34%, while the non-constant DCF result is 9.05% or 9.06%, which demonstrates the unreasonable results of his constant growth DCF model. Mr. Rothschild uses book value per share growth as a key input in his alternative form of the DCF, which makes this method invalid as a non-constant measure of the cost of equity. If the correct EPS growth would be considered, and the P-E multiple from Value Line is used, then the non-constant DCF results would be 12.72% (see Rebuttal Exhibit PRM-3).

LEVERAGE ADJUSTMENT

Q. At pages 46-54 of I&E Statement No. 3, Mr. Patel responds to your leverage adjustment and argues that it should be rejected. Do you agree?

A. No. Mr. Patel states that he opposes the leverage adjustment. In his discussion of my leverage adjustment, Mr. Patel mentions market-to-book ratios ("M/B") (see page 47 of I&E Statement No. 3). I need to be clear that my leverage adjustment is not designed to produce any particular M/B ratio.

Q. Please respond to Mr. Patel's criticism of your leverage adjustment.

A. Mr. Patel offers three reasons for not making a leverage adjustment. First, Mr. Patel notes that the credit rating agencies assess financial risk in terms of a company's booked debt obligations in their analysis of the creditworthiness of a company (see I&E Statement No. 3 page 49). I agree. But this has nothing to do with my leverage adjustment. The credit rating agencies do not measure the market required cost of equity for a company. The credit rating agencies are only concerned with the interests of lenders. They are judging risk associated with a company's ability to make timely payments of principal and interest. Hence, they are not concerned with the cost of equity or how it is applied in the rate-setting context. While Mr. Patel's observation is correct, it has no relevance to my leverage adjustment.

Q. Second, Mr. Patel also questions your leverage adjustment by reference to prior Commission orders. Please comment.

A. Mr. Patel points to several decisions where the Commission declined to make a leverage adjustment (see I&E Statement No. 3 pages 51-53). The fact that the Commission declined to use the leverage adjustment in the Aqua Pennsylvania case cited by Mr. Patel does not invalidate its use. Notably, the Commission did not repudiate the leverage adjustment in the Aqua case, but instead arrived at an 11.00% return on equity for Aqua by including a separate return increment for management performance. Just like an increment for management performance is not recognized in all rate cases, so too the Commission seems to be taking a similar approach to the leverage adjustment. As to the City of Lancaster decision, the situation there was quite different than the leverage adjustment that I propose in this case. Lancaster proposed a leverage adjustment to the cost of equity measured with the Hamada formula and applied it to the DCF result, the Risk Premium result, and the CAPM. While the Hamada formula plays a role in the CAPM, it is not applicable to the DCF or the Risk Premium measures of the cost of equity. Hence, this distinguishes the City of Lancaster approach to the leverage adjustment from mine in this case. As to the UGI Electric Utilities – Electric Division case, there the Commission granted a management performance increment rather than a leverage adjustment when arriving at a 9.85% equity return. And for Columbia, the Company accepted the I&E's recommendation of the allowed return, which was 9.86%, in a case litigated at the height of the COVID-19 Pandemic. Thus, Columbia chose not to argue the leverage adjustment in Exceptions to the Commission. However, based upon the current inputs to the DCF that indicated a low result, the Commission should now consider using the leverage adjustment, just as it did previously when the DCF was suggesting unusual results. In the PECO - electric rate case, the Commission arrived at a 10.24% return without the leverage adjustment, because that return was already deemed to be on the higher side and no additional adjustment was warranted. Finally, the Commission set the equity return at 10.00% for Aqua Pennsylvania recently without a leverage adjustment, but with an adjustment for management performance.

Q. Third, Mr. Patel argues that information provided investors is book values according to Value Line. Is this correct?

A. No. Mr. Patel contends that information presented to investors (see page 53 of I&E Statement No. 3), such as that included in the Value Line reports, argues against my leverage adjustment because investors base their investment decisions on book value. However, the Value Line reports clearly show the market capitalization of each company in his barometer group. This means that investors are well aware of the market capitalization of the electric utility stocks that Mr. Patel relies upon for his analysis of the cost of equity. More importantly, I fundamentally disagree that investors base their decisions on book values. To the contrary, it is the future cash flows that investors expect to realize that determines the price they are willing to pay for a share of common equity. Stated differently, investors are concerned with the return that will be earned on the dollars they invest (i.e., their market price) and not some accounting value of little relevance to them. The financial risk associated with the book value capital structure is different from the market value of the capitalization. I clearly demonstrate this point on Schedule 10 of UGI Electric Exhibit B. Hence, the observation of Mr. Patel is misplaced because I have clearly shown the difference in financial risk and that risk difference must be taken into account when arriving at an equity return that is applicable to the weighted average cost of capital using book value weights.

Q Mr. Rothschild criticized the leverage adjustment that you propose to account for the divergence of market capitalization and book value capitalization. Please comment.

A. Mr. Rothschild claims that the market value capital structure and the book value capital structure are two completely different ways of measuring the same thing. But it must be recognized that, in order to make the DCF results relevant in the rate-setting context, the market-derived cost rate cannot be used without modification. The importance of the leverage modification to the DCF results was fully supported in my direct testimony, wherein it was shown that the market value of the equity in the Electric Group's capitalization was much higher than its book value. The market value common equity ratio was 58.93% compared to a book value common equity ratio 45.86%. The leverage adjustment is necessary to make the market-derived DCF results applicable in the rate-setting context. Because the market-based cost rate is determined based on less financial risk than that reflected in the ratemaking capital structure, and because increased financial risk justifies a higher return on equity, it is necessary to account for the higher financial risk that arises from the lower common equity ratio measured by book value capitalization.

Q. Do you agree with Mr. Rothschild's contention that the market value capital structure and the book value capital structure are two completely different ways of measuring the same thing?

A. No. As Professors Modigliani and Miller proved 50 years ago (as discussed on page 28 of my direct testimony), the amount of leverage, or proportion of debt, in a firm's capital structure is directly related to the firm's financial risk and cost of equity. Mr. Rothschild's analogy to the measurement of weight on two scales (see page 94 of his testimony) is no analogy at all. Unlike weight, there is only one scale for measuring financial risk and that is the proportion of leverage in a firm's capital structure. A firm's financial risk changes when the quantities of debt and equity capital, on which the proportion is based, are changed. For the Electric Group, the average market value of their debt is $32,560 million and the book value of their debt is $52,068 million. Both of these measures are stated as dollar values; there has been no change in the units of measurement. Likewise, for their equity. The average market value of the Electric Group's common equity is $29,322 million and the corresponding book value is $23,500 million. Again, both are stated in dollars and there has been no change in the units of measurement. A measurement of financial risk that is based on a market-value capitalization cannot be applied directly to book-value capitalization if there is a material difference attributed to a change in financial risk between the two. Unlike weight, where the relationship between the scales of measurement is fixed (*i.e.*, one-pound equals 0.45359 kilograms), the financial risk associated with a market-value capitalization can be higher or lower than the financial risk associated with a book-value capitalization, depending on the quantities, stated in dollars, of debt and equity measured and their relative proportion to the total capitalization. Financial risk is measured as a percent of fixed-cost (*i.e.*, senior) capital. That is to say, the quantities that are used to measure financial risk account for the different quantities of debt and equity that result from market and book valuations of capital.

According to Mr. Rothschild's analogy (see page 85 of OCA Statement No. 2), one loses weight by merely changing the calibration of the scale from pounds to kilograms. Mr. Rothschild's position that a cost of equity derived from market-value capitalizations may be applied to a book-value capitalization is just like saying one kilogram is the same as one pound. This is, of course, incorrect, just as it is indisputable that there is more financial risk associated with a 45.86% common equity ratio than there is with a 58.93% common equity ratio. The risk-adjusted return associated with a higher market-value capitalization is different than and generally lower than its risk-adjusted return associated with a book-value capitalization. Indeed, Mr. Rothschild's own studies support this proposition. Using his adjustment noted in Source [F] shown on Exhibit ALR-1, the adjustment would be 0.52% (58.93% - 45.86% = 13.07% x 0.04%). Although less than my leverage adjustment of 0.97%, it does establish the propriety of the adjustment. Therefore, in order to apply a measurement of a return measured based on a firm's market-value capitalization to a book-value capitalization, the return measurement must be adjusted before it is applied to the firm's capitalization measured based on book value. All returns derived from the market models of the cost of equity are related to the price of stock established by investors and not based on book values.

COST OF COMMON EQUITY - CAPITAL ASSET PRICING MODEL

Q. At page 20 of I&E Statement No. 3, Mr. Patel tries to explain that the CAPM is less responsive than DCF to changes in the capital markets, because the CAPM uses historical betas and measures the return on equity indirectly. Do these observations defeat the usefulness of the results of the CAPM?

A. Absolutely not. The CAPM is just as responsive to changes in capital costs as is the DCF. Indeed, the CAPM is more responsive to the current level and trend in interest rates because the risk-free rate of return reflects those factors directly. The market risk premium is also forward-looking, as it is based on a DCF type calculation for the market total return, as proposed by Mr. Patel (see Schedule 9 of I&E Exhibit No. 3). And while the beta calculation is based on historical data, Value Line adjusts its historical betas for the tendency of betas to move toward 1.00 on a forward-looking basis. The bottom line is the CAPM is just as responsive to changes in capital costs as any other method.

Q. Do you have concerns regarding Mr. Patel's and Mr. Rothschild's applications of the CAPM?

A. Yes. Mr. Patel's CAPM analysis understates the cost of equity for a number of reasons: (i) his use of the yield on 10-year Treasury notes, (ii) his failure to use leveraged adjusted betas, and (iii) his failure to make a size adjustment. Mr. Rothschild uses an inappropriate yield on 30-year Treasury bonds (especially at the low end of his range), a beta that is not leverage adjusted, an unrealistic market risk premium, and ignores the size adjustment. He therefore proposes a totally unrealistic CAPM result of 7.78% to 8.60%. This compares with my CAPM of 15.95%, Mr. Patel's CAPM of 11.55%, and the Quarterly Earnings Report's CAPM of 11.22%. With regard to Mr. Patel's CAPM analysis, which produces a 11.55% cost rate, it can be argued that he has understated the risk-free rate. On Schedule 8 of I&E Exhibit No. 3, he uses a projected 10-year treasury note yield from <u>Blue Chip</u> on February 1, 2023 and December 2, 2022, producing a 3.58% risk-free rate.

Q. How does the use of the yield on 10-year Treasury notes compare with yields on longer-term Treasury bonds?

A. The <u>Blue Chip</u> report shows this comparison. For the first quarter of 2023, the gap was 0.09% (3.74% - 3.65%) between the yields on 30-year and 10-year Treasury obligations. For the period 2024-2028, that gap is projected to increase to 0.30% (3.9% - 3.6%) according to the December 2, 2022 <u>Blue Chip</u>. This shows a systematic understatement of Mr. Patel's CAPM returns. This understatement can be traced to extraordinary monetary policy actions taken by the FOMC to deal with the recession that followed the onset of the pandemic. Shorter-term rates, such as 10-year notes, respond more to the policy initiatives of monetary officials, while long-term rates, such as 30-year bonds, are more a reflection of investor sentiment of their required returns. For this reason, long-term rates, such as those revealed by 30-year Treasury bonds, should be used to measure the risk-free rate of return.

Q. How has Mr. Patel understated the risk-free rate of return?

A. The support for his risk-free rate of return is shown on his Schedule 8 of I&E Exhibit No. 3. There, he incorrectly gives the same weight to the yield on 10-year Treasury notes for the first quarter of 2023 as he does for the entire five-year period from 2024 through 2028. This approach leads to an understated risk-free rate of return. Even if 10-year rates are used, it is necessary to correct the weights assigned to the forecast data presented by Mr. Patel. I have revised his forecast below, based upon Blue Chip dated May 1, 2023. Moreover, Blue Chip provides higher yields on Treasury obligations as the forecasts are extended into the future.

The resulting risk-free rate of return is 3.6% using the yield on 10-year Treasury Notes and 3.9% using the yield on 30-year Treasury Bonds.

Year	10-Year Treasury Yield	30-Year Treasury Yield
2024	3.7%	4.0%
2025	3.5%	3.9%
2026	3.6%	3.9%
2027	3.6%	4.0%
2028	3.6%	3.9%
Average	3.6%	3.9%

Q. How should these results be used in the CAPM?

A. The risk-free rate of return should be calculated with the data that I present above. The size adjustment of 1.02% must also be incorporated into the CAPM. I have corrected Mr. Patel's CAPM as indicated below using those inputs and the forecast yield on 30-year Treasury bond shown above:

	Rf	+	β	(	Rm	-	Rf	) +	size	=	K
Gas Group	3.90%	+	0.86	(	12.85%	-	3.90%	) +	1.02%	=	12.62%

Q. Mr. Patel questions the need to adjust the CAPM results for size differences. Please comment.

A. As a preliminary matter, it is noteworthy that CAPM provides compensation solely for systematic risk, and that the size of the Electric Group must be considered separately. Just as investors have choices concerning large cap, midcap, and small cap equity investments offered by many mutual funds and ETFs, size is clearly on important investment criteria for investors. It is well recognized that the return for small cap investments outperform large cap investments. Indeed, the Ibbotson Yearbook shows that small cap stocks have outperformed large cap stocks by four percentage points (4.00%) over the past ninety-seven (97) years. As I indicated with the data presented on Schedules 2, 3 and 4 of UGI Electric Exhibit B, the electric utilities are small as they are just 16% of the size of the electric and gas utilities that comprise the S&P Public Utilities. Indeed, recent Federal Energy Regulatory Commission ("FERC") orders specifically prescribe an adjustment to the CAPM due to the size of an enterprise.[4] Mr. Patel's arguments revolve around the purported distinction between regulated utilities and unregulated industrial companies (see pages 59-60 of I&E Statement No. 3). However, the Wong article that he relies upon was authored nearly thirty (30) years ago, and employed data going back into the 1960s. Enormous changes have occurred in the industry since the 1960s that have fundamentally changed the utility business. The Wong article also noted that betas for the non-regulated companies were larger than the betas of the utilities. This, however, is not

[4] *See, e.g.*, Association of Businesses Advocating Tariff Equity, 171 FERC ¶61,154 (May 21, 2020).

a revelation, because utilities continue to have lower betas than many other companies. This fact does not invalidate the additional risk associated with small size.

The Wong article further concludes that size cannot be explained in terms of beta. Again, this should not be a surprise. Beta is not the tool that should be employed to make that determination. Indeed, beta is a measure of systematic risk and it does not provide the means to identify the return necessary to compensate for the additional risk of small size. In contrast, the famous Fama/French study (see "The Cross-Section of Expected Stock Returns," The Journal of Finance, June 1992) identified size as a separate factor that helps explain returns.

Q. How does size affect the financial performance of a small company?

A. Examples of the financial consequences of external factors that can influence the financial performance of a small company include loss of a large customer and the effect of unexpected changes in expense.

Q. In the Gas Division rate case for PECO Energy Company (Docket No. R-2020-301829), the Commission declined to make a size adjustment to the CAPM. Should the size adjustment be considered here?

A. Yes. In that case, the ALJs and Commission concluded the adjustment for size was not necessary in utility rate regulation. In this case, it is worthy to note that the beta measure of systematic risk does not account for the additional risk associated with small size, either for a non-regulated firm or a public utility. In addition, the studies that I have relied upon for the size adjustment utilized market-wide evidence that included public utilities. Likewise, the FERC has incorporated the size adjustment into its CAPM analysis. For these reasons, the Commission should revisit the propriety of including a size adjustment here.

Q. Mr. Rothschild uses a variety of approaches to apply the CAPM. Is there anything unusual in his approach?

A. Yes. Aside from his consideration of yields on 3-month Treasury bills which are rarely considered in rate cases such as these, he uses a non-standard approach for the selection of his betas and an unusual approach for his market risk premium. I know of no other witness in public utility rate cases that use "Historical Blended" betas or "Forward" betas like Mr. Rothschild. Mr. Rothschild has not shown, nor could he, that investors use his betas. If they are not used by investors, they have no relevance in establishing a market-based cost of equity. Mr. Rothschild should have used standard Value Line betas that are used by the Commission, the FERC, Mr. Patel, and almost all other rate of return witnesses, including me. His cumulative probably "Option-Implied Growth Rate" for the S&P 500 is also highly unusual and not supported in other rate cases. To show how unusual Mr. Rothschild's approach is here, just consider the market risk premium of 12.85% that Mr. Patel developed and the 10.12% market risk premium that I calculated. With Mr. Rothschild's unconventional approach, it is not surprising that he develops CAPM returns that are not credible when his range is from 7.77% to 8.60%. Those returns are clearly outside the range of reasonableness when Mr. Patel develops a CAPM of 11.55% and I obtained 12.91% without the size adjustment or the leveraged betas.

Q. Mr. Rothschild has also performed a CAPM calculation in addition to his constant growth and non-constant growth DCF models. Are the results of his CAPM useful in setting the Company's equity return in this case?

A. No. There are a variety of problems with Mr. Rothschild's CAPM approach which makes it not useful in this case. He makes CAPM calculations that produce results in the range of 7.78% to 8.60% with spot data and 6.04% to 7.25% with average data. By any reasonable standard, such low returns are simply not credible. All of Mr.

Rothschild's CAPM results are below his DCF returns. In contrast, Mr. Patel and I have provided CAPM results that exceed the DCF. Mr. Rothschild does not use betas that are available to investors, but instead uses a "phantom" beta that invalidates his CAPM. Mr. Rothschild calculates "option implied betas" that have not and could not have any influence on the types of returns investors could expect using the CAPM, such as the Value Line betas do. Rather than use betas that are available to or used by investors, Mr. Rothschild has manufactured his own betas. It is well known that investors use the Value Line data. He says he follows the Value Line approach for calculating betas, but he ignores the actual Value Line betas. This makes no sense. There is no evidence that the betas calculated by Mr. Rothschild have any bearing on investor expected returns, and in setting rates of return that is what is relevant. Even if Mr. Rothschild was correct that his calculations are valid, investors simply could not have relied on them. The Value Line data is relied upon by investors. As such, the Value Line betas should be used directly in the cost of capital computation. To augment the Value Line betas with other information that investors do not use is not appropriate, regardless of the theoretical underpinnings of the modifications.

Q. How should these results be used in the CAPM?

A. The risk-free rate of return should be calculated with the data that I present in my direct testimony. I have corrected Mr. Rothschild's CAPM by using the Value Line betas and have developed a more reasonable market return of 13.10%, which provides a 9.78% market risk premium.[5] The size adjustment of 1.02% must also be incorporated into the CAPM.

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[5] The Value Line forecast return is 10.68% (1.9% + ($1.40^{.25}$ -1) and the S&P 500 forecast return is 15.51% (1.41% (1.07) + 14.0%), which results in a 13.10% (10.68% + 15.51% - 26.19 ÷ 2) less the 2.75% risk-free rate of return provides a 10.35% market risk premium that is averaged with the historical market risk premium (10.35% + 9.21% = 19.56% ÷ 2 = 9.78%).

	Rf	+	β	(Rm	-	Rf) +	size	=	K
Electric Group	3.90%	+	0.86	(	9.27%	) +	1.02%	=	12.89%

Q. At pages 90-92 of Exhibit PRM-1, Mr. Rothschild also challenges the adjustment that you made to the results of the CAPM for the size of the Electric Group. Please respond.

A. A size adjustment is necessary because the financial impact of changes in specific dollar amounts of revenues and costs have a magnified influence on a small company because there are fewer dollars over which those revenues or costs can be spread. The SBBI/Morningstar Yearbook clearly demonstrates that the simple CAPM does not reflect the return that is associated with small size. As Ibbotson has stated:

> The security market line is based on the pure CAPM without adjusting for the size premium. Based on the risk (or beta) of a security, the expected return should fluctuate along the security market line. However, the expected returns for the smaller deciles of the NYSE/AMEX/NASDAQ lie above the line, indicating that these deciles have had returns in excess of those appropriate for their systematic risk.

COST OF COMMON EQUITY - RISK PREMIUM ANALYSIS

Q. Do you believe the Risk Premium method provides significant evidence of the cost of equity?

A. Yes. In my opinion, the Risk Premium results should be given serious consideration. The Risk Premium method is straight-forward, understandable and has intuitive appeal because it is based on a company's own borrowing rate. The utility's borrowing rate provides the foundation for its cost of equity, which must be higher than the cost of debt in recognition of the higher risk of equity (see UGI Electric Statement No. 9 page 34). So, while Mr. Patel and Mr. Rothschild decline to use the Risk Premium approach to measure the Company's cost of equity, it is an approach that provides a direct and complete reflection of a utility's risk and return because it considers additional factors not reflected in the beta measure of systematic risk. It is particularly useful when investors expect changes in the cost of debt prospectively, which is currently the expectation of investors, as I have explained above and in UGI Electric Statement No. 9, page 34. Indeed, the Risk Premium approach provides for direct reflection of prospective interest rates in the model and therefore should be given weight in determining the equity cost rate in this case.

Q. What does Mr. Patel say about your Risk Premium analysis?

A. Mr. Patel makes the unfounded assertion that the Risk Premium and CAPM methods should only be used as a comparison to the results of the DCF method because they do not carry over from the investment decision-making process to the utility rate setting process (see page 21 of OCA Statement 3). In fact, it is precisely because investors consider the results of other methods that they too should be used in addition to the DCF in the development of the cost of equity in this proceeding. Mr. Patel's assertion that the Risk Premium method does not measure the current cost of equity as directly as the DCF is similarly without foundation. As I explained in my direct testimony and earlier in this rebuttal testimony, we are facing the prospect of increasing interest rates for the future. I incorporated the trend toward higher interest rates when I developed my Risk Premium cost of equity of 11.25% (11.50% as updated), although, as noted above, actual interest rates on A-rated public utility bonds have already exceeded the projection I used for my Risk Premium cost of equity. Hence, my Risk Premium cost rate is fully responsive to changing market fundamentals and the credit quality of the Electric Group.

Q. Mr. Rothschild claims (see pages 87-88 of OCA Statement No. 2) that your Risk Premium approach is flawed for three reasons. Please respond.

A. First, investor expectations are embedded in the returns year-by-year that I used and were current at those times when the returns were realized. Second, 72-years of data is not too short to be reflective of the long-term life of public utility assets. Third, no regression analysis was necessary to clearly establish, as I have, the relationship between the level of interest rates and the magnitude of the equity risk premium. Mr. Rothschild has not effectively refuted any of the underpinnings of my Risk Premium approach.

COST OF COMMON EQUITY - COMPARABLE EARNINGS APPROACH

Q. Please respond to the criticism of the Comparable Earnings approach.

A. The underlying premise of the Comparable Earnings method is that regulation should emulate results obtained by firms operating in competitive markets and that a utility must be given an opportunity cost of capital equal to that which could be earned if one invested in firms of comparable risk. For non-regulated firms, the cost of capital concept is used to determine whether the expected marginal returns on new projects will be greater than the cost of capital, i.e., the cost of capital provides the hurdle rate at which new projects can be justified, and therefore undertaken. Further, given the 10-year time frame (i.e., five years historical and five years projected) considered by my study, it is unlikely that the earned returns of non-regulated firms would diverge significantly from their cost of capital.

The Comparable Earnings approach satisfies the comparability standard established in the Hope case. In addition, the financial community has expressed the view that the regulatory process must consider the returns that are being achieved in the non-regulated sector to ensure that regulated companies can compete effectively in the capital markets. Moreover, in a 1994 study that addressed the ROE issue, John Olson (then with Merrill Lynch) established that equity returns from non-regulated companies provide better assessment of investor requirements than those

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available for regulated utilities.[6]

MANAGEMENT PERFORMANCE

Q. Both Mr. Patel and Mr. Rothschild oppose any recognition for management performance in the determination of the return on equity. Mr. Patel and Mr. Rothschild assert that UGI Electric has only done what it is required to by law. How do you respond?

A. As I stated in my direct testimony, I believe UGI Electric has performed in an exemplary manner, as explained by UGI Electric Witness Brown, and that performance should be recognized in this case. Mr. Patel simply disagrees, without addressing any of the items highlighted by Mr. Brown as examples of UGI Electric's excellent performance. Mr. Rothschild's position regarding management performance is that the models of the cost of equity already incorporate management effectiveness. In each case, neither Messrs. Patel nor Rothschild have shown that UGI Electric is not entitled to some form of management performance recognition by the Commission. Mr. Brown's direct and rebuttal testimony establish that the Company's management performance warrants recognition by the Commission.

SUMMARY

Q. Please summarize your rebuttal testimony.

A. It is my opinion that the equity allowances proposed by Mr. Patel and Mr. Rothschild seriously understate the cost of common equity for UGI Electric. This is particularly true for Mr. Rothschild's proposal. In an environment of prospectively higher interest rates and Company-specific risk factors, an opportunity to earn a cost of equity of 11.30% is reasonable for UGI Electric.

Q. Does this conclude your rebuttal testimony at this time?

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[6] "Natural Gas: The Case for ROE Reform," John E. Olson First Vice President, Merrill Lynch & Co., October 11, 1994.

A. Yes, it does.

UGI ELECTRIC EXHIBIT PMR-1R

	Weighted Average										
	Debt	Equity									
AVANGRID, Inc.			New York State Electric & Gas Corp.			Rochester Gas and Electric Corp.			The United Illuminating Company		
			Debt	Equity [1]	Total	Debt	Equity [1]	Total	Debt	Equity [1]	Total
				($000)			($000)			($000)	
Amount			$ 1,735,709,857	$ 2,108,125,526	$ 3,843,835,383	$ 1,251,981,725	$ 1,317,308,461	$ 2,569,290,186	$ 891,960,000	$ 1,274,539,292	$ 2,166,499,292
Ratios	42.81%	57.19%	45.16%	54.84%	100.00%	48.73%	51.27%	100.00%	41.17%	58.83%	100.00%
Consolidated Edison, Inc.			Consolidated Edison Co. of New York			Orange and Rockland Utilities			Rockland Electric Company		
			Debt	Equity [1]	Total	Debt	Equity [1]	Total	Debt	Equity [1]	Total
				($000)			($000)			($000)	
Amount			$ 17,775,369,190	$ 15,930,205,649	$ 33,705,574,839	$ 899,279,617	$ 850,869,727	$ 1,750,149,344	$ -	$ 342,090,594	$ 342,090,594
Ratios	52.17%	47.83%	52.74%	47.26%	100.00%	51.38%	48.62%	100.00%	0.00%	100.00%	100.00%
Dominion Energy, Inc.			Dominion Energy South Carolina, Inc.			Virginia Electric and Power Company					
			Debt	Equity [1]	Total	Debt	Equity [1]	Total			
				($000)			($000)				
Amount			$ 3,347,878,620	$ 4,139,013,123	$ 7,486,891,743	$ 13,737,775,322	$ 15,096,604,982	$ 28,834,380,304			
Ratios	47.04%	52.96%	44.72%	55.28%	100.00%	47.64%	52.36%	100.00%			
Duke Energy Corporation			Duke Energy Carolinas			Duke Energy Progress			Duke Energy Florida		
			Debt	Equity [1]	Total	Debt	Equity [1]	Total	Debt	Equity [1]	Total
				($000)			($000)			($000)	
Amount			$ 12,676,090,630	$ 13,415,692,350	$ 26,091,782,980	$ 9,025,863,804	$ 9,705,566,334	$ 18,731,430,138	$ 6,814,868,587	$ 7,888,199,941	$ 14,703,068,528
Ratios	46.64%	53.36%	48.58%	51.42%	100.00%	48.19%	51.81%	100.00%	46.35%	53.65%	100.00%
Eversource Energy			Connecticut Light and Power Company			NSTAR Electric Company			Public Service Co. of New Hampshire		
			Debt	Equity [1]	Total	Debt	Equity [1]	Total	Debt	Equity [1]	Total
				($000)			($000)			($000)	
Amount			$ 4,364,225,444	$ 5,231,660,613	$ 9,595,886,057	$ 3,710,146,378	$ 4,544,764,821	$ 8,254,911,199	$ 1,672,981,421	$ 1,572,060,523	$ 3,245,041,944
Ratios	46.21%	53.79%	45.48%	54.52%	100.00%	44.94%	55.06%	100.00%	51.56%	48.44%	100.00%
Exelon Corporation			Commonwealth Edison Company			PECO Energy Company			Baltimore Gas and Electric Co.		
			Debt	Equity [1]	Total	Debt	Equity [1]	Total	Debt	Equity [1]	Total
				($000)			($000)			($000)	
Amount			$ 9,956,820,440	$ 11,859,958,779	$ 21,816,779,219	$ 4,339,041,145	$ 5,026,054,421	$ 9,365,095,566	$ 4,287,284,265	$ 4,301,111,679	$ 8,588,395,944
Ratios	47.50%	52.50%	45.64%	54.36%	100.00%	46.33%	53.67%	100.00%	49.92%	50.08%	100.00%
FirstEnergy Corp.			Ohio Edison Company			Pennsylvania Power Company			The Cleveland Electric Illuminating Co.		
			Debt	Equity [1]	Total	Debt	Equity [1]	Total	Debt	Equity [1]	Total
				($000)			($000)			($000)	
Amount			$ 618,539,588	$ 1,380,969,937	$ 1,999,509,525	$ 200,000,000	$ 212,777,264	$ 412,777,264	$ 1,498,017,021	$ 1,593,581,452	$ 3,091,598,473
Ratios	45.03%	54.97%	30.93%	69.07%	100.00%	48.45%	51.55%	100.00%	48.45%	51.55%	100.00%
NextEra Energy, Inc.			Florida Power & Light Company			Gulf Power Company					
			Debt	Equity [1]	Total	Debt	Equity [1]	Total			
				($000)			($000)				
Amount			$ 17,128,762,786	$ 25,945,795,009	$ 43,074,557,795	$ 1,570,332,504	$ 2,861,093,041	$ 4,431,425,545			
Ratios	39.36%	60.64%	39.77%	60.23%	100.00%	35.44%	64.56%	100.00%			
PPL Corporation			PPL Electric Utilities Corporation			Louisville Gas and Electric Company			Kentucky Utilities Company		
			Debt	Equity [1]	Total	Debt	Equity [1]	Total	Debt	Equity [1]	Total
				($000)			($000)			($000)	
Amount			$ 4,916,644,083	$ 5,882,929,777	$ 10,799,573,860	$ 2,020,195,788	$ 2,614,580,659	$ 4,634,776,447	$ 2,637,742,513	$ 3,265,675,224	$ 5,903,417,737
Ratios	44.87%	55.13%	45.53%	54.47%	100.00%	43.59%	56.41%	100.00%	44.68%	55.32%	100.00%
Public Service Enterprise Group			Public Service Electric and Gas Co.								
			Debt	Equity [1]	Total						
				($000)							
Amount			$ 11,435,852,477	$ 13,917,922,053	$ 25,353,774,530						
Ratios	45.11%	54.89%	45.11%	54.89%	100.00%						
Group Average	45.67%	54.33%									
Range											
High	52.17%	60.64%									
Low	39.36%	47.83%									

Note: [1] Excluding Accumulated Other Comprehensive Income

Source of Information: FERC Form No. 1

Central Maine Power Company		
Debt	Equity [1]	Total
	($000)	
$ 1,240,000,000	$ 2,139,887,086	$ 3,379,887,086
36.69%	63.31%	100.00%

Duke Energy Ohio		
Debt	Equity [1]	Total
	($000)	
$ 2,372,565,176	$ 4,075,482,897	$ 6,448,048,073
36.80%	63.20%	100.00%

Duke Energy Kentucky		
Debt	Equity [1]	Total
	($000)	
$ 731,539,830	$ 799,067,166	$ 1,530,606,996
47.79%	52.21%	100.00%

Duke Energy Indiana		
Debt	Equity [1]	Total
	($000)	
$ 4,105,437,204	$ 4,985,447,776	$ 9,090,884,980
45.16%	54.84%	100.00%

Potomac Electric Power Company		
Debt	Equity [1]	Total
	($000)	
$ 3,337,495,187	$ 3,351,870,303	$ 6,689,365,490
49.89%	50.11%	100.00%

Delmarva Power & Light Company		
Debt	Equity [1]	Total
	($000)	
$ 1,792,825,216	$ 1,813,127,165	$ 3,605,952,381
49.72%	50.28%	100.00%

Atlantic City Electric Company		
Debt	Equity [1]	Total
	($000)	
$ 1,498,487,249	$ 1,515,740,701	$ 3,014,227,950
49.71%	50.29%	100.00%

The Toledo Edison Company		
Debt	Equity [1]	Total
	($000)	
$ 449,329,648	$ 555,776,198	$ 1,005,105,846
44.70%	55.30%	100.00%

Monongahela Power Company		
Debt	Equity [1]	Total
	($000)	
$ 1,738,251,490	$ 1,381,563,044	$ 3,119,814,534
55.72%	44.28%	100.00%

The Potomac Edison Company		
Debt	Equity [1]	Total
	($000)	
$ 675,000,000	$ 672,620,087	$ 1,347,620,087
50.09%	49.91%	100.00%

West Penn Power Company		
Debt	Equity [1]	Total
	($000)	
$ 975,000,000	$ 971,464,871	$ 1,946,464,871
50.09%	49.91%	100.00%

Metropolitan Edison Company			Pennsylvania Electric Company			Jersey Central Power & Light Company		
Debt	Equity [1] ($000)	Total	Debt	Equity [1] ($000)	Total	Debt	Equity [1] ($000)	Total
$ 1,049,227,907	$ 1,074,695,802	$ 2,123,923,709	$ 1,298,762,690	$ 1,364,992,152	$ 2,663,754,842	$ 2,148,904,355	$ 3,793,187,034	$ 5,942,091,389
49.40%	50.60%	100.00%	48.76%	51.24%	100.00%	36.16%	63.84%	100.00%

UGI ELECTRIC EXHIBIT PMR-2R

	Debt	Equity [1]
	($000)	
Duquesne Light Company	47.12%	52.88%
Metropolitan Edison Company	48.15%	51.85%
PECO Energy Company	46.51%	53.49%
Pennsylvania Electric Company	49.02%	50.98%
Pennsylvania Power Company	50.65%	49.35%
PPL Electric Utilities Corporation	43.96%	56.04%
West Penn Power Company	51.24%	48.76%
Averge	48.09%	51.91%
Range		
High	51.24%	56.04%
Low	43.96%	48.76%

Note: [1] Excluding Accumulated Other Comprehensive Income

Source of Information: Pennsylvania Public Utility Commission 2022 Annual Report

UGI ELECTRIC EXHIBIT PMR-3R

NON-CONSTANT GROWTH DISCOUNTED CASH FLOW (DCF) - INDICATED COST OF EQUITY

(BASED ON VALUE LINE FORECASTS AND CLOSING STOCK PRICE)

RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
		Forecasted Dividends per Share					Growth	EPS	E/P	Closing Stock Price		Cash Flow From Buying and Selling Stock (At Closing Price)					
		2023	2024	2024	2025	2026	2023-26	3/31/26	3/31/26	3/31/2023	3/31/2026		2023	2024	2025	2026	IRR / DCF
		[A]	[A]	[B]	[B]	[A]	[B]	[C]		[D]	[E]	[F]	[F]	[F]	[F]	[F]	[G]
AMEREN	AEE	$2.52	NA	$2.76	$3.02	$3.30	9.41%	**$5.50**	**20.00**	$86.39	$110.00			$2.76	$3.02	$110.83	NA
AMERICAN ELEC. PWR.	AEP	$3.35	NA	$3.60	$3.87	$4.16	7.49%	**$6.80**	**18.00**	$90.99	$122.40		($88.48)	$3.60	$3.87	$123.44	14.43%
ALLETE	ALE	$2.71	NA	$2.80	$2.90	$3.00	3.45%	**$5.00**	**17.00**	$64.37	$85.00		($62.34)	$2.80	$2.90	$85.75	14.15%
AVISTA CORP.	AVA	$1.83	NA	$1.90	$1.97	$2.05	3.86%	**$3.00**	**20.00**	$42.45	$60.00		($41.08)	$1.90	$1.97	$60.51	16.77%
CMS ENERGY CORP.	CMS	$1.95	NA	$2.06	$2.18	$2.30	5.66%	**$3.75**	**17.50**	$61.38	$65.63		($59.92)	$2.06	$2.18	$66.20	5.72%
DOMINION ENERGY	D	$2.75	NA	$2.92	$3.11	$3.30	6.27%	**$5.00**	**17.50**	$55.91	$87.50		($53.85)	$2.92	$3.11	$88.33	21.43%
DUKE ENERGY	DUK	$4.06	NA	$4.14	$4.22	$4.30	1.93%	**$7.00**	**17.00**	$96.47	$119.00		($93.43)	$4.14	$4.22	$120.08	11.62%
CON. EDISON	ED	$3.24	NA	$3.39	$3.55	$3.72	4.71%	**$6.00**	**18.00**	$95.67	$108.00		($93.24)	$3.39	$3.55	$108.93	7.77%
EDISON INTERNAT'L	EIX	$2.95	NA	$3.12	$3.31	$3.50	5.86%	**$6.45**	**16.00**	$70.59	$103.20		($68.38)	$3.12	$3.31	$104.08	17.99%
EVERSOURCE ENERGY	ES	$2.71	NA	$2.95	$3.20	$3.48	8.69%	**$5.60**	**19.50**	$78.26	$109.20		($76.23)	$2.95	$3.20	$110.07	15.58%
ENTERGY CORP.	ETR	$4.30	NA	$4.52	$4.75	$5.00	5.16%	**$6.50**	**18.00**	$107.74	$117.00		($104.52)	$4.52	$4.75	$118.25	7.14%
EVERGY, INC.	EVRG	$2.53	NA	$2.69	$2.87	$3.05	6.43%	**$4.85**	**17.50**	$61.12	$84.88		($59.22)	$2.69	$2.87	$85.64	16.06%
HAWAIIAN ELECTRIC	HE	$1.44	NA	$1.49	$1.54	$1.60	3.57%	**$3.00**	**17.50**	$38.40	$52.50		($37.32)	$1.49	$1.54	$52.90	14.92%
IDACORP, INC.	IDA	$3.25	NA	$3.48	$3.73	$4.00	7.17%	**$6.30**	**19.50**	$108.33	$122.85		($105.89)	$3.48	$3.73	$123.85	7.59%
ALLIANT ENERGY	LNT	$1.81	NA	$1.96	$2.12	$2.29	8.16%	**$3.80**	**18.00**	$53.40	$68.40		($52.04)	$1.96	$2.12	$68.97	12.36%
MGE ENERGY INC.	MGEE	NA	NA	NA	NA	NA	NA	**NA**	**NA**	$77.67	NA		NA	NA	NA	NA	NA
NEXTERA ENERGY	NEE	$1.87	NA	$2.12	$2.41	$2.74	13.58%	**$4.40**	**24.00**	$77.08	$105.60		($75.68)	$2.12	$2.41	$106.29	13.89%
NORTHWESTERN	NWE	$2.56	NA	$2.60	$2.64	$2.68	1.54%	**$4.15**	**16.50**	$57.86	$68.48		($55.94)	$2.60	$2.64	$69.15	10.38%
OGE ENERGY CORP.	OGE	$1.70	NA	$1.75	$1.80	$1.85	2.86%	**$3.15**	**14.00**	$37.26	$44.10		($35.98)	$1.75	$1.80	$44.56	10.61%
PINNACLE WEST	PNW	$3.48	NA	$3.54	$3.60	$3.66	1.70%	**$5.70**	**17.50**	$79.24	$99.75		($76.63)	$3.54	$3.60	$100.67	12.53%
PORTLAND GENERAL	POR	$1.88	NA	$1.99	$2.11	$2.24	6.01%	**$3.65**	**18.50**	$48.89	$67.53		($47.48)	$1.99	$2.11	$68.09	15.51%
SOUTHERN COMPANY	SO	$2.78	NA	$2.88	$2.99	$3.10	3.70%	**$5.15**	**16.50**	$69.58	$84.98		($67.50)	$2.88	$2.99	$85.75	11.13%
WEC ENERGY GROUP	WEC	$3.12	NA	$3.33	$3.56	$3.80	6.79%	**$5.90**	**20.50**	$94.79	$120.95		($92.45)	$3.33	$3.56	$121.90	12.05%
XCEL ENERGY	XEL	$2.07	NA	$2.21	$2.36	$2.52	6.78%	**$4.25**	**20.00**	$67.44	$85.00		($65.89)	$2.21	$2.36	$85.63	11.36%
Maximum		$4.30	$0.00	$4.52	$4.75	$5.00	13.58%	$7.00		$108.33	$122.85	$0.00	($35.98)	$4.52	$4.75	$123.85	21.43%
Minimum		$1.44	$0.00	$1.49	$1.54	$1.60	1.54%	$3.00		$37.26	$44.10	$0.00	($105.89)	$1.49	$1.54	$44.56	5.72%
Median		$2.71	#NUM!	$2.80	$2.99	$3.10	5.86%	$5.00		$70.09	$87.50	#NUM!	($66.69)	$2.80	$2.99	$88.33	12.45%
Average		$2.65	#DIV/0!	$2.79	$2.95	$3.11	5.69%	$5.00		$71.72	$90.95	#DIV/0!	($68.79)	$2.79	$2.95	$91.73	$\boxed{12.77\%}$

Sources:

[A] Value Line: Most current data available at time of schedule preparation. 2026 data is VL forecast for 2025-27.

[B] Straight line interpolation based on Value Line data, assuming constant dividend growth for 2023-26.

[C] Value Line data

[D] EOD Data: Market Data as of March 31, 2023.

[E] Stock Price projected assuming constant Market to Book Ratio (Exhibit ALR-5, page 1) and using VL projected Book Value.

[F] Cash Flow from purchasing stock on April 1, 2023, receiving dividends through 2026, and selling on March 31, 2026.
Negative number in 2023 reflects cash outflow required to purchase stock.
Cash flow sources are 1) dividends and 2) proceeds of stock sale.
3 of 4 dividends assumed received in 2023 and 1 of 4 in 2026 based on purchase and sale date.

[G] Total return on equity to investor who purchased, held, and sold stock as described above,
assuming Value Line projections of Dividends and Book Value are correct and
assuming Stock Price grows at same rate as Book Value.
DCF result is an Internal Rate of Return computation made using the "IRR" function built into Microsoft Excel
based on projected cash flows from 2023 to 2026.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2022-3037368, et al.

UGI Utilities, Inc. – Electric Division

Statement No. 10-R

Rebuttal Testimony of
Sherry A. Epler

Topics Addressed: **Tariff Changes**

Dated: May 25, 2023

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Sherry A. Epler. My business address is 1 UGI Drive, Denver, PA 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Electric Statement No. 10, on January 27, 2023.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of Roger D. Colton (OCA St. No. 4) submitted on behalf of the Office of Consumer Advocate ("OCA"), specifically regarding the Company's proposed change to Rider C – Universal Service Program, which recovers universal service costs.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. No.

II. PROPOSED TARIFF CHANGES

Q. In your direct testimony, you, among other things, proposed changes to Rider C – Universal Service Program. Could you please summarize those proposed changes?

A. Yes. Rider C – Universal Service Program was revised so the Customer Assistance Program ("CAP") credit bad debt offset will be associated with the participants in excess of the number of CAP enrollees as of September 30, 2023, in place of the existing September 30, 2021 date (in the tariff). I noted in my direct testimony that this proposal is consistent with the establishment of the CAP enrollee figure in the last UGI Electric rate case at Docket No. R-2021-3023618.

Q. Did any parties oppose this proposed change?

A. No. In fact, OCA witness Colton agreed with the proposed change because "[a]greeing to set the offset threshold in this manner is reasonable." (OCA St. No. 4, p. 45.) Therefore, I believe the Commission should approve the Company's proposed changes to Rider C without modification.

III. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2022-3037368, et al.

UGI Utilities, Inc. – Electric Division

Statement No. 11-R

Rebuttal Testimony of

Daniel V. Adamo

Topics Addressed: **Past Rate Case Settlements**
USECP & EE&C Program Overview
USECP & EE&C Program Results
Bill Impact Analysis
Bill Burden Analysis
Customer Charge
LIURP Remedies & Funding

Dated: May 25, 2023

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Daniel V. Adamo. My current business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom and in what capacity are you employed?

A. I am employed by UGI Utilities, Inc. ("UGI"), as Vice President – Customer Relations. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric" or the "Company") and the Gas Division ("UGI Gas"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. Please briefly describe your responsibilities in that capacity.

A. In this position, I am responsible for managing all marketing, sales, community relations, communications, and the customer information center for UGI, as well as the customer accounting, credit and collections, customer outreach, and compliance departments. In this role, I oversee regulatory compliance with Chapter 14 of the Public Utility Code, 66 Pa.C.S. § 1401, *et seq.*, related consumer regulations, including Chapter 56 of the Pennsylvania Public Utility Code, 52 Pa. Code § 56.1, et seq., compliance with generally applicable consumer protection, collection, and consumer bankruptcy regulations, and the administration of all Universal Service Programs.

Q. What is your educational and professional background?

A. I graduated from Lehigh University in 1998 with a B.S. in Mechanical Engineering. I started my employment with UGI in 1998. My full resume is attached as UGI Electric Exhibit DVA-1R.

Q. Have you been involved in other proceedings before the Commission?

A. Yes. I testified on behalf of UGI Gas in its purchased gas cost filings in 2008 and 2009 as well as the Company's petition for approval of the Growth Extension Tariff ("GET Gas") Program in 2013. I also testified on behalf of UGI Gas in its 2019 Base Rate Case proceeding at Docket No. R-2018-3006814, its 2020 Base Rate Case proceeding at Docket No. R-2019-3015162, and its 2022 Base Rate Case proceeding at Docket No. R-2021-3030218. Further, I testified on behalf of UGI Electric in its 2021 Base Rate Case proceeding at Docket No. R-2021-3023618. Please see UGI Electric Exhibit DVA-1R for a complete listing of the proceedings in which I testified and their docket numbers.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Electric?

A. No, I did not.

Q. **Are you sponsoring any exhibits with your rebuttal testimony?**

A. Yes, I am sponsoring UGI Electric Exhibits DVA-1R through DVA-7R.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the direct testimony and exhibits of the Office of Consumer Advocate ("OCA") witness Roger D. Colton (OCA St. No. 4) and the Commission on Economic Opportunity ("CEO") witness Jennifer Warabak (CEO St. No. 1). My rebuttal testimony may not address every statement or claim made by Mr. Colton and Ms. Warabak in their direct testimonies. However, the lack of a response to any specific sentence, statement, claim or position of these witnesses does not in any way indicate my acceptance or approval thereof. Mr. Colton's testimony begins with 10 recommendations (OCA St. No. 4 at 4-5), all of which I rebut, except for his conclusion relating to UGI Electric witness Sherry A. Epler, which is addressed in UGI Electric St. No. 10-R (the rebuttal testimony of Sherry A. Epler). My rebuttal of Ms. Warabak is addressed separately in Section X below.

Regarding Mr. Colton's testimony, a summary of my opposition to his recommendations is offered below. Thereafter, I will offer detailed testimony in support of why his recommendations should be rejected.

1. Mr. Colton erroneously alleges that UGI Electric failed to comply with settlement terms from its 2018 and 2021 rate cases. Mr. Colton draws unsupported inferences and misinterprets the Company's discovery responses to reach this conclusion. Indisputable evidence demonstrates that the Company complied with these settlement terms.

2. UGI Electric's low-income and Energy Efficiency and Conservation ("EE&C") programs are performing very well, which demonstrates that Mr. Colton's proposed changes are unwarranted. For example, UGI Electric's Customer Assistance Program ("CAP") enrollments and participation are well above the industry average in Pennsylvania, the Company has seen significant growth in arrearage forgiveness, and UGI Electric is providing a greater amount of direct CARES benefits to its customers.

3. Mr. Colton's bill impact analysis is incorrect and overstated. Mr. Colton fails to recognize that the primary driver of the higher electric service bills are electric generation supply costs. Those costs reached their highest point in more than a

decade in 2022, due in large part to global natural gas supply market disruptions. Yet, Mr. Colton compares these time periods with increased electric generation supply costs to periods with low electric generation supply costs (namely, 2020, which was impacted by the COVID-19 pandemic) and then asserts that the Company's proposed base rate increase will unduly impact customer bills.

4. Mr. Colton's bill burden analysis is incorrect and misleading. Mr. Colton erroneously concludes that energy burdens for households at less than 50% Federal Poverty Level ("FPL") in UGI Electric's service territory were between 38% and 49% of income for heating customers and were between 22% and 23% of income for non-heating customers and that these will be much higher under proposed rates. Given that customers have the ability to participate in CAP, these energy burdens are more correctly stated as between 2% (non-heating) and 6% (heating) of income for households less than 50% FPL.

5. Mr. Colton errs by contending that the Company's proposed increase in the Residential customer charge from $9.50 to $13.50 will adversely affect low-income customers. As explained herein and in Mr. John D. Taylor's rebuttal testimony (UGI Electric St. No. 6-R), the Company's proposed rate structure will actually lower annual electric bills for the average use low-income customer.

6. Mr. Colton incorrectly asserts that the Company has been under-performing in controlling customer arrearages. Mr. Colton fails to perform an apples-to-apples comparison of UGI Electric's performance as compared to other Pennsylvania electric distribution companies ("EDCs"). When placed in the proper context, UGI Electric's collection activities for residential customers are better than the industry average. Further, UGI Electric agrees with Mr. Colton that budget billing is a tool that can help manage arrearages and has already assembled an internal team to evaluate potential improvements.

7. Mr. Colton's proposed "remedies" to address his concerns are meritless. If adopted, UGI Electric's Low-Income Usage Reduction Program ("LIURP") annual budget would increase by 344.24% from $298,379 to $1,027,128. Nothing presented by Mr. Colton establishes that this amount of increased spending is justified or reasonably attainable. Moreover, he fails to present any quantifiable data demonstrating that the alleged benefits of this increased spending would significantly offset these increased costs, all of which are borne by non-low-income residential customers.

Q. Do you have a general response to Mr. Colton's testimony?

A. Yes. Mr. Colton's testimony is premised on many unsupported statements, incorrect data points, and unsound methodologies. My testimony does not address these on an individual basis, because they are ultimately not relevant to the outcome of this base rate proceeding. The only concrete recommendations made by Mr. Colton in his testimony relate to the Company's current LIURP funding levels and program enrollment. LIURP is a Universal Service Program, and there is an entirely separate proceeding before the Commission to address LIURP. I am advised by counsel that the Commission has previously rejected recommendations to revise low-income and universal service programs in rate cases on the grounds that such proposals should be addressed in USECP proceedings. *See, e.g.*, *Pa. PUC v. PECO Energy Co.*, Docket Nos. R-2020-3018929, *et al.*, pp. 195-96 (Order entered June 22, 2021); *Pa. PUC v. Columbia Gas of Pa., Inc.*, Docket Nos. R-2020-3018835, *et al.*, pp. 160-61 (Order entered February 19, 2021). While Mr. Colton's testimony is flawed on an analytic basis, it should ultimately be rejected because it simply has no place in a base rate proceeding.

Q. Are there any other reasons that the Commission should reject the entire basis of Mr. Colton's testimony?

A. Yes. The recently enacted Inflation Reduction Act of 2022 provides for significant and material energy efficiency rebates, with the highest level of benefits being provided to the lowest income customers. As recently presented by Pennsylvania Department of Environmental Protection Acting Secretary Richard Negrin, Pennsylvania is slated to receive $258 million in funding from the Inflation Reduction Act ("IRA") that targets energy efficiency rebates across the Commonwealth. (*See* UGI Electric Exhibit DVA-2R, p. 14.) As these funds are distributed in Pennsylvania, including within UGI Electric's service territory, I would note that these programs will have a material impact as related to the "hurdle rate" Mr. Colton cites as a material barrier to low-income customer adoption of energy efficiency measures, as the largest rebate amounts under these programs are only available to lower income customers. (OCA St. No. 4 at 29.) It makes sense to prioritize the availability of this funding to enhance energy efficiency efforts across the Commonwealth and for utilities, like UGI Electric, to have EE&C, LIURP and other programs targeting energy efficiency adoption work in concert with the deployment of these funds. On a simple ratio basis, if the $258 million is allocated across Pennsylvania's 5.1 million households equally, UGI Electric's 55,000 residential customers will be targeted with approximately $2.8 million in new funding. ($258,000,000 / 5,100,000 x 55,000). Mr. Colton has not recognized the impact of this funding as part of his recommendations in this case and the Company would assert that this influx in funding, while providing material benefits to low income and other customers, will be a challenge in and of itself for deployment as associated contractor and supply chain impacts are realized. To ask UGI Electric to simultaneously ramp up funding for its current programs or change the targeted participation, without a comprehensive assessment of effectiveness in light of the substantial increase in federal funding, would only serve to exacerbate related challenges to deploy such funding. A summary of the specific programs and benefits which will be targeted by the $258 million in IRA funding can be found here: https://www.edf.org/article/8-ways-inflation-reduction-act-can-save-you-money.

II. <u>UGI ELECTRIC COMPLIED WITH ALL SETTLEMENT TERMS FROM ITS 2018 AND 2021 RATE CASES</u>

Q. OCA witness Colton makes several allegations about the Company's compliance with its obligations under the Partial Stipulation filed in the 2018 base rate case and the

Settlement filed in the 2021 base rate case, based on certain of the Company's responses to discovery requests in this proceeding. (OCA St. No. 4, pp. 37-44.) Based on these allegations, he recommends that the Company be directed to comply with these obligations and that the Company's alleged noncompliance be considered when the Commission is evaluating UGI Electric's proposed return on equity adder for strong management performance. (OCA St. No. 4, p. 44.) Do you have any overall observations?

A. Mr. Colton's allegations are meritless. As explained further below, UGI Electric complied with all of these settlement obligations. I note that the OCA never asked in discovery for the Company to explain how or whether UGI Electric complied with these settlement obligations. Instead, Mr. Colton drew mistaken inferences from UGI Electric's responses to discovery requests that did not mention these settlement obligations.

Q. Mr. Colton argues that UGI Electric failed to comply with Paragraph 68(d) of the 2021 base rate case settlement because the Company does not accept "verification of income eligibility 'by any community organization delivering public or private assistance'." (OCA St. No. 4, pp. 39-41.) Do you agree with Mr. Colton?

A. No. Mr. Colton bases this allegation entirely on UGI Electric's response to CAUSE-PA Set I, No. 3. (*See* UGI Electric Exh. DVA-3R.) Mr. Colton's conclusion is simply wrong. He overlooks that the Company said that it "assigns a 'confirmed low income' attribute to a customer when the customer confirms income-eligible status with a Community-Based Organization ("CBO") **and/or** the following criteria are met . . ." (emphasis added). As such, the Company designates a customer as confirmed low-income when a customer confirms income-eligible status with any CBO. The Company's designation of a customer as confirmed low-income is not dependent on the customer enrolling in CAP, receiving LIURP and weatherization services, receiving an Operation Share grant, or receiving a Low-Income Home Energy Assistance Program ("LIHEAP") Cash or Crisis payment, nor is it dependent on any specific type of CBO providing that information to UGI Electric. Thus, UGI Electric is and has been complying with Paragraph 68(d) of the 2021 base rate case settlement.

Q. Mr. Colton also claims that UGI Electric failed to comply with Paragraphs 68(a), 68(b), 68(f), and 68(g) of the 2021 base rate case settlement concerning CAP solicitations of customers who received LIHEAP and who self-reported Level 1 income. Additionally, he claims that the Company did not distribute written materials soliciting CAP participation and/or identify customers eligible for winter shutoff protections. (OCA St. No. 4, p. 41.) Is Mr. Colton correct?

A. No. Mr. Colton bases his conclusion solely on UGI Electric's response to OCA Set IV, No. 3. (*See* UGI Electric Exh. DVA-4R.) To clarify, UGI Electric complied with Paragraphs 68(a), 68(b), 68(f), and 68(g) as follows:

- **Paragraph 68(a) – "Perform a solicitation of customers who received LIHEAP in the prior 12 months for enrollment in the Company's CAP 2 times a year."**

  UGI Electric completed this solicitation on February 28, 2022. It was sent to 144 UGI Electric customers who received LIHEAP in the prior 12 months. The Company completed this solicitation again on December 6, 2022, and it was sent to 492 UGI Electric and 6,818 UGI Gas customers who received LIHEAP in the prior 12 months. Therefore, UGI Electric complied with its settlement obligation to perform this solicitation two times a year in 2022, and UGI Electric will continue to comply with that settlement obligation in 2023.

- **Paragraph 68(b) – "Perform a solicitation of customers who self-reported Level 1 income in the prior 12 months for enrollment in the Company's CAP 2 times a year."**

  UGI Electric completed this solicitation on March 1, 2022. It was sent to 3,102 UGI Electric customers who self-reported Level 1 income in the prior 12 months. The Company completed this solicitation again in May and July 2022, and it was sent to all UGI Electric and UGI Gas residential customers. Thus, UGI Electric complied with its settlement obligation to perform this solicitation two times a year in 2022, and UGI Electric will continue to comply with that settlement obligation in 2023.

- **Paragraph 68(f) – "Provide written materials, which solicit participation in UGI Electric's CAP and/or identification of customers eligible for winter shutoff protections, to: i. Public school districts in the Company's service territory, so that they can distribute the materials to school households with students eligible for the federal free and reduced school meals program; and/or Head Start programs; and ii. Community and faith-based food pantries, soup kitchens, and emergency shelters."**

  UGI Electric provided written materials as required under the settlement. Pursuant to Paragraph 68(f), UGI Electric provided the written materials to the school districts in UGI Electric's service territory, as well as a robust group of community and faith-based food pantries, soup kitchens, and emergency shelters via email and/or mail in early 2022. A list of the entities UGI Electric contacted and a representative sample of the communication and written materials is included with my testimony as UGI Electric Exh. DVA-5R. Therefore, UGI Electric complied with Paragraph 68(f) of the 2021 base rate case settlement.

- **Paragraph 68(g) – "Provide written CAP solicitation materials to be delivered by local and/or county offices delivering benefits through the federal Supplemental Nutrition Assistance Program ("SNAP") (Food Stamps), as well as through local Public Housing Authorities."**

  In August 2022, UGI Electric sent the CAP solicitation materials (as presented in UGI Electric Exh. DVA-5R to the executive directors of the following County Assistance Offices ("CAOs"), which deliver SNAP benefits and services: Adams, Bedford, Berks, Blair, Bradford, Bucks, Carbon, Centre, Chester, Clarion, Clearfield, Clinton, Columbia, Cumberland, Dauphin, Forest, Franklin, Fulton, Huntingdon, Jefferson, Juniata, Lackawanna, Lancaster, Lebanon, Lehigh, Luzerne, Lycoming, McKean, Mifflin, Monroe, Montgomery, Montour, Northampton, Northumberland, Perry, Pike, Potter, Schuylkill, Snyder, Susquehanna, Tioga, Union, Venango, Wayne, Wyoming, and York.

> Notably, UGI Electric's service territory only encompasses Luzerne and Wyoming Counties, but the Company sent the CAP solicitation materials to the executive directors of CAOs in many other counties. Indeed, UGI Electric consulted with the Pennsylvania Department of Human Services ("DHS") and sent the CAP solicitation materials to all of their suggested contacts to comply with this settlement obligation. Thus, UGI Electric complied with Paragraph 68(g) of the 2021 base rate case settlement.

Q. Mr. Colton also contends that UGI Electric failed to comply with Paragraph 68(e) of the 2021 base rate case settlement regarding contacting DHS administrators and deeming any household identified by the administrators as confirmed low-income. (OCA St. No. 4, pp. 41-42.) Do you agree with Mr. Colton?

A. No. Paragraph 68(e) stated that UGI Electric must:

> Contact administrators of applicable PA DHS public assistance programs, requesting that they ask DHS applicants enrolling in their public assistance programs to designate whether the DHS applicants want UGI Electric to be informed of their income eligibility for various customer service protections propounded by the Commission. Each household who the program administrators identify to UGI Electric as answering in the affirmative shall be deemed by UGI Electric as a Confirmed Low-Income customer and/or a customer eligible for winter shutoff protections. Normal income verification requirements maintained by the Company shall apply thereafter (for enrollment/participation in UGI Electric Universal Service programs).

UGI Electric has been in direct personal contact with DHS about this issue and made this specific request. In support, attached hereto as UGI Electric Exhibit DVA-6R is a true and correct copy of an email dated February 28, 2022, which was sent to UGI Electric by Brian Whorl, who is the Division Director, Federal Programs and Program Management at DHS. In his email, Mr. Whorl states that this information sharing will have to be addressed between DHS and the LIHEAP Advisory Committee, of which UGI Electric is a member. He also confirms that DHS will "not provide" information about a customer's receipt of benefits from other programs, such as Temporary Assistance for Needy Families ("TANF"), SNAP, and Medical Assistance ("MA" or "Medicaid").

In addition, I disagree with Mr. Colton's assumption that UGI Electric has not been in contact with DHS about this issue. In discovery, Mr. Colton stated that he is "aware of the efforts of various utilities to establish LIHEAP and Low-Income Household Water Assistance Program ("LIHWAP") data-sharing agreements with the Commonwealth's Department of Human Services." (UGI Electric Exh. DVA-7R.) UGI Electric is an active member of the LIHEAP Advisory Committee that is engaging in those efforts with DHS.

For these reasons, Mr. Colton's arguments that UGI Electric failed to comply with Paragraph 68(e) of the 2021 base rate case settlement should be dismissed.

Q. Mr. Colton further alleges that UGI Electric failed to comply with Paragraph 11(c) of the 2018 base rate case partial stipulation because the Company does not "accept self-certification of low-income status for purposes of identifying 'confirmed low-income customers' in the same way that self-certification is required to be accepted by the UGI gas affiliates." (OCA St. No. 4, pp. 43-44.) Is Mr. Colton correct?

A. No. First, to clarify, Mr. Colton is actually referring to Paragraph 11(b) of the 2018 base rate case partial stipulation, not Paragraph 11(c). Second, UGI Electric's self-certification practices are consistent with UGI Gas's practices. Thus, the Company has been and will continue to comply with Paragraph 11(b) of the 2018 base rate case partial stipulation.

Q. OCA witness Colton argues that UGI Electric's noncompliance with the settlement conditions discussed above should be considered by the Commission when "assessing UGI's request for an equity adder for strong company management." (OCA St. No. 4, p. 44.) Please respond.

A. As I explained in the prior section of my rebuttal testimony, Mr. Colton's allegations about UGI Electric's non-compliance with its settlement obligations completely lack merit. Therefore, his recommendation to deny UGI Electric's return on common equity adder for management performance on that basis should be rejected.

Q. In further support of his opposition to UGI Electric's proposed return on common equity adder, Mr. Colton disputes the Company's claim that UGI Electric has performed well in enrolling low-income customers, noting the arrearages for low-income customers and overall residential collections performance. (OCA St. No. 4, pp. 46-47.) Would you please respond?

A. Mr. Colton is incorrect to conclude that UGI's collections performance is "substantially worse than the performance of other Pennsylvania electric utilities" and "does not do a good job of using its budget billing plan to control arrearages" or to "assist customers who may be facing seasonable arrears" (OCA St. No. 4, pp. 47-54.) The facts are quite the opposite, as Section IX of my rebuttal testimony adequately details.

III. UGI ELECTRIC'S LOW-INCOME PROGRAM OVERVIEW

Q. Please describe UGI Electric's commitment to its customers.

A. UGI Electric is committed to providing support to all of its customers, and particularly to customers experiencing a financial hardship. The Company does this through a variety of programs and voluntary initiatives, and it has made tremendous strides in recent years in the number of low-income and payment troubled customers that it assists. Although there is always room for improvement, the Company continues to improve its processes and works collaboratively with low-income advocates to identify the changing needs impacting its service territory.

Q. How does UGI Electric help low-income customers save money and reduce energy usage?

A. The Company's *Universal Service & Energy Conservation Plan For the Five-Year Period January 1, 2020-December 31, 2025* ("USECP"), Docket Nos. M-2017-2598190 and M-2019-3014966, establishes the rules, terms, and conditions under which universal service and energy conservation programs and policies are administered to eligible customers. The USECP includes various programs that assist its low-income and payment troubled customers: Customer Assistance Program ("CAP"), Operation Share Energy Fund ("Operation Share"), Customer Assistance and Referral Evaluation Services ("CARES") and Low-Income Usage Reduction Program ("LIURP"). UGI Electric also actively encourages payment troubled and low-income customers to apply for Low-Income Home Energy Assistance Program ("LIHEAP") grants. Additionally, benefits are available to low-income customers through UGI Electric's Energy Efficiency and Conservation ("EE&C") Plan.

In addition, UGI Electric also assisted customers in receiving: (1) total Emergency Rental Assistance Program ("ERAP") assistance in the amount of $220,876 over the past three years; and (2) total PA Homeowner Assistance Fund ("PAHAF") assistance in the amount of $15,334 over the past two years.

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Q. What benefits does UGI Electric's CAP provide to qualifying customers?

A. A CAP customer is guaranteed to receive the most affordable bill based on the lower of percentage of income, the minimum bill, or the average bill. If a customer is on an average bill, it is because the average bill is lower than the percentage of income and higher than the minimum bill. However, if the average bill amount rises above the customer's percentage of income, the customer will qualify for the less expensive CAP rate (i.e., the percentage of income) and, therefore, is protected from rate increases. UGI Electric also does not establish a maximum CAP credit per customer.

UGI Electric utilizes CBOs to implement its CAP program. The CAP CBOs are responsible for: (1) referring participants to any other assistance, social, or governmental programs that may provide help for any other present needs; (2) monitoring each account monthly based on UGI Electric's prompted tasks, such as recertifications; and (3) providing energy education sessions to above average usage customers.

By Order entered June 16, 2022, at Docket Nos. M-2019-301499 and P-2020-3019196, the Commission approved UGI Electric's voluntary proposal to reduce the Percentages of Income ("PIP") for UGI Electric's Heating customers at 0% to 50% of the Federal Poverty Income Guidelines ("FPIG") from 7% to 6%, aligning UGI Electric's CAP program energy burdens with the Commission's policy statement concerning updated energy burdens for this lowest income category of customers.

Q. What benefits does Operation Share provide to low-income customers?

A. Operation Share provides assistance to electric customers in the form of grants up to $400. Operation Share grants are available to customers who experience unexpected circumstances affecting their ability to pay utility bills. Available hardship grants are funded by customer, employee, and public donations. Grants are provided to customers experiencing fixed or low incomes, unemployment, disabilities, or catastrophic or crisis situations. In total, there have been $256,532 of Operation Share contributions from the Company, its employees, and its customers over the past three years.

Q. What benefits does CARES provide to low-income customers?

A. CARES assists payment troubled customers by referring them to the appropriate program or agency to help address temporary situations causing an inability to pay. This program is geared toward customers with a sudden, immediate need, such as loss of income, loss of head of household, illness, or any other temporary situation resulting in an inability to pay. CARES is intended to be a short-term assistance referral program to guide a customer through a difficult time and to help inform and educate them about the available assistance. CARES also provides extensive LIHEAP outreach to help increase awareness of the program and encourage all eligible households to apply for grants, including ERAP and PAHAF grants.

Q. What benefits does LIURP provide to low-income customers?

A. LIURP consists of Weatherization and Rehabilitation Programs. The Weatherization Program helps reduce energy consumption for low-income customers through installation of conservation measures and education. Through the Rehabilitation Program, the Company funds the installation of energy efficient measures during construction/rehabilitation of low-income households.

Q. What benefits does the EE&C Plan provide to low-income customers?

A. UGI Electric's EE&C Plan[1] has programs that provide benefits available to low-income customers. EE&C measures are available to low-income customers through UGI Electric's Appliance Rebate, School Energy Education, Appliance Recycling, Residential Low-Income, and CBO Marketing programs.

IV. RESULTS OF UGI ELECTRIC'S LOW INCOME AND EE&C PROGRAMS

Q. How has UGI Electric performed in terms of its CAP participation rate in recent years?

A. UGI Electric performed well between 2019 and 2023, year-to-date ("YTD") as of April 30, 2023. Table 1 below shows UGI Electric's CAP enrollments and Confirmed Low-Income ("CLI") customers between 2019 and 2023.

Table 1: CAP Enrollment

Year	# CLI Customers on CAP	Total CLI Customers	% of CLI Customers on CAP
2019	2,796	4,670	60%
2020	3,205	4,959	65%
2021	3,236	4,641	70%
2022	2,986	5,162	58%
2023	3,492	5,656	62%
AVG.	**3,143**	**5,018**	**63%**

On average during this period, UGI Electric enrolled 63% of its total CLI customers in CAP with a high point of 70% enrollment in 2021. This data also shows that while CAP

[1] *Petition of UGI Utilities, Inc. - Gas Division for Approval of a Minor Change to Its Energy Efficiency and Conservation Plan*, Docket No. R-2018-3006814 (Jul. 23, 2021).

enrollments dipped slightly in 2022 (to 58% of total CLI customers), the participation rate is climbing back up (currently at 62%).

Q. How does UGI Electric's CAP Participation Rate compare with other Pennsylvania Electric Distribution Companies ("EDCs")?

A. UGI Electric compares quite well to other Pennsylvania EDCs. While UGI Electric's customer base is too small to be included in the Commission's Annual Universal Service and Collection Program Report ("Universal Service Report" or "Report"), the 2021 Report shows the CAP Participation Rates for other Pennsylvania EDCs. It provides a reasonable and relevant point of comparison. Table 2 below recites the participation rates for other EDCs from 2019 to 2021.

<u>**Table 2: CAP Participation Rates for Pennsylvania EDCs 2019-2021**</u>

CAP Participation – Electric Utilities – 2019-2021

Utility	2019		2020		2021	
	Participants Enrolled as of 12/31/19	CAP Participant Rate	Participants Enrolled as of 12/31/20	CAP Participant Rate	Participants Enrolled as of 12/31/21	CAP Participant Rate
Duquesne	35,853	74.1%	33,638	70.6%	35,229	73.2%
Met-Ed	13,043	17.7%	19,310	26.4%	21,280	36.7%
PECO-Electric	111,124	79.6%	114,735	84.6%	121,408	86.1%
Penelec	18,287	20.0%	25,345	28.1%	28,463	39.1%
Penn Power	3,976	19.7%	5,546	27.9%	6,281	38.9%
PPL	63,306	33.4%	65,862	34.0%	64,673	32.9%
West Penn	15,692	21.2%	22,591	30.0%	24,792	39.3%
Total/Industry Average	**261,281**	**41.0%**	**287,027**	**45.2%**	**302,126**	**50.7%**

As shown in Table 1, UGI Electric's CAP Participation rates of 60%, 65% and 70% for 2019, 2020 and 2021, respectively, are much higher than the Total/Industry Average rates of 41%, 45.2% and 50.7% for the same respective years. Accordingly, UGI Electric's CAP participation rate and enrollments are performing well above the industry average.

Q. Please explain the Company's recent Pre-Program Arrearage ("PPA") forgiveness results.

A. Table 3 below shows the total amounts of PPA forgiveness that CAP customers received between 2019 and 2022.

<u>Table 3: Pre-Program Arrearage Forgiveness, 2019-2022</u>

	2019	2020	2021	2022
PPA Forgiveness	$ 395,351	$ 453,317	$ 569,972	$ 535,657
PPA Customers	3200	3171	3429	3676

During this period, UGI Electric CAP customers received a total forgiveness of $1,954,297. This data shows that there was significant growth in the annual total of arrearage forgiveness.

Q. How has UGI Electric performed in terms of its CARES program in recent years?

A. UGI Electric has performed well in terms of direct dollars of CARES benefits provided to customers in addition to LIHEAP funds. For 2021, UGI Electric's CARES program provided total direct dollars of CARES benefits of $155,528.24. A significant portion of the CARES benefits include ERAP funding.

Q. How has UGI Electric performed in terms of its LIURP program?

A. UGI Electric has performed well compared to other Pennsylvania EDCs. Table 4 below shows the LIURP Electric Average Heating Job Costs between 2019 and 2021 as reported in the 2021 Report. UGI Electric's annual average spend per LIURP heating job between

2019 and 2021 was comparable to the largest Pennsylvania EDCs, considering the age of the housing stock in UGI Electric's service territory.[2]

Table 4: LIURP Avg. Heating Job Cost, 2019-2021

	2019	2020	2021
	Heating	Heating	Heating
Duquesne	$ 4,090	$ 1,400	$ 867
Met Ed	$ 4,206	$ 4,224	$ 4,301
PECO	$ 2,121	$ 3,739	$ 3,974
Penelec	$ 3,528	$ 4,021	$ 3,523
Penn Power	$ 4,137	$ 6,716	$ 6,059
PPL	$ 4,342	$ 4,461	$ 4,072
West Penn	$ 4,779	$ 5,095	$ 6,058
UGI Electric	**$ 4,751**	**$ 5,855**	**$ 5,978**

Table 5 below shows the LIURP Electric Average Baseload Job Costs between 2019 and 2021 as reported in the 2021 Universal Service Report. UGI Electric's annual spend per LIURP Heating job between 2019 and 2021 similarly was within the range of average baseload expenditures of other Pennsylvania EDCs.

Table 5: LIURP Avg. Baseload Job Cost, 2019-2021

	2019	2020	2021
	Baseload	Baseload	Baseload
Duquesne	$561	$869	$861
Met Ed	$2,199	$2,523	$2,988
PECO	$545	$750	$1,955
Penelec	$1,563	$1,990	$1,894
Penn Power	$1,442	$1,823	$2,358
PPL	$1,143	$1,036	$1,120
West Penn	$2,337	$3,207	$3,776
UGI Electric	**$1,144**	**$1,667**	**$1,223**

[2] Of the 134,132 total occupied housing units in Luzerne County, 98,912 (i.e., 73.74%) of them were built prior 1960. *See* https://data.census.gov/table?q=luzerne+county+pa+housing&tid=ACSST1Y2021.S2504.

Q. How has UGI Electric performed in terms of its LIHEAP program in recent years?

A. UGI Electric's LIHEAP program has performed exceptionally well in recent years, as shown in Table 6 below.

Table 6: LIHEAP Performance, 2019-2022

	LIHEAP Cash + Crisis (FY)	LIHEAP Cash + Crisis (FY)
2019	693	$ 236,291
2020	1,915	$ 797,667
2021	1,791	$ 925,363
2022	2,093	$ 1,801,373

While UGI Electric's total number of customers receiving LIHEAP grants increased by 302% since 2019, the total LIHEAP grant dollars increased by 762% since 2019.

Q. Please quantify the recent EE&C benefits provided to UGI Electric's low-income customers.

A. In 2022, UGI Electric provided 27 rebates to participating CLI customers through the appliance rebate programs, totaling $2,575. In 2023, UGI Electric provided 36 rebates to participating CLI customers, totaling $4,600. Moreover, over the past three years and excluding rebates, UGI Electric provided total EE&C benefits in the amount of $55,180 (for the installation of free heat pump water heaters and smart thermostats) to low-income electric customers.

V. MR. COLTON'S BILL IMPACT ANALYSIS IS INCORRECT AND OVERSTATED

Q. Did Mr. Colton review the history of UGI Electric's total bill values?

A. Yes. Mr. Colton reviewed the total residential non-heating bill (at 500 kWh) and residential heating bill (at 2,000 kWh) values effective January 31 of each year between 2013 and 2023 as reported in the Commission's Annual Rate Comparison Reports ("Rate Reports"). Then, Mr. Colton estimated the January 31, 2024 residential heating and non-heating bills. His estimates for 2024 assume that the Company's rate case proposal will be approved in its entirety.

Q. Do you think it was appropriate for Mr. Colton to begin his analysis in 2013?

A. No, I do not. The Company had a 20-year period where it did not file a base rate case, from 1998 to 2018. During that time, distribution rates and bills were relatively stagnant (i.e., at 1998 rates). Because the rates used in 2018 reflect distribution rates that were established in 1998 (25 years ago), they lack relevancy and, therefore, cannot be reasonably compared to rates and bills effective after the 2018 rate case. Thus, all the data presented in Mr. Colton's UGI Heating Bills and UGI Non-Heating Bills tables (OCA St. No. 4 at 7-8), prior to 2018, should be disregarded, including specifically his bill comparisons between 2016 and 2024.

Q. What other issues did you identify with his analysis?

A. Mr. Colton states, "In order to ensure that data from a different year is comparable, I rely on the PUC's definition presented in those reports for a typical heating consumption (2,000 kWh) and non-heating consumption (500 kWh)." (OCA St. No. 4 at 6.) The Introduction section for each Rate Report sets forth historically consistent "Electric Usage" values for each Residential customer type (i.e., a ceiling of 2,000 kWh and a floor of 500 kWh monthly usage). The Electric Usage values in the Rate Report that are applied to the rates for each utility are snapshots. These snapshots show what residential heating and non-heating bills would look like if a customer used 500 kWh or 2,000 kWh in January of the respective Rate Report year.

It is important to note that the rate examples shown in the applicable annual Rate Report are not representative of any other month in the year.[3] Accordingly, a residential heating customer is not defined by having a bill representative of 2,000 kWh each month. Similarly, a residential non-heating customer is not defined as using 500 kWh each month. Customer affordability cannot be determined by looking at bills during one month of each year. Therefore, Mr. Colton's analysis lacks comprehensiveness.

Moreover, the Electric Usage values, listed in the annual Reports, contain a disclaimer stating:

> These usage parameters are static figures implemented by the Commission that have been in use since the inception of the Report in order to facilitate an apples-to-apples comparison of rates and bill amounts across all utilities for all years. They do not represent a utility's average customer usage. If a reader desires such information, they should view the Average Residential Usage and Bill tables found in Section 1 of the Report.

Here, the Commission explains that while most of the data in the Rate Reports is provided at various usage levels during January, average annual bill data also is included in more

[3] It is also important to note that Mr. Colton did not obtain his January 2024 estimates from a Commission Rate Report. The 2024 annual Report will issue in April 2024. While he cites to no source for his January 2024 figures, the January 2024 estimated total bill figures in Mr. Colton's UGI Heating Bills and UGI Non-Heating Bills tables can be found in IV-D-1, which was included in UGI Electric's original rate filing.

summary fashion. Average bill data is more comprehensive than the January snapshots Mr. Colton relies upon.

Q. Do you have any other universal criticisms of Mr. Colton's analysis of the bill impacts of the Company's proposal?

A. Yes, I do. Mr. Colton's analysis looks at total bill impacts over time and does not distinguish the factors contributing to those bills. Specifically, his analysis lumps together base rate changes and generation supply cost changes. The cost of electric generation supply is the largest cost driver in UGI Electric's bills. However, this proceeding is focused exclusively on the Company's proposed adjustment to base rates. Mr. Colton's analysis makes no effort to isolate the impact that the change in base rates will have on customer bills.

Further, Mr. Colton's analysis does not acknowledge that there has been significant electric generation supply pricing volatility in the last four years. This volatility is outside the Company's control.[4] Wholesale generation supply costs were the least expensive in 2020, when the COVID-19 pandemic lockdown occurred. The cost of electric generation supply later hit its highest point in more than a decade in 2022, due in large part to global natural gas supply market disruptions. As of June 1, 2023, the generation supply costs for

[4] The PUC does not directly regulate prices for the generation portion of electric bills. Electric supply pricing is determined through the Company's procurement activity, which is done pursuant to its Default Service Plan ("DSP"). Generation costs reflected on a non-shopping customer's bill are adjusted based on the cost of obtaining the electric supply that non-shopping customers use. Generation prices are separate from the PUC-regulated rates that utilities charge for their distribution services – which cover the cost of operating and maintaining the infrastructure that delivers electricity to homes and businesses.

UGI Electric are set to decrease from $0.1254 to $0.11084 cents per kWh, or by 11.6%, compared to the rates in effect at the time of filing.[5]

VI. MR. COLTON'S BILL BURDEN ANALYSIS IS INCORRECT AND MISLEADING

Q. Why is Mr. Colton's bill burden analysis incorrect and misleading?

A. Mr. Colton includes numerous pages within his testimony calculating bill burdens relative to low-income customers served by UGI Electric in order to support numerous conclusions concerning bill affordability at current and proposed rates, as well as to discuss the hardships faced by low-income customers concerning affordability. Mr. Colton is also dismissive of the effectiveness of UGI Electric's CAP program by proclaiming that, "[i]n order for [CAP] participation to occur, UGI first needs to identify its low-income customers." (OCA St. No. 4 at 16.) However, what is truly missing from Mr. Colton's critique, is a focus on what CAP provides for the Company's lowest income customers. Specifically, for a UGI Electric heating customer who falls in the 0 to 50% FPL income range, the CAP percent of income payment is set at 6%; and for a non-heating customer who falls in the 0 to 50% FPL income range, the CAP percent of income payment is just 2%. UGI Electric's CAP program acts as safety net for qualifying low-income customers, and as demonstrated in Section IV of my testimony, the program works and has robust participation rates. Customers also have the ability to sign up for other universal service programs that UGI Electric makes available to low-income customers. These programs are designed to provide additional ways of alleviating the financial stress that low-income

[5] https://www.puc.pa.gov/press-release/2023/puc-alerts-consumers-of-june-1-electric-price-changes-urges-exploring-shopping-conservation-options-to-saveinpa

customers might experience in paying their utility bills if they were not eligible for the programs.

Thus, I disagree with Mr. Colton's conclusion that energy burdens for households at less than 50% FPL in UGI Electric's service territory were between 38% and 49% of income for heating customers and were between 22% and 23% of income for non-heating customers. I also disagree that these burdens will be much higher under proposed rates. Given that customers have the ability to participate in CAP, these energy burdens are more correctly stated as between 2% and 6% of income for households less than 50% FPL. The Commission should clearly recognize the red herring approach being taken by Mr. Colton, disregard his testimony, and reinforce messaging with customers, as UGI Electric does, that these programs are here to help those in demonstrated need.

Q. What Commission action does Mr. Colton encourage based on his bill impact and burden analyses?

A. Mr. Colton seeks for the Commission to lower UGI Electric's requested return on equity and refers to the testimony of OCA witness Aaron Rothchild on this point in OCA St. No. 2. Also, he generally states that his testimony supports OCA's other witnesses who respond to UGI Electric's requested revenue requirement, although he does not elaborate on the nature of that reliance. (OCA St. No 4 at 21.)

Q. Do you agree with Mr. Colton that the Commission should reduce UGI Electric's proposed return on equity or revenue requirement based on his bill impact and burden testimony?

A. No, I do not. As explained previously, Mr. Colton's analyses do not portray an accurate picture of the rate impact to customers, and UGI Electric has protections in place to address the impact of the proposed rate increase on its low-income customers.

VII. UGI ELECTRIC'S PROPOSED CUSTOMER CHARGE IS DESIGNED TO NOT ADVERSELY AFFECT LOW-INCOME CUSTOMERS

Q. How does Mr. Colton respond to UGI Electric's proposed customer charge?

A. Mr. Colton claims that UGI Electric's proposal to increase the current $9.50 per month Residential customer charge to $13.50 a month will adversely impact low-income customers. (OCA. St. No. 4 at 22.) He claims without evidence that "[i]t cannot be assumed that all customers who are income-eligible for CAP, but who do not participate, do not participate because they choose not to participate." (*Id.*) His statement lacks evidentiary support.

Next, he claims that a customer's decision not to participate in CAP could occur for any number of reasons. He provides theoretical examples at pages 22-23 of his direct testimony to try to support his claims. He calls his examples "information failures," as he speculates possible reasons why low-income customers may not apply for CAP. However, Mr. Colton proffers no evidence to support his claim that any information failures have occurred. Additionally, he claims without evidence that some low-income customers "cannot negotiate the administrative processes necessary to apply for the program." (OCA St. No. 4 at 23.) Then, he claims that CAP does not protect customers from the "harms of UGI's proposed increased customer charge." (*Id.*) While many of these claims lack support, low-income customers will be protected from the increased customer charge as explained in the rebuttal testimony of John D. Taylor (UGI Electric St. No. 6-R).

Q. Will UGI Electric's proposed customer charge impact the ability of low-income customers to invest in energy efficiency measures?

A. UGI Electric's low-income customers will continue to receive free weatherization services and conservation measures through LIURP and the EE&C plan. Mr. Colton testifies generally that low-income customers have difficulty investing in energy efficient appliances because, as he claims, low-income customers need a fast return on their investments (a 1-year payback). He refers to this as a "hurdle rate." (OCA St. No. 4 at 29.) Then, he claims that by increasing the customer charge, UGI Electric will increase the payback period (of efficient appliances) for low-income customers. (*Id.*)

I disagree with this analysis. As explained in the rebuttal testimony of John D. Taylor, the proposed rate structure will result in reduced bills on average for UGI Electric's low-income customers. Therefore, the proposed rate structure will not adversely affect low-income customers' ability to invest in energy-efficient devices. Moreover, the recently enacted Inflation Reduction Act provides for significant and material energy efficiency tax credits and rebates, with the highest level of benefits being provided to the lowest income customers. A summary of the programs and benefits can be found here: https://www.edf.org/article/8-ways-inflation-reduction-act-can-save-you-money. As these programs roll-out, UGI Electric will integrate related messaging to its customers, as these programs stand to provide material benefits to targeted consumer groups.

VIII. MR. COLTON'S PROPOSED REMEDIES ARE UNWARRANTED.

Q. Does Mr. Colton propose remedies for UGI Electric to implement based on his perceived harms of the customer charge to low-income customers?

A. Yes, he does. He claims that his proposed remedies, which would collectively increase the Company's annual LIURP budget substantially, are in response to this proceeding's alleged adverse impact on low-income customers. (*Id.*)

Q. Before addressing these proposals in detail, do you have any overall concerns with modifying the Company's Commission-approved USECP through this base rate case?

A. Yes. I do not believe it is appropriate to address the funding of the Company's LIURP within the context of this base rate case. I am advised by counsel that the Commission has previously rejected recommendations to revise low-income and universal service programs on the grounds that such proposals should be addressed in USECP proceedings. *See Pa. PUC v. PECO Energy Co.*, Docket Nos. R-2020-3018929, *et al.*, pp. 195-96 (Order entered June 22, 2021); *Pa. PUC v. Columbia Gas of Pa. Inc.*, Docket Nos. R-2020-3018835, *et al.*, pp. 160-61 (Order Entered February 19, 2021). Moreover, in PPL Electric Utilities Corporation's 2012 base rate case, CEO proposed to increase the annual funding for the company's LIURP. *See Pa. PUC v. PPL Elec. Utils. Corp.*, Docket Nos. R-2012-2290597, pp. 48-51 (Order entered Dec. 28, 2012). The Commission rejected that proposal, finding that "all aspects of USPs" should be addressed "through the triennial filing process and to collect all revenues through a rider to base rates." *Id.*, p. 51. Therefore, consistent with these prior findings, the Commission should deny Mr. Colton's attempt to modify the Company's USECP through this base rate case. These issues are best addressed in the context of UGI Electric's USECP proceeding, where OCA and any other interested stakeholder can be heard on the appropriate amount of funding for LIURP.

Q. What is Mr. Colton's first proposed remedy?

A. Mr. Colton first proposes that UGI Electric have part of its LIURP directed at non-heating electric customers. (OCA St. No. 4 at 33.) Specifically, he recommends that UGI Electric complete baseload LIURP jobs for 66 non-heating households at a total incremental annual cost of $132,000. (*Id.* at 35.) This would be incremental to UGI Electric's existing annual LIURP budget of $298,379. According to Mr. Colton, UGI Electric excludes non-heating customers from baseload LIURP jobs. (*Id.*) He surmises this based on UGI Electric's Attachment OCA-IV-44, which showed that between October 2021 and September 2022, the average monthly usage for non-heating customers was 743 kWh.

Q. Do you agree with Mr. Colton's first proposed remedy?

A. No. Mr. Colton was wrong to conclude that UGI Electric does not perform LIURP jobs for non-heating customers. In particular, my Table 5 (LIURP Average Baseload Job Cost) demonstrates that UGI Electric dedicates an important component of its annual LIURP budget to baseload, non-heating customers. Therefore, the premise on which his recommendation is based lacks factual support.

Q. What is Mr. Colton's second proposed remedy?

A. Mr. Colton recommends that UGI Electric perform an additional 66 LIURP jobs for heating customer households. This is in addition to the Company's existing annual budget of

$298,370 for 66 LIURP jobs a year. In essence, Mr. Colton wants UGI Electric to double its total annual LIURP jobs and budget.

I have one point of clarification to Mr. Colton's testimony here. He states that between 2014 and 2016, UGI Electric performed 71 electric LIURP projects per year. (OCA St. No. 4 at 35.) A review of the Company's *USECP for the Period January 1, 2014 through December 31, 2019*, Docket No. M-2013-2371824 (Appendix A-16) shows that UGI Electric's annual LIURP budget was $124,750 for a projected 30 electric LIURP jobs per year. Therefore, Mr. Colton is incorrect when he states: "Through its LIURP, UGI currently has budgeted for a treatment of 66 homes each year for the years 2023 through 2025. (UGI USECP, at 30). That is a reduction from the 71 LIURP jobs per year in 2014 through 2016." (OCA St. No. 4 at 35.) UGI Electric's current projection to perform 66 electric LIURP jobs per year is not a reduction from its prior USECP; it is an increase of 36 additional electric LIURP jobs each year.

Regardless, Mr. Colton projects that if UGI Electric continued performing 66 LIURP jobs a year for the next 20 years, the Company would weatherize 1,320 homes. (*Id.*) Mr. Colton's recommendation fails to provide any justification or analysis to support the effectiveness of increasing the number of LIURP jobs. Further, he fails to show whether this level of acceleration is necessary or sustainable. The number/cost of LIURP jobs will be an open topic in the Company's next USECP proceeding and does not need to be addressed here.

Next, he makes an alternative 15-year projection. He claims that "[i]f, however, UGI would double its heating job production, and assuming that low-income homes have electric heating in the same proportion as all UGI customers have electric heating (20%, OCA-IV-I-1), it could serve its low-income customer heating base in just over 15 years." (*Id.*) Again, there will be multiple USECP proceedings during such a time where the Company's LIURP program will be reviewed to determine future plans. Moreover, the number of customers qualifying for LIURP benefits will likely change over 15- and 20-year periods. These are the kinds of variables that make Mr. Colton's predictions questionable and reinforce the Company's periodic USECP proceedings as being the proper venue for review and updates.

Q. What is his third proposed remedy?

A. Mr. Colton proposes that UGI Electric incorporate an additional 27 LIURP jobs aimed at customers within 151-200% FPL. (OCA St. No. 4 at 35-36.) He states this will require an additional increase of $298,379 to the annual LIURP budget. (*Id.*)

Q. What is the Company's view of this recommendation?

A. As stated above, the Company's periodic USECP proceedings are the proper venue for review and updates.

Q. What final observations does Mr. Colton make regarding his three proposed remedies?

A. Mr. Colton relies on the Long Term Study of Pennsylvania's Low Income Usage Reduction Program: Results of Analyses and Discussion, which was created in January 2009 ("2009 Study"). The data it includes and the conclusions it makes are dated. Most importantly, the results of the study that Mr. Colton relies upon are not as clear cut as he makes them out to be. The Study explains:

> First, the average energy bill arrearage declines from the pre- to post-period. Second, ***it is not possible to assess how much of this reduction LIURP is directly responsible for. This is because part of the LIURP process is to recommend to, and enroll eligible households in payment assistance plans whenever possible, and the variables collected as part of LIURP are not specific enough to separate the impact of weatherization measures from the impact of payment assistance on reduced arrearages.*** For this reason, we can only look at general trends with regard to arrearage amounts. (Study at 39, emphasis added).

While the 2009 Study found a decline in arrearages post-weatherization, it could not determine the extent to which the decline was directly related to weatherization measures and/or other variables (e.g., CAP enrollment, payment plans, budget billing, changes in the number of household occupants, etc.). Therefore, I caution against relying on this study to increase LIURP spending because there are just too many other non-weatherization variables at play. Based on the results shown above in Section III of my rebuttal testimony, the overall efforts of UGI Electric's Universal Service programs in totality are providing significant benefits.

Q. According to Mr. Colton, 37% of electric LIURP recipients reduced their arrearages per the 2009 Study. (OCA St. No. 4 at 37.) He also states that in the year following the implementation of LIURP measures, arrearages declined by 12% per the 2009 Study. (*Id.*) Please respond.

A. As stated above, Mr. Colton is attempting to tie the total percent arrearage reductions in the 2009 Report to LIURP measures. However, the 2009 Study cautioned against making such conclusions based on the impact that non-LIURP variables play in reducing customer arrearages.

Q. What does Mr. Colton conclude regarding all of his proposed LIURP remedies?

A. He states that there will be a short-term cost increase to non-low-income customers. (*Id.*) He claims the overall cost increase will be reduced by resulting improvements to credit and collection costs, bad debt expense, and working capital. (*Id.*)

Q. Do you agree with Mr. Colton?

A. I do not. I set forth the total annual LIURP cost increase that would occur if the Commission adopted Mr. Colton's proposed remedies in Table 7 below.

<u>Table 7</u>

	Remedy 1	Remedy 2	Remedy 3	Total Incremental
Additional Jobs	66	66	27	159
Budget Increase	$ 132,000	$ 298,370	$ 298,379	$ 728,749

Accordingly, if approved, UGI Electric's LIURP budget would increase from $298,379 (current budget) to $1,027,128 (i.e., Current Budget of $298,379 + Incremental Budget of $728,749 = $1,027,128). This would increase the total annual LIURP budget by 344%. This increase does not include any predicted costs associated with the Company having to hire additional weatherization contractors to perform such a large increase in the volume of work.

In addition, Mr. Colton failed to present a specific, credible, quantifiable analysis showing that all, or at least most, of the $728,749 would be offset by improvements to credit and collection costs, bad debt expense, and working capital. Given that we know the significant costs associated with his proposal (i.e., increase in total annual LIURP budget by 344.24% from $298,379 to $1,027,128) and that those costs would be entirely borne by non-low-income residential customers, it would be unjust and unreasonable to adopt Mr. Colton's recommendation without specific, credible, quantifiable evidence on the "offset" of those costs. Also as stated previously, significant IRA funding will be flowing into the service territory for energy efficiency measures in particular targeted at lower income customers.

IX. ARREARAGES AND BUDGET BILLING

Q. What claims does Mr. Colton make regarding customer arrearages?

A. Mr. Colton asserts that "high burdens impede the ability of low-income customers to sustainably pay their bills." (OCA St. No. 4 at 17.) As support, Mr. Colton relines on data that UGI Electric provided to OCA in response to OCA-IV-8 and OCA-IV-9, which requested arrearage data in time buckets (i.e., 0-30 days, 31-60 days, 61-90 days, and 90+ days), and claims that "over that 29 month period (October 2020 through February 2023), confirmed low-income customers are consistently in greater payment difficulty." (*Id.*)

Q. Do you agree with Mr. Colton's analysis and conclusion?

A. No. There is a significant amount of variability as collection activity progresses through these periods. Moreover, the Commission's Annual Universal Service Program & Collections Performance Report does not collect or report data in this fashion. Therefore, a different, more standardized industry review was warranted to review arrearages, which I conducted.

Indeed, the following tables show the Commission's Annual Universal Service Program & Collections Performance Report for 2021 as compared to UGI Electric for the same period of time and data as required by the Commission. Table 8 shows arrearages for all Residential customers and demonstrates that while the industry average of all residential arrears for Pennsylvania EDCs was $859.74, UGI Electric's average residential arrears was $653.31 (i.e., 24.01% lower than the industry average). This shows that UGI Electric's collection activities for its Residential customers are better than the industry average.

Table 8

2021 Average Arrears - Residential Electric

Utility	Avg Arrears on Arrangement	Avg Arrears Not on Arrangement	Overall Avg Arrears
Duquesne	$1,153.30	$386.80	$609.96
Met-Ed	$1,392.37	$414.04	$802.59
PECO-Electric	$908.74	$572.77	$687.94
Penelec	$1,520.54	$424.18	$849.14
Penn Power	$1,586.25	$456.38	$892.76
PPL	$949.17	$551.25	$696.17
West Penn	$1,600.58	$428.68	$859.74
Total/ Industry Average	$1,157.06	$502.12	$859.74
UGI - Electric	$1,132.10	$320.19	$653.31

Table 9 below shows arrearages for confirmed low-income customers and demonstrates that while the industry average of confirmed low-income arrears for Pennsylvania EDCs was $1,096.68, UGI Electric's average confirmed low-income arrears was $1,092.33 (i.e., a 0.40% reduction). Thus, UGI Electric's collection activities for its low-income customers is in line with the industry average.

Table 9

2021 Average Arrears - Residential Electric (CLI)

Utility	Avg Arrears on Arrangement	Avg Arrears Not on Arrangement	Overall Avg Arrears
Duquesne	$1,293.88	$740.92	$964.91
Met-Ed	$1,608.35	$615.87	$1,025.41
PECO-Electric	$1,564.98	$1,838.86	$1,679.33
Penelec	$1,696.58	$593.31	$1,039.88
Penn Power	$1,756.69	$655.92	$1,113.14
PPL	$1,024.12	$1,155.73	$1,105.75
West Penn	$1,822.44	$636.74	$1,103.58
Total/ Industry Average	$1,454.39	$856.74	$1,096.68
UGI - Electric	$1,168.02	$568.67	$1,092.33

Q. What does Mr. Colton conclude regarding the percentage of residential customers that had an arrearage as compared to the industry average?

A. According to Mr. Colton, UGI Electric's collections performance is substantially worse than the performance of other Pennsylvania EDCs. (OCA St. No. 4 at 47.) Specifically, he claims that 23% of UGI Electric's residential customers had an arrearage as compared to the statewide average of 10% for Pennsylvania EDCs. (*Id.*)

Q. Do you agree with Mr. Colton?

A. No. Mr. Colton is comparing different statistics here. He compares the Percent of Billed Residential Accounts Having Arrears as reported in OCA-IV-42 of 23% (which is not based on an average) to the Average Total Dollars in Debt of 10% (as reported in the Annual Report). In addition, the arrearage periods are different. The Commission's Annual Reports require utilities to report debt that is at least 30 days overdue. This is the reason why the comparison appears so different. I endeavored to bring uniformity, so that the results can be compared on more apples-to-apples basis. Table 10 below compares the Average Total Dollars in Debt for UGI Electric to the industry average.

Table 10

Residential Electric Customers in Debt - 2021

Utility	On Arrangement		Not on Arrangement		Total in Debt	
	Number	% of Customers	Number	% of Customers	Number	% of Customers
Duquesne	10,292	1.9%	25,058	4.6%	35,349	6.5%
Met-Ed	19,723	3.9%	29,938	5.8%	49,662	9.7%
PECO - Electric	40,421	2.7%	77,497	5.1%	117,918	7.8%
Penelec	20,906	4.2%	33,029	6.6%	53,935	10.7%
Penn Power	5,131	3.5%	8,154	5.5%	13,285	9.0%
PPL	65,908	5.3%	115,070	9.2%	180,979	14.5%
West Penn	21,049	3.3%	36,176	5.7%	57,225	9.0%
Total/Industry Avg	183,430	3.6%	324,923	6.4%	508,352	10.0%
UGI Electric	2,296	4.2%	3,301	6.0%	5,597	10.2%

Table 10 above shows that the Average Total Dollars in Debt for UGI Electric's residential customers is 10.2%, which is in line with the industry average of 10% contained in the Commission's Annual Report. Therefore, Mr. Colton incorrectly concludes that UGI Electric's collection performance is worse than other Pennsylvania EDCs.

Q. What does Mr. Colton allege regarding his comparison of UGI Electric's mean and median arrearages for Residential customers?

A. He claims that UGI Electric's mean Residential arrearages are twice as high as the median for Residential arrearages. (OCA St. No. 4 at 47.)

Q. Please respond.

A. Again, the Commission's Annual Reports identify average arrears for all residential customers. The following Table 11 provides an accurate comparison to the performance of customer arrearage for 2021 versus other EDCs. The average arrearage for UGI Electric is $653.31 versus the industry average arrearage of $859.74. Thus, the average arrearage for UGI Electric's residential customers is 24% lower than the industry average with only one EDC having a lower balance.

<u>Table 11</u>

2021 Average Arrears - Residential Electric

Utility	Avg Arrears on Arrangement	Avg Arrears Not on Arrangement	Overall Avg Arrears
Duquesne	$1,153.30	$386.80	$609.96
Met-Ed	$1,392.37	$414.04	$802.59
PECO-Electric	$908.74	$572.77	$687.94
Penelec	$1,520.54	$424.18	$849.14
Penn Power	$1,586.25	$456.38	$892.76
PPL	$949.17	$551.25	$696.17
West Penn	$1,600.58	$428.68	$859.74
Total/ Industry Average	$1,157.06	$502.12	$859.74
UGI - Electric	$1,132.10	$320.19	$653.31

Q. What position does Mr. Colton take regarding the usefulness of UGI Electric's budget billing tool to control arrearages?

A. Mr. Colton provides in-depth analysis to show that the Company's budget billing tool is not helping customers to lower balances. (OCA St. No. 4 at 48-54.) UGI Electric agrees that this is an area of focus for improvement, so that budget billing can be utilized as a tool for customers to manage their energy bills. Moreover, the Company has already assembled an internal team that is reviewing budget billing trends and evaluating what can be done to improve this tool. Therefore, the Company is working to manage this trend.

Q. Do you have any point of clarification regarding budget billing?

A. Yes. Mr. Colton refers to UGI Electric's response to OCA-IV-19(c) and states: "UGI responded 'The Company does not permit a delinquent account to enter into a levelized budget billing plan.'" (OCA St. No. 4 at 53.). I reviewed Mr. Colton's testimony on this point and have one clarification. If a delinquent customer contacts the Company and qualifies for a payment agreement, the customer will receive a set monthly installment for the overdue balance and will go on budget billing for their current charges (in tandem with the payment arrangement).

X. <u>REBUTTAL OF CEO WITNESS MS. WARABAK</u>

Q. To what extent does CEO oppose UGI Electric's proposed Residential customer charge?

A. Specifically, CEO challenges UGI Electric's proposal to raise its customer charge[6] needed to recover its increasing costs to manage and support the safe and reliable operation and maintenance of the distribution system for customers. (CEO St. No. 1 at 3.) Ms. Warabak's reasons for challenging the customer charge are twofold: (1) the Company is not proposing any increased funding to its Universal Service Programs; and (2) any increase to the customer charge will negatively impact conservation efforts by low-income customers. (*Id.*)

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[6] The Company's proposal to increase its fixed customer charge is consistent with its need to recover unavoidable costs to serve each customer. As the Commission has explained, "the customer charge generally covers the cost of billing and collections, meters and services, meter reading, depreciation expenses and return on the meters and services and a portion of administrative and office expenses." *Pa. PUC v. Honesdale Consolidated Water Co.*, Docket No. R-00953501 (Order entered Jan. 22, 1997). I note that these expense types are needed to maintain the Company's Universal Service programs to continue providing important benefits to low-income customers.

Q. Please respond to Ms. Warabak's concerns regarding the increased customer charge without any concurrent budget increases to Universal Service programs.

A. UGI Electric's LIURP and EE&C programs are providing benefits to low-income customers and will continue to do so (under the new customer charge). Also, Mr. Taylor's rebuttal explains that average-use low-income customers will save based on the proposed rate structure, which removes the impact of the customer charge from their bills. Accordingly, there is still tremendous incentive and opportunity for customer conservation efforts to lower a customer's total bill.

Q. What specific LIURP increase does Ms. Warabak propose?

A. Ms. Warabak proposes to increase the annual LIURP budget "by the commensurate increase in rates to residential customers that result from this proceeding." (CEO St. No. 1 at 6.) She also requests that UGI Electric make a contribution to its Hardship fund similarly in an amount commensurate to the approved increase in the residential rate. (*Id.* at 7.) Finally, Ms. Warabak recommends that the Company "continue to partner with the CBOs that "it has traditionally employed to provide LIURP services to its customers. (*Id.* at 6.)

Q. Please respond to all of Ms. Warabak's requests.

A. Increases to LIURP and Operation Share are not required because the Company's rate design protects low-income customers from the proposed customer charge change. Mr. Taylor's rebuttal explains how low-income customers will be protected from the customer charge increase.

Finally, although I agree that CBOs play an important role in the management of the Company's LIURP, I do not agree that the Company should be directed to only utilize CBOs for LIURP. It is the Company's experience that CBOs have limited resources and handle weatherization projects for both the Department of Human Services and Pennsylvania utilities. If CEO's concern is to maximize the number of LIURP jobs completed per year, the Company should be encouraged to investigate opportunities to do so, whether or not the LIURP agency is a CBO or a for-profit agency.

XI. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI ELECTRIC EXHIBIT DVA-1R

Daniel V. Adamo
Vice President Customer Relations

Work Experience

UGI Utilities, Inc., Reading, PA

August 2021 – Current	Vice President Customer Relations
August 2018 – July 2021	Director Customer Service
January – August 2018	Senior Manager Billing & Compliance
2016 – 2018	Functional Lead – UNITE Project
2015 – 2016	Manager Operations
2013 – 2015	Director Marketing (Programs and Strategy)
2011 – 2013	Business Development Director
2009 – 2011	Regional Marketing Manager
2007 - 2009	Manager Rates
2005 - 2007	Project Engineer Gas Supply
2004 – 2005	Project Engineer Key Accounts
2001 – 2004	Staff Engineer New Business
2000 – 2001	Customer Service Supervisor
1998-2000	Engineer 1

Previous Testimony

UGI Penn Natural Gas Purchased Gas Cost Filing: Docket No. R-2008-2039284 2009

UGI Penn Natural Gas Purchased Gas Cost Filing: Docket No. R-2009-2105904 2009

UGI Central Penn Gas Purchased Gas Cost Filing: Docket No. R-2009-2105909 2009

UGI Utilities – Gas Division Purchased Gas Cost Filing: Docket No. R-2009-2105911

UGI Growth Extension Tariff Pilot Programs Filing: Docket No. P-2013-2356232

UGI Utilities, Inc. Gas Division Base Rate Increase Filing: Docket No. R-2018-3006814

UGI Utilities, Inc. Gas Division Base Rate Increase Filing: Docket No. R-2019-3015162

UGI Utilities, Inc. Electric Division Base Rate Increase Filing: Docket No. R-2021-3023618

UGI Utilities, Inc. Gas Division Base Rate Increase Filing: Docket No. R-2021-3030218

Education

B.S. in Mechanical Engineering from Lehigh University, 1998

UGI ELECTRIC EXHIBIT DVA-2R

Infrastructure and Investment Jobs Act
and Inflation Reduction Act Funding:

Clean Energy and Climate Focused Programs

April, 25, 2023

Josh Shapiro, Governor

Richard Negrin, Acting Secretary

Agenda

- Overview: Bipartisan Infrastructure Law (BIL or IIJA)
- Overview: Inflation Reduction Act (IRA)
- Energy Funds Overview
  - Formula - EPO
  - Competitive - EPO
  - Other Funding Opportunities
    - Big Stuff
    - Industry Stuff
    - Grid Stuff
    - Community Stuff
    - Potpourri

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BIL & IRA

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Federal Guidance

Clean energy and climate priorities for BIL and IRA:

- Invest in American manufacturing and workers.
- Expand access to energy efficiency and clean energy for families, communities and businesses.
- Reduce greenhouse gas emissions significantly by 2030.
- Deliver reliable, clean, and affordable power to more Americans.
- Build the technologies of tomorrow through clean energy demonstrations.

Spending requirements:

- Buy American
- Davis Bacon Act – Contractors and subcontractors must pay local prevailing wage
- National Environmental Policy Act – Assess environmental impacts of projects
- Historic preservation – Identify, evaluate, and preserve archaeological and cultural resources
- Justice 40 – 40% of funding impact dedicated to benefit Environmental Justice neighborhoods

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Bipartisan Infrastructure Law

Signed into law on November 15, 2021

Allows for $1.2 trillion in government spending:

Major Areas of Investment Include:

- Transportation
- Electric Vehicles
- Legacy Pollution
  - Abandoned Mine Reclamation
  - Abandoned Oil and Gas Well Plugging
  - Brownfields
- Clean Water
- Broadband and Digital Equity
- Clean Energy

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Bipartisan Infrastructure Law

Energy Programs Office: Receiving approximately $67 million in formula funding:

- Predetermined and noncompetitive, but must be applied for and approved.
- Can be used for existing or new energy/climate programs managed by EPO, provided as subgrants for local government or nonprofit energy efficiency programs, or invested in clean energy/energy efficiency revolving loan programs.

Required objectives:

- ➢ Invest in environmental justice communities to reduce energy burden.
- ➢ Expand access to energy efficiency solutions and measures for families, communities, and businesses.
- ➢ Increase the generation of reliable, clean, and affordable power.
- ➢ Deploy clean and resilient energy infrastructure to combat the effects of climate change.
- ➢ Develop a clean energy workforce and manufacturing capabilities.

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Inflation Reduction Act

Signed into law on August 16, 2022

Largest Investment into addressing climate change in history

- Provides **$369 billion** in spending on energy and climate change

Projected to reduce GHG emissions to 40% below 2005 levels by 2030

- IRA and IIJA together could reduce emissions by 1,000 million metric tons or about a gigaton in 2030

A launching pad for long-term GHG reductions

- Investments in new technologies will drive emissions toward **net-zero by 2050**

Major Areas of investment include:

- GHG Reduction, Climate, Environmental Justice via
  - Transportation
  - Buildings
  - Clean Energy Development
  - Tax Credits

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Inflation Reduction Act

Energy Programs Office: Receiving over $261 million formula funds:

- Predetermined and noncompetitive, but must be applied for and approved.
- Formula funds are for a new, prescribed, Residential Efficiency Program (energy efficiency and electrification)

Required Objectives:

- Invest in environmental justice communities to reduce energy burden.
- Expand access to energy efficiency solutions and measures for families, communities, and businesses.
- Increase the generation of reliable, clean, and affordable power.
- Develop a clean energy workforce and manufacturing capabilities.
- Plan for and support the deployment of the technologies of tomorrow to reduce GHGs.

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DEP-EPO Investment Status Report

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Clean Energy-Related Funding Groups

Delivery mechanisms for clean energy funding

1. **Formula grants to state energy offices:** DEP Energy Programs Office is the only recipient and identifies uses (within a list of broad categories).

2. **Eligible competitive grant programs:** DEP Energy Programs Office and partners are eligible to apply for specific subject areas.

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Formula Grant to State Energy Office

State Energy Program: **(IIJA - DOE)**

- **$14 million** to implement programs and initiatives to address energy efficiency and renewable energy sources—energy security and resilience planning, industry, buildings, transportation, electric power and renewable energy, energy education, policy, and planning.

• ALRD issued	3/23/2022	
• Initial Application	5/3/2022	(submitted)
• Full Application Due	9/30/2022	(submitted)
• DOE Award Date	X/XX/2023	(did not receive award yet)

What's in the Application:

✓ Planning for implementing energy efficiency and energy management systems for equitable outcomes.

✓ Shared Energy Manager for Local Communities w/emphasis on EJ

✓ Clean Energy Infrastructure Deployment Projects

✓ Energy Security/Energy Assurance Planning/Duties/Exercises

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Formula Grant to State Energy Office

Energy Efficiency Revolving Loan Fund: (IIJA – DOE)

- **$3.3 million** in new funding to capitalize or support a revolving loan fund for commercial (includes gov't and nonprofits) & residential energy efficiency loans.
  - ALRD issued 11/15/2022
  - Application Due 5/26/2023 (working on it)
  - DOE Award Date X/XX/2023

Energy Efficiency and Conservation Block Grant Program: (IIJA – DOE)

- **$3.0 million** to support small local governments and nonprofits programs with grants/rebates/financing for energy efficiency, renewable energy, and zero-emission transportation.
  - ALRD issued 1/18/2023
  - Pre-Award Info Sheet 4/28/2023 (submitted)
  - Application Due 7/31/2023 (working on it)
  - DOE Award Date X/XX/2023

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Formula Grant to State Energy Office

Preventing Outages and Enhancing the Resiliency of the Electric Grid: **(IIJA – DOE)**

- **$40.5 Million** PA to receive $8.1 million per year/5years to mitigate impacts to the grid from extreme weather. Requires matching funds 15%. Must apply each year

• Notice of Intent	Q2 2022	
• 1st ALRD Issued (yr. 1)	9/8/2022	
• 1st Application	11/22/2022	(submitted)
• 2nd ALRD Issued (yr. 2)	12/8/2022	
• 2nd Application	3/31/2023	(submitted)
• DOE Award Date	X/XX/2023	(did not receive award yet)
• Sub Grant Program	Fall 2023	(anticipated)

What is in the application:

✓ EPO will focus on providing subawards to eligible entities for projects that enhance grid resiliency for communities, including upgrades to critical infrastructure and delivery of health benefits to disadvantaged Pennsylvanians in low-income and vulnerable communities within both rural, and urban areas.

✓ EPO anticipates awarding grants—without a capped award amount resulting in larger and high-quality projects. Also, there will be a small utility carve out.

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Formula Grant to State Energy Office

HOMES and HEERA Rebates for Energy Efficiency: **(IRA – DOE)**

- Section 50121 Home Energy Performance-Based, Whole-House Rebates: Also known as Hope for Homes or HOMES rebates, provides **$4.3 billion** for State Energy Offices to offer rebates for energy efficiency improvements.

- Section 50122 High-Efficiency Electric Home Rebate Program: provides **$4.275 billion** for State Energy Offices to offer rebates for electric appliances.

PA to receive approx. $129 Million for each program; a total of $258 Million over 10 years.

• RFI Due	3/3/2023	(submitted)
• ALRD #1 Issued	3/23/2023	(for pre-award Admin costs)
• Application Due	Rolling	(planning to submit)
• ALRD #2	7/1/2023	(anticipated)
• Application Due	9/X/2023	(anticipated)
• DOE Award Date	Winter 2023/24	

Program details:

✓ Prescribed whole house EE programs: single family or multifamily, modeled or measured approach – higher rebate amounts (2x) for Low to Moderate Income households.

✓ EE Rebate for prescribed appliances for low income. Contractor incentives and training included.

Formula Grant to State Energy Office

Climate Pollution Reduction Grants (IRA – EPA)

Provides **$250 million** to states, municipalities, air pollution control agencies, territories, and tribes to pursue climate planning activities tailored to unique needs and resources, delivery capacity, and key sectors responsible for emitting and absorbing greenhouse gas pollution. State of PA to expect **~$3 million.** Phila. area & Pgh. ~$1 million each

• Guidance issued	3/1/2023
• NOI to participate	3/31/2023 (submitted)
• Application Due	4/28/2023 (working on it)
• DOE Award Date	Summer (anticipated)

<u>Content:</u>

- Priority Climate Action Plan (PCAP) due March 1, 2024 (near term implementation ready).
    - At a later date, EPA will issue a separate notice of funding opportunity to access $4.6 billion in CPRG implementation grants.
    - Implementation grants will be awarded through a competitive process for initiatives covered by the PCAP
- Comprehensive Climate Action Plan due in 2025 (near and long term GHG emission reduction goals and strategies)
- Status report due in 2027

Competitive Grant – SEO Only

Energy Auditors Training Program: $40 Million (IIJA – DOE)

Maximum grant request of **$2 million** for State Energy Offices to provide energy auditor training assistance – essentially workforce development for energy efficiency sector.

• RFI Due	1/26/2023 (submitted)
• ALRD Issued	X/XX/2023
• Application Due	X/XX/2023
• DOE Award Date	X/XX/2023

<u>Content:</u>

- ✓ RFI was combined with Career Skills Training funding and IRA grants for Energy Efficiency training for Contractors (HOMES and HEERA $200 Million contractor training program)
- ✓ Planning to work with energy efficiency training centers established within PA to expand in-person and online building science-based training designed for a new clean energy workforce in the residential and commercial sectors.
- ✓ Aim to support via funding; instruction to weatherization workers, instructors, and industry partners in the building performance field

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Competitive Grant Programs

Building Codes Assistance/Training: $225 million (IIJA – DOE)

Funds to be made available nationally over the next five years to be used for energy code workforce training, codes updates, implementation, and compliance. State Energy Offices **(EPO)** can also apply in partnership with other eligible entities to support energy code workforce development.

FOA issued	12/19/2022
Concept Paper	1/31/2023 (submitted)
Application Documents Due	3/27/2023 (submitted)
DOE Award Date	6/26/2023 (anticipated)

Content:

✓ Inventorying and mapping of curriculum and programs for building technical training programs at career and technical high schools and centers and 2-year colleges.

✓ Ensuring career and technical high schools and centers are instructing students in building science and codes, by providing improved lessons and curriculum, instructor professional development and tools for ensuring energy code compliance.

***2nd application: Northeast Energy Efficiency Partnerships as primary applicant with Delaware and Pennsylvania as partners to complete energy code field studies of single-family residential, multi-family, and commercial/mixed-use buildings.

Competitive Grant Programs

Building Energy Codes (IRA– DOE)

- **$670 million** to be provided for grants to state and local governments to support efforts to achieve the zero energy provisions of the 2021 IECC and a plan to promote full compliance.
- **$330 million** is directed to states and local governments to support adoption of codes that meet or exceed the 2021 IECC for residential buildings and ANSI/ASHRAE/IES Standards 90.1-2019 for commercial buildings, and to support a plan to achieve compliance, and include training, enforcement and measurement.

RFI/Notice of Intent	4/26/2023 (working on it)
FOA Released	October 2023
Application Documents Due	Fall/Winter 2023
DOE Award Date	X/XX/2024

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Competitive Grant Programs

Greenhouse Gas Reduction Grants (IRA – EPA)

The **$27 Billion** Greenhouse Gas Reduction Fund provides competitive funding for financial and technical assistance to enable zero-emission technologies and projects that reduce or avoid greenhouse gas emissions and other air pollution, including in low-income and disadvantaged communities. These funds are available to EPA to award grants until September 30, 2024.

RFI	12/5/2022 (submitted)
Application Due	X/XX/2023
DOE Award Date	X/XX/2023

What is the Focus?:

Two programs: Zero Emissions Technology Program (ZETP)(**$7 Billion**) & Clean Energy Financing Program (CEFP) **($20 Billion** – $8 Billion dedicated to Low Income)

- ✓ ZETP - State and local clean energy finance institutions and grant programs who provide grants, loans, and other kinds of financial and technical assistance to enable low-income and disadvantaged communities to deploy zero-emission technologies and other GHG-reducing activities (State community and residential solar programs)
- ✓ CEFP – non-profit financial institutions that can rapidly deploy green finance (national green banks or green finance networks that can provide sustained, recycled, directed green finance for projects throughout the U.S.)

Note: Energy Infrastructure Reinvestment Financing - LPO (IRA - DOE) BILLIONS!

Competitive Grant Programs

Clean Heavy Duty Vehicles (IRA – EPA)

$1 billion, with $400 million set aside for communities located in nonattainment areas, for grants and rebates for up to 100% of costs for clean heavy-duty vehicles (e.g., school buses and garbage trucks) as well as associated maintenance, workforce training, and planning. States, municipalities, Tribes, and nonprofit school transportation associations are eligible.

RFI Submitted	1/18/2023 (submitted)
Application Due	X/XX/2023
DOE Award Date	X/XX/2023

Potential Submission:

✓ Support a round 2 MHD ZEV Fleet Demonstration program and/or supplement additional Truck and Bus Fleet Grant programs under Driving PA Forward Program.

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Clean Energy-Related Funding Groups

Delivery mechanisms for clean energy funding

1. **Competitive or formula grants directed at other programs or state agencies:** DEP Energy Programs Office is not eligible or is not the best state representative to apply – We are interested, tracking and encouraging others.

2. **Competitive applications and tax credits:** DEP Energy Programs Office and other state agencies are not eligible to apply. Local governments, businesses, academic institutions, etc. are eligible. – We are interested, tracking and encouraging others.

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Other Funding Opportunities

- **National Abandoned Mine Reclamation Fund (IIJA)** <u>$244.9 million to PA</u> per year for 15 years (total of **$3.2 billion**).
- **Orphaned Well Site Remediation Plugging (IIJA)** <u>$330 million to PA</u> to plug abandoned and orphan wells through September 30, 2030
- **Brownfields (IIJA)** <u>$1.5 million to PA</u> on 12/9/22 for EPA's 128(a) program
  - $300,000 of that will be used to conduct Brownfields Inventories in 12 underserved communities.
  - Applied for competitive funding for Community Wide Assessment Grant <u>$2 million</u> to target communities in Pennsylvania for assistance with reuse planning and assessing impacted sites. 5-year grant, Under review by EPA currently
- **National Electric Vehicle Charging Program (IIJA)** $5 Billion
  - 2.5 Billion Formula Award: PennDOT <u>$171 million to PA over 5 years.</u>
  - 2.5 Billion Competitive: Grants to state, local, and public entities to install alternative fuel infrastructure along Federal Highway Administration-designated Alternative Fuel Corridors. <u>$700 Million this round</u>: Application due: <u>5/30/23</u>
    - 50% of funds dedicated to "Community Grants"
    - Priority to rural, Low and Moderate Income, underserved communities, and multi-unit dwellings

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Other Funding Industry/Decarb

- **Regional Clean Hydrogen Hubs: (IIJA – DOE $8 billion)** Application due 4/7/2023
  - Dedicated to establishing four to six diverse hubs; fossil fuels, nuclear, renewable; industrial, commercial transportation etc.
  - To support commercialization and deployment
- **Industrial Decarbonization Demonstration to Deployment (IIJA $500 Million)** Concept papers due: 4/21/23; Applications due: 8/4/23
  - Industrial production processes, including technologies and processes that achieve emissions reduction in high emissions industrial/chemical materials production processes; achieve emissions reduction in chemical production processes; leverage smart manufacturing technologies or sustainable manufacturing, or increase the energy efficiency of industrial processes
- **Enhanced Geothermal Systems Pilot Demonstrations (IIJA $74 million)** Applications due: 6/16/23
  - EGS have the potential to provide the most growth for district heating and other direct-use applications including electricity generation.
- **Clean Energy Demonstration Program on Current and Former Mine lands (IIJA – DOE $450 Million)** Concept Papers due 5/11/2023, Applications due 8/31/23.
  - Solar, Micro-grids, Geothermal, Direct air capture, Fossil-fueled electricity generation with carbon capture, utilization, and sequestration, Energy storage, including pumped storage hydropower and compressed air storage. Advanced nuclear technologies.

Other Funding GRIPs

Grid Resilience and Innovation Partnerships (GRIP) Grants

- **Smart Grid Grants - (IIJA – DOE $3 Billion FY 22-26)** Rd 1 Applications due 3/17/23
  - Supports activities increasing the flexibility, efficiency, and reliability of the electric power system.
  - EPO provided Support letters to 2 applicants.
- **Grid Resilience Grants - (IIJA - DOE $2.5 Billion FY 22-26)** RD 1 Applications due 4/6/23
  - Supports activities that will modernize the electric grid to reduce impacts due to extreme weather and natural disasters.
  - EPO provided support letters to 2 applicants
- **Grid Innovation Program - (IIJA - DOE $5 Billion FY 22-26)** Rd 1 Applications due 5/19/23
  - Provides financial assistance to government entities to collaborate with electric sector owners and operators to deploy projects that use innovative approaches to transmission, storage, and distribution infrastructure to enhance grid resilience and reliability.
- **Energy Improvement in Rural or Remote Areas (IIJA - DOE $1 Billion FY 22-26)** Concept papers due 4/14/23; Applications due 6/28/23
  - Provides financial investment, technical assistance, and other resources to advance clean energy demonstrations and energy solutions in rural and remote areas.
  - Likely 1 letter of support (not yet submitted)

Other Funding GRID

- **Grants to Facilitate the Siting of Interstate Electricity Transmission Lines (IRA – DOE $760 Million)** RFI was due 2/28/23
  - Provides grants to authorities to carry out activities that will facilitate the siting and permitting of certain interstate onshore and offshore electricity transmission lines.
- **Transmission Facility Financing (IRA – DOE $2 Billion)**
  - Provides direct loan program for certain transmission project development to promote energy security or enabling the use of intermittent energy sources such as wind and solar.
- **Rural and Municipal Utility Advanced Cybersecurity Grant and Technical Assistance Program (IIJA – DOE 250 Million FY 22-26)** RFI was due 12/19/22
  - Provides grants and cooperative agreements to enhance the security posture of electric utilities through improvements in their ability to protect against, detect, respond to, and recover from cybersecurity threats.

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Other Funding - Storage

- **Battery Manufacturing & Recycling (IIJA – DOE $3 Billion)** Apps were due: 7/2022
  - To provide grants to ensure that the United States has a viable domestic manufacturing and recycling capability to support a North American battery supply chain
- **Advanced Energy Manufacturing and Recycling Grants (IIJA – DOE $200 Million)** Concept papers were due 3/14/23, Applications due: 6/8/2023.
  - Research, development, and demonstration of electric vehicle battery recycling and second-life applications for vehicle batteries
- **Long Duration Energy Storage Demonstrations (IIJA – DOE $150 Million)** RFI 6/16/2022, Applications were due: 3/8/2023
  - Projects that -- demonstrate promising long-duration energy storage technologies at different scales; and(ii) help new, innovative long-duration energy storage technologies become commercially viable.
- **Hydropower Research, Development, and Demonstration Program (IIJA - DOE $36 Million)** Applications: open until expended
- **Innovative Technologies to Enable Low-Impact Hydropower and Pumped Storage Hydropower Growth (IIJA – DOE $14.5 Million)** Applications were due: 3/5/23
  - To further the sustainable development of hydropower and pumped storage hydropower (PSH).

Other Funding - Community

- **Grants for Energy Efficiency and Renewable Energy Improvements at Public School Facilities (IIJA – DOE $80 Million)** Application due: 4/21/23
  - Improve, repair, renovate or install in a school: energy efficiency measures, e.g.., HVAC, building envelope improvements, lighting retrofits, sensors and controls, renewable energy technologies, Alternative fueled vehicle infrastructure, purchase or lease of alternative fueled vehicles
- **Clean School Bus Program (IIJA – EPA $5 Billion**) Round 2 Applications Fall 2023
  - To replace existing school buses with zero-emission and low-emission models. $500 million was available through the 2022 Clean School Bus Rebates for zero-emission and low-emission school bus rebates as the first funding opportunity. (Rd 1 Application closed 8/9/2022)
- **Industrial Assessment Centers (IIJA – DOE $54 Million)**
  - To provide grants (two topic areas) to institutions of higher education to establish building training and assessment centers to educate and train building technicians and engineers on implementing modern building technologies.
    - FOA Issue date 4/7/2023, Concept Papers 5/25/23; Application Due: 7/31/23

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Other Funding - Community

- **Weatherization Assistance Program (IIJA)** $3.5 Billion
  - Formula Award, $186 million to PA over 5 years to Department of Community and Economic Development
- **Low Income Home Energy Assistance Program (IIJA**) DHS ~ $20 million add
- **Environmental and Climate Justice Block Grants (IRA – EPA $3 Billion)** RFI was due: 4/10/2023
  - Empowering community efforts to confront and overcome persistent pollution challenges in underserved communities. Community-led air pollution monitoring, prevention and remediation; mitigating climate and health risks from extreme heat; climate resiliency and adaptation; and reducing indoor air pollution
- **Pollution Prevention Grants EJ in Communities (IIJA – EPA $8 Million)** Application due: 6/6/2023
  - Grantees deliver technical assistance to businesses – including those communities with environmental justice concerns – to identify and adopt source reduction practices and technologies that benefit businesses, communities, and local economies.
- **Neighborhood Access and Equity Grants (IRA – FHWA $3 Billion)**
  - Grants to entities such as state governments to district authorities for the improvement of walkability, safety, accessibility, and externality remediation as they relate to transportation, especially in disadvantaged communities.

Other Funding

- **Congestion Relief Program (IIJA – DOE 250 Million/5 years)**
  - Grants in the amounts of 10 million or greater to advance innovative, integrated, and multimodal solutions to reduce congestion and the related economic and environmental costs in the most congested metropolitan areas with an urbanized area population of 1 million or more.
- **Congestion Mitigation & Air Quality Improvement Program (IIJA FHWA $12.5 Billion FY 22-26)**
  - Congestion Mitigation and Air Quality Improvement Program (CMAQ) to provide a flexible funding source to State and local governments for transportation projects and programs to help meet the requirements of the Clean Air Act. Funding is available to reduce congestion and improve air quality for areas that do not meet the National Ambient Air Quality Standards for ozone, carbon monoxide, or particulate matter (nonattainment areas) and for former nonattainment areas that are now in compliance (maintenance areas)
- **Mobile Source Grants (IIJA EPA $5 million)**
  - Available for states to adopt and implement zero-emission standards for mobile sources per Section 177 of the CAA. PA DEP's BAQ is evaluating.

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Other Funding

- **Methane Emissions Reduction Program (IRA – EPA $1.55 Billion)**
  - To reduce methane emissions through financial assistance (grants, rebates, contracts, loans, and other activities) and technical assistance as well as to implement a statutorily required waste emissions charge. Eligible recipients for these funds include, but are not limited to, air pollution control agencies, other public or nonprofit private agencies, institutions, and organizations, and to individuals. The grant program specifies that IRA allocates at least $700 million that must be used for methane mitigation for activities at marginal conventional wells. RFI was due 1/18/23

- **Rural Energy for America Program (IRA – USDA $2 Billion)**
  - Rural Business and Cooperative Service (RBCS) Rural Energy for America Program (REAP) with $303 million set aside for underutilized technologies and technical assistance. Funds may be used for energy efficiency improvements & renewable energy systems, such as biomass (e.g., biodiesel and ethanol, anaerobic digesters, solid fuels); geothermal for electric generation or direct use; hydropower below 30 MW; hydrogen; small and large wind generation; small and large solar generation
    - REAP opened 4/1/2023 and has 6 application windows (quarterly)

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Questions and Discussion

Thank you!

David Althoff
Director
Energy Programs Office
dalthoff@pa.gov

DEP Website: www.dep.pa.gov
DEP Climate Website: www.dep.pa.gov/climate
DEP Energy Programs Website:
DEP > Businesses > Energy > Energy Programs Office

UGI ELECTRIC EXHIBIT DVA-3R

CAUSE-PA-I-3

Request:

Please identify all categories or identifiers that UGI Electric includes when calculating its "confirmed low income customer" count.

Response:

The Company assigns a "confirmed low income" attribute to a customer when the customer confirms income-eligible status with a Community-Based Organization (CBO) and/or the following criteria are met:

- customer enrolls in CAP
- customer receives LIURP services and weatherization measures are installed and completed
- customer receives an Operation Share grant
- customer receives a LIHEAP Cash or Crisis payment

Prepared by or under the supervision of: Daniel V. Adamo

UGI ELECTRIC EXHIBIT DVA-4R

OCA-IV-32

Request:

Please provide all metrics adopted by the Company through which it measures the outcomes of its:

a. Outreach promoting the Company's CAP;

b. Outreach promoting LIHEAP;

c. Outreach seeking to confirm the low-income status of customers;

Response:

a. The Company monitors the following metrics in efforts related to CAP and LIHEAP enrollment campaigns:

- Email delivery, open, and click rates
- On hold messaging link activity
- UGI.com website visits to specific content referenced in any outreach sent by USPS mail
- Enrollment into CAP and grants issued for LIHEAP

b. Please see the response to (a) above.

c. While the Company presents messaging about low income programs to all residential customers (through email, direct mail, UGI.com content, and on-hold messages), the Company has not done a specific targeted campaign to confirm the low income status of customers other than interactions with UGI's Call Center Representatives, UGI Outreach Team members and Company's CBOs.

Prepared by or under the supervision of: Daniel V. Adamo

UGI ELECTRIC EXHIBIT DVA-5R

Agency/Organization	Address
All Saints Parish Christian Service Center Food Pantry Christian Service Center Plymouth	66 Willow Street Plymouth, PA 18651
Back Mountain Food Pantry Trucksville United Methodist Church	40 Knob Hill Road Trucksville, PA 18708
Back Mountain Harvest Assembly Church	340 Carverton Road Trucksville, PA 18708
Care and Concern Ministries	37 Williams Street Pittston, PA 18640
Catholic Social Services of the Diocese of Scranton Saint Vincent de Paul Kitchen - Food Pantry - Wilkes Barre	504 Penn Ave Scranton, PA 18509
CEO - Senior Food Box Program	185 Research Drive Pittston, PA 18640
CEO - Summer Food Program - Wyoming County	819 Hunter Highway Wyoming County Human Services Bldg Tunkhannock, PA 18657
CEO - Weinberg NE Regional Food Bank	185 Research Drive Pittston, PA 18640
Greater Wyoming Valley Area YMCA	40 West Northhampton Street Wilkes Barre, PA 18701
Luzerne/Wyoming Counties Area Agency on Aging	2813 Sullivan's Trail Falls, PA 18615
Salvation Army Wilkes-Barre - Food Pantry	17 South Pennsylvania Avenue Wilkes Barre, PA 18701
Shickshinny First United Methodist Church	6 East Butler Lane Shickshinny, PA 18655
Sidney and Pauline Friedman Jewish Community Center Friedman JCC - Sarah's Table at Kraus Chaiken Food Pantry	613 S.J. Strauss Lane Kingston, PA 18704
Sweet Valley Food Pantry - Weinburg North East Regional Food Bank	Sweet Valley Church of Christ 5439 Main Road Sweet Valley, PA 18656
Volunteers of America - Northeast Regional Office Volunteers of America - Food Pantry - Wilkes-Barre	25 North River Street Wilkes Barre, PA 18702
Wilkes-Barre CEO Food Pantry Good Shepherd Community Center	190 S. Main Street

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From: Mchugh, Timothy
Sent: Thursday, March 10, 2022 6:15 PM
To: Nathan Barrett [redacted]
Subject: RE: UGI's Universal Services Programs for Low-Income Students and Families -- Assistance Requested

Superintendent Barrett,

I enjoyed speaking with today, and I'm very glad that UGI is in a position to help some of your students and their families.

As discussed, please find attached the information relating to UGI Electric's Universal Services Programs. Within it, it includes information regarding our Low Income Usage Reduction Program, Customer Assistance Referrals Evaluation Services, Low Income Home Energy Assistance Program, Customer Assistance Program, and Operation Share. Collectively, these programs help to reduce qualified low-income customers' bills by either reducing their usage or providing some type of assistance. The qualification guidelines are located on the last page of the brochure.

I was able to confirm that we do not include the attached information on our website because of concerns regarding ADA compliance, but I was able to locate a link that provides some information regarding assistance programs. It also includes videos, one in English and one in Spanish, that explains some of the programs. Maybe this will be helpful too. The link is here: https://www.ugi.com/assistance-programs/ [ugi.com].

Please do not hesitate to contact me if you have any questions or concerns.

Thanks,
Tim

From: Nathan Barrett [redacted]
Sent: Wednesday, March 9, 2022 12:56 PM
To: Mchugh, Timothy <MchughT@ugicorp.com>
Subject: Re: UGI's Universal Services Programs for Low-Income Students and Families -- Assistance Requested

WARNING:This message came from an external source. Please exercise caution when opening any attachments or clicking on links.

I can have my Secretary send a zoom invite.

On Wed, Mar 9, 2022 at 12:55 PM Mchugh, Timothy <MchughT@ugicorp.com> wrote:

> That works! Would you prefer that we speak by phone or Zoom? Either works for me.
>
> Thanks,
> Tim
>
> **From:** Nathan Barrett [redacted]
> **Sent:** Wednesday, March 9, 2022 12:53 PM
> **To:** Mchugh, Timothy <MchughT@ugicorp.com>
> **Subject:** Re: UGI's Universal Services Programs for Low-Income Students and Families -- Assistance Requested
>
> WARNING:This message came from an external source. Please exercise caution when opening any attachments or clicking on links.
>
> How about tomorrow at noon?
>
> On Tue, Mar 8, 2022 at 8:10 PM Mchugh, Timothy <MchughT@ugicorp.com> wrote:
>
>> Unfortunately, I have a call at 11 a.m. on Thursday. If Thursday afternoon works better for you, I am available from 12 p.m. until 3 p.m., and then again after 4 p.m. If Friday works betters for you, I am free up until 1 p.m. and then after 2 p.m.
>>
>> Please let me know what day and time works best for you.
>>
>> Thanks,
>> Tim
>>
>> **From:** Nathan Barrett [redacted]
>> **Sent:** Tuesday, March 8, 2022 3:28 PM
>> **To:** Mchugh, Timothy <MchughT@ugicorp.com>
>> **Subject:** Re: UGI's Universal Services Programs for Low-Income Students and Families -- Assistance Requested

WARNING:This message came from an external source. Please exercise caution when opening any attachments or clicking on links.

Mr. McHugh,

Thursday would be better for me, my Wednesday filled up. Would you be free at 11 on Thursday?

On Mon, Mar 7, 2022 at 9:15 PM Mchugh, Timothy <MchughT@ugicorp.com> wrote:

Superintendent Barrett,

I apologize for my delayed response. At this time, my Wednesday afternoon is very flexible. Would 1 p.m. work for you?

I look forward to speaking with you.

Thanks,
Tim

From: Nathan Barrett [redacted]
Sent: Thursday, March 3, 2022 4:06 PM
To: Mchugh, Timothy <MchughT@ugicorp.com>
Subject: Re: UGI's Universal Services Programs for Low-Income Students and Families -- Assistance Requested

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Thank you for the quick response. Do you have anything free on Wednesday after 11?

On Thu, Mar 3, 2022 at 1:55 PM Mchugh, Timothy <MchughT@ugicorp.com> wrote:

Superintendent Barrett,

I would welcome a Zoom meeting with you to discuss this. I am free today after 4 p.m., tomorrow after 1 p.m., and Monday between 12 p.m. – 1 p.m. If none of these times work for you, please let me know, and I will look at more dates/times next week.

I look forward to speaking with you.

Thanks,
Tim

From: Nathan Barrett [redacted]
Sent: Thursday, March 3, 2022 12:49 PM
To: Mchugh, Timothy <MchughT@ugicorp.com>
Subject: Re: UGI's Universal Services Programs for Low-Income Students and Families -- Assistance Requested

WARNING:This message came from an external source. Please exercise caution when opening any attachments or clicking on links.

Hello,

Would you be available for a zoom meeting? If so, can you give me dates/times available?

Thank you,

Nathan

On Mon, Feb 28, 2022 at 10:36 AM Mchugh, Timothy <MchughT@ugicorp.com> wrote:

Superintendent Barrett,

I know you are busy, but I wanted to follow-up with you to see if you have any time to discuss UGI's Customer Assistance Program and how it can help low-income families in your school district.

If you prefer, I can email you a pamphlet that describes some of our programs. With the economic hardships that many currently face, we want to make sure that our customers (and your students and their families) have this information. If possible, I would appreciate the opportunity to briefly discuss this with you.

I look forward to speaking with you.

Thanks,
Tim

From: Mchugh, Timothy
Sent: Monday, January 24, 2022 9:48 PM
To: [redacted]
Subject: UGI's Universal Services Programs for Low-Income Students and Families -- Assistance Requested

Superintendent Barrett,

I am counsel for UGI Corporation, and we have been exploring ways to inform customers in our electric service territory of the various public assistance programs that we offer. More specifically, we seek to inform eligible customers about the benefits of enrolling in our Customer Assistance Program ("CAP") and identifying customers who may be eligible for winter shutoff protections. With this in mind, as part of our last electric base rate case, we readily agreed with the Pennsylvania Public Utility Commission to reach out to local school districts to help us identify students and families who my qualify for these programs.

As a former high school teacher and school solicitor, I know you are very busy, but I also know your commitment to your students. To that end, I was hoping to schedule a quick call with you to discuss these programs that benefit low-income families and help to ensure that they have electricity, especially during these cold months. If you feel there is a person in your district that is better situated to discuss this with me, I would greatly appreciate it if you would provide me with their contact information.

I look forward to speaking with you and hope that we can help your students.

[google.com]

Thanks,
Tim

Timothy K. McHugh

Counsel -- Energy & Regulation

UGI Corporation

460 N. Gulph Road [google.com]

King of Prussia, PA 19406 [google.com]

(717) 608-0742 (c)

MchughT@ugicorp.com

From: Mchugh, Timothy
Sent: Monday, February 28, 2022 11:50 AM
To: Joseph Long [redacted]
Subject: RE: UGI's Universal Services Programs for Low-Income Students and Families -- Assistance Requested

Superintendent Long,

I appreciate the quick response.

Please find attached the information relating to UGI Electric's Universal Services Programs. It includes information regarding our Low Income Usage Reduction Program, Customer Assistance Referrals Evaluation Services, Low Income Home Energy Assistance Program, Customer Assistance Program, and Operation Share. Collectively, these programs help to reduce qualified low-income customers bills by either reducing their usage or providing some type of assistance.

I am confident that you are in the best position to determine how to get this information to your students. However, if you have any questions, please do not hesitate to contact me.

Thanks,
Tim

From: Joseph Long [redacted]
Sent: Monday, February 28, 2022 11:45 AM
To: Mchugh, Timothy <MchughT@ugicorp.com>
Subject: Re: UGI's Universal Services Programs for Low-Income Students and Families -- Assistance Requested

WARNING:This message came from an external source. Please exercise caution when opening any attachments or clicking on links.

Email me the pamphlet
TY
Joe

On Mon, Feb 28, 2022 at 10:42 AM Mchugh, Timothy <MchughT@ugicorp.com> wrote:

Superintendent Long,

I know you are busy, but I wanted to follow-up with you to see if you have any time to discuss UGI's Customer Assistance Program and how it can help low-income families in your school district.

If you prefer, I can email you a pamphlet that describes some of our programs. With the economic hardships that many currently face, we want to make sure that our customers (and your students and their families) have this information. If possible, I would appreciate the opportunity to briefly discuss this with you.

I look forward to speaking with you.

Thanks,
Tim

From: Mchugh, Timothy
Sent: Monday, January 24, 2022 10:03 PM
To: [redacted]
Subject: UGI's Universal Services Programs for Low-Income Students and Families -- Assistance Requested

Superintendent Long,

I am counsel for UGI Corporation, and we have been exploring ways to inform customers in our electric service territory of the various public assistance programs that we offer. More specifically, we seek to inform eligible customers about the benefits of enrolling in our Customer Assistance Program ("CAP") and identifying customers who may be eligible for winter shutoff protections. With this in mind, as part of our last electric base rate case, we readily agreed with the Pennsylvania Public Utility Commission to reach out to local school districts to help us identify students and families who my qualify for these programs.

As a former high school teacher and school solicitor, I know you are very busy, but I also know your commitment to your students. To that end, I was hoping to schedule a quick call with you to discuss these programs that benefit low-income families and help to ensure that they have electricity, especially during these cold months. If you feel there is a person in your district that is better situated to discuss this with me, I would greatly appreciate it if you would provide me with their contact information.

I look forward to speaking with you and hope that we can help your students.

Thanks,
Tim

Timothy K. McHugh

Counsel -- Energy & Regulation

UGI Corporation

460 N. Gulph Road

King of Prussia, PA 19406

(717) 608-0742 (c)

McHughT@ugicorp.com

From: Mchugh, Timothy
Sent: Monday, February 28, 2022 11:22 AM
To: [redacted]
Subject: UGI's Universal Services Programs for Low-Income Students and Families -- Assistance Requested

Superintendent Booth,

I am counsel for UGI Corporation, and we have been exploring ways to inform customers in our electric service territory of the various public assistance programs that we offer. More specifically, we seek to inform eligible customers about the benefits of enrolling in our Customer Assistance Program ("CAP") and identifying customers who may be eligible for winter shutoff protections. With this in mind, as part of our last electric base rate case, we readily agreed with the Pennsylvania Public Utility Commission to reach out to local school districts to help us identify students and families who my qualify for these programs.

As a former high school teacher and school solicitor, I know you are very busy, but I also know your commitment to your students. To that end, I was hoping to schedule a quick call with you to discuss these programs that benefit low-income families and help to ensure that they have electricity, especially during these cold months. If you feel there is a person in your district that is better situated to discuss this with me, I would greatly appreciate it if you would provide me with their contact information.

I look forward to speaking with you and hope that we can help your students.

Thanks,
Tim

Timothy K. McHugh
Counsel -- Energy & Regulation
UGI Corporation
460 N. Gulph Road
King of Prussia, PA 19406
(610) 768-3639 (o)
(717) 608-0742 (c)
MchughT@ugicorp.com

From: Mchugh, Timothy
Sent: Tuesday, March 1, 2022 9:21 AM
To: Dave Tosh [redacted]
Cc: David Novrocki [redacted]; Anthony Dicton [redacted]
Subject: RE: [EXTERNAL] RE: UGI's Universal Services Programs for Low-Income Students and Families -- Assistance Requested

Superintendent Tosh,

I appreciate the response.

Please find attached the information relating to UGI Electric's Universal Services Programs. It includes information regarding our Low Income Usage Reduction Program, Customer Assistance Referrals Evaluation Services, Low Income Home Energy Assistance Program, Customer Assistance Program, and Operation Share. Collectively, these programs help to reduce qualified low-income customers bills by either reducing their usage or providing some type of assistance. The qualification guidelines are located on the last page of the brochure.

I am confident that you are in the best position to determine how to get this information to your students. However, if you have any questions, please do not hesitate to contact me.

Thanks,
Tim

From: Dave Tosh [redacted]
Sent: Tuesday, March 1, 2022 9:14 AM
To: Mchugh, Timothy <MchughT@ugicorp.com>
Cc: David Novrocki [redacted]; Anthony Dicton [redacted]
Subject: [EXTERNAL] RE: UGI's Universal Services Programs for Low-Income Students and Families -- Assistance Requested

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WARNING: This email originated outside of the Wyoming Valley West School District email system.

DO NOT CLICK links or attachments unless you recognize the sender and know the content is safe.

Pamphlet would be great!

Thank you

From: Mchugh, Timothy <MchughT@ugicorp.com>
Sent: Monday, February 28, 2022 10:48 AM
To: Dave Tosh [redacted]
Subject: RE: UGI's Universal Services Programs for Low-Income Students and Families -- Assistance Requested

You don't often get email from mchught@ugicorp.com. Learn why this is important [aka.ms]

Superintendent Tosh,

I know you are busy, but I wanted to follow-up with you to see if you have any time to discuss UGI's Universal Services Programs and how they can help low-income families in your school district.

If you prefer, I can email you a pamphlet that describes some of our programs. With the economic hardships that many currently face, we want to make sure that our customers (and your students and their families) have this information. If possible, I would appreciate the opportunity to briefly discuss this with you.

I look forward to speaking with you.

Thanks,
Tim

From: Mchugh, Timothy
Sent: Tuesday, January 25, 2022 11:26 AM
To: [redacted]
Subject: UGI's Universal Services Programs for Low-Income Students and Families -- Assistance Requested

Superintendent Tosh,

I am counsel for UGI Corporation, and we have been exploring ways to inform customers in our electric service territory of the various public assistance programs that we offer. More specifically, we seek to inform eligible customers about the benefits of enrolling in our Customer Assistance Program ("CAP") and identifying customers who may be eligible for winter shutoff protections. With this in mind, as part of our last electric base rate case, we readily agreed with the Pennsylvania Public Utility Commission to reach out to local school districts to help us identify students and families who my qualify for these programs.

As a former high school teacher and school solicitor, I know you are very busy, but I also know your commitment to your students. To that end, I was hoping to schedule a quick call with you to discuss these programs that benefit low-income families and help to ensure that they have electricity, especially during these cold months. If you feel there is a person in your district that is better situated to discuss this with me, I would greatly appreciate it if you would provide me with their contact information.

I look forward to speaking with you and hope that we can help your students.

Thanks,
Tim

Timothy K. McHugh
Counsel -- Energy & Regulation

UGI Corporation
460 N. Gulph Road
King of Prussia, PA 19406
(717) 608-0742 (c)
McHughT@ugicorp.com

LOW INCOME USAGE REDUCTION PROGRAM (LIURP)

UGI's LIURP offers free weatherization measures to qualified low-income residential heating customers in order to limit heat loss and provide long-term energy savings. These energy savings measures may include window and baseboard caulking, door and window weather-stripping, attic and sidewall insulation, duct and pipe insulation, ventilation, water conservation devices, furnace inspections and energy education.

In addition, non-heating UGI Electric accounts may qualify for measures such as refrigerator replacement and high-efficiency lighting.

LIURP ELIGIBILITY CRITERIA

To be eligible the customer must have: (1) an active UGI gas or electric heating account with twelve (12) or more continuous billing periods for the same account number; (2) higher than average gas or electric heating usage during the twelve month period to meet specified consumption levels for the program; (3) renters can qualify with written permission from landlords; (4) Gross Annual Income must be at or below 150% of the Federal Poverty Level *(see insert for details)*. A percentage of customers who may have extenuating circumstances can be accepted at 200% of Federal Poverty Level.

One additional LIURP program called the UGI Rehabilitation Program is designed to take a

CONTINUED ON BACK PANEL

proactive approach to install approved energy efficient measures at the time of new construction or rehabilitation. Email **liurpteam@ugi.com** for more information.

CUSTOMER ASSISTANCE REFERRALS EVALUATION SERVICES (C.A.R.E.S.)

C.A.R.E.S. provides referrals to other helpful programs in your community. UGI will send any customer, regardless of income, a Customer Assistance Guide and energy-related information specifically for your area. In addition to LIHEAP and LIURP, these programs can include budget counseling or Office of Aging programs.

C.A.R.E.S. ELIGIBILITY CRITERIA

Customer must be a residential customer experiencing a temporary personal or financial crisis.

Additional Services offered by UGI:

- **Conservation literature**
- **Gift credits**
- **Third party notification**
- **Online bill pay**
- **Budget billing**
- **Payment arrangements**
- **Extended due date**

Energy to do more®

www.ugi.com

Energy to do more®

Universal Services

PROGRAMS

For more information please call:
800 UGI-WARM
800 844-9276

To learn more or enroll visit www.ugi.com/electrichelp

Everybody needs help now and then.

We want to help guide you through the many programs available to help customers manage their energy bills. Look at the table below and select the option that best describes your situation, then look at the Program you should start with.

Your Current Situation	Start With This Program
You have no heat, or an active termination notice, and limited income. (Note: Enrollment for this program occurs in early November of each year and ends in April the following year.)	Low Income Home Energy Assistance Program (LIHEAP)
You have high debt, and need help managing monthly energy bills. You want “forgiveness” of utility debt as long as you continue to make on-time payments to UGI for 3 years.	Customer Assistance Program (CAP)
You have a temporary hardship (death of wage earner, loss of job, sickness, etc.) that prevents you from paying your utility bills.	Operation Share
Your home is cold and drafty, and keeping the thermostat low doesn’t result in lower energy bills.	Low Income Usage Reduction Program (LIURP)

LOW INCOME HOME ENERGY ASSISTANCE PROGRAM (LIHEAP)

LIHEAP (Low Income Home Energy Assistance Program) is a federally funded program administered by each state that helps low income households pay their heating bills through energy assistance grants. There are two components to the LIHEAP program: CASH and CRISIS.

ELIGIBILITY FOR CASH GRANT

A customer must be responsible for home heating costs. CASH grants are applied directly to your account. This is not a loan and the money does not have to be paid back.

ELIGIBILITY FOR CRISIS GRANT

CRISIS grants help families who are in danger of being without heat due to situations like:

- **Utility services shut-off**
- **Active termination notice**
- **Broken heating equipment or leaking fuel lines**

Homeowners or renters whose gross annual income meets the income guidelines (see insert for details) established for the program by the State are eligible.

To apply, a customer must have a recent heating bill, and the names, Social Security numbers, and proof of income for all household members.

For more information regarding this program, customers can contact UGI or their local County Assistance Offices (**www.ugi.com/CAO**).

CUSTOMER ASSISTANCE PROGRAM (CAP)

UGI’s Customer Assistance Program (CAP) benefits include:

- **A personalized monthly payment based on income and average bill;**
- **Past due debt forgiveness with on time monthly payments;**
- **The difference between the CAP payment and the actual usage bill may also be forgiven.**

UGI partners with local community agencies to provide this useful program to customers.

CAP ELIGIBILITY CRITERIA

To be eligible, a customer must: (1) have household gross income at or below 150% of Federal Poverty Level; (2) be a residential customer with active energy service. Income Guidelines change annually, see insert for details.

OPERATION SHARE

The Operation Share program provides energy assistance grants to qualified customers who experience difficulty paying their heating bills. This community-based program is funded by voluntary donations from UGI employees, UGI customers, and concerned citizens. In addition, UGI provides a corporate donation to help fund the program.

OPERATION SHARE ELIGIBILITY CRITERIA

To be eligible the customer must: (1) have an active UGI account; (2) have gross income (see insert for details) at or below 200% of Federal Poverty Level; (3) have not received an Operation Share grant within the past twelve (12) month period.

Energy to do more®

CAP & LIHEAP Household Income
150% Federal Poverty Guidelines
Valid Through January 31, 2023*

Household Members	Annual Income	Monthly Income	Weekly Income
1	$20,385	$1,699	$392
2	$27,465	$2,289	$528
3	$34,545	$2,879	$664
4	$41,625	$3,469	$800
5	$48,705	$4,059	$937
6	$55,785	$4,649	$1,073
7	$62,865	$5,239	$1,209
8	$69,945	$5,829	$1,345

For each additional person add $7,080/person annual income ($590/person monthly income or $136/weekly income).

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LIURP & Operation Share Household Income
200% Federal Poverty Guidelines
Valid Through January 31, 2023*

Household Members	Annual Income	Monthly Income	Weekly Income
1	$27,180	$2,265	$523
2	$36,620	$3,052	$704
3	$46,060	$3,838	$886
4	$55,500	$4,625	$1,067
5	$64,940	$5,412	$1,249
6	$74,380	$6,198	$1,430
7	$83,820	$6,985	$1,612
8	$93,260	$7,772	$1,793

For each additional person add $9,440 /person annual income ($787/person monthly income or $182/weekly income).

Visit www.ugi.com/electrichelp
to learn more or enroll in a program.

*Income guidelines will increase in January of each year. If your income levels are close to what is above, please contact UGI at the above number to verify eligibility.
~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~

UGI ELECTRIC EXHIBIT DVA-6R

[redacted]

From: Whorl, Brian <bwhorl@pa.gov>
Sent: Monday, February 28, 2022 9:24 AM
To: Irizarry, Matthew; Meilinger, Brian J
Cc: Myricks, Katrina; Cordell, Lisa
Subject: UGI CAP settlement requests

WARNING: This message came from an external source. Please exercise caution when opening any attachments or clicking on links.

Good morning, Matthew and Brian,

My apologies for the delay in sending this, but with SNAP, LIHEAP, P-EBT, and LIHWAP, we are extremely busy at the moment. Thank you for the meeting the other week to discuss your requests from DHS in response to UGI's CAP program.

Regarding your requests: as you are aware, there are currently ongoing data sharing discussions between DHS and a subcommittee of the LIHEAP Advisory Committee (LAC). Depending on the results of these discussions, DHS may be able to make LIHEAP information available to all regulated utilities, including UGI. However, with regard to the request to provide information for DHS' recipients of other programs, such as Temporary Assistance for Needy Families (TANF, more commonly referred to as cash assistance), Supplemental Nutrition Assistance Program (SNAP, formerly known as food stamps), and Medical Assistance (MA, also referred to as Medicaid), DHS will not provide this information. None of these programs requires the individual or household to identify their utility provider and in fact, only SNAP collects whether the household even has a heating and/or electric responsibility. Further, there is no permission collected from these households to perform any data sharing with their utility. This is one of the key parts of the discussions occurring with the LAC subcommittee is that before DHS will share any information, we would have to make appropriate updates to our LIHEAP application to accurately capture the household's specific consent to share any data information with their selected utility.

For the second request regarding distribution of materials, if UGI can provide copies of the materials to me (in PDF or other soft copy format), I will discuss with DHS leadership the possibility of sharing the materials with the County Assistance Offices (CAOs) in UGI's service area with a request that they print out the materials and have them available in their lobbies. I do not foresee an issue with this request since it would be limited to only the CAOs in UGI's area and would be simply providing information about UGI's CAP and not specifically advertising UGI as a utility provider.

Please let me know if you have any additional questions or need any further information.

Brian Whorl| Division Director, Federal Programs and Program Management
Department of Human Services | Office of Income Maintenance
Bureau of Policy
CoPA HUB, Suite 240/250 | 2525 N. 7th Street
Harrisburg, PA 17110

UGI ELECTRIC EXHIBIT DVA-7R

44) Reference OCA Statement No. 4, pages 41-42. Is Mr. Colton or the OCA aware of the LIHEAP Advisory Committee's efforts to establish a process with the Pennsylvania Department of Human Services to share applicant information with utilities for those customers who consent to share their information?

Response:

Mr. Colton is aware of the efforts of various utilities to establish LIHEAP and LIHWAP data-sharing agreements with the Commonwealth's Department of Human Services.

Witness: Roger Colton
Date: May 8, 2023

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2022-3037368, et al.

UGI Utilities, Inc. – Electric Division

Statement No. 1-RJ

Rejoinder Testimony of
Christopher R. Brown

Topics Addressed: **Management Performance**

Dated: June 12, 2023

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christopher R. Brown. My business address is 1 UGI Drive, Denver, PA 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Electric Statement No. 1, on January 27, 2023. I also submitted my rebuttal testimony, UGI Electric Statement No. 1-R, on May 25, 2023.

Q. What is the purpose of your rejoinder testimony?

A. My rejoinder testimony responds to certain portions of the surrebuttal testimony submitted by the Office of Consumer Advocate ("OCA") witness Mr. Roger D. Colton, OCA St. 4SR, regarding the Company's management performance and recognition.

Q. If you do not address specific aspects of the other parties' surrebuttal testimony that responded to your rebuttal testimony, does that mean you agree with the other party?

A. No. Unless otherwise specifically noted in my rejoinder testimony, UGI Electric maintains its rebuttal position in response to each adjustment raised by the other parties.

II. MANAGEMENT PERFORMANCE

Q. Do you have any response to the claims made by Mr. Colton in his surrebuttal testimony.

A. Yes. Mr. Colton has made a number of claims in his surrebuttal testimony, on pages 6 to 8, that are in response to my testimony. The Company generally denies his claims based on the facts that I have already put forward in my testimony. Further, the Company disagrees that certain of Mr. Colton's assertions in his surrebuttal testimony are relevant to the Commission's ultimate determination on management performance for the reasons identified in my rebuttal testimony. The Commission should reject the arguments made by Mr. Colton as they are a wholesale misconstruction of the facts or are irrelevant to the Commission's analysis.

Q. What elements has Mr. Colton ignored in his recommended disallowance of the Company's management performance claim?

A. Mr. Colton ignores the totality of the activities undertaken by UGI Electric that provide vital support for its customers and the communities it serves. Many of these activities are voluntary in nature. In total, UGI Electric's strong management performance is indicated by the following activities:

- UGI Electric filed and maintains a voluntary Long Term Infrastructure Improvement Plan;
- UGI Electric filed and maintains a voluntary Energy Efficiency and Conservation ("EE&C") Plan;
- UGI Electric has had excellent reliability performance, year over year;
- UGI Electric has adopted voluntary customer portal enhancements that directly support enhanced customer experience and satisfaction;

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- UGI Electric has upgraded key portions of its data management systems through its UNITE program to provide more robust metrics and record keeping that facilitates a better customer experience and greater responsiveness to regulators;
- UGI Electric maintains its commitment to safety through strong multifaceted programs, including training for local volunteer fire departments, that prioritize the safety of UGI Electric's customers, its employees, and the communities it serves;
- UGI Electric advances diversity, equity and inclusion through the Company's recruitment, hiring, and procurement activities;
- UGI Electric maintains robust programs to support payment troubled customers and customers that are in need of short-term assistance, including significant contributions by the Company to its Operation Share fund;
- UGI Electric plays an active role in connecting its vulnerable customer population with federally available programs, such as the Low Income Home Energy Assistance Program ("LIHEAP"); and
- UGI Electric maintains a strong local presence in the communities it serves through the dedicated and coordinated volunteer efforts of the Company and its employees, including education programs for children, and training and mentoring programs for women and minority engineering students.

The Commission should consider this total package of activities, and the positive impact these activities have on customers and the communities UGI Electric serves, in granting the Company's requested management performance adjustment.

III. CONCLUSION

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2022-3037368, et al.

UGI Utilities, Inc. – Electric Division

Statement No. 2-RJ

Rejoinder Testimony of
Tracy A. Hazenstab

Topics Addressed:	**Overtime Costs** **Misc. Customer Accounts Expense** **Misc. Customer Information Expense** **Act 40 of 2016**

Dated: June 12, 2023

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tracy A. Hazenstab. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Electric Statement No. 2, on January 27, 2023. I also submitted my rebuttal testimony, UGI Electric Statement No. 2-R, on May 25, 2023.

Q. What is the purpose of your rejoinder testimony?

A. My rejoinder testimony responds to certain portions of the following surrebuttal testimony submitted by the Office of Consumer Advocate ("OCA"). Specifically, I address OCA Statement No. 1SR, the surrebuttal testimony of Mr. Dante Mugrace, with respect to his: (1) proposed adjustments to salaries and wages expense related to overtime costs; (2) assertion that the Company's claimed amounts for the fully projected future test year ending September 30, 2024 ("FPFTY") for Misc. Customer Accounts Expense and Misc. Customer Information Expenses were adjusted using a blanket inflation factor based on the Consumer Price Index ("CPI"), and (3) arguments regarding Act 40 of 2016.

Q. If you do not address specific aspects of the other parties' surrebuttal testimony that responded to your rebuttal testimony, does that mean you agree with the other party?

A. No. Unless otherwise specifically noted in my rejoinder testimony, UGI Electric maintains its rebuttal position in response to each adjustment raised by the other parties.

Q. Are you sponsoring any exhibits with your rejoinder testimony?

A. Yes, as part of my rejoinder testimony I am sponsoring UGI Electric Exhibit TAH-1RJ.

II. UPDATES TO CASE

Q. Since the filing of your rebuttal testimony, has the Company identified any additional components of its filing that should be updated?

A. No. The Company's final accounting exhibit for this proceeding is UGI Electric Exhibit A – Fully Projected (REBUTTAL), which I sponsored with my rebuttal testimony.

III. OVERTIME COSTS

Q. Do any of the other parties address the Company's claimed salaries and wages expense?

A. Yes. OCA witness Mr. Mugrace addresses the Company's projected overtime expenses for the FPFTY. OCA St. No. 1SR at 5-6. He asserts that the assumptions that underlie the Company's projected workload "have not changed" and, therefore, he is withdrawing his proposed $23,333 adjustment (specified in OCA St. No. 1 at 22-23) to payroll expense based on a three year average review. Accordingly, he proposes to remove his overtime payroll adjustment of $23,333[1] and accept the Company's originally proposed payroll expense amount of $567,000. OCA St. No. 1SR at 6.

[1] In his direct testimony, Mr. Mugrace proposed a $23,333 increase to the Company's overtime expense based on a three year average of these costs over the HTY, FTY and FPFTY. OCA St. No. 1 at 22-23. In support of this adjustment, he claimed that his three year average was warranted because "[t]hese types of payroll costs fluctuate takes into consideration the level of employees, capital project work, and O&M spending for operation related to electric utility distribution system." *Id.*

Q. Does the Company agree with Mr. Mugrace's proposed withdrawal?

A. Yes.

IV. MISC. CUSTOMER ACCOUNTS EXPENSE AND MISC. CUSTOMER INFORMATION EXPENSE – ALLEGED CPI INFLATION FACTOR

Q. Do any of the other parties continue to challenge the Company's claim for the Miscellaneous Customer Accounts expense for the FPFTY?

A. Yes. While OCA witness Mr. Mugrace accepted my position that a reduction to the Customer Records/Collection Expenses in this account, without a corresponding reduction to revenue, would affect the fully-reconcilable nature of how these expenses are recovered, he asserts that "the remaining costs related to Meter Reading and Miscellaneous Customer Accounts Expenses…were increased based on the Consumer Pricing Index percentage." OCA St. No. 1SR at 16. He further states that he does not believe the CPI is known and measurable, and argues that these costs increases should be disallowed as a blanket-type adjustment. OCA St. No. 1SR at 16.

Q. Do you agree with Mr. Mugrace's claim that Meter Reading and Miscellaneous Customer Accounts Expenses claimed for the FPFTY were based upon an adjustment by the CPI?

A. No, and it is not clear how Mr. Mugrace arrived at this conclusion. Nowhere in the Company's testimony or its discovery responses did the Company indicate that it used the CPI to calculate a portion of its claim. To the contrary, the Company represented in its response to OCA-II-14 that "UGI Electric's budget process did not use the Consumer Price Index (CPI) for the purpose of establishing the budgets for the FTY or the FPFTY." (*See*

UGI Electric Exhibit TAH-1RJ.) Mr. Mugrace's argument that a portion of the Miscellaneous Customer Accounts Expenses claimed by the Company should be disallowed on this ground is simply unsupported.

Q. Do any of the other parties continue to challenge the Company's claim for the Miscellaneous Customer Information Expenses for the FPFTY?

A. Yes. While OCA witness Mr. Mugrace accepted my position that a reduction to the expenses in this account, without a corresponding reduction to revenue, would affect the fully-reconcilable nature of how these expenses are recovered, he asserts that "these costs were adjusted based on a CPI percentage." OCA St. No. 1SR at 18. He further states that he does not believe the CPI is known and measurable, and argues that these cost increases should be disallowed as a blanket-type adjustment. OCA St. No. 1SR at 18.

Q. Do you agree with Mr. Mugrace's assertion that Miscellaneous Customer Information Expenses claimed for the FPFTY were based upon an adjustment by the CPI?

A. No, for the same reasons I discounted Mr. Mugrace's assertions above that the Company adjusted its Miscellaneous Customer Accounts Expenses by the use of a CPI factor. The Company did not use a CPI percentage to arrive at its projected level of expenses in this account for the FPFTY.

V. PENNSYLVANIA ACT 40

Q. Does OCA witness Mr. Mugrace continue to assert in his surrebuttal testimony that the Company has not complied with the requirements of Pennsylvania Act 40 ("Act 40") of 2016?

A. Yes, he does.

Q. Do you have any response to Mr. Mugrace's assertion that the Commission "does not have to rely on whether any IRS violation exists" (OCA St. No. 1SR at 27) in considering his proposal to use 50% of the Act 40 calculation to offset the Company's claims in this case?

A. Yes. To the extent that Mr. Mugrace is suggesting that the Commission would accept a ratemaking adjustment that could result in a violation of IRS tax normalization requirements, this suggestion fails to acknowledge the materiality of the IRS normalization requirements and the serious cash consequences to the Company and ratepayers if the IRS rules that tax normalization requirements have been violated as explained in my rebuttal (UGI Electric St. No. 2-R at 26). Mr. Mugrace's position is unreasonable, contrary to the public interest, and should be rejected.

VI. CONCLUSION

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

UGI ELECTRIC EXHIBIT TAH-1RJ

UGI Utilities, Inc. - Electric Division
Docket No. R-2022-3037368
UGI Electric 2023 Base Rate Case
Responses to OCA Set II (1 - 49)
Delivered on March 9, 2023

OCA-II-14

Request:

Refer to Mr. Brown's testimony at 7. Please provide a schedule of all CPI inflation adjustments that UGI-Electric used and included in its development of its revenue requirement increase of $11.425 million. Please provide by Operation and Maintenance Expense categories. (Schedules D-1 and D-2).

Response:

UGI Electric's budget process did not use the Consumer Price Index (CPI) for the purpose of establishing the budgets for the FTY or the FPFTY. The Company budgets at individual cost center levels based on expected work and materials required, and estimated costs associated with those. The estimated costs are based on known costs where possible or anticipated future costs that weigh a variety of impacts, including inflation. Each department, while establishing its budget, evaluates expected future costs based on their knowledge and experience with the cost drivers composing their budget to forecast a reasonable assumption.

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

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2022-3037368, et al.

UGI Utilities, Inc. – Electric Division

Statement No. 3-RJ

Rejoinder Testimony of
Vivian K. Ressler

Topics Addressed: **O&M Expense Adjustments**

Dated: June 12, 2023

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vivian K. Ressler. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Electric Statement No. 3, on January 27, 2023. I also submitted my rebuttal testimony, UGI Electric Statement No. 3-R, on May 25, 2023.

Q. What is the purpose of your rejoinder testimony?

A. My rejoinder testimony briefly responds to certain portions of the following surrebuttal testimony submitted by the Office of Consumer Advocate ("OCA") and the Pennsylvania Public Utility Commission's ("Commission") Bureau of Investigation and Enforcement ("I&E"): OCA Statement No. 1SR, the surrebuttal testimony of Dante Mugrace, and I&E Statement No. 2-SR, the surrebuttal testimony of Christopher Keller. More specifically, I respond to both OCA witness Mr. Mugrace's and I&E witness Mr. Keller's surrebuttal testimony regarding the Company's claimed incentive compensation expense.

Q. If you do not address specific aspects of the other parties' surrebuttal testimony that responded to your rebuttal testimony, does that mean you agree with the other party?

A. No. Unless otherwise specifically noted in my rejoinder testimony, UGI Electric maintains its rebuttal position in response to each adjustment raised by the other parties.

Q. Are you sponsoring any exhibits with your rejoinder testimony?

A. No.

II. INCENTIVE COMPENSATION

Q. Do any of the other parties' surrebuttal testimony continue to oppose the Company's claimed incentive compensation expense?

A. Yes. OCA witness Mr. Mugrace continues to oppose the Company's claim for recovery of certain incentive compensation expenses. OCA St. No. 1SR at 6-11. Similarly, I&E witness Mr. Keller continues to oppose the Company's claim for recovery of certain incentive compensation expenses. I&E St. No. 2-SR at 2-14. I note that the specific details of OCA's and I&E's proposed adjustments are set forth in my rebuttal testimony. Since their positions have not changed from their direct testimony, I do not restate those adjustments here.

Q. Please summarize OCA witness Mr. Mugrace's and I&E witness Mr. Keller's primary surrebuttal arguments against the Company's claimed incentive compensation expense.

A. Each of these witnesses continues to incorrectly argue that certain parts of the program are based upon the achievement of financial goals and metrics that do not benefit ratepayers (OCA St. 1SR at 8; I&E St. No. 2-SR at 4-5, 8-9, 12-13). In addition, both witnesses take issue with relying on the Commission's prior review and approval of the Company's same claim to recover the costs of its incentive compensation programs in the *UGI Electric 2018 Order*. OCA St. No. 1SR at 8; *see, e.g.*, I&E St. No. 2-SR at 8-9.

OCA witness Mr. Mugrace also acknowledges that the Company must attract and retain a qualified workforce but that the decision of "how" to attract and retain this workforce is a "business risk" that should be borne by the Company. OCA St. No. 1SR at 8. He also claims that the Commission "is not required to accept the Company's total compensation package (as an all or nothing approach), but rather the Commission should allow recover[sic] of costs that benefit ratepayers in the provision of utility service." OCA St. No. 1SR at 8. In addition, Mr. Mugrace attempts to highlight a specific portion of the Company's incentive compensation plan to argue that it is not aimed at enhancing productivity and efficiency of the utility. OCA St. No. 1SR at 8. Finally, Mr. Mugrace further argues that, in order for an expense to be prudently incurred, it must benefit customers and suggests that he "do[es] not believe that ratepayers should be burdened with costs related to the access of capital markets and to have the Company be attractive to investors to access capital markets." OCA St. No. 1SR at 9. I will address each of these claims below.

Q. As an initial matter, do Mr. Mugrace or Mr. Keller respond to the fact that the Company's incentive compensation is a component of its overall compensation program to attract and retain qualified employees, managers and executives?

A. No. In fact, both of these witnesses fail to acknowledge that their continued attempts to evaluate individual aspects of the Company's incentive compensation program in isolation run afoul of prior Commission orders, *i.e.*, the *PPL Electric 2012 Order*,[1] the *UGI Electric*

[1] *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-2012-2290597, at p. 26 (Final Order entered December 28, 2012).

2018 Order,[2] and the *Aqua 2021 Order*.[3] As explained in my rebuttal testimony, those orders made it clear that incentive compensation programs must be evaluated "as a whole" when determining whether the plan includes goals that benefit customers. UGI Electric St. No. 3-R at 9-12. While Mr. Keller does acknowledge that he misquoted the *Columbia 2021 Order*[4] in his direct testimony, he ignores the fact that the utility in that proceeding voluntarily withdrew its claim for stock options and restricted stock awards. Here, UGI Electric is not withdrawing its claim for stock options and restricted stock awards. Furthermore, the *Aqua 2021 Order* was issued after the *Columbia 2021 Order*.

Contrary to the testimony of OCA and I&E, UGI Electric's incentive compensation program, as a whole, is linked to performance and operational objectives, including safety, customer service, employee retention, diversity and inclusion initiatives, cost control and the satisfaction of compliance initiatives. Moreover, the Company's incentive compensation program is an essential component of attracting and retaining qualified employees to provide safe and reliable electric service to the Company's customers. As such, the Company should be permitted to recover these expenses.

[2] *Pa. PUC, et al. v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058, at p. 73-74 (Order entered Oct. 25, 2018).

[3] *Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc. v. Pa PUC, et al.*, Docket Nos. R-2021-3027385 and R-2021-3027386, et al. (Opinion and Order entered May 16, 2022).

[4] *Pa. PUC v. Columbia Gas of Pennsylvania Inc.*, Docket Nos. R-2020-3018835, et al. (Order Entered February 19, 2021).

Q. Do Mr. Mugrace or Mr. Keller address the fact that the financial performance goals included in the Company's incentive compensation programs do in fact benefit ratepayers?

A. No, neither witness responds to my rebuttal testimony on this point or the fact that the Company's incentive compensation program as a whole includes both financial and operating metrics and goals that benefit customers. While Mr. Keller attempts to claim that there are no measurable or quantifiable benefits to ratepayers associated with the achievement of financial goals under these programs, he ignores the fact that in order to provide reasonable, safe and reliable public utility service, the Company must attract investment in its operations. Financial goals that strengthen the profile of the Company and its parent improve its ability to attract capital in the competitive market on reasonable terms, which ultimately benefits ratepayers. In addition, incentive compensation goals that are tied to the Company's financial performance and strength also ensure that its workforce (i.e., employees, managers, executives and directors) endeavor to maintain and improve the Company's ability to attract the capital required to perform its essential utility functions.

Q. Please respond to OCA witness Mr. Mugrace's and I&E witness Mr. Keller's attempts to ignore the *UGI Electric 2018 Order*.

A. Both OCA and I&E take the position that the Commission's review of incentive programs should be done on a case by case basis. However, this argument does nothing to discredit the Commission's authoritative determinations that the costs of the incentive compensation program claimed in this case are recoverable.

Q. How does the incentive compensation program at issue in this proceeding compare to the incentive compensation program that was approved in the *UGI Electric 2018 Order*?

A. While certain details of the program components have changed since 2018, the changes actually reflect additional benefits to customers. Below is a table that compares the program components included in the current case to the ones that were approved for recovery in the UGI Electric 2018 case.

Plan	Approved for Recovery in 2018 Electric Case	Included in the 2023 Electric Case Claim
Management Incentive Plan	Yes	Yes
Executive Bonus Plan	Yes	Yes
Restricted Stock Awards	Yes	Yes
Stock Options	Yes	Yes

Q. What details of the Company's incentive compensation programs have changed since the *UGI Electric 2018 Order*?

A. Certain of these plans have been revised to include specific metrics that directly benefit customers. For example:

Within the existing <u>Management Incentive Plan</u>, the following metrics were added:

- Sustainability metrics, which benefit ratepayers by contributing toward reductions of emissions in the Company's service territory;
- Capital deployment metrics specific to the Electric division, which benefit ratepayers by improving the reliability of the electric distribution system; and

- Employee engagement and retention metrics, which benefit ratepayers by increasing the likelihood that employees are engaged, happy and able to provide superior customer service and that qualified employees are retained by the Company.

Within the Executive Bonus Plan, a diversity and inclusion metric was added, which allows ratepayers to benefit from diverse viewpoints and opinions. Because the Company's incentive compensation programs were approved for recovery in the *UGI Electric 2018 Order*, the service-focused enhancements to those programs made since then, further demonstrate that the entirety of the programs are recoverable in this proceeding.

Q. Please respond to Mr. Mugrace's claim that the decision of "how" to attract and retain a qualified workforce is a business risk that should be borne by the Company and its shareholders (OCA St. No. 1SR at 7).

A. It is the Company's workforce (i.e., its employees, managers, executives and directors) that is responsible for the provision of safe, reasonable and reliable electric service to its customers. As explained in my rebuttal testimony, UGI Electric's ability to attract and retain qualified individuals is directly related to its ability to provide them with reasonable and competitive compensation; if the Company did not offer incentive compensation, then alternative incentive compensation or higher base compensation (e.g., salary) would be necessary. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**

Q. Do you agree with Mr. Mugrace's attempt to highlight a specific portion of the Company's incentive compensation plan to argue that it is not aimed at enhancing productivity and efficiency of the utility (OCA St. No. 1SR at 8)?

A. No, I do not. In fact, Mr. Mugrace's example does not help his argument.

Q. Please explain.

A. Mr. Mugrace attempts to assert that the Company's incentive compensation related to its **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** OCA St. No. 1SR at 8. This is incorrect. Rather, as indicated in the Company's response to I&E-RE-14-D at CONFIDENTIAL Attachment I&E-RE-14 (C), despite not budgeting for this plan in Fiscal 2023 or Fiscal 2024, the Company recorded expense for this lineman plan in the first four (4) months of Fiscal 2023. The plan was not budgeted due to oversight; however, the lineman bonus is being paid to the eligible linemen. Absent this oversight, the Company would have included in base rates **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** While the Company did not update its claimed revenue requirement to include this amount in its base rate claim, the Company will pay the employees qualified for this program.

Q. Do you agree with Mr. Mugrace's claim that an expense must provide a positive benefit to customers in order to be considered prudent (OCA St. 1SR at 9)?

A. No. I am advised by counsel that Mr. Mugrace's proposed test for the recovery of an expense is not supported by law and that UGI Electric will address this argument further in its briefs. However, I note that there are a number of categories of expenses that have long been considered "reasonable and prudent" that do not provide a positive benefit to customers, including costs such as accounting, accounts payable, human resources, property taxes, cleaning and maintenance of Company buildings, rate case expenses, etc. Notably, Mr. Mugrace has not challenged the recoverability of the Company's accounts payable function or otherwise applied his proposed prudency standard to these expenses. This demonstrates that his proposed standard is unreasonable and should not be adopted.

III. CONCLUSION

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2022-3037368, et al.

UGI Utilities, Inc. – Electric Division

Statement No. 4-RJ

Rejoinder Testimony of
Eric W. Sorber

Topics Addressed:	**Vegetation Management** **Battery Storage Project**

Dated: June 12, 2023

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Eric W. Sorber. My business address is One UGI Center, Wilkes Barre, Pennsylvania 18711.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Electric Statement No. 4, on January 27, 2023. I also submitted my rebuttal testimony, UGI Electric Statement No. 4-R, on May 25, 2023.

Q. What is the purpose of your rejoinder testimony?

A. My rejoinder testimony responds to certain portions of the surrebuttal testimony submitted by the Office of Consumer Advocate ("OCA"). Specifically, I address portions of the testimony submitted by Dante Mugrace, OCA St. 1SR, as well as the testimony submitted by Morgan DeAngelo, OCA St. 5SR.

Q. If you do not address specific aspects of the other parties' surrebuttal testimony that responded to your rebuttal testimony, does that mean you agree with the other party?

A. No. Unless otherwise specifically noted in my rejoinder testimony, UGI Electric maintains its rebuttal position in response to each adjustment raised by the other parties.

Q. Are you sponsoring any exhibits with your rejoinder testimony?

A. Yes, as part of my rejoinder testimony, I am sponsoring UGI Electric Exhibits EWS-1RJ through EWS-2RJ.

II. VEGETATION MANAGEMENT

Q. Does Mr. Mugrace continue to oppose the Company's claimed vegetation management expense?

A. Yes, in OCA St. 1SR, Mr. Mugrace continues to oppose the Company's total vegetation management expense. However, in response to the "Company's need to remove the deteriorating and rotting trees to maintain service reliability and safety issues," Mr. Mugrace does make a significant adjustment to his position, reducing his disallowance by 50% from the position in his direct testimony, to $715,565. (OCA St. No. 1SR at 13.)

Q. Does the Company have any response to the reduced disallowance proposed by Mr. Mugrace on page 13 of his testimony?

A. Mr. Mugrace does not provide any basis in ratemaking for what he recommends as "a sharing of this disallowance . . . from the Company's proposed level of $3,931,777." (*Id.*) Calling the adjustment shared is inappropriate because OCA has not shown that any portion of the Company's claimed vegetation management expense is unreasonable, and OCA does not experience the disallowance in any way. Rather, the effects of the disallowance will be experienced by the Company in the form of a reduced ability to undertake necessary vegetation work, and by its customers in the form of resulting increased outages, all else being equal. Also, as related to the impact on customers, Mr. Mugrace's reduced disallowance effectively suggests that the Company should reduce vegetation management from planned levels that the Company has supported as reasonable and prudent for reducing the risks to the distribution system, thereby raising risks to customers of vegetation related outages. Further, Mr. Mugrace's factual basis for his adjustment is what he describes as "new information" regarding the vegetation threats being experienced in the Company's service territory. (*Id.*) This is not new information. UGI Electric has consistently identified the threat of diseased and dying trees in its discussion of its acceleration of vegetation management in base rate proceedings since 2018, and the Commission has repeatedly acknowledged these same risks in in its recent annual reliability reports. Finally, I note that the effect of Mr. Mugrace's adjustment is merely to bring his recommended allowance up to an amount that is still less than the Company spent in FY2021, reflecting no actual acceleration of funding for vegetation activities despite Mr. Mugrace's apparent recognition that diseased trees pose a major threat to reliability.

Q. Are there any flaws in the analysis presented in Mr. Mugrace's surrebuttal testimony?

A. Yes. I noticed certain inconsistencies and flaws in the analysis presented in Mr. Mugrace's surrebuttal testimony. First, Mr. Mugrace acknowledges that the 2020 vegetation management expense was impacted by COVID-19 and "should be considered an outlier." (OCA St. 1SR at 12.) However, Mr. Mugrace does not then exclude 2020 from his normalization calculation or final recommendation. Doing so would reduce his final recommended disallowance, including the 50% adjustment, by an additional $80,227.

Second, Mr. Mugrace relies on data from FY2021 through FY2024 (i.e., the FPFTY) to assert that the Company has not accelerated its vegetation management activities. This assertion should be rejected for two reasons. Focusing on spending levels from FY2021 to FY2024 only does show an overall acceleration of almost $700,000. While there was a small decrease in spending in FY2022, the Company is well on its way to incurring a much larger expense in FY2023 and expects a further incremental acceleration in FY2024. But on a more fundamental level, the choice to use only the data from FY2021 forward to conclude that there has been no acceleration, and not the data for the entirety of Mr. Mugrace's own normalization period (i.e., FY2018 forward), is inconsistent and misleading. If Mr. Mugrace started with the FY2018 vegetation management expense of $2,011,036, it is very apparent that there has been significant acceleration since that time, as FY2024 vegetation management expense is projected at $3,931,777, or nearly double the FY2018 level.

I point out these inconsistencies to emphasize that Mr. Mugrace's analysis does not reflect the current state of the Company's vegetation management program and should be rejected as a means for correctly identifying the appropriate level of cost recovery needed to address UGI Electric's vegetation management expense in the FPFTY.

Q. Do you have any updates to the data you provided in your rebuttal testimony?

A. Yes, I do. Since the submission of my rebuttal testimony, the Company has finalized its actual expense for the month of May. As a result, I have updated what was marked as Table 2 in my rebuttal, below. Table 2 had used an estimated value of $321,000 for May. The actual results for May are $332,859. The Company continues to be on track to meet or exceed its vegetation management budget of $3,807,997 for FY2023, further supporting the reasonableness of the Company's projections, including an anticipated spending level in FY2024 of $3,931,777 for vegetation management.

Table 2: Actual and Forecasted Distribution Vegetation Maintenance Expense For FY2023

Month	Spend	
Oct	$ 420,087	
Nov	$ 259,723	
Dec	$ 291,316	
Jan	$ 303,421	
Feb	$ 261,360	
Mar	$ 349,630	
Apr	$ 291,501	
May	$ 332,859	
Jun	$ 321,000	(1)
Jul	$ 321,000	(1)
Aug	$ 321,000	(1)
Sep	$ 381,000	(2)
Total	$ 3,853,897	

Note (1) – Through May is actual, June forward is forecasted baseline resource spend for balance of year

Note (2) **-** *Includes baseline resource spend plus additional planned third-party contractor*

Q. Does Mr. Mugrace raise any new vegetation management arguments or proposals in his surrebuttal?

A. Yes, he does. Mr. Mugrace claims that the Company has not provided a specific plan for acceleration or details regarding its approach to vegetation management and, consequently, recommends that the Company prepare a report on an annual or semi-annual basis addressing these elements. (OCA St. 1SR at 13.)

Q. Please respond to Mr. Mugrace's claims regarding the need for a specific plan.

A. The Company already provides its planned vegetation management activities to the Commission in a public docket. The Company files its *Biennial Plan for the Periodic Inspection, Maintenance, Repair and Replacement of Facilities* ("I&M Plan") with the Commission every two years, as required by 52. Pa. Code § 57.198, at Docket No. M-

2009-2094773. I have included the most recent I&M Plan, covering the period January 1, 2023, through December 31, 2024 (*i.e.*, nine months of the FTY and all of the FPFTY), as UGI Electric Exhibit EWS-1RJ. Pages 1 through 5 of the I&M Plan provide a detailed review of the Company's planned vegetation management activities, including the specific circuits and miles anticipated for inspection and active management, and a description of the other activities being undertaken by the Company as part of its overall vegetation management program. UGI Electric will file its next I&M Plan this October.

Q. Please respond to Mr. Mugrace's concerns regarding the Company's approach to vegetation management.

A. UGI Electric has specific vegetation management criteria that are used to produce consistent results across its system. Included with my rejoinder testimony as UGI Electric Exhibit EWS-2RJ is the current version of the Company's specifications, which have not changed substantively since the commencement of the Company's accelerated program in 2018. The specifications provide comprehensive guidelines on the activities and objectives for the Company's vegetation management program.

I do wish to note an incorrect statement by Mr. Mugrace in his surrebuttal testimony regarding the scope of the Company's activities. Mr. Mugrace incorrectly states on page 13 of his surrebuttal that the Company does not have authority to trim off-right of way trees. While the Company does not have an inherent right to trim off-right of way trees, UGI Electric regularly engages in discussions with property owners to obtain the right to trim off-right of way danger trees that have been identified by the Company as a danger to the Company's facilities and performs off-right of way vegetation management work as a result. This type of misunderstanding on the part of Mr. Mugrace has led him to incorrectly undervalue the time, cost, and scope of UGI Electric's vegetation management program.

Q. Should Mr. Mugrace's proposed further reporting requirement be adopted?

A. No, it should not because Mr. Mugrace's proposal is unnecessary. The Company already addresses its upcoming vegetation management plans, as well as anticipated and experienced costs, in its rate cases and in its biennial I&M Plan. No further reporting is needed, and Mr. Mugrace has not identified any benefit or objective that would be accomplished by requiring further reporting.

Q. Do you have any concluding comments regarding the OCA's testimony on vegetation management?

A. At no point in this case has the OCA claimed that additional vegetation management activities are not needed. Nor have they claimed that UGI Electric cannot accomplish the additional vegetation management activities that I have identified in my testimony. Simply put, OCA's testimony fails to provide a legitimate basis for reducing an expense that the Commission recognizes is one of the most critical and cost-effective activities that an electric distribution company can undertake to reduce outages and increase reliability. The adjustments proposed by the OCA should be rejected.

III. BATTERY STORAGE PROJECT

Q. Does OCA witness DeAngelo provide a response to your testimony regarding the customers served off Ruckle Hill Road?

A. Yes, Ms. DeAngelo continues to raise concerns regarding the customers served off Ruckle Hill Road.

Q. Please respond to Ms. DeAngelo's claims that the Company should have already addressed the reliability concerns for Ruckle Hill Road.

A. Ms. DeAngelo's contention ignores the challenges identified by the Company in the 2021 base rate proceeding that led the Company to propose a battery solution in the first place. Specifically, UGI Electric had exhausted low-cost and readily available solutions, and the only options for long-term reliability solutions involved extensive capital projects, which the Company described in my rebuttal testimony in the 2021 base rate case. Upon approval of the 2021 base rate proceeding, the Company engaged a consultant experienced with battery projects to undertake a detailed assessment of the engineering specifications. The Company ultimately determined that the battery storage project was not feasible in mid-2022. Given that timeline, and the very long timelines of alternative solutions, it simply was not possible for an alternative to already be completed at this time. However, as noted in my rebuttal testimony, the Company is actively continuing its work to identify solutions to deploy for supporting reliability on Ruckle Hill Road and anticipates undertaking work that will improve reliability on Ruckle Hill Road during the FPFTY.

Q. Ms. DeAngelo recommends that the Company both develop a plan for identifying a project and report every six months on the status of its process. (OCA St. 5SR at 3-5.) Do you agree with these recommendations?

A. No, I do not. The Company has exhaustively explored potential projects for Ruckle Hill Road based on currently available technology and, as noted above, continues work to identify and evaluate options. Specifically, as part of its annual project planning process, the Company will continue to review the changing conditions on the circuit and the technology available to provide additional reliability support. The Company's comprehensive planning process looks at its entire system and all of its available resources to ensure that the most critical reliability threats are being addressed. An additional process just for this circuit is not warranted because the circuit continues to be considered as part of the Company's current risk management process. Further, Ms. DeAngelo's recommendation of a report every six months would not be an effective planning process, as an annual timing coincides with key drivers for planning such as annual growing seasons, annual storm seasons, and system upgrade projects that are planned for and completed annually.

Q. Please respond to Ms. DeAngelo's claims regarding reallocation of the $1.5 million originally budgeted for the battery storage project.

A. Ms. DeAngelo's testimony ignores that the $1.5 million that was included in the Company's budget in the 2021 FPFTY (i.e., FY2022) was ultimately spent on reliability projects that improved reliability to hundreds of customers, including in part the 67 customers that would have been originally served by the battery storage project. On a fundamental level, the OCA's testimony attempts to tie dollars in the budget with an individual project and a specific group of customers and maintains that if those dollars cannot be used for that specific application, then the Company should reserve them for later projects related to that specific group of customers. That is simply not how the Company's budget and project management activities work, particularly with regard to reliability and betterment projects. There are many reasons why UGI Electric may need to shift the order of its planned projects or the total budget associated with a project. Where it does so, the budgeted money is ultimately spent on other projects that support reliable service to customers. UGI Electric has consistently spent its entire budget and more. (*See* UGI Electric Exhibit VAS-2.) Flexibility in prioritization is critical so that the Company can respond adequately to changing conditions and emergent issues on its system. There is no reason to earmark these budget dollars for specific customers or projects because doing so comes at the expense of the rest of the Company's customers and may compromise other reliability projects with an equal or greater impact. Where the Company identifies project activities that will benefit Ruckle Hill Road customers, it will fold the planning and execution of those activities into a normal budget cycle for completion on a timely basis.

IV. <u>CONCLUSION</u>

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

UGI Electric Exhibit EWS-1RJ

Michael S. Swerling, Esq.

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October 21, 2021

VIA EXPRESS MAIL

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

Re: Inspection, Maintenance, Repair and Replacement Standards For Electric Distribution Companies, Docket No. M-2009-2094773

Dear Secretary Chiavetta:

UGI Utilities, Inc. – Electric Division ("UGI Electric") hereby requests that the enclosed Biennial Filing of UGI Utilities, Inc. – Electric Division's Biennial Plan for the Periodic Inspection, Maintenance, Repair and Replacement of Facilities for the period of January 1, 2023 through December 31, 2024 (the "Plan") be accepted *Nunc Pro Tunc*. Pursuant to 52 Pa. Code §57.198(a), the Plan was due on October 1, 2021. The Company's failure to submit the report by the due date was inadvertent in nature.

Should you have any questions concerning this filing, please feel free to contact Eric Sorber at 570-332-4272 or esorber@ugi.com.

Respectfully submitted,

/s/ Michael S. Swerling

Michael S. Swerling

Enclosure

Biennial Inspection, Maintenance, Repair and Replacement Plan of UGI Utilities, Inc. – Electric Division For the period of January 1, 2023 – December 31, 2024

Submitted by:

Eric W. Sorber
One UGI Center
Wilkes Barre, PA 18711-0600
570-332-4272
esorber@ugi.com

Dated: October 21, 2021

Introduction

UGI Utilities Inc., - Electric Division ("UGI Electric" or the "Company") hereby submits this Biennial Inspection and Maintenance Plan ("I&M Plan" or the "Plan"), pursuant to 52 Pa. Code § 57.198, for the periodic inspection, maintenance, repair and replacement of its facilities (during the January 1, 2023 through December 31, 2024 period). The I&M Plan is designed to facilitate the Company's compliance with the reliability performance benchmarks and standards established by the Pennsylvania Public Utility Commission ("Commission").

I&M Plan

***Section 57.198 (b)*. Plan Consistency.** *The plan must be consistent with the National Electrical Safety Code, Codes and Practices of the Institute of Electrical and Electronic Engineers, Federal Energy Regulatory Commission Regulations and the provisions of the American National Standards Institute, Inc*.

UGI Electric's Plan is consistent with the National Electrical Safety Code, Codes and Practices of the Institute of Electrical and Electronic Engineers, Federal Energy Regulatory Commission Regulations and the provisions of the American National Standards Institute, Inc. as applicable to the work performed.

***Section 57.198 (m)*. Recordkeeping.** *An EDC shall maintain records of its inspection and maintenance activities sufficient to demonstrate compliance with its distribution facilities inspection, maintenance, repair, and replacement programs as required by subsection (n). The records shall be made available to the Commission upon request within 30 days. Examples of sufficient records include:*

(1) Date-stamped records signed by EDC staff who performed the tasks related to inspection.
(2) Maintenance, repair and replacement receipts from independent contractors showing when and what type of inspection, maintenance, repair or replacement work was done.

UGI Electric maintains records of its biennial inspection and maintenance activities in the form of date-stamped paper or electronic records (e.g. work orders and associated time-sheets) with the name of the UGI Electric employee that completed the relevant tasks (e.g., inspection, maintenance, repair, and replacement activities). The Company also maintains receipts and/or equivalent computer-based records with the name of independent contractors that similarly complete relevant inspection and maintenance tasks for the Company (including the nature of the work performed).

***Section 57.198 (n) (1)*. Vegetation Management.** *The Statewide minimum inspection and treatment cycle for vegetation management is between 4 - 8 years for distribution* *facilities. An EDC shall submit a condition-based plan for vegetation management for its distribution system facilities explaining its treatment cycle*.

Vegetation Management Line Inspection

UGI Electric has fifty (50) overhead distribution circuits on its system. The total miles of overhead primary line on these circuits is approximately 1,104 miles. The circuits are all located in Luzerne and Wyoming Counties, Pennsylvania.

UGI Electric performs a vegetation management inspection on approximately half the total circuit mileage each year ensuring a complete inspection of all overhead facilities every two years. The purpose of the vegetation management inspection is to assess the condition of vegetation on and off the primary lines' right of ways to identify situations that may pose a threat to reliability or may damage overhead distribution facilities. The inspection schedule for 2023 and 2024 is shown below:

UGI Utilities Inc.		**Vegetation Management Line Inspection Planned Circuit Miles *1,104.38 (total circuit miles)***	
Feeder Count	**Feeder Name**		
		2023	**2024**
1	Courtdale 8000	0	39.63
2	Courtdale 8002	0	8.76
3	Courtdale 8003	0	5.79
4	Dallas 350	0	5.75
5	Dallas 1930	0	5.66
6	Dallas 1954	0	4.32
7	Glenview 370	0	1.41
8	Glenview 372	0	18.55
9	Glenview 8004	0	48.58
10	Hunlock 419	19.88	0
11	Hunlock 420	124.05	0
12	Hunlock 421	48.30	0
13	Huntsville 240	0	23.19
14	Huntsville 242	0	32.35
15	Huntsville 244	0	71.99
16	Huntsville 757	0	12.47
17	Huntsville 759	0	22.18
18	Kingston 315	0	9.41

19	Kingston 1215	0	4.29
20	Kingston 2530	0	8.99
21	Kingston 2555	0	1.71
22	Koonsville 7536	35.71	0
23	Koonsville 7540	197.28	0
24	Kunkle 500	0	31.4
25	Kunkle 510	0	40.91
26	Kunkle 520	0	57.55
27	Lincoln 602	5.36	0
28	Lincoln 603	7.46	0
29	Lincoln 604	15.94	0
30	Lincoln 606	5.47	0
31	Loomis 102	7.87	0
32	Loomis 103	10.60	0
33	Loomis 104	0.30	0
34	Loomis 202	6.05	0
35	Loomis 203	4.51	0
36	Loomis 204	0.70	0
37	Plymouth 10	6.33	0
38	Plymouth 23	10.54	0
39	Plymouth 45	15.56	0
40	Plymouth 67	5.78	0
41	Plymouth 80	41.64	0
42	Swoyersville 116	0	13.51
43	Swoyersville 147	0	20.32
44	Swoyersville 216	0	6.15
45	Swoyersville 237	0	5.69
46	Swoyersville 247	0	17.02
47	Swoyersville 347	0	6.02
48	Hanover 70	8.53	0
49	Hanover 75	0.05	0
50	Hanover 8005	2.87	0

Accordingly, in 2023 and 2024, UGI Electric plans to inspect 580.6 circuit miles and 523.6 circuit miles respectively, for vegetation management risks.

Vegetation Management Treatment Plan

UGI Electric develops a condition-based vegetation management treatment plan each year. This plan is based largely on the results of its vegetation management line inspections (from the previous year). In addition, the Company reviews the number of tree-related interruptions on feeders (that were inspected in the prior year) and updates their established maintenance cycles (as needed).

For 2023 and 2024, UGI Electric plans to perform vegetation maintenance work on 300-400 miles of distribution overhead lines during the 2023 and 2024 Plan years. This work involves:

- Routine trimming/pruning of vegetation along each circuit per the appropriate specification for the right-of-ways.
- Distribution herbicide application to limit growth of brush under conductors and along right-of-ways. UGI Electric plans to chemically treat approximately 50 – 100 acres of distribution overhead lines each year.
- An active Danger Tree Removal Program mainly focuses on the removal of dead or declining trees on and off-road right-of-ways (when authorized by the landowner) that pose a threat to UGI Electric overhead facilities.

Vegetation Treatment Cycle

UGI Electric has established vegetation line treatment cycle times for its distribution circuits. The cycle times result from the operation of the vegetation management treatment plan described above. The treatment cycles range from 4 to 8 years. The expected treatment cycles for each of UGI Electric's fifty (50) overhead distribution circuits are shown in the table below:

Feeder Count	Feeder Name	EXPECTED TREATMENT CYCLE (Years)
1	Courtdale 8000	6
2	Courtdale 8002	6
3	Courtdale 8003	6
4	Dallas 350	6
5	Dallas 1930	6
6	Dallas 1954	6
7	Glenview 370	6
8	Glenview 372	6
9	Glenview 8004	7

10	Hunlock 419	6
11	Hunlock 420	7
12	Hunlock 421	7
13	Huntsville 240	7
14	Huntsville 242	7
15	Huntsville 244	7
16	Huntsville 757	6
17	Huntsville 759	6
18	Kingston 315	4
19	Kingston 1215	4
20	Kingston 2530	4
21	Kingston 2555	4
22	Koonsville 7536	6
23	Koonsville 7540	8
24	Kunkle 500	7
25	Kunkle 510	7
26	Kunkle 520	6
27	Lincoln St 602	5
28	Lincoln St 603	5
29	Lincoln St 604	5
30	Lincoln St 606	5
31	Loomis 102	4
32	Loomis 103	4
33	Loomis 104	4
34	Loomis 202	4
35	Loomis 203	4
36	Loomis 204	4
37	Plymouth 10	5
38	Plymouth 23	5
39	Plymouth 45	5
40	Plymouth 67	5
41	Plymouth 80	6
42	Swoyersville 116	5
43	Swoyersville 147	5
44	Swoyersville 216	5
45	Swoyersville 237	5
46	Swoyersville 247	5
47	Swoyersville 347	5
48	Hanover 70	6
49	Hanover 75	6
50	Hanover 8005	6

Justification (per Section 57.198 (c))

This inspection plan complies with the Statewide minimum inspection and treatment cycle of between 4-8 years for distribution facilities per Section 57.198(n)(1). Moreover, the Company's vegetation management is performed in accordance with ANSI A300 and Z133 Standards, utilizing generally accepted industry practices.

Section 57.198 (n) (2)*. *Pole Inspections. *Distribution poles shall be inspected at least as often as every 10-12 years except for the new southern yellow pine creosoted utility poles which shall be initially inspected within 25 years, then within 12 years annually after the initial inspection. Pole inspection must include:*

- *(i) Drill tests at and below ground level.*
- *(ii) A shell test.*
- *(iii) Visual inspection for holes or evidence of insect infestation.*
- *(iv) Visual inspection for evidence of unauthorized backfilling or excavation near the pole.*
- *(v) Visual inspection for signs of lightning strikes.*
- (vi) *A load calculation*.

Program Description

UGI Electric inspects all distribution poles on a 10 to 12-year cycle. These inspections maintain system reliability and safety by ensuring that all poles meet or exceed minimum strength requirements to support their attached facilities. The inspections also ensure that the poles and attachments are free from damage and environmental conditions that could compromise these facilities. A maintenance and treatment program (done in conjunction with the distribution pole inspections) aims to extend the useful life of poles.

All poles are inspected for decay, damage, and other potential hazards associated with electrical equipment. Poles suspected of having internal decay are inspected by the sound and bore method. Poles manufactured greater than 20 years before the inspection date are inspected below ground level whenever possible based on installation location and ground conditions (i.e., not installed in concrete or asphalt). The remaining strength of the pole (as compared to the original pole strength when installed) is calculated using data gathered from the inspection. If the remaining strength of the pole is found to be deficient, the pole is classified as: 1) a reject pole (a pole that fails the ground-line inspection but does not meet the criteria found in Section 57.198(n)(3) of the Pennsylvania Code); 2) a re-enforceable reject pole (a pole that can be restored to an acceptable strength when re-enforced with a steel truss or similar device); or 3) a danger pole (danger poles meet the criteria found in Section 57.198(n)(3)).

Further details can be found in UGI Electric's T&D Engineering Instruction Manual, Section 10.8.

Pole Inspection Plan

UGI Utilities, Inc.	Area	Pole Inspections Planned (Number of Poles)	
		2023	2024
Approximately 45,000 distribution poles, system wide	All or portions of Ross Township and Union Township	2,100	400
	All or portions of Lake Township and Noxen Township	1,700	0
	All or portions of Huntington Township, Jackson Township, Lehman Township, Hunlock Township, Plymouth Township	0	3,400

Justification (per Section 57.198 (c))

UGI Electric is requesting a waiver from pole loading calculations under Section 57.198(n)(2)(vi) due to construction standards that at a minimum, require the use of a Class 3, 40-foot pole for primary construction and more typically a Class 2, 45-foot pole based on the need for additional pole space. In addition, a review of interruption data from December 2019 through June 2021 identified only three (3) pole failures which contributed just 0.002% of the total customer minutes interrupted for the period. The inclusion of pole loading calculations would result in a significant cost increase relative to the inspection and maintenance program without an appreciable increase in reliability.

<u>Section 57.198 (n) (3)</u>*. *Pole Inspection Failure. *If a pole fails the groundline inspection and shows dangerous conditions that are an immediate risk to public or employee safety or conditions affecting the integrity of the circuit, the pole shall be replaced within 30 days of the date of inspection*.

<u>Corrective Maintenance</u>

Pole inspections that result in a Section 57.198(n)(3) determination are brought to the attention of UGI Electric's program administrator and prioritized accordingly. UGI Electric replaces these poles within 30 days of the date of inspection. Poles classified as rejects, that are not considered an immediate priority, are scheduled for replacement based on criticality. UGI Electric has seen an increase in pole reject rates in recent years, which has resulted in an accelerated pole replacement program under the UGI Electric Long-Term Infrastructure Improvement Plan ("LTIIP").

<u>Justification (per Section 57.198 (c))</u>

UGI Electric's Corrective Maintenance Program meets the requirements of 52 Pa. Code § 57.198 (n)(3).

<u>Section 57.198 (n) (4)</u>. Distribution Overhead Line Inspections. *Distribution lines shall be inspected by ground patrol a minimum of once every 1-2 years. A visual inspection must include checking for:*

I. Broken insulators.
II. Conditions that may adversely affect operation of the overhead distribution line.
III. Other conditions that may adversely affect operation of the overhead distribution line.

<u>Program Description</u>

UGI Electric inspects its overhead distribution facilities by ground patrol every two years. The purpose of the inspection program is to verify that the overhead facilities are in a safe, operational, and reliable condition. The inspections are performed by qualified Company representatives or approved contractors. The overhead lines and equipment are inspected for damage including broken insulators, failed cross-arms, leaks, and any other conditions which may adversely affect the distribution system. Inspection information is documented and forwarded to the appropriate engineering department when corrective action is required.

Further details can be found in UGI Electric's T&D Engineering Instruction Manual, Section 02-02.

<u>Distribution Overhead Line Inspection Plan</u>

UGI Utilities Inc.		**Overhead Line Inspection Plan Planned Circuit Miles *1,104.38 (total circuit miles)***	
Feeder Count	**Feeder Name**		
		2023	**2024**
1	Courtdale 8000	0	39.63
2	Courtdale 8002	0	8.76
3	Courtdale 8003	0	5.79
4	Dallas 350	0	5.75
5	Dallas 1930	0	5.66
6	Dallas 1954	0	4.32
7	Glenview 370	0	1.41
8	Glenview 372	0	18.55
9	Glenview 8004	0	48.58
10	Hunlock 419	19.88	0
11	Hunlock 420	124.05	0

12	Hunlock 421	48.30	0
13	Huntsville 240	0	23.19
14	Huntsville 242	0	32.35
15	Huntsville 244	0	71.99
16	Huntsville 757	0	12.47
17	Huntsville 759	0	22.18
18	Kingston 315	0	9.41
19	Kingston 1215	0	4.29
20	Kingston 2530	0	8.99
21	Kingston 2555	0	1.71
22	Koonsville 7536	35.71	0
23	Koonsville 7540	197.28	0
24	Kunkle 500	0	31.40
25	Kunkle 510	0	40.91
26	Kunkle 520	0	57.55
27	Lincoln 602	5.36	0
28	Lincoln 603	7.46	0
29	Lincoln 604	15.94	0
30	Lincoln 606	5.47	0
31	Loomis 102	7.87	0
32	Loomis 103	10.60	0
33	Loomis 104	0.30	0
34	Loomis 202	6.05	0
35	Loomis 203	4.51	0
36	Loomis 204	0.70	0
37	Plymouth 10	6.33	0
38	Plymouth 23	10.54	0
39	Plymouth 45	15.56	0
40	Plymouth 67	5.78	0
41	Plymouth 80	41.64	0
42	Swoyersville 116	0	13.51
43	Swoyersville 147	0	20.32
44	Swoyersville 216	0	6.15
45	Swoyersville 237	0	5.69
46	Swoyersville 247	0	17.02
47	Swoyersville 347	0	6.02

48	Hanover 70	8.53	0
49	Hanover 75	0.05	0
50	Hanover 8005	2.87	0

<u>Justification (per Section 57.198 (c))</u>

UGI's Distribution Overhead Line Inspection Plan meets the requirements of 52 Pa. Code § 57.198 (n) (4).

<u>Section 57.198 (n) (5)</u>. Inspection Failure. *If critical maintenance problems are found that affect the integrity of the circuits, they shall be repaired or replaced no later than 30 days from discovery*.

<u>Corrective Maintenance</u>

Any deficiencies on UGI Electric's overhead distribution system, discovered during performance of its Distribution Overhead Line Inspections, are addressed based on the severity of the situation. Those items that may affect the integrity of circuits are repaired or replaced within 30 days of discovery. Safety issues are addressed immediately.

UGI Electric maintains adequate inventory and manpower to take corrective actions as indicated above.

<u>Justification (per Section 57.198 (c))</u>

UGI Electric's Distribution Overhead Line Inspection Plan meets the requirements of 52 Pa. Code § 57.198 (n) (5).

<u>Section 57.198 (n) (6)</u>. Distribution Transformer Inspections. *Overhead distribution transformers shall be visually inspected as part of the distribution line inspection every 1-2 years. Above-ground pad-mounted transformers shall be inspected at least as often as every 5 years and below-ground transformers shall be inspected at least as often as every 8 years. An inspection must include checking for:*

- *(i)* *Rust, dents or other evidence of contact*
- *(ii)* *Leaking oil*
- *(iii)* *Installations of fences or shrubbery that could adversely affect access to and operation of the transformer*
- (iv) *Unauthorized excavation or changes in grade near the transformer*.

<u>Program Description</u>

UGI Electric inspects all of its overhead distribution transformers on a two-year cycle as part of the overhead distribution line inspection program.

UGI Electric inspects all of its padmount and below ground transformers on a five-year cycle. The purpose of the inspection is to verify that all transformers are in a safe, operational, and reliable condition. The inspections are performed by qualified Company representatives or approved contractors. The inspectors look for rust, dents and other evidence of contact, leaking oil, installations of fences and shrubbery that could adversely affect access to and operation of the transformer, unauthorized excavations or changes in grade near the transformer, and any other conditions which may affect the safety, access to or operation of the transformer.

Inspection information is documented. Conditions that require follow up are forwarded to the Engineering department for corrective action. Safety related issues are corrected immediately. Other reported problems are handled based on the severity of the situation.

UGI Electric maintains adequate inventory and manpower to take corrective action as indicated above.

Further details can be found in UGI Electric's T&D Utilities Engineering Instruction Manual, Section 02-08.

Distribution Transformer Inspection Plan

UGI Utilities, Inc.	**Overhead Transformer Inspections Planned**		
11,388 Overhead Type	**Feeder**	**Overhead Transformer/Feeder**	
2 Year Cycle		**2023**	**2024**
1	Courtdale 8000	0	426
2	Courtdale 8002	0	127
3	Courtdale 8003	0	87
4	Dallas 1930	0	52
5	Dallas 1954	0	57
6	Dallas 350	0	74
7	Glenview 370	0	13
8	Glenview 372	0	214
9	Glenview 8004	0	511
10	Hanover 0070	98	0
11	Hanover 0075	11	0
12	Hanover 8005	28	0
13	Hunlock 419	170	0
14	Hunlock 420	1198	0
15	Hunlock 421	468	0
16	Huntsville 240	0	268
17	Huntsville 242	0	273
18	Huntsville 244	0	815
19	Huntsville 757	0	170
20	Huntsville 759	0	237
21	Kingston 315	0	168
22	Kingston 1215	0	71
23	Kingston 2530	0	157
24	Kingston 2555	0	26
25	Koonsville 7536	581	0
26	Koonsville 7540	1370	0
27	Kunkle 500	0	293
28	Kunkle 510	0	350
29	Kunkle 520	0	555

30	Lincoln Street 602	60	0
31	Lincoln Street 603	94	0
32	Lincoln Street 604	204	0
33	Lincoln Street 606	54	0
34	Loomis 102	75	0
35	Loomis 103	123	0
36	Loomis 104	0	0
37	Loomis 202	69	0
38	Loomis 203	24	0
39	Loomis 204	0	0
40	Plymouth 10	89	0
41	Plymouth 23	134	0
42	Plymouth 45	198	0
43	Plymouth 67	66	0
44	Plymouth 80	411	0
45	Swoyersville 116	0	211
46	Swoyersville 147	0	248
47	Swoyersville 216	0	84
48	Swoyersville 237	0	68
49	Swoyersville 247	0	155
50	Swoyersville 347	0	153

UGI Utilities Inc. Padmount & Below Ground Transformers *5 Yr Cycle*	**Feeder**	**Transformer Inspection Plan** **Transformers/Feeder**	
		2023	**2024**
1	Courtdale 8000	3	10
2	Courtdale 8002	2	0
3	Courtdale 8003	0	0
4	Dallas 350	0	0
5	Dallas 1930	6	12
6	Dallas 1954	2	2
7	Glenview 370	0	0

8	Glenview 372	4	14
9	Glenview 8004	17	46
10	Hunlock 419	0	5
11	Hunlock 420	0	1
12	Hunlock 421	2	0
13	Huntsville 240	49	0
14	Huntsville 242	6	21
15	Huntsville 244	0	0
16	Kingston 315	0	0
17	Kingston 1215	22	0
18	Kingston 2530	0	0
19	Kingston 2555	0	0
20	Koonsville 7536	0	0
21	Koonsville 7540	0	5
22	Kunkle 500	0	5
23	Kunkle 510	0	0
24	Kunkle 520	2	2
25	Lincoln 602	0	12
26	Lincoln 603	0	0
27	Lincoln 604	9	16
28	Lincoln 606	7	7
29	Loomis 102	0	0
30	Loomis 103	0	0
31	Loomis 104	0	0
32	Loomis 202	0	0
33	Loomis 203	0	0
34	Loomis 204	0	0
35	Plymouth 10	23	0
36	Plymouth 23	23	1
37	Plymouth 45	0	0
38	Plymouth 67	0	0
39	Plymouth 80	7	15
40	Swoyersville 116	0	0
41	Swoyersville 147	0	5

42	Swoyersville 216	0	0
43	Swoyersville 237	0	0
44	Swoyersville 247	1	3
45	Swoyersville 347	0	3
46	Hanover 70	13	2
47	Hanover 75	0	13
48	Hanover 8005	0	0
49	Hanover 8006	0	0
50	Hanover 8007	0	0

Justification (per Section 57.198 (c))

UGI Electric's Distribution Transformer Inspection Plan meets the requirements of 52 Pa. Code § 57.198 (n) (6).

***Section 57.198 (n) (7)*. Recloser Inspections**. *Three-phase reclosers shall be inspected on a cycle of 8 years or less. Single-phase reclosers shall be inspected as part of the EDC's individual distribution line inspection plan*.

Program Description

UGI Electric inspects all of its three phase reclosers on a one-year cycle or less. UGI Electric inspects all single phase reclosers on a two-year cycle as part of the distribution overhead line inspection program.

The purpose of performing the inspections is to ensure continued safe and reliable operation of the reclosers. The inspections are conducted by qualified company representatives. The inspection check for physical damage, oil leaks, and any other conditions that could adversely affect the safe and reliable operation of the recloser.

Inspection information is documented. Conditions that require follow up are forwarded to the Engineering department for corrective action. Safety related issues are corrected immediately. Other reported problems are handled based on the severity of the situation.

Further details can be found in UGI Electric's T&D Engineering Instruction Manual, Section 02-06.

Recloser Inspection Plan

	Type	Recloser Inspection Plan	
		2023	2024
UGI Utilities, Inc. *128 Three Phase* *159 Single Phase*	Three Phase 1 Yr Cycle	128	140
	Single Phase 2 Yr Cycle	79	80

Justification (per Section 57.198 (c))

UGI's Recloser Inspection Plan meets the requirements of 52 Pa Code Chapter 57 Section 57.198 (n) (7).

***Section 57.198 (n) (8)*. Substation Inspections.** *Substation equipment, structures, and hardware shall be inspected on a cycle of 5 weeks or less*.

Program Description

UGI Electric inspects all of its distribution substations on a cycle of 5 weeks or less. The inspections are conducted by qualified Company representatives. The inspectors walk through each substation yard and control house documenting various equipment parameters and noting any physical damage, unsafe conditions, or potential problems with substation equipment, structures, and hardware. Substation fence integrity is verified along with the posting of danger and no trespassing signs. A description of the Company's Substation Inspection Program can be found in UGI Electric's T&D Engineering Instruction Manual, Sections 4-2-1 & 4-2-2.

The purpose of substation inspections is to ensure continued safe and reliable operation of the substations.

Inspection information is documented. Conditions that require follow-up are forwarded to the Engineering department for corrective action. Safety related issues are corrected immediately. Other reported problems are handled based on the severity of the situation.

Substation Inspection Plan

	Substation	**Substation Inspection Plan**	
		2023	**2024**
UGI Utilities, Inc. *Total Substations 15*	Mountain 230/66	12	12
	Courtdale 66/13	12	12
	Dallas 66/13	12	12
	Glenview 66/13	12	12
	Hanover 66/13	12	12
	Hunlock 66/13	12	12
	Huntington Mills 13/8	12	12
	Huntsville 66/13	12	12
	Kingston 66/13	12	12
	Koonsville 66/13	12	12
	Kunkle 66/13	12	12
	Lincoln 66/13	12	12
	Loomis 66/13	12	12
	Plymouth/Lance 66/13	12	12
	Swoyersville 66/13	12	12

Justification (per Section 57.198 (c))

UGI Electric's Substation Inspection Plan, which follows a monthly inspection cycle, is in-line with industry standards and meets the requirements of 52 Pa. Code § 57.198 (n) (8).

UGI Electric Exhibit EWS-2RJ

UGI Utilities, Inc.

Electric Division

511 East Northampton Street

Wilkes-Barre, PA 18711

Line Clearance Specifications

Contents

LINE CLEARANCE SPECIFICATIONS

I. Line Clearance Program Objectives

This specification defines procedures and practices to be followed by Contractors engaged in line clearance work for UGI Utilities, Inc. ("Company").

A. Reliable Electric Service

Through our line clearance program, our objective is to aid in maintaining an uninterrupted low of electricity to our customers by preventing power outages caused by trees.

B. Safe Electric Service

Through our line clearance program, our objectives are to trim and remove enough vegetation in order that a safe clearance can be maintained between the wires and trees, minimizing the chances of people coming in contact with our facilities (electricity).

C. Cost Effective Customer Services

We strive to maintain safe and reliable electric service to our customers, at a reasonable rate. Therefore, it is the Line Clearance Department's responsibility to effectively and efficiently utilize Contractors to perform our work. Crews, equipment, and workload are managed within the fiscal budget to achieve the highest quality and quantity of work possible.

II. Liaison

The Company will appoint a supervisor who will be the liaison between the Company and the Contractor. They will be responsible for the scheduling and inspecting the Contractor's work as outlined in the specifications and right-of-way releases furnished by the Company.

III. Safety

The Contractor will take the necessary safety precautions to prevent injury to human life or damage to property and will operate with minimal interference to traffic or inconvenience to the public. All applicable rules and regulations of the Company, OSHA, and the Pennsylvania Department of Transportation will be strictly adhered to.

The Contractor must treat every circuit and/or line, as *always energized*. Inquire and be aware of the nature of the circuits involved in all cases before work is commenced. The electric circuits are to continue in normal operation during this work; therefore, the Contractor is to use all necessary protection for their employees and to guard against interference with the normal operation of the circuits. If, in the judgment of the Contractor foreman, it is hazardous to trim or remove trees with the circuits energized, the Company supervisor will be contacted. If necessary, protective equipment or de-energized circuits will be provided by the Company to ensure the safe completion of work.

IV. Public Relations/Property Owner Contact

The Contractor and their employees must carry out this work efficiently, economically and with the goal of improving or continuing good public relations for the Company.

When performing the work, the Contractor's employees must keep in mind that the Company in some cases has secured a right-of-way agreement for that property, and pursuant to its agreement, the Company has the right to construct, operate, and maintain its facilities within the boundaries of the right-of-way. The right to maintain includes the right to "<u>cut, trim, or remove all trees and undergrowth that may interfere with or threaten to interfere with</u>" these facilities.

However, there are other considerations that must be observed in order to maintain a safe facility and good business relationships between the Company and its customers. The Contractor will:

D. Contact the property owner prior to performing work. This contact is to notify the property owner of our intent to work on their property, not to ask permission.

E. When it is necessary to cross owner's property to gain access to the right-of-way, permission to cross the property should be secured from the property owner.

F. Along state highways and in many municipalities with shade tree commissions, tree work may be performed only after written permits have been obtained from the proper authority by the Company. These permits must be carried by the Contractor foreman in charge of the work in the area for which the permit has been secured.

G. The Contractor should keep a record of contacts with each property owner.

V. Communication Tools for Crew Foreman

A door hanger (provided by the Contractor) will be used by crew foreman when, on the first visit, a property owner is found to be "not at home." Property owner completes the form, hanging it back on the door. Crew foreman picks up signed door hanger and retains for permanent record. The signed door hanger should be retained in Contractor's office for a period of two years in case damage claims are made against the Contractor. Whenever possible, the foreman should give property owner one week notice prior to performing the work.

VI. Procedure with Problems

Problems encountered by the Contractor regarding customers refusing any work being done on their property, will be referred to the Company supervisor.

VII. Employee Qualifications

The Contractor supervisor and the crew foreman must be certified and licensed commercial applicators by the appropriate regulatory authority to perform the application of herbicides.

Contractor must be familiar with the American National Standard entitled, "Safety Requirements for Pruning, Trimming, Repairing, Maintaining and Removing Trees, and for Cutting Brush," designated ANSI Z-133.1.

The crew foreman must be familiar with herbicide treatment methods used to control right-of-way vegetation. They must be familiar with the woody plants and the herbaceous vegetation normally found on the Company's rights-of-way. They must understand the Company's method of numbering and locating poles on map sections and circuit maps. They must be capable of contacting property owners and explaining the right-of-way line clearance program objectives for that particular circuit.

All Contractor employees must be physically capable and have the necessary skills to efficiently and safely perform the work. Their appearance and conduct must be satisfactory from a public relations standpoint.

Each member of the crew will be periodically evaluated by the Company supervisor. The Contractor will promptly replace any employee who does not receive a satisfactory evaluation in accordance with the following standards:

A. Foreman

1. A minimum of two years' experience in tree trimming and related work.
2. A sound knowledge and understanding of the Company's specifications covering the work assigned.
3. Courteous in their contacts with property owners.
4. The ability to safely perform all duties of a tree trimmer.
5. The ability to prepare legible and correct reports.
6. The ability to plan and perform assigned tree work to efficiently utilize the men and equipment in their charge.

B. Tree Trimmer/Climber

1. A minimum of four month's experience in tree trimming work for promotion from apprentice to trimmer/climber on Company property.
2. The ability to climb and find their way efficiently and safely through any tree.

3. The ability to safely remove limbs or branches that overhang conductors.

4. A sound knowledge and understanding of the principles of natural trimming.

5. A sound knowledge of natural trimming that will maintain the characteristic shape of each species.

6. A sound knowledge of the strength and special characteristics of native tree species.

7. A sound knowledge of rope rigging and other skills used in tree removal.

VIII. Crew Size

The Company supervisor will specify the crew size for all hourly rate work, based on the type of work to be performed.

When qualified trimmers/climbers are not available and the Company supervisor agrees, Contractor may hire one apprentice per crew.

The Contractor foreman and the Contractor supervisor will be responsible for training crew members.

An apprentice climber may be promoted to a qualified climber after a minimum of four months' training and the agreement of the crew foreman, their supervisor, and the Company supervisor as to their demonstrated ability.

IX. Contractor Inspection

The Contractor supervisor will inspect each crew at no less than weekly intervals. During these inspections, they will be responsible for the following:

A. Inspection of all tools and equipment, immediately replacing those which are dull, damaged, or unsafe.

B. Inspection of work performed as well as work in progress, spending sufficient time with the crew to train them in proper trimming methods according to this specification.

C. Maximizing crew production through instruction on the efficient use of men and equipment.

D. Immediately removing and replacing any or all of the crew members who cannot or refuse to perform the work according to this specification.

E. Inspect the worksite for proper setup according to PENDOT Regulations.

F. Verify all crew members have appropriate personal protective equipment and following safe work practices.

In addition to the weekly inspections, the Contractor supervisor will discuss the work with the Company supervisor at no less than weekly intervals.

X. Company Inspection

The Company supervisor will periodically inspect the crew, tools, equipment, and work when the work begins to determine adherence to this specification. When this specification is not being adhered to, they will immediately report the deviation to the Contractor supervisor for immediate correction.

All significant violations of these specifications must immediately be corrected by the Contractor at no cost to the Company and repeated violations of these specifications will be sufficient cause for the replacement of the crew foreman.

XI. Scheduling of Work

The Company supervisor shall inspect all transmission circuits annually and half the distribution circuit mileage annually. Upon completing the visual inspection, circuits should be scheduled for line clearance work accordingly.

On transmission, no vegetation shall approach a distance to the conductor of less than five (10) feet for 69 kV lines and ten (20) feet for 230 kV lines.

If visual inspection determines any vegetation inside the zones specified, line clearance work shall be scheduled immediately.

XII. Right-of-Way Widths

Normally, all rights-of-way will be maintained to the originally established clearances or the limits defined on the right-of-way agreement, whichever is greater. Listed below are the minimum clearances desired on UGI's system.

Distribution Primary (4 kV to 13 kV) – 20 feet (10 feet each side of center line ground to sky new construction)

Distribution Primary (4 kV to 13 kV) – 20 feet (10 feet each side of center line or hard tree edge whichever comes first ground to sky)

Transmission (66 kV) – 50 feet (25 feet each side of center line, or to the full width of the R.O.W. ground to sky)

Transmission (230 kV) – 150 feet (75 feet each side of center line, or to the full width of the R.O.W. ground to sky)

XIII. Definition of a Tree

For this specification, a tree is defined as a woody plant, normally single stemmed, that is four inches DBH (diameter breast height) or greater.

Since trees cannot be easily measured after being cut down, an arbitrary stump diameter of four inches or greater has been established to define a tree removed. Areas having stump diameters less than four inches will be recorded as units cleared. (One unit equals 1,000 square feet.)

XIV. Tree Trimming Objectives

There are several objectives to keep in mind when trimming for line clearance:

A. To obtain the required clearances, if possible, given the type of tree, property owner demands, and any local or state regulations that may apply (shade tree commissions, State Highway Department, etc.)

B. Utilize the American National Standard for Tree Care Operations (ANSI-A300) to maintain the health of the tree.

C. To trim the tree as efficiently as possible.

XV. Trimming Methods

A. <u>Directional</u> (also-natural, drop crotch). This method involves trimming the tree so that the remaining growth after trimming is “directed” away from the conductors, encouraging future growth away from the conductors. Directional trimming can be used on trees growing under and along side of the conductors (top trimming and side trimming). (See Exhibits 1 and 2.)

The most important aspect of directional trimming is to remove most of the growth points directly underneath the wires. This means that large limbs under the conductors should be removed back to their parent limbs. Once this is done, the remaining growth should be trimmed so that little, if any, branches grow directly toward the conductors. The result of this will be that little re-sprouting will take place beneath the conductors, the tree will direct its energy to growth points growing away from the conductors, and therefore future need for trimming will be reduced.

This method is preferred over “rounding-over” for trees growing beneath the conductors because it is more efficient (less cuts), better for the tree’s health (less cuts – will not need to be trimmed as often) and provides better line clearance over a period of time.

B. <u>Minimum Clearance. For the various lines specified, a minimum clearance must be obtained when performing routine maintenance trimming. (Clearance listed is from primary conductor)</u>

- <u>Distribution lines 4kV to 13kV – six (6) feet from conductor.</u>
- <u>Transmission 66kV – fifteen (15) feet from conductor</u>
- <u>Transmission 230kV – twenty (25) feet from estimated maximum sag of the conductor.</u>

C. <u>Roundovers</u> (also shaping, pole-clip clearance, etc.) This method involves shaping the crown of the tree so that clearance can be obtained and still make the tree "look like a tree." This is usually done by clipping every branch on the tree a few feet back into the crown. When the trimming is completed, a lollipop-shaped tree remains.

This method of trimming is to be avoided whenever possible unless customer specifies it or where the tree in question, by virtue of large size, shape, or limb structure, does not lend itself to natural trimming. One reason to avoid roundovers is that it takes too long. Secondly, this method does nothing to decrease the amount of growth beneath the conductors. A year after trimming with this method, every cut will sprout 1 to 5 new branches, and all you have done is multiplied the problem. Each one of those hundreds of cuts must be walled-off or "compartmentalized" by the tree, straining its food supply normally used for growth and development.

D. <u>Side Trimming</u> (also side-walling, etc.) This method is used on trees not directly underneath the conductors but lying off to one side. These trees are usually on the right-of-way edge. Side trimming is compatible with directional trimming in that you remove branches from the tree that are growing toward the conductor and trimming the remaining growth so that future growth will grow away from the conductors. Also, any branches that are growing over or "overhanging" the conductors should be removed "ground to sky" whenever possible so that if they break during a storm, etc., they will not fall onto or lay on the electric wires.

XVI. Trimming Techniques

A. <u>Target Trimming/Branch Bark Ridge Cut</u> (modified flush-cutting). This technique of trimming is the healthiest way of trimming individual large branches of a tree. The term "target trimming" refers to the circle-shaped cut that is left when you follow this method rather than the oval-shaped cut usually left when flush cutting.

Tree's natural defenses are contained in a protective zone surrounding the branch where it meets the main stem. This raised ring around the branch is called the <u>branch collar</u> (BC). Another protective zone occurs at any place where two branches join, called the <u>branch bark ridge</u> (BBR). If these areas are allowed to remain on the tree after the branch is cut, the protective zone will more quickly wall-off the injured area and therefore minimize infection and decay. Flush-cutting removes these protective zones, and therefore should be avoided. (See Exhibit 3.)

B. Trimming to Lateral Branches. This refers to cutting branches back to their parent stem, just above the branch collar. It is important not to cut off the branch collar but it is just as important not to cut too far above the branch collar either. This is known as "stubbing." It not only looks unprofessional, but it also does not give the branch collar a chance to properly heal the cut.

When cutting a branch back to a lateral, cut back to a lateral that has enough foliage and size to support itself and the cut branch. Cutting back to a branch which is one-third the diameter of the cut branch is the basic rule-of-thumb for this. (See Exhibit 3.)

C. Deadwood Removal. Large deadwood should be removed from trees where it overhangs the conductors, where it may endanger the public or property, or where it is very unsightly. Smaller deadwood which does not meet the above criteria should not be removed.

D. Pollarding (hat-racking). Pollarding is basically trimming every branch so that no live growth is left and sprouting is needed to make the tree survive. This method is to be avoided, even if the customer demands it, because it is unhealthy for the tree and is unsightly, which makes our program appear very unprofessional.

XVII. Tree Removal

This can be a valuable tool to eliminate problem trees, improve service reliability, and cut costs. In some cases, though, it can also be unnecessary, time-consuming, and expensive.

The following are some guidelines to follow when deciding whether to remove a tree.

A. A tree should be removed when:

1. Tree is under primary lines.

2. Tree is within 10 feet either side of primary lines and is less than 30 inches DBH.

3. Tree is dead or dying and within contact distance of the primary lines.

4. Tree has evidence of people climbing it (bird houses, rope swing, tree house, edible fruit, etc.) and is close enough to the primary lines that people could make contact with these wires.

B. **A tree may not be removed when**:

1. Tree is back further than 10 feet from the Company's facilities.

2. Tree is near service wire only. Inform property owner that they must remove tree privately; but if they notify the Company they will drop the service wire free of charge.

3. Tree is near secondary wire only.

4. Tree's location falls under government jurisdiction such as State Highway Department, local shade tree commissions, etc.

5. Tree is next to primary lines and has a DBH of over 30-inches.

Before a removal can take place for any of the circumstances listed above in Section B, the Company supervisor must first give their approval.

A tree designated to be removed should be cut down entirely to a stump as flush to the ground as possible unless property owner demands otherwise.

XVIII. Clear Cutting/Selective Clearing

This involves removal of all trees (and brush) for a certain length and width on a right-of-way. Selective clearing is different from clear cutting in that with selective clearing, you would not cut low-growing trees or shrubs:

<u>Examples</u>:

Arrow Wood	Hawthorne	Rhododendron
Azalea	High Bush Blueberry	Scrub Oak
Crabapple	Laurel	Spicebush
Dogwood	Leatherwood	Sumac
Eastern Red Cedar	Redbud	Witch Hazel

Selective clearing is only done at the request of the property owner, the Company supervisor, or a governmental official. Otherwise, remove all vegetation, including low-growing.

A site that has brush (areas of dense, small trees) should be cleared at all times, not trimmed. If a property owner demands that brush should be trimmed instead of cleared, do not trim but inform the Company supervisor.

When brush is cut, stumps will not exceed a height of three inches. Right-of-way length and width will be measured to nearest five (5) feet for convenience in calculation of units cleared. All measurements will be horizontal.

XIX. Brush Disposal

All brush resulting from tree work will be disposed of daily in accordance with recognized safety rules and satisfaction of the property owner. There are various methods of brush disposal to be considered.

A. In wooded areas, brush may be piled at edge of the right-of-way for wildlife cover.

B. In wooded areas, brush may be chipped and blown onto the right-of-way.

C. In wooded areas, brush may be dropped and scattered on the right-of-way.

D. When none of the preceding methods apply or when property owner refuses these methods, the brush may be chipped and hauled to a dump site.

E. Burning brush is prohibited!

Wood chip disposal is the Contractor's responsibility, although the Company may provide some locations for dumping as chip requests are received from the public. Chips are not to be sold to anyone, anytime! Chip dumping locations farther than 15 minutes from crew's current jobsite are not allowed without prior approval from the Company supervisor (maximum of one-half hour per load of chips).

XX. Large Wood and Stumps

Wood that cannot be chipped should be left on the property it was cut from. The wood should be cut into moveable lengths and stacked on the right-of-way edge or next to the tree it was cut from. Wood should not be cut any smaller than necessary; do not cut into fireplace lengths unless property owner demands it. Wood may also be left in whole lengths if property owner requests it (board lengths). Never haul wood from jobsite unless approved by Company supervisor.

Tree stumps should be cut as flush to the ground as possible. You should make this clear to a property owner, that we cannot remove stumps at all.

XXI. Overall Cleanup

A. Areas around homes and businesses should be thoroughly raked and paved/concrete surfaces should be swept. Debris from raking and sweeping should be disposed of properly.

B. Wooded areas, farm fields, and other unpopulated areas do not have to be raked or swept. However, all chipped brush should be disposed of so that the site still looks clean.

C. Any trash made by crews should be cleaned up and disposed of properly. Do not throw in with chips. Some form of litter bag is suggested!

XXII. Obstructing Road, Stream, Etc.

In no case will brush or wood be left in a location where it may obstruct other utility rights-of-way, roads, trails, paths, or water channels.

XXIII. Danger Trees

Trees located outside the right-of-way which pose a threat to service reliability ("danger trees") will be removed on an individual tree basis. "Danger trees" are generally diseased, damaged, or lean toward the line in a manner which poses a threat to service reliability and/or integrity of the line under any weather condition. The Company supervisor will instruct Contractor as to determination of "danger trees" and Contractor will remove trees in accordance with those instructions.

XXIV. Streetlights

Street lights will be kept free of trees. All limbs which cause the street to be poorly lighted must be removed only when routine trimming is being performed on that circuit or unless otherwise advised by Company supervisor.

XXV. Secondaries

Secondaries will be cleared 18 inches to 20 inches only when routine trimming is being performed on that circuit or unless otherwise advised by Company supervisor.

XXVI. Pole Sites

The circumference around each pole installation shall be cleared to an extent of five (5) feet.
Vines attached to/growing on poles shall be cut <u>not pulled off</u>, and if permitted by landowner treated with herbicide. Vines that are growing into primary or secondary that are pulled down could result in a potential outage and/or injury. Poles covered in vines shall be cut or clipped so that the grid stencils can be easily read.

XXVII. Services

Service will not be routinely trimmed; however, the following conditions may warrant an exception.

A. Service wires are bare and grown in.

B. Large limbs are pushing on service.

C. Large dead limbs overhang service.

D. Directed to do so by Company supervisor.

XXVIII. Stump Treatment

Stumps will be treated the same day, weather permitting, with herbicides when removals and small clearing jobs are performed. If weather does not permit, stumps should be treated next possible working day.

Areas involving large amounts of clearing should also be treated and noted on circuit map to be scheduled for a herbicide treatment two growing seasons after clearing. Every effort will be made to spray undesirable vegetation on areas which have been previously clear cut.

All herbicides must be used in strict accordance with EPA labeled instructions and use precautions.

XXIX. Herbicide Treatment

Herbicide application is encouraged in right-of-ways where clear cutting previously was performed.

Various herbicide application techniques and different herbicides are used system wide. Choosing the technique and herbicide to be utilized for a given area is determined by visual inspection by the Company supervisor and Contractor general foreman. **The Companies Herbicide Use Policy must be followed**.

Listed below are some of the different applications:

A. Selective high volume stem/foliar.

B. Selective low volume foliar.

C. Selective ultralow volume foliar.

D. Selective low volume basal.

Herbicides are only used where permission is granted in the right-of-way agreement or permission has been obtained by the property owner.

The season for all foliar applications is between June and the end of September when the trees are in full leaf.

The low volume basal can be performed year-round if desired.

XXX. Treatment of Cuts

A wound on a healthy tree, such as the area where a limb has been removed, is eventually covered by new wood, callous tissue, and bark.

Because of this ability to heal itself, painting of cuts is unnecessary except where Company supervisor, property owner, local governing bodies, or good judgment (in cases of large exposed cuts) indicate such action is necessary.

XXXI. Emergency Clearance

When there is an emergency involving trees, the major consideration is the restoration of service. Under emergency conditions, only enough trimming or clearance to permit the rapid restoration of service should be done. No disposal of wood or brush is permitted, although both should be placed on the property from which the tree came.

XXXII. Inclement Weather

For both production and safety reasons, trimming of trees should normally not be performed during weather conditions which might make the work hazardous or unsafe. The Contractor foreman and the Contractor supervisor will make that determination. However, tree work and right-of-way clearing may be performed in the same area provided the work can be done safely, satisfactorily, and in an efficient manner. Areas of clearing and brush cutting should be saved just for this purpose.

XXXIII. Operating Troubles

When a condition is found that might cause a service interruption, the matter will be immediately reported to the Company.

XXXIV. Time Report

The Time Report will be prepared daily by the Contractor foreman and submitted weekly to the Company supervisor following the performance of the work. This report will be complete and factual specifying type of crew, work location, work activities performed, hours worked, equipment and materials used for tree trimming, tree removal, and clearing and spraying of rights-of-way. There is one Time Report per day per crew.

XXXV. Daily Reporting

The Contractor foreman must report their work location and crew composition to the Company System Operator at the start of each workday by telephone or Company radio.

When work is stopped for the day due to equipment failure or inclement weather, the Contractor foreman must report the early quit to the Company System Operator immediately by telephone or Company radio.

When changes occur in work location during the day, the Contractor foreman must report to the Company System Operator immediately, by telephone or Company radio, of their new location.

<u>Illustration 1 – Top Trimming</u>

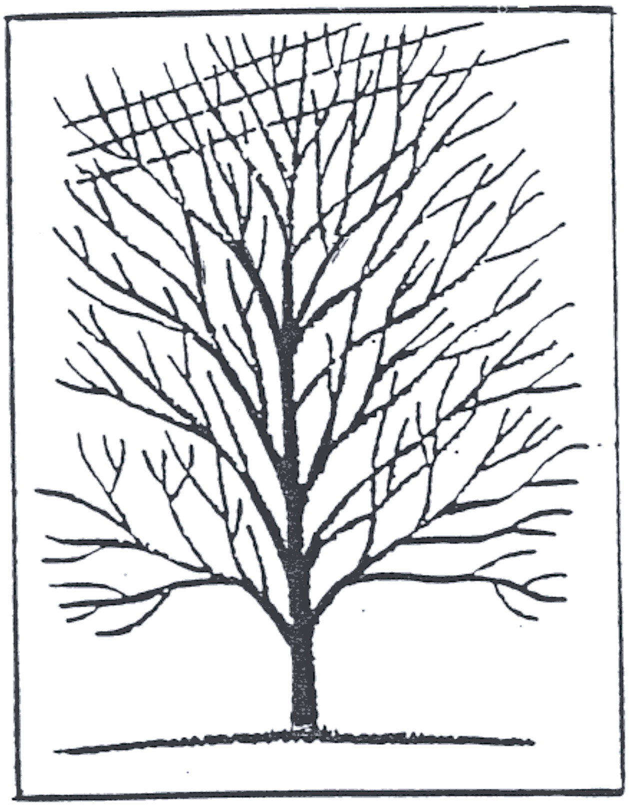
<u>Illustration 2 – Side Trimming</u>

<u>Illustration 3 – Removing Limbs</u>

Illustration 1 - TOP TRIMMING

Utilizing the Directional/Natural Method

BEFORE TOP TRIMMING



AFTER TOP TRIMMING

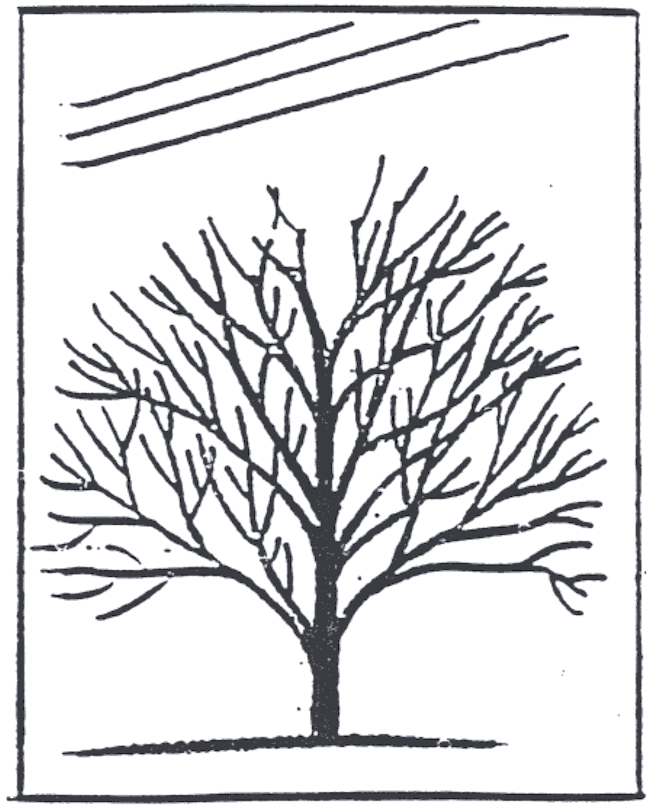
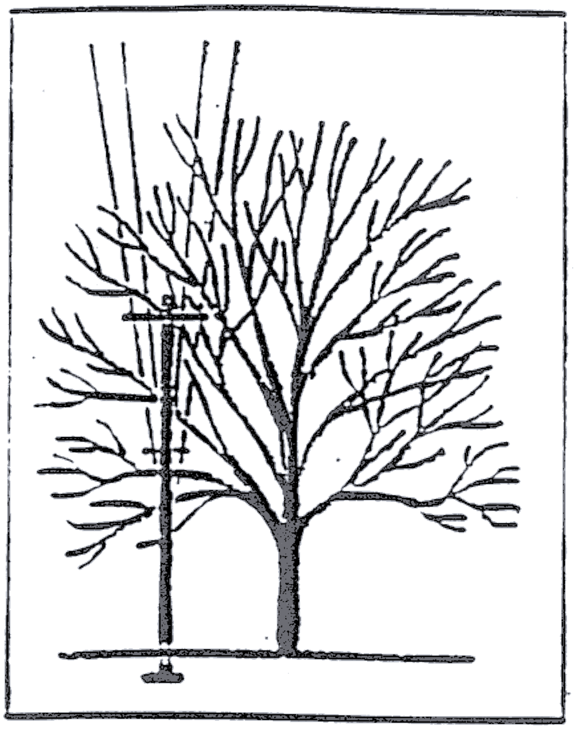


Illustration 2 - SIDE TRIMMING

Utilizing the Directional/Natural Method

BEFORE SIDE TRIMMING



AFTER SIDE TRIMMING

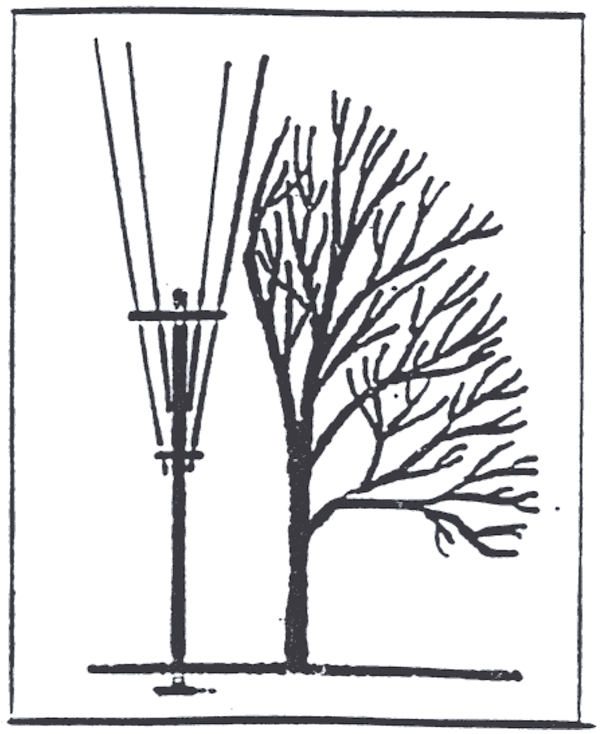
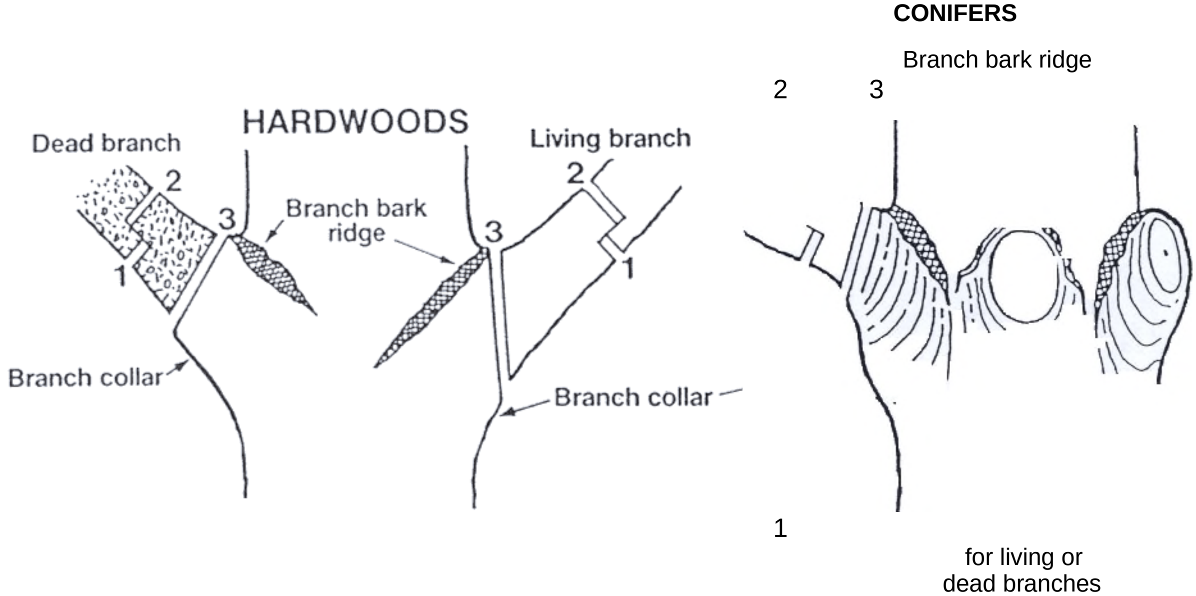


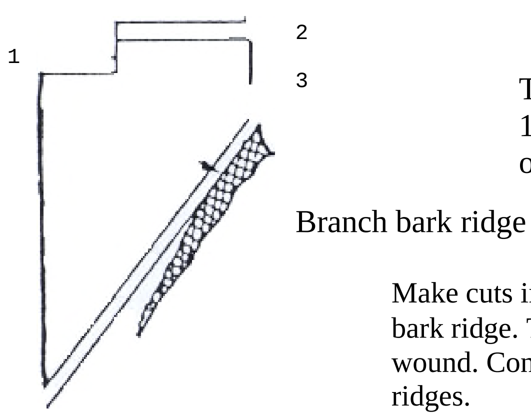
Illustration 3 – REMOVING LIMBS

Methods of Sawing and Removing Branches from Trees

<u>SIDE TRIMMING</u>



Make 3 **cuts in removing** a **large branch. Cuts** 1 **and** 2 **keep the wood from splintering and cut** 3 **(parallel to trunk and flush with top of branch collar) leaves** a **smooth surface that will heal quickly. When no noticeable branch collar exists, make cut** 3 **parallel and flush with trunk. Cuts should not remove branch bark ridge.**

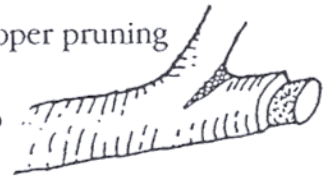


Top Trimming

The branch should be at least 1/3 the diameter of the trunk or limb being removed.

Make cuts in vertical limbs at an angle of about 45° and above branch bark ridge. This will prevent water from collecting and seeping into the wound. Conifers will require horizontal cut to preserve branch bark ridges.

Result of improper pruning



Tree trimmer should have made cut at fork. The stub has nothing to feed (it will decay and drop off.) The decay will work through the branch into the tree trunk and eventually destroy the whole tree.

ALWAYS MAKE A CLEAN SMOOTH CUT.
A JAGGED WOUND OR A SPLINTERED SURFACE WILL CAUSE DECAY.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2022-3037368, et al.

UGI Utilities, Inc. – Electric Division

Statement No. 6-RJ

Rejoinder Testimony of
John D. Taylor, Managing Partner
Atrium Economics, LLC

Topics Addressed:	**Cost of Service** **Residential Customer Charge**

Dated: June 12, 2023

Table of Contents

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Electric Statement No. 6, on January 27, 2023, and rebuttal testimony, UGI Electric Statement No. 6-R, on May 25, 2023.

Q. What is the purpose of your rejoinder testimony?

A. My rejoinder testimony responds to certain arguments of the surrebuttal testimony submitted by the Office of Consumer Advocate ("OCA"). Specifically, I respond to OCA Statement 3SR, the surrebuttal testimony of Karl R. Pavlovic ("OCA witness Pavlovic"), and OCA Statement 4SR, the surrebuttal testimony of Roger D. Colton ("OCA witness Colton"). The areas addressed include the following:

- Allocated Cost of Service Study Methodology
- Residential Customer Charge and Low-income Customer Impact

Q. Are you sponsoring any exhibits with your rejoinder testimony?

A. No.

II. ALLOCATED CLASS COST OF SERVICE STUDY

Q. How do you respond to OCA witness Pavlovic's claim that UGI Electric's planning documents do not discuss the number of customers or the need to connect customers?

A. Mr. Pavlovic's position is inconsequential. OSBA witness Knecht correctly explained in his surrebuttal testimony, "One would think that simple observation would verify that extending the distribution system to serve more geographically diverse residential customers would confirm that economies of scale exist for serving larger customers in more concentrated commercial areas."[1] This supports the basic understanding that the distribution system is designed according to the number of customers connected and their system demands. My rebuttal testimony also supports this principle, wherein I stated that "all distribution planners and engineers understand the simple law of physics that the use of electricity by a customer requires that customer to be attached to the circuits which are providing the electricity."[2] (UGI Electric St. No. 6-R at 15.)

Q. Is the concept of needing to connect customers to the distribution grid a fundamental understanding of utility operations and circuit design?

A. Yes. This is one of the first concepts introduced to students when teaching circuit design. The following is a basic educational article found online at www.kids.briannica.com:

- "A basic electric circuit consists of a power source, a device that will use the power, and <u>wires to connect them</u>." (emphasis added.)
- "An electric circuit has to have a power source, wires for the electricity to flow through, and a device such as a lamp or a motor that uses the electric current. <u>All</u>

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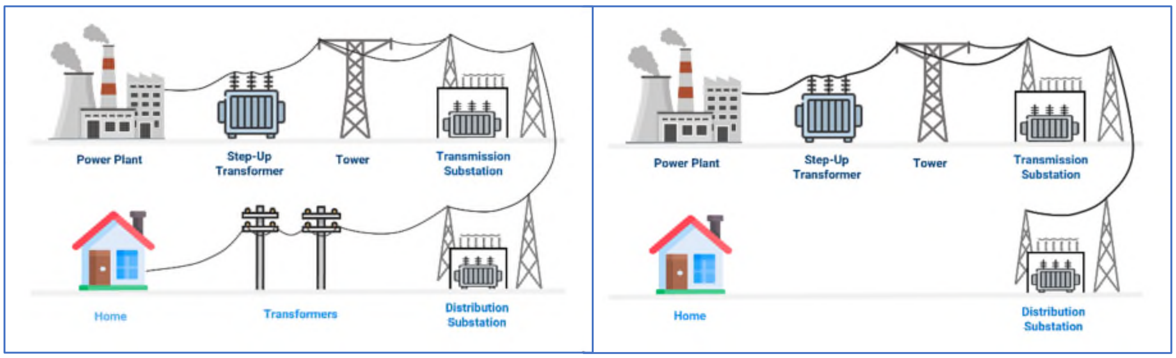
[1] OSBA St. No. 1-S at 2.
[2] UGI Electric St. No. 6-R at 15.

of these parts must be connected so that the current continues to flow." (emphasis added).[3]

Figure 1 below demonstrates two scenarios: on the left is an illustration of an operable distribution circuit that connects a home and the grid, whereas the right side illustrates a non-operable distribution grid where there is no connection between the home and the grid. The home on the right side of the figure will not be able to consume power because a circuit requires wires to connect the power source and the devices that use the power.

Figure 1 – Operable and Non-Operable Distribution Grid



Contrary to the testimony of OCA witness Pavlovic, UGI Electric incurs costs simply to attach customers to the grid so that they can consume power, and the minimum system study presented in my direct testimony provides an appropriate analysis of the costs associated with connecting customers to the distribution grid.

Q. Does OCA witness Pavlovic present any new evidence or arguments in his surrebuttal testimony regarding classifying the distribution plant into customer and demand components?

[3] https://kids.britannica.com/kids/article/electric-circuit/443114

A. No. Mr. Pavlovic simply states that the evidence presented in my rebuttal testimony "does not demonstrate that the portion of distribution plant investment that UGI's ACOSS classifies as customer-related varies directly with its number of customers." (OCA St. 3SR at 8-9.) Mr. Pavlovic provides no further explanation or evidence of how the data in Table 3 in my rebuttal testimony, which shows a correlation between the average number of customers and distribution plant investments, is unreasonable.

III. RESIDENTIAL CUSTOMER CHARGE AND LOW-INCOME CUSTOMER IMPACT

Q. How does OCAwitness Pavlovic articulate the impact of increasing the residential customer charge?

A. According to Mr. Pavlovic, an "increase in the customer charge will reduce the volumetric distribution charge and thereby reduce customers' incentive to conserve and ability to control their bills." However, the issue under consideration is whether a four-dollar fixed charge increase, as a component of the total bill, limits a customer's ability to control their bills. As demonstrated in Table 7 of my rebuttal testimony (UGI Electric St. No. 6-R), approximately 900 kWh of monthly consumption is a breakpoint, after which the customer benefits from the shift between higher customer charge and lower volumetric charge. As demonstrated in this proceeding, the consumption level for an average UGI Electric customer is 854 kWh, 1,036 kWh for an average low-income customer, and 1,229 kWh for an average CAP customer. Under the proposed rate structure, low-income and CAP customers will benefit[4] from lower volumetric charges without taking any additional conservation measures, while an average customer may only see a $0.30 higher bill under

[4] UGI Electric St. No. 6-R at 27.

the $13.50 customer charge. The Company's proposal aligns with gradualism because the average residential customer's bill is $0.30 different between keeping the customer charge at $9.50 or setting it at $13.50.

In addition, this result better aligns with the existing regulatory objective to match fixed costs incurred by the utility for the provision of service with the fixed charges paid for by the utility customers. A four-dollar increase is a reasonable balance of these objectives and only modestly moves toward the objective of economically efficient pricing. As such, the OCA's recommendation to keep the customer charge at the current level of $9.50 should be rejected.

Q. What is your response to OCA witness Colton's critique of your low-income customer impact analysis presented in UGI Electric St. No. 6-R?

A. OCA's witness Colton critiques my reliance on the Company's records of customer consumption data. However, these usage figures are based on the Company's metering equipment, which is tested and maintained and is used to develop the Company's supply purchase needs, provide accurate billing to customers, produce reporting data to the Commission, and establish the billing determinants utilized in this case as shown in UGI Gas Exhibit E – Proof of Revenue. This is the only factual and reliable data specifically relating to UGI Electric's customer base that exists on the record and is appropriately used in the low-income impact analysis I present.

Q. Do you agree with Mr. Colton that "the overwhelming evidence is that low-income customers, typically and disproportionately, have low consumption"? (OCA St. 4SR at 39.)

A. No, I do not. The overwhelming evidence that Mr. Colton refers to is the Residential Energy Consumption Survey ("RECS") data that he normally relies upon as his source to support his broad claims that low-income customers, who are the ones he also claims will not be able to conserve at a higher customer charge, are low energy consumers. Mr. Colton solely relies on this federal data, which collects and reports energy use based on survey results. Counties throughout the entire United States are randomly selected for inclusion in the publicly-reported RECS data. It is unclear the extent to which either of UGI Electric's counties (Wyoming and Luzerne) are included in the 2020 RECS survey results. Regardless, UGI Electric's actual customer usage data is the most relevant data that the Commission can rely upon to determine the energy characteristics of UGI Electric's low-income customers. That usage data is used to bill low-income customers and, therefore, is the most reliable record for the Commission to review. Finally, this case is about Pennsylvania customers, and Pennsylvania customers specifically within UGI Electric's service territory, not customers in all 50 states.

Table 6, presented in my rebuttal testimony (UGI Electric St. No. 6-R at 27), which shows that average use low-income and CAP customers will pay reduced total bills under the proposed customer charge, was based on UGI Electric's actual customer usage records, which are the most reliable and reasonable data source to determine the impact of the proposed customer charge. Accordingly, Mr. Colton's position lacks reliability and wholly ignores the actual usage characteristics of UGI Electric's low income and CAP customers.

Q. Does this conclude your rejoinder testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368, et al.

UGI Utilities, Inc. – Electric Division

Statement No. 9 - RJ

Rejoinder Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

Dated: June 12, 2023

REJOINDER TESTIMONY OF PAUL R. MOUL

Q. Please state your name, occupation and business address.

A. My name is Paul R. Moul and I am Managing Consultant at the firm P. Moul & Associates. My business address is 251 Hopkins Road, Haddonfield, NJ 08033-3062.

Q. Mr. Moul, have you previously submitted testimony in this proceeding?

A. Yes. My direct testimony (UGI Electric St. No. 9) was submitted with the Company's case-in-chief on January 27, 2023 and my rebuttal testimony (UGI Electric St. No. 9-R) was submitted on May 25, 2023.

Q. What is the purpose of your rejoinder testimony?

A. UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company") has requested that I respond to the surrebuttal testimony presented by Mr. D.C. Patel, a witness appearing on behalf of the Pennsylvania Public Utility Commission's ("Commission") Bureau of Investigation and Enforcement ("I&E"), and Mr. Aaron L. Rothschild, a witness appearing on behalf of the Office of Consumer Advocate ("OCA"). If I fail to address each and every issue in the surrebuttal testimony of Mr. Rothschild and Mr. Patel, it does not imply agreement with those issues.

Q. Based on your review of the surrebuttal testimony of Messrs. Patel and Rothschild, do you propose any change in your recommended return for UGI Electric in this proceeding?

A. No. There was nothing contained in the surrebuttal testimony of Messrs. Patel and Rothschild that changes my position that UGI Electric is entitled to an 11.30% rate of return on common equity.

Q. What is your overall assessment of the surrebuttal testimony of Messrs. Patel and Rothschild.

A. The proposals of Messrs. Patel and Rothschild of 8.76% and 8.44%, respectively, are entirely too low by reference to returns set by the Commission in recent rate cases and the Distribution System Improvement Charge ("DSIC") return of 9.55% (as established in the Quarterly Earnings Report at Docket No. M-2023-3040145) that I describe in my rebuttal testimony (page 18 of UGI Electric Statement No. 9-R). Furthermore, Mr. Patel has disregarded the position taken by the Commission in the Aqua Order (at Docket No. R-2021-3027385) concerning the use of additional methods besides Discounted Cash Flow ("DCF"). (*Id.*) Mr. Patel laments the Aqua Order for departing from long standing practice of stating the cost of equity in terms of the DCF. He fails to acknowledge that the Commission expressed the view that the DCF is slow to react to a rising interest rate/inflation rate environment.

Q. What role do you see for the DSIC return in this case?

A. Mr. Patel's argument that the DSIC rate is merely a benchmark (*see* page 14 of I&E Statement No. 3-SR) to identify "overearning" and that it provides an incentive for investment in infrastructure replacement and betterment is misplaced. The actual collection of revenues from the DSIC can only occur if earnings are below the DSIC rate. And it is illogical that once DSIC assets enter the rate base, the utility should be penalized with a lower return. Such a result would occur if Mr. Patel's recommended 8.76% equity return was accepted because it is well below the Commission's 9.55% DSIC rate (*see Bureau of Technical Utility Services Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended December 31, 2022*, Docket No. M-2023-3040145 (May 18, 2023)). So, although the Commission has stated that the DSIC return is not company specific and is determined on a quarterly basis (*see Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.*, Dkt. No. R-2021-3027385 (Order entered May 16, 2022), page 178), it does provide an overall benchmark to gauge the reasonableness of the proposed return.

I also would note that the Staff Quarterly Report was established long before the DSIC was enacted in 2012. Moreover, the DSIC rate comes into play only if the utility has not had a recent rate case determination of cost of equity. In other words, it is a default rate when there has been no rate case and is obviously not intended to establish a cap on rate case cost of equity findings.

Q. Is there evidence from any rate case decisions that the Commission usually sets the rate of return on common equity higher than the DSIC return published in the Quarterly Report?

A. Yes. Four rate case decisions substantiate this position. In the PPL Electric Utilities rate case at Docket No. R-2012-2290597,[1] the Commission set the return on equity at 10.40% when the DSIC return was 10.20% for electric utilities. In the UGI Electric rate case at Docket No. R-2017-2640058,[2] the Commission set the rate of return on common equity at 9.85% when the DSIC return was 9.65% for electric utilities. In the PECO gas rate case at Docket No. R-2020-3018929,[3] the equity return was set at 10.24% when the DSIC rate was 10.20%. The same is true in the Aqua Pennsylvania rate case at Docket No. R-2021-3027385,[4] where the Commission set the return on equity at 10.00% when the water DSIC return was 9.80% (*see* page 15 of I&E Statement No. 3-SR). So, this evidence supports a higher return in base rate cases than the prevailing DSIC return, contrary to Mr. Patel's opinion expressed on pages 9 through 12 of his surrebuttal testimony (I&E Statement No. 3-SR).

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[1] *Pennsylvania Public Utility Commission v. PPL Electric Utilities*, Dkt. No. R-2012-2290597 (Order entered Dec. 28, 2012).

[2] *Pennsylvania Public Utility Commission v. UGI Utilities, Inc. – Electric Division*, Dkt. No. R-2017-2640058 (Order entered Oct. 25, 2018)(UGI Electric 2018 Rate Case).

[3] *Pennsylvania Public Utility Commission v. PECO Energy Company – Gas Division*, Dkt. No. R-2020-3018929 (Order entered June 22, 2021).

[4] *Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.*, Dkt. No. R-2021-3027385 (Order entered May 16, 2022)(Aqua Order).

REJOINDER TESTIMONY OF PAUL R. MOUL

Q. On pages 7 through 11 of his surrebuttal testimony (I&E Statement No. 3-SR), Mr. Patel asserts that the percentage of electric utility assets is not the appropriate criterion to assemble a barometer group. Does Mr. Patel adequately support his position?

A. No. Mr. Patel says that the value of a utility's assets depends on its age. While this is true, it has nothing to do with the validity of using assets to identify if a particular company is predominately a utility. The basic ratesetting formula accounts for the level of depreciated assets in the determination of the rate base. Therefore, highly depreciated assets for a utility means that the rate base is low and therefore earnings are low. There is a direct relationship between assets and earnings for a public utility. Therefore, there is no reason to ignore the percentage of assets in the screening process for the barometer group. On page 8, Mr. Patel says that it is possible that utility assets could be predominantly depreciated. His observation runs counter to his argument for ignoring utility assets as a criterion because highly depreciated utility assets would suppress their percentage to total assets. We know that this is not true by reference to the analysis presented on page 15 of UGI Electric Statement No. 9-R. Whether utility assets are highly depreciated has nothing to do with the validity of using assets to identify if a particular company is predominately a regulated utility. The basic ratesetting formula accounts for the level of depreciated assets through the determination of the rate base. Therefore, I reiterate that highly depreciated assets for a utility means that the rate base is low and therefore earnings are low. The opposite is also true. Accordingly, there is a direct relationship between assets and earnings for a public utility related to the amount of depreciation previously accrued, and there is no reason to ignore the percentage of assets in the screening process for the barometer group.

Q. Mr. Patel acknowledges that he erroneously excluded Exelon from his barometer group based on the revenue percentage (*see* page 9 of I&E Statement No. 3-SR), but he claims that it should remain excluded due to the lack of <u>Value Line</u> data. Is that reasonable?

A. No. While <u>Value Line</u> may not be reporting forecasts for Exelon (instead it is showing non-meaningful figure ("NMF")), there are forecasts of earnings growth available from I/B/E/S-First Call (i.e., Yahoo! Finance) and Zacks. The availability of these data demonstrates that a reasonable analysis of Exelon is possible.

Q. At page 12 of his surrebuttal testimony (I&E Statement No. 3-SR), Mr. Patel discusses the relative weight that should be assigned to the DCF. Please respond.

A. His discussion as to the weight that should be given to models other than DCF is somewhat difficult to follow. As near as I can tell, he proposes that the Capital Asset Pricing Model ("CAPM") should only be used as a comparison to DCF, but not as additional input. It seems to me that ignoring the CAPM results in exclusive use of the DCF, meaning that there would be no need to calculate a CAPM return in the first place. But his CAPM return of 11.55% clearly shows that the DCF return needs validation. His position of exclusive reliance on DCF is contrary to the Commission's recent Aqua Order that established a range of equity returns using DCF and CAPM. While Mr. Patel seems troubled by alternative models, including CAPM, there is no basis to ignore the results of these models when the DCF is producing unreasonably low results.

Q. On pages 16-17 of his surrebuttal testimony (I&E Statement No. 3-SR), Mr. Patel states that he has removed projected growth rates for some companies, and then criticizes you for making other exclusions. Is his approach

reasonable?

A. No. There is just no way that the DCF returns that I listed on page 22 of my rebuttal testimony can play any role in the determination of the equity return in this case. We know that his recommendation is too low based upon the other rate case decisions I report in my rebuttal testimony. Indeed, the 8.76% return advocated by Mr. Patel on page 5 of his surrebuttal testimony (*see* I&E Statement No. 3-SR) is unreasonable because it is based solely on one method, i.e., DCF. The Commission has taken the position that it is looking for a range of returns that includes the results using the CAPM as well.

Q. At page 20 of his surrebuttal testimony (I&E Statement No. 3-SR), Mr. Patel claims that the financial risk of a company is not related to the capital structure of a company. Is this correct?

A. This statement is unquestionably wrong. Furthermore, it conflicts with his statement on page 24 of I&E Statement No. 3-SR regarding the book value of debt. The recognized measure of a company's financial risk is revealed by the balance sheet of a company. Indeed, it is the balance sheet that provides the foundation for calculating the weighted average cost of capital, which is the basis for a public utility's weighted average cost of capital established in rate cases. As stated in The Regulation of Public Utilities[5]:

> …it is widely held that the cost of capital is related to a utility's capital structure. As the proportion of debt increases, the added *financial risks* for both the debt and equity holders result in higher and higher costs for both debt and equity capital.

Q. Mr. Patel claims on page 25 of his surrebuttal (I&E Statement No. 3-SR) that his use of spot stock prices provides the most up-to-date information that

[5]Charles F. Phillips, Jr., The Regulation of Public Utilities (Public Utilities Reports, Inc. 1993) 233.

accounts for recent inflation and interest rate data. Does this remedy the situation where the DCF results lag current interest rates?

A. No. While spot prices provide an indication of current dividend yields, those yields reflect mainly the assessment of current analysts' growth forecasts. Those growth rate forecasts relate to company-specific fundamentals that existed when those forecasts were made in the past. We do not know if current interest rates and inflation expectations today are embedded in analysts' forecasts made in the past. So spot prices in the DCF would reflect today's interest rate and inflation expectation only by chance.

Q. On page 6 of I&E Statement No. 3-SR, Mr. Patel provides inflation data and suggests that with the decline in inflation capital costs have passed their peak. Please respond.

A. While inflation has declined from its peak in June 2021, it has continued to exceed substantially the policy goal of 2% established by the Federal Open Market Committee ("FOMC"). Moreover, it has exceeded the rate that existed since the time of the Company's last fully litigated rate case. The rate of inflation was 2.5% in October 2018 when the Commission issued its order in that case.[6] The history of inflation since then is shown below:

Oct-18	2.5%
Dec-18	1.9%
Dec-19	2.3%
Dec-20	1.4%
Dec-21	7.0%
Dec-22	6.5%
Apr-23	4.9%

So even with the recent decline in inflation, it continues to run at a rate nearly double the rate at the time of the Company's last fully litigated rate case. Therefore, a

[6] *See* UGI Electric 2018 Rate Case.

higher return on equity is necessary today to reflect this fact.

Q. On page 28 of his surrebuttal testimony (I&E Statement No. 3-SR), Mr. Patel claims that less weight should be given to more distant forecasts because they are less reliable. Please respond.

A. I find his observations to conflict with his use of five-year projections of earnings growth in his DCF analysis. If reliance upon five-year projections, whatever their reliability, is acceptable for DCF purposes, then there is no reason to discount any of the projections of Treasury yields when looking for the appropriate risk-free rate of return in the CAPM.

Q. What issues were contained in the surrebuttal testimony of OCA witness Rothschild?

A. Mr. Rothschild has addressed the following issues: capital structure, response to inconsistencies in his testimony, the discounted cash flow model, analyst's growth projections, market-to-book ratios, and betas.

Q. In his surrebuttal testimony (*see* pages 24-25 of OCA Statement No. 2-SR), Mr. Rothschild opines that the Company's proposed capital structure is unreasonable and unfairly prejudices ratepayers. Do you agree?

A. No. Mr. Rothschild adopts a hypothetical capital structure for UGI Electric in place of its actual capital structure to remedy his perceived perception. But he is wrong on this matter. The Commission's policy on capital structure places a limit on the common equity ratio that triggers the imposition of a hypothetical capital structure. Further, it is incorrect for Mr. Rothschild to argue on page 24 of his surrebuttal testimony (OCA Statement No. 2-SR) that his hypothetical capital structure complies with Commission policy. I have explained at length in my rebuttal testimony why this is not correct. Therefore, there is no need to repeat my justification here. He also fails to acknowledge my alternative analysis of public utility capital structures. As shown on Rebuttal Exhibit PRM-1 and PRM-2, the range of common equity ratios is 47.83% to 60.54% and 48.76% to 56.04%, respectively. The common equity ratio for UGI Electric in this case is 54.59%, which clearly falls within these ranges. Hence, the Company's proposal is reasonable and should be accepted.

Q. Mr. Rothschild attempts to respond (*see* pages 4-7 of OCA Statement No. 2-SR) to your observation concerning the many inconsistencies in his direct testimony. Has he successfully done so?

A. For the most part, no. Many of his responses in his surrebuttal testimony attempt to distinguish investor expectations from expert forecasts and the necessary use of historical data due to the limitations of capital market data. But what Mr. Rothschild has failed to explain is how his testimony addresses these factors in any way that is superior to my use of these data. That is to say, expert forecasts are the only hard data that we can use to gain insight into investor expectations, and historical data provides the foundation upon which expectations are formed. As is often repeated, past performance provides no guarantee of future returns. But what it does is to provide a basis for judgments on how the future will diverge from the past given changing fundamentals that impact the capital markets. And that is how I used historical data in my testimony.

Q. On page 12 and again at page 16 of his surrebuttal testimony (OCA Statement No. 2-SR), Mr. Rothschild attempts to diminish the usefulness of analysts' projected growth rates in the DCF. Please respond.

A. Mr. Rothschild sets forth two arguments. He claims that analysts' projected growth rates are overly optimistic and that the retention rate must be considered in the DCF.

First, in an article published in The Wall Street Journal on April 26, 2010,[7] it was reported that 64% of companies had beaten analysts' forecasts since the start of 1999. More importantly, however, investors rely heavily on analysts' forecasts in determining the price they are willing to pay for a particular stock. Consequently, if the forecasted earnings growth rates were to be discounted, a downward adjustment would also have to be made to the stock prices those forecasts have produced. This, in turn, would generate higher dividend yields in the DCF analysis. I have specifically noted that Myron Gordon established that analysts' forecasts of earnings growth are the best growth rate measures in the DCF, and retention growth was not the preferred approach. (*See* UGI Statement No. 9-R, p. 25.) Second, there is no requirement in the DCF model that the growth rate must include a retention rate factor/percentage. Mr. Rothschild's paycheck analogy is way off the mark. The paycheck in his example is represented by the dividend receipts component that establishes the dividend yield in the DCF equation. This is distinct from the expected growth in future paychecks that an individual might expect. Hopefully, an individual will realize a growing paycheck in the future attributed to (i) inflation and (ii) the relationship between the employer and employee. Hence, paycheck growth occurs mostly from these two factors and has nothing to do with the amount an individual retains in his/her bank account.

Q. In his surrebuttal testimony (*see* page 13 of OCA Statement No. 2-SR), Mr. Rothschild claims to have used a "holistic analysis" when employing analysts' five-year growth rate forecasts. Has his "holistic analysis" improved upon use of analysts' forecasts directly?

[7] *Wall Street's Missed Expectations*, Liam Denning (Apr. 26, 2010).

A. No. My understanding of holism is that the whole is worth more than merely the sum of the parts. Mr. Rothschild used many parts in his analysis, i.e., earnings per share, dividends per share, book value per share, dividend payout ratios, earnings book ratios, market to book ratios, and analysts' forecasts. In his use of these data sets, Mr. Rothschild has missed some key components in pursuit of a truly holistic outcome. We know this because the sum of all the parts used by Mr. Rothschild produces a result that fails the holistic analysis because it is less than the analysts' forecasts used directly.

Q. Regarding the issue of market-to-book ratios, Mr. Rothschild claims on page 15 of his surrebuttal testimony (OCA Statement No. 2-SR) that when investors pay more than book value, they require a lower return than what they expect a utility will earn. Is this correct?

A. No. Since utility stock prices are today, and have been generally throughout history, considerably higher than book value, Mr. Rothschild's apparent desire is to reduce those prices to book value. Of course, no rational investor would take a position in a utility stock with the expectation that the price would decline, thereby losing capital. And even if he were correct, his argument further supports my leverage adjustment because the financial risk associated with book value (i.e., accounting) return is much higher than the financial risk associated with the market returns.

Q. At pages 19 through 22 of OCA Statement No. 2-SR, Mr. Rothschild criticizes the historical nature of the Value Line betas. Are his criticisms valid?

A. No. What Mr. Rothschild fails to acknowledge is that Value Line adjusts its betas in recognition of the regression bias associated with use of historical data. What Value Line has done is to recognize that the betas of low beta stocks must be adjusted upward, and high beta stocks must be adjusted downward. These adjustments recognize that high and low beta stocks will revert to the mean beta of 1.0 moving from historical performance to expectations. Therefore, Value Line has already acknowledged Mr. Rothschild's observation and adjusted for it.

Q. On pages 34-36 of his surrebuttal testimony (I&E Statement No. 3-SR), Mr. Patel claims that management performance need not be considered as an issue in this case. Is that correct?

A. No. The Commission has a long history of recognizing management performance (either positively or negatively) in rate case decisions. If the Commission were to abandon its constructive ratesetting approaches that include recognition of management performance, or to significantly reduce the return to levels suggested by Mr. Patel, then the Company's ranking would surely suffer. Mr. Patel asserts that recognition of management performance is "nonsensical" in that higher equity returns should not occur for management initiatives that are funded by ratepayers. Mr. Patel does acknowledge that the legislature authorized this approach and that the Commission has followed it. He also attempts to distinguish the Aqua case because they were acquiring troubled water companies. In fact, ratepayers pay for those acquisitions.

Q. Does this conclude your rejoinder testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2022-3037368, et al.

UGI Utilities, Inc. – Electric Division

Statement No. 11-RJ

Rejoinder Testimony of

Daniel V. Adamo

Topics Addressed: **Compliance with Past Rate Case Settlements**
USECP Performance
EE&C Plan

Dated: June 12, 2023

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Daniel V. Adamo. My current business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Electric?

A. Yes, I previously submitted UGI Electric Statement No. 11-R, my written rebuttal testimony and exhibits, on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company").

Q. **Are you sponsoring any exhibits with your rejoinder testimony?**

A. Yes. I am sponsoring UGI Electric Exhibit DVA-1RJ.

Q. What is the purpose of your rejoinder testimony?

A. My rejoinder testimony responds to the surrebuttal testimony and exhibits of the Office of Consumer Advocate ("OCA") witness Roger D. Colton (OCA St. 4SR). My rejoinder testimony may not address every statement or claim made by Mr. Colton in his surrebuttal testimony. However, the lack of a response to any specific sentence, statement, claim or position of Mr. Colton does not in any way indicate my acceptance or approval thereof.

II. UGI ELECTRIC COMPLIED WITH ALL SETTLEMENT TERMS FROM ITS 2018 AND 2021 RATE CASES

Q. OCA witness Colton continues to allege that the Company failed to comply with its obligations under the Partial Stipulation filed in the 2018 base rate case and the

Settlement filed in the 2021 base rate case. (OCA St. 4SR at 12-22.) Do you have any preliminary observations?

A. Mr. Colton is wrong. Rather than accept my representations and evidence that the Company did what it committed to do, Mr. Colton continues to question the Company's compliance by drawing inaccurate inferences and making unsupported assumptions. Again, Mr. Colton never asked the Company in discovery whether UGI Electric complied with each of these settlement obligations. Instead, he relies on responses to discovery requests (most prominently, CAUSE-PA-I-3 and 4) that did not even mention these settlement obligations. The bottom line is that UGI Electric complied with all of its settlement obligations referenced by Mr. Colton, as explained in my rebuttal testimony and this rejoinder testimony. Further, to put these issues to rest, UGI Electric hereby supplements its discovery responses to specifically incorporate the information contained in my rebuttal and rejoinder testimony regarding UGI Electric's settlement compliance.

Q. Please respond to Mr. Colton's allegation in his surrebuttal testimony that UGI Electric failed to perform a solicitation of customers who received Low-Income Home Energy Assistance Program ("LIHEAP") in the prior 12 months two times a year for enrollment in its Customer Assistance Program ("CAP"), as required by Paragraph 68(a) of the 2021 base rate case settlement. (OCA St. 4SR at 12-13.)

A. In my rebuttal testimony, I confirmed that UGI Electric performed these required solicitations on February 28, 2022, by sending a solicitation to 144 UGI Electric customers, and on December 6, 2022, by sending a solicitation to 492 UGI Electric customers, all of whom received LIHEAP in the prior 12 months. (*See* UGI Electric St. No. 11-R at 8.)

Regardless, Mr. Colton continues to dispute the Company's compliance, claiming that UGI Electric's number of customers who received the solicitation does not match **his estimation** of the number of customers who received LIHEAP but were not already enrolled in CAP. (OCA St. 4SR at 12-13.) Specifically, Mr. Colton contends that in "Program Year 2022, UGI had 2,093 customers that received LIHEAP" and that the Company "[h]istorically" has "reported that roughly 36% of its LIHEAP recipients did *not* also participate in CAP." (OCA St. 4SR at 12-13.) Therefore, Mr. Colton concludes that the Company should have sent the solicitation to "more than 750 LIHEAP non-CAP participants (2,093 x 0.36 = 753). (OCA St. 4SR at 13.)

This is a significant change from Mr. Colton's initial claim on this point. In his direct testimony, Mr. Colton alleged that UGI Electric did not perform "a specific targeted campaign to confirm the low income status of customers." (OCA St. 4 at 42.) In other words, he claimed that UGI Electric did not solicit any low-income customers for CAP enrollment. After reading my rebuttal testimony, which detailed the efforts undertaken to solicit these customers, Mr. Colton changed his position and now claims that the solicitations, which he now admits occurred, were not extensive enough. He does not base this new claim on any actual customer data or records of the Company. Instead, he makes an unsupported claim that, historically, UGI Electric reported that approximately 36% of its LIHEAP recipients did not participate in CAP. (OCA St. 4SR at 12-13.) The problem with that claim is that Mr. Colton did not provide any source or reference for it, so I do not know where he is obtaining that figure.

In actuality, the Company sent both the February 28, 2022 and December 6, 2022 solicitations to non-CAP participants who received LIHEAP in the prior 12 months

measuring from those points. The critical flaw with Mr. Colton's analysis is that he relies on "Program Year 2022," a time period that does not match the 12-month periods that, under the 2021 settlement, were required to be used for determining the solicitations' list of recipients. Indeed, Program Year 2022 was the 12-month period of January 1, 2022, through December 31, 2022. Also, Mr. Colton fails to account for the fact that the list of recipients was narrowed by excluding customers who had placed "do not solicit" indicators on their accounts; the Company did not narrow the list solely by excluding customers who were already enrolled in CAP. Moreover, through performing these solicitations, UGI Electric has implemented improvements for sending customers the solicitations by email and direct mail, where appropriate. Thus, Mr. Colton's "estimation" is based on data for the wrong 12-month time periods that were used to develop the solicitations' recipient lists and fails to account for the exclusion of customers who placed "do not solicit" indicators on their accounts. As such, the Pennsylvania Public Utility Commission ("Commission") should completely reject Mr. Colton's allegation.

Q. Mr. Colton also maintains that UGI Electric failed to comply with Paragraph 68(d) of the 2021 base rate case settlement because the Company does not accept verification of income eligibility by any community organization delivering public or private assistance. (OCA St. No. 4SR at 13-15.) What is Mr. Colton's position in his surrebuttal testimony?

A. Mr. Colton continues to allege that UGI Electric does not assign "confirmed low-income" status to a customer when the customer confirms income eligible status with a Community-Based Organization ("CBO"). (OCA St. 4SR at 13-14.) Despite my clear declaration in rebuttal that UGI Electric does assign confirmed low-income status upon receipt of income verification from a CBO or a customer, Mr. Colton continues to dispute this fact by pointing to the Company's response to CAUSE-PA Set I, No. 3 (which he did in his direct testimony) and its response to CAUSE-PA Set I, No. 4.[1] Again, Mr. Colton's position is based on unsupported and flawed interpretations of those discovery responses.

Q. How does Mr. Colton misinterpret those discovery responses?

A. He does so in two critical ways. First, Mr. Colton misinterprets how the conjunction "and/or" works in the response to CAUSE-PA Set I, No. 3. To show this, I will quote the entirety of Mr. Colton's surrebuttal testimony on this point:

> The response to CAUSE-PA-1-3 states in its entirety:
>
> The Company assigns a "confirmed low income" attribute to a customer when the customer confirms income-eligible status with a Community-Based Organization (CBO) and/or the following criteria are met:
>
> customer enrolls in CAP[;]
>
> customer receives LIURP services and weatherization measures are installed and completed[;]
>
> customer receives an Operation Share grant[;]
>
> customer receives a LIHEAP Cash or Crisis payment[.]"
>
> (CAUSE-PA-I-3).
>
> When parsed, the UGI response identifies two circumstances where UGI will "assign a 'confirmed low-income' attribute to a customer" when: (1) the customer confirms income eligible status with a Community-Based Organization (CBO) and the following criteria are met: the customer enrolls in CAP; the customer receives LIURP;

[1] UGI Electric notes that although the Company does track and uses the self-certified low income characteristic consistent between its gas and electric divisions, the data reported out in this interrogatory excluded self-certified low-income customers. The Company still considers these customers "confirmed low-income customers" and includes them in its confirmed low-income customer counts that are submitted to the Commission.

> the customer receives an Operation Share grant; the customer receives a LIHEAP Cash or Crisis payment; or (2) the customer does not confirm their income eligible status with a Community-Based Organization (CBO) and the following criteria are met: the customer enrolls in CAP; the customer receives LIURP; the customer receives an Operation Share grant; the customer receives a LIHEAP Cash or Crisis payment". In either instance, the list program participation criteria must be met. This process is at odds with Mr. Adamo's testimony.

(OCA St. 4SR at 13-14.)

Here, the conjunction "and/or" means that the first proposition can be true, the second proposition can be true, or both propositions can be true. In other words, if a person would like a sandwich and/or a salad for lunch, the person would like a sandwich, a salad, or both for lunch. Mr. Colton, however, misinterprets "and/or" by asserting that it means the first and second propositions are true or only the second proposition is true. Therefore, under the lunch example, Mr. Colton would posit that the person would like a sandwich and a salad for lunch or only a salad for lunch. This incorrect interpretation of the Company's discovery response leads Mr. Colton to conclude that "[i]n either instance, the list program participation criteria must be met."

In reality, as explained in response to CAUSE-PA Set I, No. 3, UGI Electric assigns confirmed low-income status to customers in any of the following three scenarios: (1) when the customer confirms income-eligible status with a CBO; (2) when the customer enrolls in CAP, receives LIURP services and weatherization measures are installed and completed, receives an Operation Share grant, or receives a LIHEAP Cash or Crisis payment; or (3) when the customer confirms income eligible status with a CBO and enrolls in CAP, receives LIURP services and weatherization measures are installed and completed, receives an Operation Share grant, or receives a LIHEAP Cash or Crisis payment.

Second, when Mr. Colton relies on UGI Electric's response to CAUSE-PA Set I, No. 4 as support for his position, he, once again, misinterprets the Company's response. Mr. Colton quotes the following relevant passage from that discovery response:

> The Confirmed Low-Income indicator is date sensitive. The date is updated when specific activities occur. Activities include a customer receiving LIHEAP grants, enrolling in CAP, receiving an Operation Share grant, or participating in LIURP.

(OCA St. 4SR at 14-15.) Mr. Colton asserts that this "direct quote" shows how the Company does not assign confirmed low-income status when a customer confirms income-eligible status with a CBO. (OCA St. 4SR at 14-15.) He further asserts that "[t]here is no mention, no implication, and no basis upon which to reach an implication, that one of the 'specific activities' that will result in a customer's 'Confirmed Low-Income indicator' being 'updated' will occur based upon the confirmation of such status by any CBO." (OCA St. 4SR at 15.)

To provide context, the full discovery response states:

> The Company began extracting and recording confirmed low income counts at month end, beginning in October 2022. Monthly data prior to October 2022 is not available. The Confirmed Low Income indicator is date sensitive. The date is updated when specific activities occur. Activities include a customer receiving LIHEAP grants, enrolling in CAP, receiving an Operation Share grant, or participating in LIURP.

(UGI Electric Exh. DVA-1RJ.)

Mr. Colton overlooks a critical word in the Company's discovery response in reaching his inaccurate conclusion. The "[a]ctivities" that trigger updating the confirmed low-income indicator's date "**include** a customer receiving LIHEAP grants, enrolling in CAP, receiving an Operation Share grant, or participating in LIURP." (*Id.*) (emphasis added). The word "include" means that this is not an exhaustive list. I am advised by counsel that Black's Law Dictionary defines the word "include" as "[t]o contain as part of something" and that "[t]he participle *including* typically indicates a partial list"; however, "some drafters use phrases such as *including without limitation* and *including but not limited to* which mean the same thing."[2] Here, the Company's use of the word "include" clearly indicated a partial, not exhaustive, list (*i.e.*, the Company provided some examples). Thus, Mr. Colton's misinterpretation of the response to CAUSE-PA Set I, No. 4, upon which he continues to base his meritless allegation, should be rejected.

Q. Mr. Colton also continues to argue that UGI Electric failed to comply with Paragraph 68(e) of the 2021 base rate case settlement, which required the Company to contact Pennsylvania Department of Human Services ("DHS") administrators and deem any household identified by the administrators as confirmed low-income. (OCA St. 4SR at 15-18.) Could you please summarize Mr. Colton's argument in his surrebuttal testimony?

A. Mr. Colton's argument is now based on flawed inferences he draws from the February 28, 2022 email sent to UGI Electric by Brian Whorl, who is the Division Director, Federal Programs and Program Management at DHS. According to Mr. Colton, the language used by Mr. Whorl in his email suggests that UGI Electric failed to comply with this settlement obligation, *i.e.*, request that DHS program administrators ask applicants enrolling in their public assistance programs to designate whether the applicants want UGI Electric to be informed of their income eligibility for various customer service protections propounded by the Commission. (OCA St. 4SR at 15-18.)

[2] BLACK'S LAW DICTIONARY, 11TH EDITION, p. 912 (emphasis added) (defining "include").

However, at the meeting with Mr. Whorl on February 7, 2022, which is referenced in that February 28, 2022 email, UGI Electric specifically communicated that request and discussed other issues with him. In his email after that meeting, Mr. Whorl states that "there is no permission collected from these households to perform any data sharing with their utility" and that "before DHS will share any information, we would have to make appropriate updates to our LIHEAP application to accurately capture the household's specific consent to share any data information with their selected utility." (UGI Electric Exh. DVA-6R.)

I do not see how Mr. Colton can conclude, based on Mr. Whorl's email, that UGI Electric failed to request that DHS applicants be asked about whether they want UGI Electric to be informed of their income eligibility. The Company made that specific request, and Mr. Whorl stated that DHS does not currently collect this permission from applicants and that before it can do so, DHS would have to update its LIHEAP application to facilitate the sharing of any "data information with" the applicants' "selected utility." Lastly, regardless of whatever language Mr. Whorl used in the February 28, 2022 email, UGI Electric unquestionably made this specific request to Mr. Whorl at that meeting. Additionally, it was clear that DHS would need to not only change the LIHEAP application that impacts all utilities, but also make IT system changes to facilitate this data sharing request. At that point in time, the Company was actively engaged in the LIHEAP Advisory Committee ("LAC"), which was making significant headway on data sharing across all public utilities with DHS to maximize low-income participation in Universal Service Programs and revising the LIHEAP application. These changes were originally on track to be completed by the end of calendar year 2023 but have now been moved to the fall of 2024.

Q. Mr. Colton continues to allege that UGI Electric failed to comply with Paragraph 11(b) of the 2018 base rate case partial stipulation because he believes that the Company does not accept self-certification of low-income status for purposes of identifying "confirmed low-income customers" in the same way that self-certification is required to be accepted by UGI Utilities, Inc. – Gas Division ("UGI Gas"). (OCA St. 4SR at 19-21.) Is that true?

A. No. As explained in my rebuttal testimony, UGI Electric's self-certification practices are consistent with those of UGI Utilities, Inc. – Gas Division ("UGI Gas"), meaning that the Company accepts self-certification of low-income status for purposes of identifying confirmed low-income customers in the same way that self-certification is required to be accepted by UGI Gas under Section 62.2 of the Commission's regulations. *See* 52 Pa. Code § 62.2. Mr. Colton's surrebuttal position is premised on the Company's responses to CAUSE-PA Set I, Nos. 3 and 4. As explained previously, the response to CAUSE-PA Set I, No. 4 used the word "include," meaning that the instances in which the Company assigns confirmed low-income status that were listed in that response were not exhaustive. Moreover, to clarify the response to CAUSE-PA Set I, No. 3, the Company also assigns confirmed low-income status to customers in the same way that self-certification is required to be accepted by UGI Gas.

III. UGI ELECTRIC'S UNIVERSAL SERVICE AND ENERGY CONSERVATION PLAN ("USECP") PERFORMANCE

Q. Mr. Colton disputes your contention that UGI Electric has performed well in enrolling customers in its universal service programs. (OCA St. 4SR at 21-24.) Could you please summarize his claims?

A. First, Mr. Colton compares UGI Electric's CAP enrollment rate to its projected participation rate included in its most recent USECP. From that Mr. Colton alleges that "UGI is falling further and further behind its own projections of the number of low-income customers it should be enrolling in CAP." (OCA St. 4SR at 22.)

Mr. Colton errs by comparing actual and projected CAP participation in 2020-2021 versus 2022-2023 to draw this conclusion that the Company's performance is declining. He fails to acknowledge that on or about March 1, 2020, through June 30, 2021,the Company's CAP recertification requirements were suspended. The Company then took multiple steps over the following months to provide notice to customers about the need to recertify before removing the customers from CAP if they did not provide proof for recertification. Therefore, during that period, customers could stay enrolled in CAP without having to recertify their income eligibility. When those suspensions ended, there was a substantial amount of required recertifications that needed to be completed. As such, the Company's CAP enrollment rate compared to its projected participation rate for 2022 (*i.e.*, 81%) was lower than 2021 (*i.e.*, 102%). However, the Company's rate rebounded in 2023 to 85%, as shown in Mr. Colton's table on page 23 of his surrebuttal testimony. Furthermore, the total number of CAP participants in 2023 of 3,492 was the highest of any of the four years evaluated by Mr. Colton.

Second, Mr. Colton tries to compare UGI Electric's and other electric utilities' number of confirmed low-income customers enrolled in CAP versus their estimated low-income customer population. (OCA St. 4SR at 23-24.) Based on his analysis, Mr. Colton concludes that UGI Electric's enrollment of estimated low-income customers in CAP is the lowest in the Commonwealth. (OCA St. 4SR at 23-24.)

Mr. Colton's analysis is flawed. Mr. Colton uses UGI Electric's data from 2022 but uses the other utilities' data from the Commission's Bureau of Consumer Services ("BCS") report for 2021. As such, Mr. Colton is not performing a pure "apples-to-apples" comparison (in terms of the years compared). This is particularly problematic, given that, as noted previously, 2021 had higher CAP enrollment rates due to utilities waiving CAP recertification requirements. In fact, when comparing UGI Electric's 2021 data to the other utilities' 2021 data, UGI Electric was not the lowest performer, as alleged by Mr. Colton. Specifically, in 2021, UGI Electric had 3,236 customers enrolled in CAP out of its 16,037 estimated low-income customer population. Therefore, 20.2% of UGI Electric's estimated low-income customers were enrolled in CAP in 2021. Comparing that percentage to those listed in the table on page 24 of Mr. Colton's surrebuttal testimony, UGI Electric actually placed <u>**third**</u> among those utilities, trailing only Duquesne Light Company and PECO Energy Company. Thus, Mr. Colton's claim that the Company's performance ranked last in 2021 is completely inaccurate.

Further, the Commission's BCS does not evaluate utilities' CAP enrollment performance by comparing their actual CAP enrollments to their estimated low-income customer population. Instead, BCS compares actual CAP enrollments to actual confirmed low-income customers. This is a much more reliable metric for evaluating CAP performance. When placing the Company's CAP performance in that appropriate context, UGI Electric's CAP participation rate and enrollments are performing well above the industry average. (*See* UGI Electric St. No. 11-R at 17.)

For these reasons, the Commission should reject Mr. Colton's allegations about the Company's CAP performance.

IV. <u>UGI ELECTRIC'S ENERGY EFFICIENCY AND CONSERVATION ("EE&C") PLAN</u>

Q. Mr. Colton also criticizes the Company's EE&C Plan for not providing weatherization services to low-income customers. (OCA St. 4SR at 25-27.) Was this the same criticism he made in his direct testimony?

A. No. In his direct testimony, Mr. Colton criticized the Company's EE&C Plan for allegedly lacking any low-income component. Specifically, he stated the following:

> The Company's EE&C Plan, however, does not provide services to low-income customers. The Company instead restricts its low-income energy efficiency investments to its LIURP program.

(OCA St. 4 at 59.) After I pointed out in my rebuttal testimony that the Company's EE&C Plan does indeed provide services to low-income customers and includes a Residential Low-Income Program,[3] Mr. Colton now claims that his direct testimony actually stated how the Company's EE&C Plan fails to "offer a program component making investments in low-income <u>weatherization</u> through its EE&C Plan." (OCA St. 4SR at 25) (emphasis added).

Mr. Colton did not say in his direct testimony that UGI Electric fails to provide "weatherization" services to low-income customers through its EE&C Plan. He said that

[3] (*See* UGI Electric St. No. 11-R at 16, 20.)

the Company "does not provide services to low-income customers," meaning no such services at all. I believe this reveals Mr. Colton's lack of familiarity with the Company's EE&C Plan offerings and, therefore, his criticisms based on what is or is not offered under the Company's EE&C Plan should be disregarded.

Q. Are there any other flaws with Mr. Colton's position?

A. Yes. Mr. Colton fails to recognize that the Phase III EE&C Plan's Residential Low-Income Program was designed, under the Commission-approved settlement, to offer "additional and/or different measures" than the weatherization measures provided through the Company's Low-Income Usage Reduction Program ("LIURP"). Specifically, under Paragraph 23(b) of the Commission-approved settlement in that case:

> The Company will set aside $140,000 to launch one or more residential customer programs in PY 2 through PY 5, including a residential low-income customer program by no later than June 1, 2020. The residential low-income program shall not be specifically limited to the measures offered under the three existing low-income programs that are being eliminated or phased out as part of the Phase III EE&C Plan. <u>The residential low-income program will provide an opportunity for the Company to offer additional and/or different measures than those offered through the Company's Low Income Usage Reduction Program ("LIURP"). The parties acknowledge that this low-income program is not LIURP</u> and is not subject to the provisions of Chapter 58 of the Commission's regulations. Such costs shall only be recovered from Class 1 customers.[4]

Importantly, the OCA agreed to and supported this settlement. Therefore, given that the settlement effectively directed the Company not to provide weatherization services to low-

[4] *Petition of UGI Utils., Inc. – Elec. Div. for Approval of Phase III of its Energy Efficiency and Conserv. Plan*, Docket No. M-2018-3004144, p. 7 (Recommended Decision dated Feb. 19, 2019) (emphasis added), *adopted without modification*, Docket No. M-2018-3004144 (Order entered Mar. 14, 2019).

income customers through its Residential Low-Income Program, I do not believe it is appropriate for Mr. Colton to criticize the EE&C Plan on that ground.

V. CONCLUSION

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

UGI Electric Exhibit DVA-1RJ

CAUSE-PA-I-4

Request:

For 2018 to present, disaggregated by month and year, how many UGI Electric customers were/are categorized as a confirmed low income customer? Please provide this data in a live excel spreadsheet.

Response:

The Company began extracting and recording confirmed low income counts at month end, beginning in October 2022. Monthly data prior to October 2022 is not available. The Confirmed Low Income indicator is date sensitive. The date is updated when specific activities occur. Activities include a customer receiving LIHEAP grants, enrolling in CAP, receiving an Operation Share grant, or participating in LIURP.

However, the Company has fiscal year end "snapshots" that were previously provided in the 2021 Electric Base Rate Case.

Please see Attachment CAUSE-PA-I-4.

Prepared by or under the supervision of: Daniel V. Adamo

I&E Statement No. 1
Witness: Vanessa Okum

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – ELECTRIC DIVISION

Docket No. R-2022-3037368

Direct Testimony

of

Vanessa Okum

Bureau of Investigation & Enforcement

Concerning:

OVERALL REVENUE REQUIREMENT

OPERATING AND MAINTENANCE EXPENSES

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<u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Vanessa Okum. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed as a Fixed Utility Financial Analyst in the Pennsylvania Public Utility Commission's (Commission) Bureau of Investigation and Enforcement (I&E).

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. Appendix A, which is attached to my testimony, describes my educational background and professional experience.

Q. DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. The I&E analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires balancing the interests of the ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to present recommended adjustments to claims made in the base rate filing of UGI Utilities, Inc. – Electric Division (UGI Electric or Company) and to present the I&E overall recommended revenue requirement. In this testimony, I make recommendations regarding operating and maintenance (O&M) expenses within UGI Electric's proposed fully projected future test year (FPFTY) ending September 30, 2024.

Q. DOES YOUR DIRECT TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 1 contains schedules that support my direct testimony.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS.

A. The following table summarizes my recommended adjustments:

	Company Claim	**I&E Recommended Allowance**	**I&E Adjustment**
O&M Expenses:			
Rate Case Expense	$385,000	$307,600	($77,400)
Total O&M Expense Adjustments			**($77,400)**

OVERALL I&E RECOMMENDED REVENUE REQUIREMENT

Q. WHAT TEST YEARS HAS THE COMPANY USED IN THIS PROCEEDING?

A. The Company used the twelve months ended September 30, 2022 as the historic test year (HTY), the twelve months ending September 30, 2023 as the future test year (FTY), and the twelve months ending September 30, 2024 as the FPFTY.[1]

Q. SUMMARIZE THE COMPANY'S OVERALL CLAIMED REVENUE REQUIREMENT.

A. The Company's base rate case filing was submitted on January 27, 2023, requesting an increase of $11,425,000 to claimed present rate revenues of $152,691,000 resulting in a total overall revenue requirement of $164,116,000.[2]

Q. WHAT IS I&E'S TOTAL RECOMMENDED REVENUE REQUIREMENT?

A. I&E's total recommended revenue requirement for the Company is $159,520,000. This recommended revenue requirement represents an increase of $6,829,000 to the Company's present rate revenues of $152,691,000. This total recommended allowance incorporates my adjustments made in this testimony to O&M expenses, and those recommended adjustments made in the testimonies of I&E witnesses Christopher Keller[3] and DC Patel.[4]

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[1] UGI Electric Statement No. 2, p. 2.
[2] UGI Electric Exhibit A - Fully Projected, Schedule A-1.
[3] I&E Statement No. 2.
[4] I&E Statement No. 3.

A calculation of the I&E recommended revenue requirement is shown below:

UGI Electric		TABLE I			
R-2022-3037368		INCOME SUMMARY			
In Thousands					
	9/30/24	INVESTIGATION & ENFORCEMENT			
	Proforma	[--]			
	Present Rates	Adjustments	Present Rates	Allowances	Proposed
	$	$	$	$	$
Operating Revenue	152,691	0	152,691	6,829	159,520
Deductions:					
O&M Expenses	127,107	-858	126,249	126	126,375
Depreciation	8,553	0	8,553		8,553
Taxes, Other	9,718	0	9,718	402	10,120
Income Taxes:					
Current State	-483	77	-406	566	160
Current Federal	-833	164	-669	1,204	535
Deferred Taxes	2,139	0	2,139		2,139
ITC	0	0	0		0
Total Deductions	146,201	-617	145,584	2,298	147,882
Income Available	6,490	617	7,107	4,531	11,638
Rate Base	172,242	-77	172,165	0	172,165
Rate of Return	3.77%		4.13%		6.76%

<u>RATE CASE EXPENSE</u>

Q. BRIEFLY DESCRIBE THE NATURE AND TYPES OF EXPENDITURES TYPICALLY ALLOWED AS A PART OF A REGULATED UTILITY'S OVERALL RATE CASE EXPENSE.

A. The nature and types of individual expenditures that comprise a utility's allowable claim for rate case expense are those directly incurred to compile, present, and defend a utility's request for a base rate increase before the Commission. The actual expenditures and estimated costs typically found in an allowable rate case expense claim include legal fees for outside counsel, fees to outside consultants, and the cost of printing, document assembly, and postage.

Q. HOW HAS THE COMMISSION TRADITIONALLY TREATED RATE CASE EXPENSE FOR RATEMAKING PURPOSES?

A. The Commission has historically stated that it considers prudently incurred rate case expense as an ongoing expense, occurring at irregular intervals, related to the rendering of utility service. The Commission has also cited the importance of considering the involved utility's history regarding the frequency of rate case filings as an essential element to determine the normalized level of rate case expense for ratemaking purposes.

Q. HOW IS THE FREQUENCY OF RATE CASE FILINGS DETERMINED?

A. The frequency is determined by calculating the average number of months between the utility's recent rate case filings.

Q. WHAT IS THE COMPANY'S CLAIM FOR RATE CASE EXPENSE?

A. The Company's claim for rate case expense is $385,000.[5]

[5] UGI Electric Exhibit A - Fully Projected, Schedule D-10.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company estimated its total rate case expense amount to be $769,000 and has requested a normalization period of two years (24 months).[6] This produced a normalized rounded claim of $385,000 [($769,000 ÷ 24 months) x 12 months]. The Company stated that it will make regular rate case filings going forward due to capital investments in accordance with its Long-Term Infrastructure Improvement Plan (LTIIP).[7]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. I recommend that the Company's rate case expense be normalized over a period of 30 months (two and a half years) resulting in an annual expense of $307,600 [($769,000 ÷ 30 months) x 12 months], or a reduction of $77,400 ($385,000 - $307,600) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I disagree with the claimed 24-month normalization period, because it is not supported by the Company's historic filing frequency. The proposed

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[6] UGI Electric Exhibit A - Fully Projected, Schedule D-10.
[7] UGI Electric Statement No. 2, p. 16.

normalization period fails to properly rely upon the historic data and is speculative in nature.

In contrast to the Company's claimed 24-month normalization period, I recommend a 30-month normalization period, which is reasonable and validated by the Company's recent base rate filing history as identified in the Company's response to I&E-RE-2-D.[8]

Docket No.	Filing Date	Filing Interval - Months
R-2022-3037368	January 27, 2023	24 Months
R-2021-3023618	February 8, 2021	36 Months
R-2017-2640058	January 26, 2018	

My recommendation is based on the three most recent cases, including the current proceeding, which is reasonable and excludes prior cases not representative of recent activity.

Q. HAVE OTHER UTILITIES BEEN GRANTED A NORMALIZATION PERIOD BASED ON SPECULATION OF FUTURE FILINGS, AND IF SO, WHAT WAS THE RESULT?

A. Yes. In 2012, the Commission granted PPL Electric Utilities Corporation (PPL) permission to normalize its rate case expense over a 24-month period based on PPL's representations regarding its expected timing of future base rate case

[8] I&E Exhibit No. 1, Schedule 1, p. 2.

filings.[9] That base rate case was filed on March 30, 2012; however, despite PPL's representations, that company did not file its next rate case until March 31, 2015, which was 36 months after the 2012 rate case filing. It should be noted that I&E's recommended normalization period in the 2012 PPL proceeding was a 32-month interval based on PPL's historic filing frequency.[10] The I&E recommendation in that instance produced a much more accurate result than relying on PPL's stated future intention to file a rate case.

Q. ARE THERE ANY COMMISSION DECISIONS THAT SUPPORT YOUR RECOMMENDATION FOR A RATE CASE FILING INTERVAL BASED ON HISTORIC FILING FREQUENCY?

A. Yes. In a base rate case filed by Emporium Water Company, the Commission adopted the I&E recommended historic filing frequency finding in favor of I&E's recommended five-year normalization period based on a historic average filing frequency that was rounded down from 64 months.[11] Additionally, in a decision for the City of DuBois, the Commission agreed with I&E's recommendation to use a historic filing frequency, finding in favor of I&E's recommended 64-month normalization period, which matched the actual historic filing frequency.[12]

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[9] *PA. PUC v. PPL Electric Utilities Corporation*, Docket No. R-2012-2290597, pp. 47-48 (Order Entered December 28, 2012).

[10] I&E Statement No. 2, pp. 13-14 at Docket No. R-2012-2290597.

[11] *PA PUC v. Emporium Water Company*, Docket No. R-2014-2402324, p. 50 (Order Entered January 28, 2015).

[12] *PA PUC v. City of DuBois - Bureau of Water*, Docket No. R-2016-2554150, pp. 65-66 (Order Entered March 28, 2017); *PA PUC v. City of DuBois - Bureau of Water*, Docket No. R-2016-2554150, p. 13 (Order Entered May 18, 2017).

More recently, in the Columbia Gas base rate proceeding of 2020, the Commission held that the normalization period should align with the historic data rather than Columbia's intent to file its next rate case.[13] Finally, and most recently, the Commission affirmed this position in the PECO Energy Company – Gas Division's (PECO's) 2020 base rate proceeding, which granted I&E's recommended five-year normalization period rather than PECO's claim based on a three-year period because the Commission determined a normalization period based on actual historic filing frequency is more reliable than future speculation.[14]

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

[13] *PA PUC v. Columbia Gas,* Docket No. R-2020-3018835, Opinion and Order, pp. 78-79 (Order Entered February 19, 2021).

[14] *PA PUC v. PECO Energy Company- Gas Division*, Docket No. R-2020-3018929, Opinion and Order, pp. 117-119 (Order Entered June 22, 2021).

Vanessa Okum

Professional and Educational Background

EXPERIENCE:

Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania
June 2022 – Present
Fixed Utility Financial Analyst, Bureau of Investigation and Enforcement

Magnolia Realty Services, Elizabethville, Pennsylvania
February 2016 – Present
Realtor

May 2015 – May 2019
Business Manager

The Vanguard Group, Malvern, Pennsylvania
October 2011 – December 2014
Financial Administrator, Corporate Financial Services

March 2010 – October 2011
Financial Analyst, Fund Financial Services

June 2008 – March 2010
Financial Associate, Fund Financial Services

EDUCATION/PROFESSIONAL DEVELOPMENT:

University of Massachusetts – Amherst, Amherst, Massachusetts, 2012
Master of Business Administration

Elizabethtown College, Elizabethtown, Pennsylvania, 2008
Bachelor of Science in International Business
Concentration in Finance

<u>TESTIMONY SUBMITTED</u>:

I have submitted testimony in the following proceedings:

- R-2023-3037428 – National Fuel Gas Distribution Corporation (1307(f))

I have assisted with testimony in the following proceedings:

- R-2022-3031704 – Borough of Ambler Water Department
- R-2022-3032764 – Leatherstocking Gas Company, LLC

I&E Exhibit No. 1
Witness: Vanessa Okum

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – ELECTRIC DIVISION

Docket No. R-2022-3037368

Exhibit to

Accompany

the

Direct Testimony

of

Vanessa Okum

Bureau of Investigation & Enforcement

Concerning:

OVERALL REVENUE REQUIREMENT

OPERATING AND MAINTENANCE EXPENSES

UGI Utilities, Inc. - Electric Division
Docket No. R-2022-3037368
UGI Electric 2023 Base Rate Case
Responses to I&E (RE-1-D thru RE-6-D)
Delivered on March 9, 2023

I&E-RE-2-D

Request:

Reference UGI Electric Book IV, Exhibit A – Fully Projected Future, Schedule D-10 concerning rate case expense, provide the following details for the last three base rate cases filed with the Commission:

A. The docket number, date of filing, and method of resolution (e.g., settlement or litigation).

B. Requested rate case expense and actual rate case expense incurred.

Response:

Please see the response to OCA-II-28.

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

UGI Utilities, Inc. - Electric Division
Prior Rate Case Costs Incurred

Company	Docket No.	Filing Date	Rate Case Costs Incurred	Rate Case Costs Requested	Resolution
UGI Utilities, Inc. - Electric Division	R-2021-3023618	February 8, 2021	$ 719,330	$ 839,000	Settlement
UGI Utilities, Inc. - Electric Division	R-2017-2640058	January 26, 2018	$ 868,967	$ 676,000	Fully Litigated
UGI Utilities, Inc. - Electric Division	R-00953534	January 26, 1996	Not Available	$ 360,000	Settlement
UGI Utilities, Inc. - Electric Division	R-00932862	November 1, 1993	$ 372,000	Not Available	Fully Litigated
UGI Utilities, Inc. - Electric Division	R-00922195	June 12, 1992	$ 261,000	Not Available	Settlement

I&E Statement No. 1-SR
Witness: Vanessa Okum

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – ELECTRIC DIVISION

Docket No. R-2022-3037368

Surrebuttal Testimony

of

Vanessa Okum

Bureau of Investigation & Enforcement

Concerning:

OVERALL REVENUE REQUIREMENT

OPERATING AND MAINTENANCE EXPENSES

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<u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Vanessa Okum. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. ARE YOU THE SAME VANESSA OKUM WHO SUBMITTED TESTIMONY IN I&E STATEMENT NO. 1 AND I&E EXHIBIT NO. 1?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of UGI Utilities, Inc. – Electric Division (UGI Electric or Company) witness Tracy Hazenstab (UGI Electric Statement No. 2-R) and to present the updated I&E overall recommended revenue requirement.

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN EXHIBIT?

A. No. However, I refer to my direct testimony in this surrebuttal testimony (I&E Statement No. 1).

OPERATING AND MAINTENANCE EXPENSE ADJUSTMENTS

Q. PLEASE SUMMARIZE THE COMPANY'S UPDATED REQUESTED REVENUE INCREASE.

A. In rebuttal testimony, UGI Electric continues to request an increase of $11,425,000 to claimed present rate revenues; however, its supported revenue increase is revised to $11,453,000 due to various revisions, including changes to customer deposit balance, materials and supply balance, weighted average cost of debt, salary and wage expense, and forfeited discounts.[1]

Q. PLEASE SUMMARIZE YOUR RECOMMENDED O&M ADJUSTMENTS TO THE COMPANY'S REBUTTAL POSITION.

A. The following table summarizes my recommended adjustments:

	Company Claim	**I&E Recommended Allowance**	**I&E Adjustment**
O&M Expenses:			
Rate Case Expense	$385,000	$307,600	($77,400)
Total O&M Expense Adjustments			**($77,400)**

SUMMARY OF I&E OVERALL UPDATED POSITION

Q. WHAT IS I&E'S TOTAL UPDATED RECOMMENDED REVENUE REQUIREMENT?

A. I&E's total recommended revenue requirement for the Company is $159,575,000.

[1] UGI Electric Statement No. 2-R, pp. 3-5.

This recommended revenue requirement represents an increase of $6,864,000 to the Company's present rate revenues of $152,711,000. This total recommended allowance incorporates my adjustment made in this testimony to rate case expense, and those recommended adjustments made in the testimonies of I&E witnesses Christopher Keller,[2] and DC Patel.[3]

An updated calculation of the I&E recommended revenue requirement is shown below:

UGI Electric		TABLE I			
R-2022-3037368		INCOME SUMMARY			
$ in thousands					
	9/30/24	INVESTIGATION & ENFORCEMENT			
	Proforma	[-------	-------	-------	-------]
	Present Rates	Adjustments	Present Rates	Allowances	Proposed
	$	$	$	$	$
Operating Revenue	152,711	0	152,711	6,864	159,575
Deductions:					
O&M Expenses	127,094	-856	126,238	126	126,364
Depreciation	8,553	0	8,553		8,553
Taxes, Other	9,714	0	9,714	404	10,118
Income Taxes:					
Current State	-486	77	-409	569	160
Current Federal	-839	164	-675	1,211	536
Deferred Taxes	2,139	0	2,139		2,139
ITC	0	0	0		0
Total Deductions	146,175	-615	145,560	2,310	147,870
Income Available	6,536	615	7,151	4,554	11,705
Rate Base	172,186	-59	172,127	0	172,127
Rate of Return	3.80%		4.15%		6.80%

2 I&E Statement No. 2-SR.
3 I&E Statement No. 3-SR.

RATE CASE EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR RATE CASE EXPENSE.

A. I recommended UGI Electric's rate case expense be normalized over a period of 30 months, in line with the Company's historic rate case filing frequency, producing an annualized amount of $307,600 [($769,000 ÷ 30 months) x 12] per year. This resulted in a reduction of $77,400 ($385,000 - $307,600) to the Company's annual rate case expense claim.[4]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. UGI Electric witness Tracy Hazenstab disagrees with my recommendation.

Q. PLEASE SUMMARIZE MS. HAZENSTAB'S RESPONSE.

A. Ms. Hazenstab asserts that the frequency of past rate cases is not a predictor of the frequency of future rate cases. She states that the Commission has previously approved a projected normalization period for UGI Electric in its 2018 base rate case (at Docket No. R-2017-2640058), and that the Company has filed base rate cases consistent with its projected intervals during the last two base rate filings. Ms. Hazenstab further states that the Company continues to anticipate a two-year frequency for base rate cases due to future capital requirements and the cost of other long-term improvements as identified in the Company's Long-Term

[4] I&E Statement No. 1, pp. 6-9.

Infrastructure Improvement Plan, along with inflationary pressures, capital cost rates, a higher risk associated with the rate of return, and reaching the 5% DSIC maximum.[5]

Additionally, Ms. Hazenstab points out that a 30-month normalization period does not align with UGI Electric's practice of filing rate cases in January with new rates being effective in October of the same year.[6]

Q. WHAT IS YOUR RESPONSE TO MS. HAZENSTAB'S ASSERTIONS?

A. I disagree with the Company's claimed two-year normalization period and reiterate that it is not supported by UGI Electric's historic filing frequency, the proposed normalization period fails to properly rely upon the historical data, and the claimed period is speculative in nature as discussed in my direct testimony.[7]

Normalization of rate case expense based on the future need or expectation to file a rate case is speculative and is subject to various unpredictable future economic and financial conditions; therefore, determination of a rate case expense normalization period based on future expectations or the intention to file a rate case is not reliable.

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[5] UGI Electric Statement No. 2-R, pp. 10-12.
[6] UGI Electric Statement No. 2-R, p. 13.
[7] I&E Statement No. 1, pp. 6-7.

Q. SHOULD THE NORMALIZATION PERIOD ALIGN WITH UGI ELECTRIC'S PRACTICE OF FILING RATE CASES IN JANUARY?

A. No. It is not necessary for the normalization period to align with UGI Electric's practice of filing rate cases in January. When a regulated utility files a rate case earlier or later than previously anticipated, the actual recovery of rate case expense will be over or under by a certain amount. While adjustments are not made for prior expenses which would improperly constitute retroactive ratemaking, those variances tend to balance out the recovery over time, thereby lending appropriateness to the use of a historic filing frequency in determining the proper interval.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. No. I continue to recommend normalizing rate case expense over 30 months which yields an annual allowance of $307,600. This is a reduction of $77,400 ($385,000 - $307,600) to UGI Electric's annual rate case expense claim.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Statement No. 2
Witness: Christopher Keller
NON-PROPRIETARY

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – ELECTRIC DIVISION

Docket Nos. R-2022-3037368

Direct Testimony

of

Christopher Keller

Bureau of Investigation and Enforcement

Concerning:

Operating and Maintenance Expenses
Cash Working Capital

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher Keller. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. SUMMARIZE YOUR EDUCATION AND EMPLOYMENT HISTORY.

A. An outline of my education and employment history is attached as Appendix A.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. I&E's analysis in the proceedings is based on its responsibility to represent the public interest. This responsibility requires the balancing the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review the base rate filing of UGI Utilities, Inc. – Electric Division (UGI Electric or Company) and make recommended adjustments to UGI Electric's proposed operating and maintenance (O&M) expenses and cash working capital for the fully projected future test year (FPFTY) ending September 30, 2024.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 2 contains schedules that support my direct testimony.

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS.

A. The following table summarizes my recommended adjustments.

	Company Claim	I&E Adjustment	I&E Recommended Allowance
O&M Expenses and Taxes:			
{BEGIN PROPRIETARY}			
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
{END PROPRIETARY}			
Advertising Expense	$113,000	($54,000)	$59,000
Total O&M Expense and Tax Adjustments		($779,800)	
Rate Base Adjustments:			
Cash Working Capital	$11,466,885	($77,477)	$11,389,408
Total Rate Base Adjustments		($77,477)	

Q. WHAT TEST YEARS HAS UGI ELECTRIC USED IN THIS PROCEEDING?

A. UGI Electric used the twelve months ended (TME) September 30, 2022 as the historic test year (HTY), the TME September 30, 2023 as the future test year (FTY), and the TME September 30, 2024 as the FPFTY in this proceeding.

<u>STOCK OPTIONS AND RESTRICTED STOCK AWARDS</u>

Q. WHAT ARE STOCK OPTIONS AND RESTRICTED STOCK AWARDS?

A. Stock options are a type of compensation in the form of an option given by a company to certain employees to buy stock in the Company at a discount or at a stated fixed price. Restricted stock awards are a type of compensation given to key employees in the form of shares of stock subject to restrictions on sale and risk of forfeiture until vested by continued employment.

Q. WHAT IS THE COMPANY'S CLAIM FOR STOCK OPTIONS AND RESTRICTED STOCK AWARDS?

A. In the confidential response to I&E-RE-14-D, the Company's claim for stock options and restricted stock awards **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}**. This results in a total claim for stock options and restricted stock awards of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}**

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR STOCK OPTIONS AND RESTRICTED STOCK AWARDS?

A. I recommend disallowance of the Company's entire claim of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** for stock options and restricted stock awards.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. Stock-based compensation such as stock options and restricted stock awards are based on achieving financial goals and targets that serve primarily to benefit shareholders. This expense should not be funded by ratepayers as financial goals do not assist in providing safe and reliable service to ratepayers. Allowing this claim in rates would result in higher rates and revenues at the expense of ratepayers, while providing a benefit to the parent company and shareholders' financial goals. Therefore, stock options and restricted stock options should be paid for by shareholders, and not by ratepayers, as they are directly linked to the benefit of shareholders.

Q. ARE THERE ANY COMMISSION DECISIONS THAT SUPPORT YOUR RECOMMENDATION?

A. Yes. In a recent Columbia Gas of Pennsylvania, Inc. (Columbia) base rate case, the Commission disallowed Columbia's claim for stock options expense and stock rewards expense.[1] In that proceeding, the Commission stated the following,

> Stock options and stock awards are forms of incentive compensation where the value is based on the achievement of financial goals. Financial goals related to the appreciation of common stock are shareholder-oriented goals, not ratepayer-oriented goals. Higher Company earnings are directly linked to higher rates which increase the value of common stock.

It should also be noted that Columbia voluntarily withdrew its claim for the stock compensation portion of its incentive compensation program.[2]

<u>INCENTIVE COMPENSATION AND EXECUTIVE BONUS PLAN</u>

Q. WHAT ARE INCENTIVE COMPENSATION AND THE EXECUTIVE BONUS PLAN?

A. Incentive compensation is additional money or other rewards that are supplementary to base pay. The executive bonus plan is a form of incentive compensation for high level UGI employees such as the president and CEO, vice presidents, controller, etc.

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[1] *Pa. PUC v. Columbia Gas,* Docket No. R-2020-3018835, Opinion and Order, pp. 73-75 (Order Entered February 19, 2021).

[2] *Pa. PUC v. Columbia Gas,* Docket No. R-2020-3018835, Opinion and Order, p. 75 (Order Entered February 19, 2021).

Q. WHAT IS THE COMPANY'S CLAIM FOR INCENTIVE COMPENSATION AND THE EXECUTIVE BONUS PLAN?

A. In the confidential response to I&E-RE-14-D, the Company's claim for incentive compensation and the executive bonus plan **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** This results in a total claim for incentive compensation and the executive bonus plan of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}**.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR INCENTIVE COMPENSATION AND THE EXECUTIVE BONUS PLAN?

A. I recommend an allowance of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** for incentive compensation and the executive bonus plan, or a reduction of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation for incentive compensation and the executive bonus plan is based on the removal of the portion that is attributable to achieving financial goals. In the confidential response to I&E-RE-14-D (I&E Exhibit No. 2, Schedule 1), **{BEGIN PROPRIETARY}**, [redacted] **{END PROPRIETARY}**

In the Company's confidential response to OCA-II-25 (I&E Exhibit No. 2, Schedule 2, pp. 6-9), **{BEGIN PROPRIETARY}** [redacted]

[redacted] **{END PROPRIETARY}**

Based on the responses above, a large portion of the incentive compensation and executive bonus plans is based on achieving financial goals and targets that serve primarily to benefit shareholders. Therefore, the portion of the incentive compensation and executive bonus plans attributable to financial goals should not be funded by the ratepayers as financial goals do not assist in providing safe and reliable service to ratepayers. Therefore, I recommend disallowance of any portion of the incentive compensation and executive bonus plans attributable to financial performance.

Q. EXPLAIN HOW YOU CALCULATED YOUR ADJUSTMENT TO INCENTIVE COMPENSATION AND THE EXECUTIVE BONUS PLAN.

A. My adjustment is based on the removal of the portion of incentive compensation and the executive bonus plans that are financial goals. **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** This results in a recommended allowance of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** for incentive compensation and the executive bonus plan, or a **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** to Company's claim.

<u>DIRECTORS' EQUITY COMPENSATION</u>

Q. WHAT IS DIRECTORS' EQUITY COMPENSATION?

A. Directors' equity compensation is a type of compensation in the form of stock options, restricted stock, and other equity based awards given by a company to high level employees.

Q. WHAT IS THE COMPANY'S CLAIM FOR DIRECTORS' EQUITY COMPENSATION?

A. In the confidential response to I&E-RE-14-D, the Company's claim for directors' equity compensation is **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}**

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR DIRECTORS' EQUITY COMPENSATION?

A. I recommend disallowance of the Company's entire claim of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** for directors' equity compensation.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on achieving financial goals and targets that serve primarily to benefit shareholders that should not be funded by the ratepayers as financial goals do not assist in providing safe and reliable service to ratepayers. In the confidential response to I&E-RE-14-D (I&E Exhibit No. 2, Schedule 1, p. 6), **{BEGIN PROPRIETARY}** [redacted]

{END PROPRIETARY}

Allowing this claim in rates would result in higher rates and revenues at the expense of ratepayers, while providing a benefit to the parent company and shareholders' financial goals. Therefore, directors' equity compensation should be paid for by shareholders, and not by ratepayers, as it is directly linked to the benefit of shareholders.

Q. ARE THERE ANY COMMISSION DECISIONS THAT SUPPORT YOUR RECOMMENDATION?

A. Yes. As discussed earlier in my testimony, in a base rate case filed by Columbia the Commission disallowed Columbia's claim for stock options expense and stock rewards expense.[3] In that proceeding, the Commission stated the following,

> Stock options and stock awards are forms of incentive compensation where the value is based on the achievement of financial goals. Financial goals related to the appreciation of common stock are shareholder-oriented goals, not ratepayer-oriented goals. Higher Company earnings are directly linked to higher rates which increase the value of common stock.

Again, it should be noted that Columbia voluntarily withdrew its claim for the stock compensation portion of its incentive compensation program.[4]

ADVERTISING EXPENSE

Q. WHAT IS INCLUDED IN ADVERTISING EXPENSE?

A. Advertising expense includes community information advertising such as conservation of energy, explanation of billing practices, rates, etc., public health and safety, and other advertising programs (UGI Electric Volume 1, Responses to Section 53.53–II–D – Income Statement Supporting Schedules, II-D-7, Attachment II-D-7(d)).

Q. WHAT IS THE COMPANY'S CLAIM FOR ADVERTISING EXPENSE?

A. The Company's total distribution claim for advertising expense is $113,000.

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[3] *Pa. PUC v. Columbia Gas,* Docket No. R-2020-3018835, Opinion and Order, pp. 73-75 (Order Entered February 19, 2021).

[4] *Pa. PUC v. Columbia Gas,* Docket No. R-2020-3018835, Opinion and Order, p. 75 (Order Entered February 19, 2021).

Q. WHAT IS THE BASIS OF THE COMPANY'S CLAIM?

A. The Company started with total advertising expense of $141,000 which was further broken down between the amount allocated to transmission of $28,000 and the amount allocated to distribution of $113,000 (UGI Electric Volume 1, Responses to Section 53.53–II–D – Income Statement Supporting Schedules, II-D-7, Attachment II-D-7(d)). This claim includes advertising related to conservation of energy, explanation of bill practices, rates, and consumer programs, public health and safety, and other advertising programs (I&E Exhibit No. 2, Schedule 3).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR ADVERTISING EXPENSE?

A. I recommend an allowance of $59,000 for distribution advertising expense or a reduction of $54,000 ($113,000 - $59,000) to the Company's distribution claim. This was determined by starting with a total (transmission and distribution) recommendation for advertising expense of $74,000 which can be further broken down for the amount allocated to transmission of $15,000 and the amount allocated to distribution of $59,000. This results in a total reduction of $67,000 ($141,000 - $74,000) to the Company's total claim which can be broken down for the amount allocated to transmission of $13,000 and the amount allocated to distribution of $54,000.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on a reduction of other advertising expense to the HTY amount of the Company's claim. For the HTY, the Company's total other advertising expense was $24,000 which can be further broken down for the amount allocated to transmission of $5,000 and the amount allocated to distribution of $19,000. For the FPFTY, the Company's total claim for other advertising expense is $91,000 which can be further broken down for the amount allocated to transmission of $18,000 and the amount allocated to distribution of $73,000.

In response to I&E-RE-27-D, the Company provides a breakdown of its advertising expense claim by type and year as well as an explanation for yearly fluctuations in advertising expense (I&E Exhibit No. 2, Schedule 3). The Company states that the fluctuations in other advertising expense for the TME September 30, 2020, 2021, and HTY 2022 is mainly due to the reduction in event sponsorships, builder meetings, tradeshows, and arena signage opportunities due to the COVID-19 pandemic and the Company expects to have a closer to normal level of these activities in the FTY and FPFTY.

My recommendation is based on reducing the other advertising expense portion of advertising expense to the HTY amount as the increase to the FPFTY claim is primarily for event sponsorships, builder meetings, tradeshows, and arena signage. In response to I&E-RE-27-D, the Company provides examples that include advertisements for an annual book drive and fair where the Company is the sponsor of the event and another where the Company is a paid sponsor for the 2023 Young Professionals Conference.

These types of advertising should not be paid for by ratepayers as they are more representative of goodwill advertising or promotional advertising, that would provide little, if any, benefit to ratepayers. Ratepayers should not be required to fund the Company's decision to pay for such promotional advertising. If the Company is spending this money in an attempt to benefit the overall community in some way, this is inappropriate since it becomes more of a charitable contribution of which ratepayers have no say who receives the money or services. Finally, not all customers who attend these events are UGI Electric ratepayers, and many UGI Electric ratepayers may never attend these events. So, even if the Company were to claim that these payments are for safety and e-billing promotions, there would be more effective and potentially less costly ways to reach the ratepaying community.

Q. EXPLAIN HOW YOU CALCULATED YOUR ADJUSTMENT TO ADVERTISING EXPENSE.

A. My adjustment is based on the removal of the increase in other advertising expense from the HTY to the FPFTY. The Company's total other advertising expense for the HTY was $24,000 which can be further broken down for the amount allocated to transmission of $5,000 and the amount allocated to distribution of $19,000. For the FPFTY, the Company's total claim for other advertising expense is $91,000 which can be further broken down for the amount allocated to transmission of $18,000 and the amount allocated to distribution of $73,000. The difference in total other advertising expense from the FPFTY and the HTY is $67,000 ($91,000 - $24,000) which can be further broken down for the amount allocated to transmission of

$13,000 ($18,000 – $5,000) and the amount allocated to distribution of $54,000 ($73,000 - $19,000).

As a result, I recommend an allowance of $74,000 for total advertising expense which can be further broken down for the amount allocated to transmission of $15,000 and the amount allocated to distribution of $59,000. This results in a reduction of $67,000 ($141,000 - $74,000) to the Company's total claim which can be broken down for the amount allocated to transmission of $13,000 and the amount allocated to distribution of $54,000 (I&E Exhibit No. 2, Schedule 4).

CASH WORKING CAPITAL

Q. WHAT IS A CASH WORKING CAPITAL (CWC) ALLOWANCE FOR RATEMAKING PURPOSES?

A. CWC includes the amount of funds necessary to operate a utility during the interim between the rendition of service, including the payment of related expenses, and the utility's receipt of revenue in payment of services rendered.

Q. HOW DOES THE COMPANY CALCULATE ITS CWC CLAIM?

A. UGI Electric calculates its CWC by using a lead/lag study. A lead/lag study measures the differences in time between: (1) the time services are rendered until payment of those services is received, and (2) the time between the point when a utility has incurred an expense and the actual payment of the expense. Stated another way, the lead/lag study measures how many days exist on average between the midpoint of the service period and the date the payment is made.

Q. WHAT IS UGI ELECTRIC'S CLAIM FOR CWC?

A. UGI Electric's claim for CWC is $11,466,885 (UGI Electric Book IV, Exhibit A – Fully Projected Future, Schedule C-4, p. 1, line 5).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. UGI Electric's claim is based on a HTY lead/lag study, applying total revenues and total expenses for the FPFTY ending September 30, 2024.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND?

A. I recommend a total allowance of $11,389,408 or a decrease of $77,477 ($11,466,885 - $11,389,408) to the Company's claim (I&E Exhibit No. 2, Schedule 5, p. 1).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on adjustments to O&M expenses as discussed in I&E witness Vanessa Okum's direct testimony (I&E Statement No. 1) and in my testimony.

Q. IS YOUR RECOMMENDED CWC ALLOWANCE A FINAL RECOMMENDATION?

A. No. All adjustments to UGI Electric's claims for revenues, expenses, taxes, and rate base must be continually brought together in the Administrative Law Judge's Recommended Decision and again in the Commission's Final Order. This process, known as iteration, effectively prevents the determination of a precise calculation until all adjustments have been made to the Company's claim.

Q. WHAT O&M ADJUSTMENTS DID YOU INCORPORATE WHEN DETERMINING A RECOMMENDED CWC ALLOWANCE?

A. All O&M adjustments that are cash-based expense claims should be included when determining the Company's CWC requirement. Therefore, I have included cash-based O&M recommendations when computing the overall recommended CWC allowance.

Q. SUMMARIZE WHERE EACH OF THE RECOMMENDED O&M EXPENSE ADJUSTMENTS ARE REFLECTED IN THE CWC COMPUTATIONS.

A. <u>Other Expenses (less Uncollectibles) – Expense Lag Days</u>:

The following recommended adjustments (I&E Statement No. 1, p. 3 and I&E Statement No. 2, p. 2) are reflected in the Other Expenses (less Uncollectibles) Expense Lag Days calculation (I&E Exhibit No. 2, Schedule 4, p. 1, line 5): rate case expense adjustment of $77,400, stock options and restricted stock awards adjustment of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}**, incentive compensation and executive bonus plan adjustment of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}**, directors' equity compensation adjustment of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}**, and advertising expense adjustment of $84,000 as discussed above and in I&E Statement No. 1, resulting in a total decrease of $857,200 to the Other Expenses Lag Days calculation (I&E Exhibit No. 2, Schedule 5, p. 2).

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Professional and Educational Experience
Christopher Keller

Professional Experience

January 2014 to Present
Fixed Utility Financial Analyst
Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania
Bureau of Investigation & Enforcement

September 2008 to January 2014
Insurance Company Financial Analyst
Pennsylvania Insurance Department, Harrisburg, Pennsylvania
Bureau of Licensing & Financial Analysis

Education and Training

FAI Utility Finance and Accounting for Financial Professionals, Boston, MA
May 21-23, 2014

York College of Pennsylvania, York, Pennsylvania
Master of Business Administration, Finance Concentration, 2008
Bachelor of Science, Accounting, 2006

Testimony Submitted

I have testified and/or submitted testimony in the following proceedings:

- Docket No. R-2022-3035730 – National Fuel Gas Distribution Corporation (O&M)
- Docket No. R-2022-3031340 – York Water Company – Water (ROR)
- Docket No. R-2022-3032806 – York Water Company – Wastewater (ROR)
- Docket No. R-2022-3032300 – Valley Energy, Inc. (ROR)
- Docket No. R-2022-3031704 – Borough of Ambler – Water Department (ROR)
- Docket No. R-2022-3032242 – UGI Utilities, Inc. – Gas Division (1307(f))
- Docket No. R-2022-3031211 – Columbia Gas of Pennsylvania, Inc. (ROR)
- Docket No. A-2021-3026132 – Aqua Pennsylvania Wastewater, Inc. – Acquisition of the Wastewater Collection and Conveyance System Assets of East Whiteland Township (1329)
- Docket No. P-2021-3030012 – Metropolitan Edison Company (DSP)
- Docket No. P-2021-3030013 – Pennsylvania Electric Company (DSP)
- Docket No. P-2021-3030014 – Pennsylvania Power Company (DSP)
- Docket No. P-2021-3030021 – West Penn Power Company (DSP)
- Docket No. R-2021-3026116 – Borough of Hanover – Water (ROR)
- Docket No. R-2021-3025206 – Community Utilities of Pennsylvania – Water Division (ROR)

Professional and Educational Experience
Christopher Keller

<u>Testimony Submitted (Continued)</u>

I have testified and/or submitted testimony in the following proceedings:

- Docket No. R-2021-3025207 – Community Utilities of Pennsylvania – Wastewater Division (ROR)
- Docket No. R-2021-3025652 – UGI Utilities, Inc. – Gas Division (1307(f))
- Docket No. R-2021-3024750 – Duquesne Light Company (O&M and ROR)
- Docket No. R-2021-3024296 – Columbia Gas of Pennsylvania, Inc. (ROR)
- Docket No. R-2020-3018929 – PECO Energy Company – Gas Division (ROR)
- Docket No. P-2020-3020914 – Twin Lakes Utilities, Inc. (529 Proceeding)
- Docket No. R-2020-3018835 – Columbia Gas of Pennsylvania, Inc. (ROR)
- Docket No. R-2020-3019680 – UGI Utilities, Inc. (1307(f))
- Docket No. P-2020-3019356 – PPL Electric Utilities Corporation (DSP)
- Docket No. R-2019-3015162 – UGI Utilities, Inc. – Gas Division (ROR)
- Docket No. R-2019-3010955 – City of Lancaster – Sewer Fund (O&M)
- Docket No. R-2019-3009647 – UGI Utilities, Inc. – Gas Division (1307(f))
- Docket No. R-2018-3006818 – Peoples Natural Gas Company LLC (O&M)
- Docket No. R-2018-3000124 – Duquesne Light Company (O&M)
- Docket No. R-2018-3001631 – UGI Central Penn Gas, Inc. (1307(f))
- Docket No. R-2018-3001632 – UGI Penn Natural Gas, Inc. (1307(f))
- Docket No. R-2018-3001633 – UGI Utilities, Inc. (1307(f))
- Docket No. R-2018-2645938 – Philadelphia Gas Works (1307(f))
- Docket No. P-2017-2637855 – Metropolitan Edison Company (DSP)
- Docket No. P-2017-2637857 – Pennsylvania Electric Company (DSP)
- Docket No. P-2017-2637858 – Pennsylvania Power Company (DSP)
- Docket No. P-2017-2637866 – West Penn Power Company (DSP)
- Docket No. R-2017-2602627 – UGI Central Penn Gas, Inc. (1307(f))
- Docket No. R-2017-2602638 – UGI Utilities, Inc. (1307(f))
- Docket No. R-2017-2586783 – Philadelphia Gas Works (O&M)
- Docket No. R-2017-2587526 – Philadelphia Gas Works (1307(f))
- Docket No. I-2016-2526085 – Delaware Sewer Company (529 Proceeding)
- Docket No. R-2016-2531550 – Citizens' Electric Company (O&M)
- Docket No. R-2016-2531551 – Wellsboro Electric Company (O&M)
- Docket No. R-2016-2537349 – Metropolitan Edison Company (CWC and CAP)
- Docket No. R-2016-2537352 – Pennsylvania Electric Company (CWC and CAP)
- Docket No. R-2016-2537355 – Pennsylvania Power Company (CWC and CAP)
- Docket No. R-2016-2537359 – West Penn Power Company (CWC and CAP)
- Docket No. R-2016-2543311 – UGI Central Penn Gas, Inc. (1307(f))

Professional and Educational Experience
Christopher Keller

Testimony Submitted (Continued)

- Docket No. R-2015-2518438 – UGI Utilities, Inc. – Gas Division (CWC and USP)
- Docket No. P-2015-2511333 – Metropolitan Edison Company (DSP)
- Docket No. P-2015-2511351 – Pennsylvania Electric Company (DSP)
- Docket No. P-2015-2511355 – Pennsylvania Power Company (DSP)
- Docket No. P-2015-2511356 – West Penn Power Company (DSP)
- Docket No. R-2015-2468056 – Columbia Gas of Pennsylvania, Inc. (O&M)
- Docket No. P-2014-2404341 – Delaware Sewer Company (529 Investigation)
- Docket No. R-2014-2452705 – Delaware Sewer Company (O&M)
- Docket No. R-2014-2428304 – Borough of Hanover – Water (O&M)
- Docket No. R-2014-2419774 – Wellsboro Electric Company (Customer Choice Support Charge)
- Docket No. R-2014-2420279 – UGI Central Penn Gas, Inc. (1307(f))

Assisted with the Following Cases

- Docket No. R-2017-2631441 – Reynolds Water Company (ROR)
- Docket No. R-2016-2580030 – UGI Penn Natural Gas, Inc. (ROR)
- Docket No. R-2014-2462723 – United Water Pennsylvania (CWC)
- Docket No. R-2014-2428742 – West Penn Power Company (CWC)
- Docket No. R-2014-2428743 – Pennsylvania Electric Company (CWC)
- Docket No. R-2014-2428744 – Pennsylvania Power Company (CWC)
- Docket No. R-2014-2428745 – Metropolitan Edison Company (CWC)
- Docket No. R-2013-2397353 – Pike County Light & Power Company (Gas) (O&M)
- Docket No. R-2013-2397237 – Pike County Light & Power Company (Electric) (O&M)

I&E Exhibit No. 2
Witness: Christopher Keller
NON-PROPRIETARY

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – ELECTRIC DIVISION

Docket Nos. R-2022-3037368

Exhibit to Accompany

the

Direct Testimony

of

Christopher Keller

Bureau of Investigation and Enforcement

Concerning:

Operating and Maintenance Expenses
Cash Working Capital

I&E Exhibit No. 2
Schedule 1
Page 11 of 12
CONFIDENTIAL

I&E-RE-27-D

Request:

Reference UGI Electric Book I, Responses to Section 53.53 – II-D – Income Statement Supporting Schedules, II-D-7(d), concerning advertising expense. Provide the following:

A. Provide similar breakdown of advertising expenses by year for: TME September 30, 2020, 2021, HTY 2022, 2023 YTD, 2023 FTY claim, and the FPFTY 2024 claim of $141,000.

B. Provide a detailed description of each type of advertisement included in response to Part A.

C. Provide a copy or link of all advertisements in response to Part B.

D. Provide a detailed explanation how each of the advertisements in Part B are necessary for the provision of safe and reliable service to existing ratepayers.

E. Explain any +/-10% yearly fluctuation in each category as reported in response to Part A above.

F. Provide the line number(s) and amounts where the Company's claim for advertising expense is included in UGI Electric Book IV, Exhibit A – Fully Projected Future, Schedule B-4.

Response:

A. Please see Attachment I&E-RE-27-D (A). Please note that the attachment reflects the correct categorization of claimed expenses for the 2023 FTY claim and the FPFTY 2024 claim of $141,000.

B. Description of Types of Advertising:

Conservation of Energy:

Media for distributing information on energy conservation. It includes digital search engine and social media advertising, printed brochures and billing inserts. Collateral media includes energy efficiency fact sheets, consumer guides, and information on rebate programs for smart hardware, equipment and appliances.

I&E-RE-27-D (Continued)

Explanation of Bill Practices, Rates, Consumer Programs:

Billing inserts and other printed material regarding bill education, new customer welcome packets, and low income program outreach (e.g., LIURP and LIHEAP). Other topics include information on customer choice, standards and billing practices, and connecting with UGI on social media platforms.

Public Health & Safety:

Materials distributed to new customers with tips on using electricity safely, handling emergent situations and appliance safety.

Other Advertising Programs:

The majority of these expenditures involve community-based sponsorship opportunities, wherein UGI advertises through community service and economic development organizations (e.g., special event activities, event program advertisements, website displays, signage, etc.).

C. Please see Attachment I&E-RE-27-D (C) for examples of advertising detailed in Part B.

D. Necessity of Advertising:

Conservation of Energy:

Advertising content that informs customers of strategies and programs to lower their energy costs. This outreach helps to lower payment delinquencies and promotes the efficient use of energy, demand management and load upon electric infrastructure.

Explanation of Bill Practices, Rates, Consumer Programs:

Content in this advertising provides customers with information on how to: (1) manage their utility costs; (2) shop for commodity suppliers: (3) enroll in customer assistance programs; (4) receive budget billing; and (5) utilize different payment options, all of which can lead to lower payment delinquencies. Additional information includes mandated customer communications regarding customer rights and responsibilities.

I&E-RE-27-D (Continued)

Public Health & Safety:

This content is designed to keep customers, employees and our communities safe. It discussed topics such as PA One Call, downed power wires and appliance safety.

Other Advertising Programs:

The recognition and promotion achieved through local community sponsorships, relationships and related events promotes energy conservation and sustainability, awareness of customer assistance programs and offerings. It also provides critical community support for organizations that can assist UGI customers with services that may lead to lower payment delinquency. Sponsorships also provide the opportunity to develop relationships with local businesses and community leaders to promote local growth and the responsible and safe use of electricity.

E. Please see Attachment I&E-RE-27-D (A).

F. Please see Attachment I&E-RE-27-D (A).

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

UGI UTILITIES, INC. - ELECTRIC DIVISION
SCHEDULE OF ADVERTISING EXPENSES
FOR THE YEARS ENDING SEPTEMBER 30, 2020 THROUGH 2024

	Expenditure Type *(in Thousands)*	2020	2021	2022	FYTD 2023	2023	2024
A	**Advertising Expense - Conservation of Energy**	27	32	23	5	15	17
	Less: 19.95% allocable to Transmission	(5)	(6)	(5)	(1)	(3)	(3)
	Portion claimed for Distribution	**22**	**26**	**18**	**4**	**12**	**13**
E	Year over Year Change (+/- 10%)		**20%**	**-29%**		**-35%**	**11%**

HTY 2022 saw a general reduction in expenditures in support of cost-saving initiatives, which is expected to continue in FTY 2023, with an 11% rise in costs in FPFTY 2024 for expected vendor price increases.

	Expenditure Type *(in Thousands)*	2020	2021	2022	FYTD 2023	2023	2024
A	**Explanation of Bill Practices, Rates, Consumer Programs**	17	11	29	7	28	31
	Less: 19.95% allocable to Transmission	(3)	(2)	(6)	(1)	(6)	(6)
	Portion claimed for Distribution	**14**	**9**	**23**	**6**	**22**	**25**
E	Year over Year Change		**-34%**	**155%**		**-3%**	**11%**

Increased supplier costs, especially paper and labor, resulted in higher expenditures in the HTY 2022. These increased costs are expected to continue in FTY 2023, with an 11% rise in costs for expected vendor price increases in FPFTY 2024.

	Expenditure Type *(in Thousands)*	2020	2021	2022	FYTD 2023	2023	2024
A	**Public Health & Safety**	2	1	2	1	2	2
	Less: 19.95% allocable to Transmission	(0)	(0)	(0)	(0)	(0)	(0)
	Portion claimed for Distribution	**2**	**1**	**1**	**1**	**2**	**2**
E	Year over Year Change		**-63%**	**155%**		**7%**	**11%**

Expenditures have been consistent year over year.

	Expenditure Type *(in Thousands)*	2020	2021	2022	FYTD 2023	2023	2024
A	**Other Advertising Programs**	30	24	24	8	82	91
	Less: 19.95% allocable to Transmission	(6)	(5)	(5)	(1)	(16)	(18)
	Portion claimed for Distribution	**24**	**19**	**19**	**6**	**66**	**73**
E	Year over Year Change		**0%**	**1%**		**242%**	**11%**

The variance in Fiscal Years 2020, 2021 and 2022 is driven primarily by the reduction in event sponsorship, builder meetings, tradeshows and arena signage opportunities as a result of the COVID-19 pandemic. The Company expects a more normal level of these activities in the FTY and the FPFTY.

		2024
F	FERC Income Statement Advertising GLs FERC 5920, 5930	2
	FERC Income Statement Advertising GLs FERC 9030, 9050, 9210	10
	FERC Income Statement Advertising GLs FERC 9301	44
	FERC Income Statement Advertising GLs FERC 9302	57
	Excludes Advertising for Employment Services	113

00279561

Need a helping hand?

You may be eligible for LIHEAP, an energy assistance program designed to help pay your heating bills.

Free heating assistance is available.

Turn to the back of this insert for additional information.

UGI

Energy to do more®

LIHEAP assistance available.

Pennsylvania's Low-Income Home Energy Assistance Program (LIHEAP) helps eligible energy consumers pay their heating bills through energy assistance grants. If eligible, a grant is sent to UGI on your behalf. The minimum amount of a LIHEAP cash grant is $300. The maximum is $1,000.

Contact UGI at 1 800 UGI-WARM (1 800-844-9276) for an application if you meet the income guidelines at right:

To fill out an application online, log on to www.ugi.com/LIHEAP

	Monthly income	Annual income
1 person	$1,699	$20,385
2 people	$2,289	$27,465
3 people	$2,879	$34,545
4 people	$3,469	$41,625
5 people	$4,059	$48,705
6 people	$4,649	$55,785
7 people	$5,239	$62,865
8 people	$5,829	$69,945
each additional person	$590	$7,080

Para mas información o si tiene preguntas sobre ayuda con su cuenta de UGI llame al 1 800 UGI-WARM.

Welcome Home

Customer Information Guide

UGI Energy to do more®

Nice to Meet You!

Thank you for trusting your family's energy needs to UGI.

We know that safe, reliable, and affordable energy is a necessity for you, whether you use it to keep your home warm, your water hot, or your lights on. That's why we take pride in delivering your fundamental energy needs through dependable service.

With UGI as your energy supplier, you get:

- Energy questions answered by knowledgeable staff
- Expert emergency service when you need it, day or night, from skilled employees
- Options to help manage your new account and control expenses

We pride ourselves on being a responsive, engaging energy company. Every day we strive to exceed your expectations.

In this guide, you'll find information on how your service works and how to save money. You can also visit **www.ugi.com** at any time or call 800-276-2722 for even more information.

Thank you again for choosing UGI. With our dependable service, you now have the **energy to do more.**

Headquarters:
Denver, PA
Total Employees:
~1,700
Natural Gas Pipeline Network:
~12,400 miles
Electric Line Network:
~2,700 miles
Annual Employee Volunteer Hours:
~40,000 hours

Applies to natural gas customers

Applies to electric customers

At a Glance

UGI Utilities, Inc. is a natural gas and electric utility committed to delivering reliable, safe, and affordable energy to our 740,000 customers in 46 counties in Pennsylvania and one county in Maryland.

Understanding Your Bill

1 ***Customer Account Number***
Please have this number ready when you contact us about your account.

2 ***How to Contact UGI***
Use this contact information for questions regarding your bill or service.

3 ***Next Scheduled Reading***
This is the scheduled date of your next UGI meter reading.

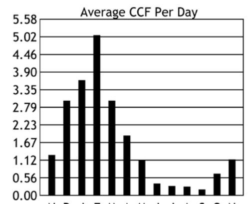
4 ***Meter Reading***
The meter reading for the current billing period and amount of energy used; natural gas is shown in CCFs (1 CCF = 100 cubic feet of gas) and electric in kWh. Our personnel are scheduled to read your meter monthly. However, there are occasions when you may receive an estimated bill. We base estimates on usage history and the actual temperature during the billing period.

5 ***Price Comparison***
Your current price to compare when shopping for an alternate energy supplier.

6 ***Messages***
Important messages from us regarding programs you may participate in, such as budget billing and the "GET Gas" program.

7 ***Due Date/Amount Due***
The amount currently owed to us and the date your payment is due.

If you have any questions or want more information, visit **www.ugi.com/billpay** or call 800-276-2722.



Energy to do more®

Billing Summary for Service to:
MR. JOHN DOE
123 MAIN ST
ANYWHERE PA 19601

Rate Classification (R):
Residential Heating

Billing Period:
10/13/2022 to 11/10/2022 (29 days)
Actual Read

Questions?
Call (800) 276-2722 or write to UGI at
PO Box 13009
Reading, PA 19612-3009
*Your current UGI charges include State taxes totaling about $0.68.

Past Bill Information

The balance on your last bill was	$0.00
Thank you for your payment of	0.00
Amount due as of 11/10/2022	0.00

Current Bill Information

Customer Charge	14.78
Commodity Charge (33 CCF at $0.86030)	28.39
Distribution Charges (33 CCF at $0.51030)	16.84
Weather Normalization Adjustment	-1.03
Current Charges	58.98
Utility charges owed this bill	**$58.98**
Total Amount Due By 12/01/2022	**$58.98**

Account Number
411001234567

Average	Last Year	This Year
CCF/Day	1.28	1.14
Daily Temperature	54°F	55°F

Meter Information - Next Read Date December 13, 2022

Meter Number	Previous Reading	Present Reading	CCF Used
1234567	4635	4668	33

Shopping Information Box
When shopping for natural gas with a Natural Gas Supplier, please provide the following data below. If you are already shopping, know your contract expiration date.
Account Number: 411001234567 Rate Schedule: R_H

Important message(s) from UGI
- Your current UGI natural gas price to compare is $0.86063/CCF.
- Effective OCT 29, 2022, the Natural Gas System Improvement Charge decreased fro...0% to 0.00%.
- Your distribution charges have been adjusted to reduce the impact of colder than normal weather.
- Your natural gas total annual usage is 632 CCF. Your natural gas average monthly usage is 53 CCF.
- We can make your energy costs easier on your budget with our 12 month Budget Billing plan. Your monthly payment would be approximately $75.00. For more information about this plan call UGI.

If you pay at a payment agent please take your entire bill. Make check payable to UGI.
Keep this part for your records. Important information is on the back of this bill.

Energy to do more®

UGI Utilities, Inc.
PO Box 15503
Wilmington, DE 19886-5503

Account Number
411001234567

The amount due will be deducted from your account on December 01, 2022.

Due Date	December 01, 2022
Amount Due	$58.98
With Late Charge	$59.86

MR. JOHN DOE
123 MAIN ST
ANYWHERE PA 19601

411001234567100000006104000000061966

I&E Exhibit No. 2
Schedule 3
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Paying Your Bill

Online at ugi.com

When you enroll in Paperless Billing, you'll receive an email alert when your monthly bill is available. Sign up quickly and easily when you register your account in our Online Account Center at **www.ugi.com**. Not only will you reduce clutter and simplify your life, but you'll also be able to view and download your monthly bills and usage, schedule future payments, and receive paperless billing exclusive email reminders when your bill is nearing its due date.

All UGI customers can make one-time payments via bank account or credit card at no additional charge. To view your payment options, **www.ugi.com/billpay**.

Other Payment Methods

- **Phone -** Call 800-276-2722 to pay your bill from your checking account, debit or credit card with no fee.
- **Mail -** Mail payments to P.O. Box 15503, Wilmington, DE 19886-5503. Always include your account number on your check.
- **Payment Agency -** Visit **www.ugi.com** or call us for approved payment agency locations. Walk-in payment centers may collect a fee for their service.

Payment Agreements for Past-Due Bills

If you have a problem paying your bill, please call us at 800-276-2722. Our customer care agents are happy to discuss options available to you.

Due Date Extensions

If you are on a permanent fixed income, our Due Date Extension program gives you additional time to deposit monthly checks so you can avoid late fees. Call us for an application.

Third-Party Notification Program

With this program, we send a copy of any past-due and shut-off notices to a designated third party—any friend, relative, caregiver, or even a preferred social services agency. **IMPORTANT: The third party is not responsible for paying any of your bills.** We simply give the designated party the opportunity to remind you to pay your bill and keep your account up to date. Call us to sign up.

Budget Billing

If your electric or gas usage varies widely from month to month or seasonally, our budget billing plan will spread your costs evenly throughout the year. Enrollment in this plan is free of charge. Sign up at **www.ugi.com** or call us with your UGI customer number handy.

AutoPay

Enrolling in this plan will save you time each month by automatically transferring your bill amount from your checking or savings account. Visit **www.ugi.com** or call us to sign up.

Income-Based Customer Assistance Programs

UGI is committed to helping customers who make a sincere effort to pay their bills. Our representatives can provide information on energy assistance programs and fuel funds, make referrals to local agencies, or establish payment arrangements. Call 800-UGI-WARM or 800-844-9276 to learn more. Typically, assistance is available for households with income up to 250% of the Federal Poverty Levels however, program eligibility is determined during the enrollment process. Programs include:

- Low Income Home Energy Assistance Program (LIHEAP) – Grant program run by the commonwealth of PA, which does not have to be paid back. Apply online at https://compass.state.pa.us or phone the LIHEAP Hotline at 866-857-7095.
- UGI Customer Assistance Program (CAP) – A personalized monthly payment plan based on percentage of income or average bill. Learn more at www.ugi.com/CAP.
- Operation Share – Grant program for customers experiencing a hardship like death of wage earner, sickness or loss of job, which does not need to be paid back. Call 800-UGI-WARM.
- UGI Low Income Usage Reduction Program (LIURP) – A program providing energy-saving repairs and upgrades to your home, at no cost to you. Visit www.ugi.com/LIURP to learn more.

I&E Exhibit No. 2
Schedule 3
Page 10 of 27

Using Your New Energy Service Safely

Natural Gas Safety

Natural Gas is Naturally Odorless

To make it detectable, a chemical known as *Mercaptan* is added. It has a smell that is similar to rotten eggs. If you smell this odor, you need to act. There is **no cost** to you for UGI to investigate a natural gas odor.

What to Do if You Smell Gas

- **LEAVE** the inside of a building immediately. Take everyone and pets with you. Leave the door open if possible, and proceed to a safe location where you can no longer smell the odor of natural gas (approximately 500 feet away from the building).
- **CALL UGI's** gas emergency line 800-276-2722 from a safe location, 24 hours a day, 7 days a week, if you smell natural gas indoors, outdoors, or near a gas meter.
- **CALL 911** from a safe location if you ever hear or see natural gas blowing anywhere.

Use your eyes and ears as well.

Be aware of any indication of a possible natural gas pipeline leak, including:

- Air blowing the dirt, grass, or trees near a pipeline
- Bubbling or blowing air in a pond or stream
- Dead grass or plants in an otherwise green area
- Flames coming out of the ground
- Unusual hissing sounds

If you notice signs of a possible leak, contact UGI at 800-276-2722 or call 911 from a safe location.

What NOT to Do if You Smell Gas

- DO NOT use phones (standard or cellular), computers, appliances, elevators, lamps, garage door openers, or electrical devices if an odor of gas is present.
- DO NOT touch electric outlets, switches or doorbells.
- DO NOT smoke or use a lighter, match or other flame.
- DO NOT operate vehicles or power equipment where leaking gas may be present.
- DO NOT try to re-light a pilot light.
- DO NOT e-mail UGI or post emergency notifications on our social media if you smell natural gas or suspect a natural gas leak. *Please call UGI or 911.*
- DO NOT re-enter a building until it has been inspected by a UGI technician.

Visit www.ugi.com for more information, and teach your family what to do, and what NOT to do, if anyone ever notices the odor that is added to odorless natural gas.

Carbon Monoxide Safety

While natural gas has a scent added to it, incomplete combustion of ANY fossil fuel could produce an odorless, tasteless, and colorless gas called carbon monoxide (CO). Here's what you need to know about CO to protect yourself:

Protect your home with CO detectors.

- CO can enter living spaces in your home as a result of a malfunctioning appliance or blocked chimney.
- All fuel-burning equipment should be installed and regularly serviced by an experienced professional.
- All fuel-burning equipment requires proper venting and air flow for safe operation. Do not install equipment in a confined space. When renovating, have a professional specify space required for fuel-burning equipment.
- Signs that you may have a CO problem include: water vapor condensing on windows (other than normal bathroom and kitchen moisture), pets acting lethargic or lazy, headaches, dizziness, flu-like symptoms, and nausea.
- A CO detector should be installed on each floor of a home, particularly near every sleeping area.
- If you are alerted by your CO detector, or if you suspect CO poisoning, move to fresh air and call UGI or 911.

I&E Exhibit No. 2
Schedule 3
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Electric Safety

Electrical emergencies can happen anywhere, anytime. Follow these tips to increase your safety in any situation.

Fallen Wires

Stay away from fallen wires and warn others to keep away. Call us immediately. If a wire touches your vehicle, stay inside. However, if your car catches fire, jump clear of the car without touching the car's metal and the ground at the same time.

Indoor Electrical Fires

Without touching the appliance, unplug it or turn off the electric supply. Use a Class C rated fire extinguisher, if available. If one is not available, throw baking soda on the fire—never use water on an electrical fire. If necessary, call your fire department.

Portable Generators

Never use a generator indoors or in any enclosed space. Always use proper power cords and follow instructions. Do not overload the generator with more equipment than its output rating. Also make sure your generator is properly grounded.

Light Bulbs

Be sure to turn light switches off before changing bulbs. Use only bulbs of the appropriate wattage for the fixture.

Electric Cords and Outlets

Replace any frayed or damaged cords. Also use proper extension cords—heavy-duty cords for power tools and moisture-resistant cords for working outdoors. If you have children in your home, make sure to install safety plugs and outlet covers. Also, never plug too many cords into one circuit.

Tree Planting and Trimming

Trees should be kept a safe distance from all electrical wires. Call us for a free "Trees for Streets and Lawns" brochure to learn more.

Safety & Security Lighting Program

We can install outdoor lighting that automatically comes on at dusk and goes off at dawn. Adequate outdoor lighting improves visibility, reduces accidents, and deters burglars and vandals. Call us for more information.

Gas Line Safety

Safe habits go beyond the walls and foundation of your home. Follow these guidelines to avoid unnecessary damage to natural gas distribution lines, electric lines, and other utilities' facilities as you enjoy your home and property.

Aboveground Pipe Safety

You should never hang anything from aboveground pipes. The added weight can weaken or break pipe joints or fittings, resulting in a leak.

Underground Pipe Safety

Call 811 three business days before a digging project—it's the law. Whether you're doing a major excavation or minor landscaping, safeguard yourself from hazards related to damaging underground pipelines. A simple call gets all your public utility lines marked to help protect you from injury and costly property damage.

811®

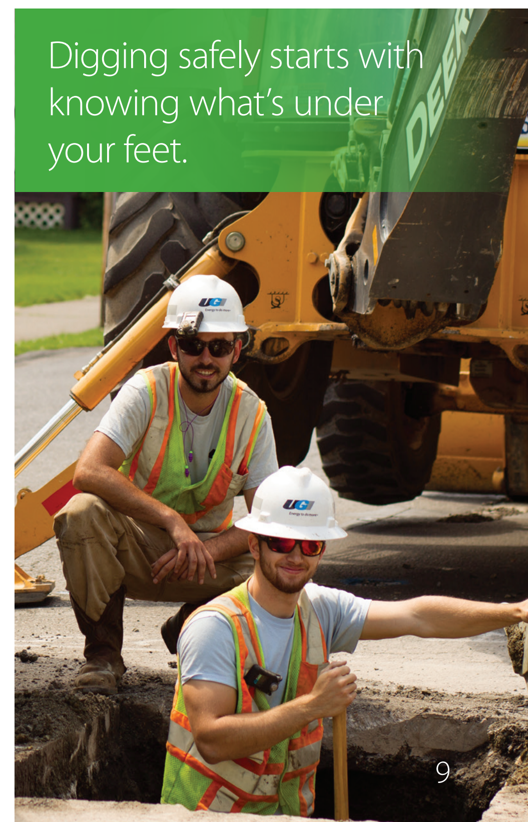
Know what's below.
Call before you dig.

What About Gas Lines Beyond the Meter?

We are responsible only for maintaining pipes that run up to and include the meter. All natural gas pipes on the property beyond the meter must be maintained by the property owner.

Before digging near buried natural gas pipes, locate the pipes and mark the area. To ensure the safety and soundness of the pipes and customer-owned fuel lines, periodically inspect them for leaks and corrosion and never hang anything from them.

Should you need assistance in locating, inspecting, or repairing pipes, you can contact your local plumber or heating contractor or call us.



Customer Choice Information

Under the Electric and Natural Gas Choice Program, you have the option to choose a third-party energy supplier. Regardless of which supplier you choose, you will receive the same level of service and reliability you already enjoy from us.

Choosing Another Supplier

While we cannot recommend suppliers or provide information on their pricing, you can look at your most recent bill for our current Price to Compare (see the sample bill on page 3) or check **www.ugi.com/price-to-compare.**

Questions you could ask third-party suppliers:

- What is your price per kWh of electricity or per CCF of natural gas? Does this price include transmission and state-mandated alternative energy costs?
- Is this rate fixed or can it change?
- Do I need to sign a contract? What is the length of the agreement?
- Are there penalties for switching or canceling?
- Will I get one bill or two? Do I have a choice?
- Are there restrictions on how much energy I can use or when I can use it?
- Do your quoted rates include taxes?
- Are there any other charges or fees?

For a list of licensed electric generation and natural gas suppliers, visit the sites below:

- For electric generation suppliers: **www.ugi.com** or **www.papowerswitch.com**.
- For natural gas suppliers: **www.ugi.com** or **www.pagasswitch.com**.

If you decide that another electric generation or natural gas supplier is right for you:

- Notify your chosen supplier. The supplier will send you a statement outlining the terms of your agreement. You may cancel your choice within three business days of receiving the statement.
  A penalty may apply if you do not remain with a supplier for the entire agreement period.
- Your chosen supplier will notify us.
- You will receive a letter from us confirming your choice. Please make sure that it is the correct supplier.

IMPORTANT: If you participate in the Customer Assistance Program (CAP) and you wish to choose a supplier, please contact us for assistance.

I&E Exhibit No. 2
Schedule 3
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Your Rights and Responsibilities

The Pennsylvania Public Utility Commission (PUC) has updated its **Standards and Billing Practices for Residential Service**.

Your Rights and Responsibilities as a Utility Consumer is a booklet prepared by the PUC to explain the rules regarding a utility's billing, credit, dispute handling and shut-off practices.

This useful booklet also includes information about various payment options for your utility bill, understanding the components of your utility bill, policies regarding security deposits, steps and rules about utility shut-offs, and how to shop for electricity or natural gas service.

You'll find a copy of the Rights and Responsibilities booklet to review or print at **www.ugi.com.** We will continue providing you with safe and reliable utility service, clear and concise bills, and fair policies. You, the consumer, should know your rights and fulfill your responsibilities to maintain your service.

As a residential utility customer, you have the RIGHT to:

- Safe and reliable service.
- A clear, concise, and accurate bill.
- Fair credit and deposit policies.
- Know how your bill is calculated and how to tell if it is too high.
- Question or disagree with your utility company.
- Personal privacy. *UGI has the responsibility of safeguarding your personal information against unauthorized use.*

As a residential utility customer, you also have the RESPONSIBILITY to:

- Pay your bill on time.
- Provide us with access to your meter.
- Give UGI at least 7 days' notice before you move or wish to discontinue service. *If you fail to notify us, you remain responsible to pay the bills.*

Special Protections

You may qualify for special protections if you:

- Are a victim of domestic violence and have a Protection From Abuse Order.
- Live in a low-income household.
- Are seriously ill or a member of your household is seriously ill. You will be required to provide proof to your provider.

Billing

All UGI customers receive bills for electric service once during a regular billing cycle (approximately one month). Customers can enroll in a program (at www.ugi.com) to pay their bills online. Please refer to www.ugi.com and "Pay Bill Online" in the left center side of the page for a list of options.

Meter Readings

Each month on approximately the same date, meter readers are scheduled to read the electric meter at your residence. Meter readers and utility service personnel carry identification, which you may ask to see for your protection. UGI has moved to an Automated Meter Reading (AMR) system throughout most of our service territory. Using the AMR system, UGI is able to record meter readings by simply driving or walking by your home. Employees use devices known as ERTs (Encoder-Receiver-Transmitters) that allow them to obtain an accurate meter reading.

- Through Automated Meter Reading, monthly bill statements are based on actual meter reads and exact electric usage. Therefore, customers will no longer routinely receive estimated electric bills.

Welcome Home.

UGI Emergency Contact:
UGI Contacto de emergencia:

800-276-2722 - Customers of UGI Gas and Electric Service

Billing and Customer Inquiries:
800-276-2722
Customer Assistance Programs:
800-844-9276 (800-UGI-WARM)
For Hearing Impaired:
800-654-5988

*Discover everything UGI does for homes and businesses at **www.ugi.com***

Energy to do more®

Ways to Save

UGI's Energy Efficiency Program wants to help our customers save energy and money by providing rebates and programs to reward investing in energy efficient systems.

Savings that stick... around the house.

Basics

- LED bulbs use approx. **70-90%** less energy, last about **15 times** longer, and save about **$55** in electricity costs over their lifetime than incandescent.
- Keep doors and vents closed in empty rooms. Open up blinds and draperies on sunny days. Close them at night to keep cold air out.
- Replace old appliances with energy-efficient models carrying the ENERGY STAR® label and start saving right away.
- Cover bare floors with carpeting or rugs, as layers add comfort and retain heat.

Weather

Sealing air leaks saves **10%** on overall energy costs

- Install a door sweep or weather stop to keep cold air out and warm air in.
- Use caulking and weather stripping around doors and windows to reduce air flow.
- Add a layer of insulation around ventilator ducts and water pipes in unheated areas.

Heating & Cooling

- Use programmable thermostats to maintain energy-saving temperatures when you're away.
- Direct your vents' air flow across the floor to allow warm air to rise.
- Keep your fireplace's flue damper closed to alleviate heat loss when not in use.
- Install a door sweep or weather stop to keep cold air out and warm air in.
- Have your furnace cleaned and serviced yearly for greater efficiency.

Laundry

90% energy reduction using cold water for laundry

- Use cold water for laundry. Water heating makes up as much as **90%** on washer energy use.
- Clean the lint trap after each use of your dryer to improve air flow and increase dryer efficiency.

Water

ENERGY STAR® clothes washers use an average of **33%** less water

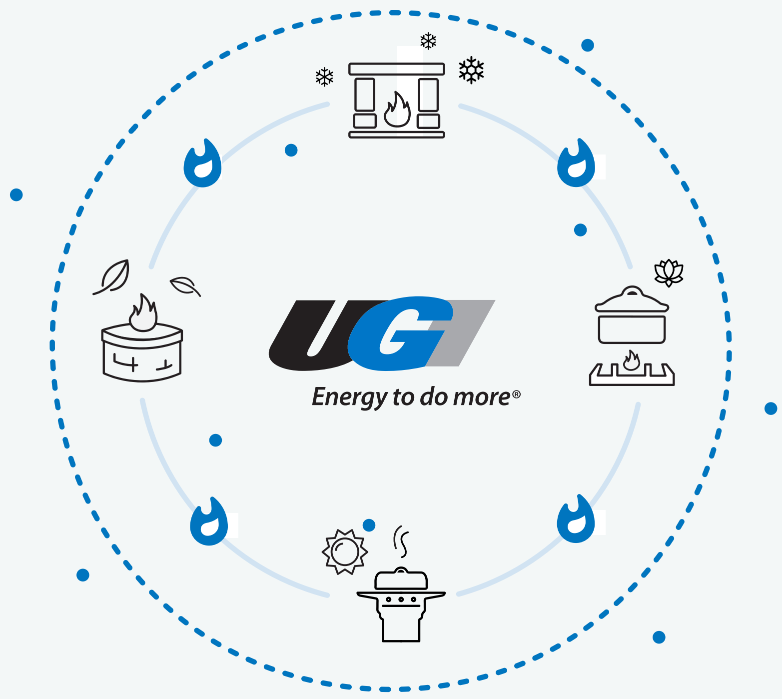
- Set your water heater thermostat at 120°F or lower. According to the US Department of Energy, you can save 3% - 5% in energy costs for every 10°.
- Run full loads of dishes or laundry to maximize your water heating efficiency and reduce your overall consumption.
- Switch to a low-flow showerhead. They cost as little as $5, and reduce water usage by up to 66%, while retaining the same water pressure.

Check Rebate Availability

Up to $1500 in rebates available for gas & electric customers in select areas.

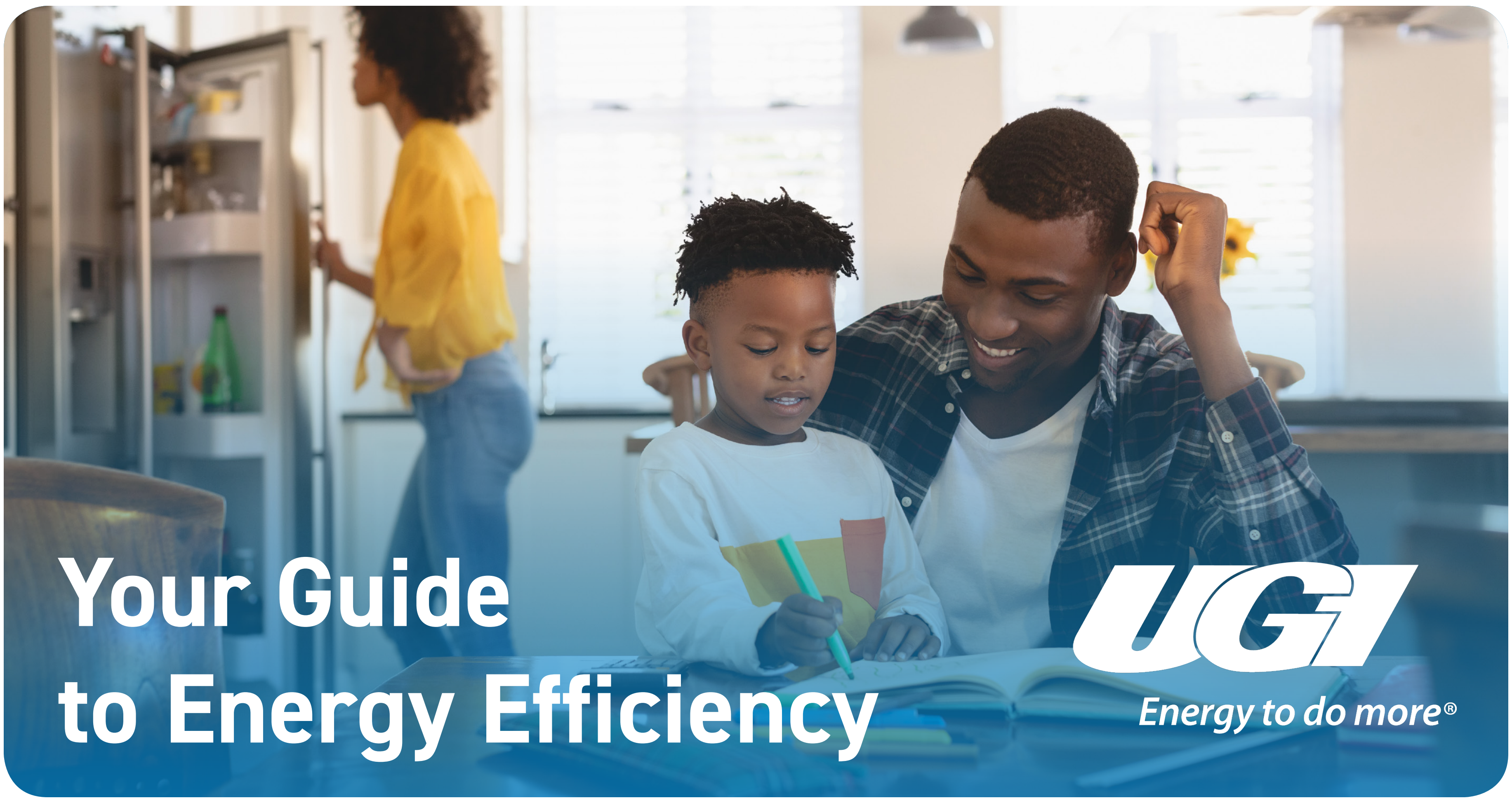
UGI SAVE SMART

ugi.com/rebatesavailable



all year round.

UGI Utilities, Inc.
1 UGI Drive
Denver PA, 17517



Customer Safety Guide

Safety is a core value at UGI. We are committed to providing safe and reliable energy service to all of our customers and communities. We encourage you to follow safe energy practices in your home and place of work and be aware of potential hazards. This safety guide provides important information to help keep you and your family safe.

Energy to do more®

Think Safety

Ask for Identification

When our representative arrives, ask for proper identification before letting them enter. Our employee should present a card with the UGI logo, the employee's photo, and employee number. If the person's ID or activities are suspicious, don't let them enter. Instead, call us to verify that the person is scheduled to perform work in your home, business, or neighborhood.

Prevent Illegal Meter and Line Tampering

Call us immediately if you discover any meter tampering or service theft.

Secure Your Pets

To ensure a safe environment for our employees, please confine any pets away from the natural gas meter, the appliances to be serviced or other work area before we arrive, otherwise your service call may be rescheduled.

Gas Line Safety

Safe habits go beyond the walls and foundation of your home. Follow these guidelines to avoid unnecessary damage to natural gas distribution lines, electric lines, and other utilities' facilities as you enjoy your home and property.

Aboveground Pipe Safety

You should never hang anything from aboveground pipes. The added weight can weaken or break pipe joints or fittings, resulting in a leak.

Underground Pipe Safety

Call 811 three business days before a digging project—it's the law. Whether you're doing a major excavation or minor landscaping, safeguard yourself from hazards related to damaging underground pipelines. A simple call gets all your public utility lines marked to help protect you from injury and costly property damage.

What About Gas Lines Beyond the Meter?

Before digging near buried natural gas pipes, locate the pipes and mark the area. To ensure the safety and soundness of the pipes and customer-owned fuel lines, periodically inspect them for leaks and corrosion and never hang anything from them.

Should you need assistance in locating, inspecting, or repairing pipes, you can contact your local plumber or heating contractor or call us.

811®

Know what's below.
Call before you dig.

Digging safely starts with knowing what's under your feet.

Applies to natural gas customers | Applies to electric customers

Natural Gas Safety

Natural Gas is Naturally Odorless

To make it detectable, a chemical known as *Mercaptan* is added. It has a smell that is similar to rotten eggs. If you smell this odor, you need to act. There is **no cost** to you for UGI to investigate a natural gas odor.

What to Do if You Smell Gas:

- **LEAVE** the inside of a building immediately. Take everyone and pets with you. Leave the door open if possible, and proceed to a safe location where you can no longer smell the odor of natural gas (approximately 330 feet away from the building).
- **CALL UGI's** gas emergency line 800-276-2722 from a safe location, 24 hours a day, 7 days a week, if you smell natural gas indoors, outdoors, or near a gas meter.
- **CALL 911** from a safe location if you ever hear or see natural gas blowing anywhere.

Use your eyes and ears as well.

Be aware of any indication of a possible natural gas pipeline leak, including:

- Air blowing the dirt, grass, or trees near a pipeline
- Bubbling or blowing air in a pond or stream
- Dead grass or plants in an otherwise green area
- Unusual hissing sounds

If you notice signs of a possible leak, contact UGI at 1-800-276-2722 or call 911 from a safe location.

What NOT to Do if You Smell Gas:

- DO NOT use phones (standard or cellular), computers, appliances, elevators, lamps, garage door openers, or electrical devices if an odor of gas is present.
- DO NOT touch electric outlets, switches or doorbells.
- DO NOT smoke or use a lighter, match or other flame.
- DO NOT operate vehicles or power equipment where leaking gas may be present.
- DO NOT try to re-light a pilot light.
- DO NOT e-mail UGI or post emergency notifications on our social media if you smell natural gas or suspect a natural gas leak. *Please call UGI or 911.*
- DO NOT re-enter a building until it has been inspected by a UGI technician.

Visit www.ugi.com for more information, and teach your family what to do, and what NOT to do, if anyone ever notices the odor that is added to odorless natural gas.

Electric Safety

Electrical emergencies can happen anywhere, anytime. Follow these tips to increase your safety in any situation.

Fallen Wires

Stay away from fallen wires and warn others to keep away. Call us immediately. If a wire touches your vehicle, stay inside. However, if your car catches fire, jump clear of the car without touching the car's metal and the ground at the same time.

Indoor Electrical Fires

Without touching the appliance, unplug it or turn off the electric supply. Use a Class C rated fire extinguisher, if available. If one is not available, throw baking soda on the fire—never use water on an electrical fire. If necessary, call your fire department.

Portable Generators

Never use a generator indoors or in any enclosed space. Always use proper power cords and follow instructions. Do not overload the generator with more equipment than its output rating. Also make sure your generator is properly grounded.

Tree Planting and Trimming

Trees should be kept a safe distance from all electrical wires. Call us for a free "Trees for Streets and Lawns" brochure to learn more.

Safety & Security Lighting Program

We can install outdoor lighting that automatically comes on at dusk and goes off at dawn. Adequate outdoor lighting improves visibility, reduces accidents, and deters burglars and vandals. Call us for more information.

Carbon Monoxide Safety

Incomplete combustion of ANY fossil fuel could produce an odorless, tasteless, and colorless gas called carbon monoxide (CO). Here's what you need to know about CO to protect yourself:

- CO can enter living spaces in your home as a result of a malfunctioning appliance or blocked chimney.
- All fuel-burning equipment should be installed and regularly serviced by an experienced professional.
- Do not install equipment in a confined space. When renovating, have a professional specify space required for fuel-burning equipment.
- Signs that you may have a CO problem include: water vapor condensing on windows (other than normal bathroom and kitchen moisture), pets acting lethargic or lazy, headaches, dizziness, flu-like symptoms, and nausea.
- A CO detector should be installed on each floor of a home, particularly near every sleeping area.
- If you are alerted by your CO detector, or if you suspect CO poisoning, move to fresh air and call UGI or 911.

Protect your home with CO detectors.

Meter Safety

Here are some important tips to help keep your meter functioning properly, safely, and dependably.

If You Have an Outdoor Meter:

- Keep meter clear of any landscaping that obstructs access or visibility. Shrubs and plants should be trimmed regularly.
- Do not build decking or fencing that blocks access to the meter.
- Instruct children not to climb on or play near a meter.
- Carefully clear ice and snow from the meter and appliance exhaust vents.
- Never use a snow blower or plow around a meter. Shovel the immediate area carefully.
- If the snowfall is deep, please clear a safe path to the meter.

If You Have an Indoor Meter:

- Keep the area surrounding the meter clear of boxes, furniture, shelves, etc.
- Do not build walls or add panels that obstruct access to the meter.
- Never hang on or lean anything against a meter.
- Instruct children not to climb on or play near a meter.

Appliance and Water Heater Safety

- Follow the manufacturer's directions regarding care and operation.
- Equipment should be installed, repaired, and regularly serviced by an experienced professional.
- A gas flame should be primarily blue. If it is yellow or orange, turn off the equipment and call for service (gas fireplaces are an exception).

Temperature of the Water	Time to Cause a Bad Burn
150°F (66°C)	2 seconds
140°F (60°C)	6 seconds
125°F (52°C)	2 minutes
120°F (49°C)	10 minutes

Source: University of Michigan Health System

- Always make sure there is no gas buildup around a pilot or burner before relighting it.
- Keep the flues of your gas appliances clean and properly vented. If you installed a gas conversion burner in the past year, be alert for soot and buildup from the previous fuel. A buildup could block the flue and chimney base.
- Teach children to never turn on or light gas appliances.
- Keep trash and other flammable materials away from natural gas appliances.
- If you own an old gas appliance, you should have the appliance connectors checked by a qualified plumber, HVAC, or appliance repair contractor. Don't try to move appliances to check the connectors by yourself.
- Reduce the temperature setting on your water heater to 120°F. Water temperature higher than that can cause bad burns within seconds.

Be Safe!

Turn your hot water down to 120°F (49°C) for safety as well as efficiency.

I&E Exhibit No. 2
Schedule 3
Page 19 of 27

8TH ANNUAL CHILDREN'S BOOK DRIVE

COLLECTING CHILDREN'S BOOKS

Purchase new or donate gently used board books,
picture books, and chapter books

COLLECTION DROP OFF:

Friday, April 14th | 11 am – 1 pm
United Way of Wyoming Valley, 100 N. Pennsylvania Avenue, 2nd Floor, Wilkes-Barre

BOOK DRIVE & FAIR SPONSORED BY:

UGI
Energy to do more®

United Way

United Way
of Wyoming Valley

2023 YOUNG PROFESSIONALS CONFERENCE - THE FUTURE OF NEPA

Back to Search
(https://business.wyomingvalleychamber.org/calendar/search?from=03%2f22%2f2023&to=03%2f23%2f2023&mode=0&cid=5108&datefilter=5)

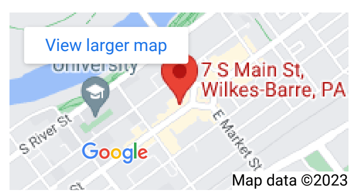
Wednesday, March 22, 2023 (8:30 AM - 3:30 PM) (EDT ((GMT-05:00) Eastern Time))

Description

Our 5th Annual Young Professionals Conference is happening on March 22nd, 2023, hosted in partnership with the United Way of Wyoming Valley and our regional chambers, and presented by UGI Utilities, Inc. This day-long conference is aimed at developing our area's talented professionals, featuring amazing speakers in our region between the ages of 20-45. Join us in the THINK Center in Downtown Wilkes-Barre. The theme of this year's conference is "The Future of NEPA" and will feature two tracks of breakout sessions, with topics like wellness, personal finance, leadership development, innovation, and getting involved in our community!

Registration Closed

Address
7 S Main Street
Wilkes-Barre, PA 18701 United States



Event Contact
Michaela Grundowski
Send Email
(mailto:michaela@wyomingvalleychamber.org)

Wednesday, March 22, 2023 (8:30 AM - 3:30 PM) (EDT ((GMT-05:00) Eastern Time))

Categories
Young Professionals
General
Downtown WB
Chamber
Community

8TH ANNUAL CHILDREN'S BOOK DRIVE

LIVE UNITED

NEED MORE INFORMATION?

Contact Yvette Magistro
ymagistro@unitedwaywb.org
(570) 270-9117

COLLECTION DROP OFF:

Friday, April 14th
United Way of Wyoming Valley
100 N. Pennsylvania Avenue
2nd Floor
Wilkes-Barre
11 am – 1 pm

COLLECTING NEW & GENTLY USED BOOKS

WHAT CAN YOU DO TO MAKE YOUR DRIVE A SUCCESS!

- Donate or purchase board books, picture books, and chapter books
- Designate a collection/drop-off area in your workplace
- Cash donations will be used to purchase books for children within Wyoming Valley. Checks may be made payable to United Way of Wyoming Valley
- Access our book drive toolkit at **unitedwaywb.org/bookdrive** for tips and helpful hints on successful book drives

BOOK DRIVE & FAIR SPONSORED BY:

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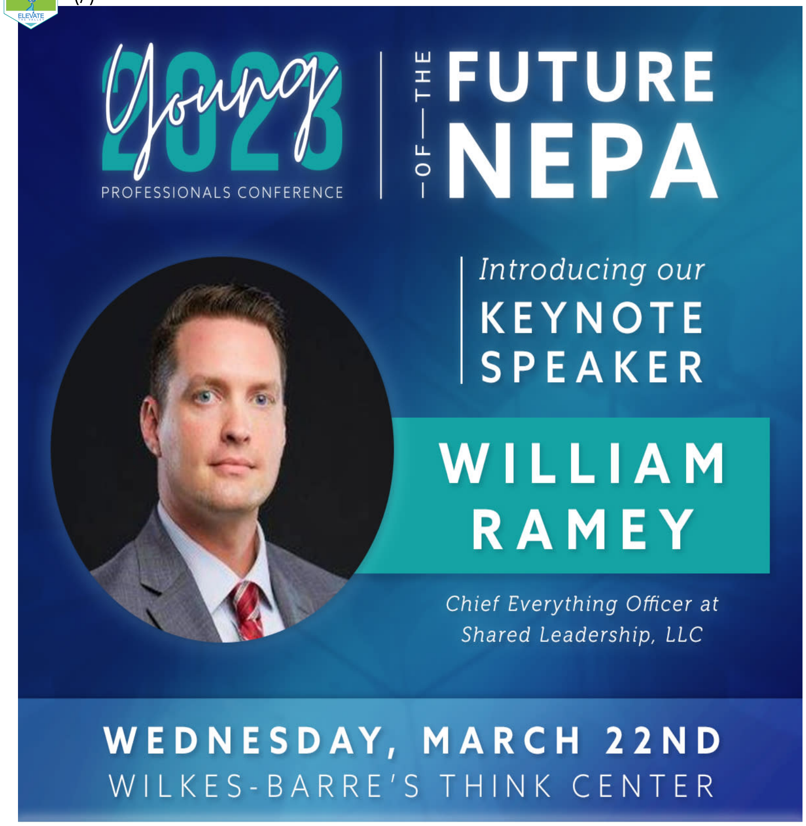
United Way of Wyoming Valley

Announcing our 2023 Young Professionals Conference Keynote Speaker!

(/)



William has had the privilege of leading teams with combined experiences serving as a U.S. Army Officer, a group leader for a Fortune 50 Company, and leading at the Director level for the Department of Defense. He has led a variety of teams from maintenance and distribution to city management and space control. Yes, space, the final frontier where he earned the little-known Army Space Badge. Will's favorite aspect of leadership has been helping others grow & reach their full potential so that teams achieve success together. He's been a student of leadership and organizational behavior for most of his career. This intrigue led him to study and learn about the relationship of leaders and teams at the doctoral level of academia. Will has researched leaders and teams receiving his Doctorate from Drexel University. Now, you can find Will currently serving as the CXO of Shared Leadership, LLC, a full spectrum leadership and team development solutions company. He gets the opportunity to work with amazing individuals and teams to positively impact their lives by improving work environments.

Stay tuned for more information on our 2023 speakers!

Sponsors

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(http://www.thekatylagency.com)

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Snyder & Clemente Accountants and Consultants (http://www.clementecpa.com)

Get In Touch!

(tel:(570) 823-2101) (570) 823-2101 (tel:(570) 823-2101)

7 South Main Street, 3rd Floor, Suite 4, Wilkes-Barre, PA 18701

PO Box 759, Wilkes-Barre, PA, 18703

(mailto:info@wyomingvalleychamber.org) info@wyomingvalleychamber.org (mailto:info@wyomingvalleychamber.org)

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Thank You to Our Visionary Members!

Energy to do more®
(https://www.ugi.com/)

Sign up for email updates!

* **Email**

By submitting this form, you are consenting to receive marketing emails from: Greater Wyoming Valley Chamber of Commerce, 2 Public Square, Wilkes-Barre, PA, 18701, US, https://www.wyomingvalleychamber.org. You can revoke your consent to receive emails at any time by using the SafeUnsubscribe® link, found at the bottom of every email. Emails are serviced by Constant Contact. (https://www.constantcontact.com/legal/service-provider)

Subscribe!

UGI Utilities, Inc. - Electric Division
Advertising Expense Adjustment
For the Twelve Months Ended September 30, 2024

	Total Advertising Expense		
	Total	Distribution	Transmisson
Total Advertising Expense	141,000	113,000	28,000
Other Advertising Expense	91,000	73,000	18,000

	Other Advertising Expense		
	Total	Distribution	Transmission
FPFTY Claim	91,000	73,000	18,000
HTY Amount	24,000	19,000	5,000
I&E Recommended Adjustment	(67,000)	(54,000)	(13,000)

	I&E Recommendation		
	Total	Distribution	Transmisson
Total Advertising Expense Claim	141,000	113,000	28,000
I&E Recommended Adjustment	(67,000)	(54,000)	(13,000)
I&E Recommendation	74,000	59,000	15,000

UGI Utilities, Inc. - Electric Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2024

Summary of Working Capital

		[1]	[2]		[3]	[4]	[5]
Line #	Description	Reference	Test Year Expenses		Factor	Number of (Lead) / Lag Days [2] * [3]	Totals
WORKING CAPITAL REQUIREMENT							
1	REVENUE LAG DAYS	Page 3					59.56
2	EXPENSE LAG DAYS	Page 4					
3	Payroll	Sch D-7	$ 6,196,008		12.00	$ 74,352,096	
4	Purchased Power Costs	Sch D-6	91,176,313		33.30	3,035,751,812	
5	Other Expenses	L 19 - L 2 to L 4	25,638,386	(a)	30.76	788,636,753	
6	Total	Sum (L 3 to L 5)	$ 123,010,707			$ 3,898,740,661	
7	O & M Expense Lag Days	L6, C 4 / C 2					31.69
8	Net (Lead) Lag Days	L 1 - L 7					27.87
9	Operating Expenses Per Day	L 6, C 2 / 365					$ 337,016
10	Working Capital for O & M Expense	L 8 * L 9					$ 9,391,180
11	Interest Payments	Page 7					(295,398)
12	Tax Payment Lag Calculations	Page 8					261,289
13	Prepaid Expenses	Page 9					2,032,337
14	Total Working Capital Requirement	Sum (L 10 to L 13)					$ 11,389,408

(a) Ref: I&E Exhibit No. 2, Schedule 5, p. 2

UGI Utilities, Inc. - Electric Division
Cash Working Capital Other Expenses Adjustment
For the Twelve Months Ended September 30, 2024

		I&E Recommendded Adjustment
1	Rate Case Expense	(77,400)
2	Stock Options and Restricted Stock Awards	(497,000)
3	Incentive Compensationa and Executive Bonus Plan	(192,800)
4	Directors' Equity Compensation	(36,000)
5	Advertising Expense	(54,000)
6	Total	(857,200)

Ref: I&E Statement No. 1, p. 2 and I&E Statement No. 2, p. 3

I&E Statement No. 2-R
Witness: Christopher Keller

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – ELECTRIC DIVISION

Docket No. R-2022-3037368

Rebuttal Testimony

of

Christopher Keller

Bureau of Investigation & Enforcement

Concerning:

Low-Income Usage Reduction Program

TABLE OF CONTENTS

<u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher Keller. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME CHRISTOPHER KELLER WHO SUBMITTED THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 2 AND I&E EXHIBIT NO. 2?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of the Office of Consumer Advocate (OCA) witness Roger D. Colton concerning his recommended $430,379 increase to UGI Utilities, Inc. – Electric Division's (UGI Electric or Company) Low-Income Usage Reduction Program (LIURP) budget (OCA Statement No. 4) and Commission of Economic Opportunity (CEO) witness

Jennifer Warabak concerning her recommended increase to UGI Electric's LIURP budget based on the percentage increase in rates to residential customers as a result of this proceeding (CEO Statement No. 1).

Q. DOES YOUR REBUTTAL TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 1-R supports my rebuttal testimony.

<u>RESPONSE TO OCA WITNESS ROGER D. COLTON</u>

Q. SUMMARIZE OCA WITNESS ROGER D. COLTON'S DIRECT TESTIMONY REGARDING UGI ELECTRIC'S LIURP BUDGET.

A. Mr. Colton recommends the Company increase its LIURP budget to address three remedies for the increase in rates in this proceeding. First, Mr. Colton recommends an increase in LIURP funding to provide 66 additional LIURP baseload jobs per year. Second, Mr. Colton recommends an increase in LIURP funding to provide 66 additional LIURP heating jobs per year. Third, Mr. Colton recommends that 20% of LIURP funding or 27 of the 132 total jobs ([66 jobs + 66 additional jobs] x 20% of total jobs) as recommended by Mr. Colton be allocated to customers with an annual income between 150% and 200% of the federal poverty line (FPL) (OCA Statement No. 4, pp. 34-35).

Q. WHAT IS THE BASIS FOR MR. COLTON'S RECOMMENDATION?

A. Mr. Colton calculates his recommended addition to the Company's LIURP budget using a speculative 66 baseload jobs which is based on the number of jobs currently budgeted for heating jobs and applying this to a typical LIURP baseload job cost of $2,000 for an increase to the Company's current LIURP budget for baseload jobs of $132,000 (66 jobs x $2,000) (OCA Statement No. 4, pp. 33-35). Next, Mr. Colton uses the current LIURP budget amount of $298,379 for a speculative addition of 66 heating jobs per year which is based on the same number of jobs and cost currently budgeted for heating jobs (OCA Statement No. 4, p. 35). This results in a total increase in LIURP funding of $430,379 ($132,000 + $298,379) (OCA Statement No. 4, pp. 35-36).

Q. DO YOU AGREE WITH MR. COLTON'S RECOMMENDATION?

A. No. While Mr. Colton's recommendation is well-intentioned, it is inappropriate to consider an increase in the LIURP budget in this base rate case proceeding for the reasons stated below.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that no increase to the budgeted LIURP amount be allowed.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. In response to CAUSE-PA-II-13, UGI Electric has shown it was unable to exhaust its LIURP budget over the last three years (I&E Exhibit No. 2-R, Schedule 1). In fact, the LIURP dollars spent over this three-year period totaled $513,148 (2020-

$86,821, 2021- $168,097, 2022- $258,230), which is only slightly more than the annual $430,379 budget increase proposed by Mr. Colton. Additionally, Mr. Colton does not provide adequate support for how UGI Electric would complete the additional jobs and exhaust its existing LIURP budgeted funds.

Q. ARE THERE ANY OTHER REASONS THE COMMISSION SHOULD REJECT MR. COLTON'S RECOMMENDATION TO INCREASE THE LIURP BUDGET IN THIS PROCEEDING?

A. Yes. The Commission recently issued an order associated with UGI Electric's 2020-2025 Universal Service and Energy Conservation Plan (USECP),[1] where the parties had an opportunity to review and make recommended changes to the plan. It is inappropriate to grant an increase to the LIURP budget in this base rate proceeding as proposed by Mr. Colton without consideration and evaluation of all the program's performance indicators and provision of comments by all stakeholders and interested parties.

Mr. Colton contends that it is not reasonable to confine plan proposals to the USECP proceeding as those five-year program periods cannot capture the impact of intervening rate proceedings (OCA Statement No. 4, pp. 32-33). His contention would imply that the participants in that forward-looking five-year program lacked the foresight to contemplate any intervening cost of living escalation that would impact affordability for low-income customers when making

[1] *UGI Utilities, Inc. – Electric Division Universal Service and Energy Conservation Plan for 2020-2025*, Docket No. M-2019-3014966 (Order entered on January 16, 2020).

recommendations in that proceeding. I find this implication unlikely and do not consider it a convincing argument to support intervening increases to budgeted low-income programs.

<u>RESPONSE TO CEO WITNESS JENNIFER WARABAK</u>

Q. SUMMARIZE MS. WARABAK'S TESTIMONY CONCERNING UGI ELECTRIC'S LIURP BUDGET.

A. Ms. Warabak recommended the Company increase its LIURP budget by the percentage increase in rates to residential customers as a result of this proceeding (CEO Statement No. 1, p. 6).

Q. WHAT IS THE BASIS FOR MS. WARABAK'S RECOMMENDATION?

A. Ms. Warabak's recommendation is based on the number of estimated and confirmed low-income customers in its territory, the flat LIURP funding, and the limited number of customers it serves, along with the increase in rates in this proceeding (CEO Statement No. 1, p. 6).

Q. DO YOU AGREE WITH MS. WARABAK'S RECOMMENDATION?

A. No. While Ms. Warabak's recommendation is well-intentioned, it is inappropriate to consider an increase in the LIURP budget in the instant proceeding. As mentioned above in response to Mr. Colton's recommended increase to LIURP, the Company has shown it has been unable to exhaust the existing budget (I&E

Exhibit No. 2-R, Schedule 1), and Ms. Warabak has not shown that UGI Electric would be able to utilize the increased budgeted funds.

Q. DO YOU HAVE ANY ADDITIONAL OVERALL COMMENTS REGARDING YOUR RECOMMENDATION TO DENY THESE PROGRAM INCREASES IN THIS PROCEEDING?

A. Yes. While my responses to the witnesses' recommendations explained above specifically relate to the witnesses' failure to provide support for UGI Electric's ability to utilize the additional funding, it is important to note that these program costs are directly funded by ratepayers who do not receive assistance from low-income programs. It is unreasonable to implement an increase to LIURP when the Company's ability to utilize these additional funds is uncertain. Additionally, it is unreasonable for ratepayers who are not receiving assistance from LIURP to pay for the additional proposed costs to LIURP when it is not certain that the additional funds will be utilized.

Q. ARE THERE ANY RECENT COMMISSION DECISIONS THAT SUPPORT YOUR RECOMMENDATION TO DENY THE INCREASE TO LIURP FUNDING AS PROPOSED BY MR. COLTON AND MS. WARABAK?

A. Yes. In a recent PECO Energy Company – Gas Division proceeding the Commission did not consider CAUSE-PA's proposals relating to CAP and other universal service program issues within the context of the base rate proceeding because they would be more properly considered in its USECP proceeding.[2] The Commission referenced a Columbia Gas of Pennsylvania, Inc. (Columbia Gas) proceeding[3] in which it concluded, "that energy burdens should not be considered separately from other parts of the Company's CAP and universal service programs but should be considered as part of the Company's entire universal service plan, including the need for changes and associated costs."[4] It should be noted that in the Columbia Gas proceeding the Commission rejected a similar proposal related to the Health and Safety Pilot Program from CAUSE-PA.[5] In that proceeding, the Commission agreed with the Administrative Law Judge's recommended decision denying any change to the pilot program until its effectiveness can be evaluated.[6]

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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[2] *PA PUC v. PECO Energy Company – Gas Division*, Docket No. R-2020-3018929, pp. 195-196 (Order Entered June 22, 2021).

[3] *PA PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835 (Order Entered February 19, 2021).

[4] *PA PUC v. PECO Energy Company – Gas Division*, Docket No. R-2020-3018929, p. 195 (Order Entered June 22, 2021).

[5] *PA PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835, pp. 160-161 and 173-174 (Order Entered February 19, 2021).

[6] *PA. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835, p. 174 (Order Entered February 19, 2021).

I&E Exhibit No. 2-R
Witness: Christopher Keller

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – ELECTRIC DIVISION

Docket Nos. R-2022-3037368

Exhibit to Accompany

the

Rebuttal Testimony

of

Christopher Keller

Bureau of Investigation and Enforcement

Concerning:

Low-Income Usage Reduction Program

CAUSE-PA-II-13

Request:

Please indicate for each year from 2020 to date, disaggregated by year:

a. Whether UGI has exhausted its LIURP budget for its electric division;
b. The total amount of budgeted LIURP dollars for UGI Electric;
c. The total amount spent of LIURP dollars for UGI Electric;
d. If UGI LIURP budget was exhausted in a given year for its electric division, indicate the number of UGI Electric LIURP applicants that did not receive LIURP services despite being found to be LIURP eligible.

Response:

a. For years 2020, 2021, and 2022 the Company did not exhaust its LIURP budget for the Electric Division.

b. The total amount of budgeted LIURP dollars for UGI Electric:

   2020 - $274,750
   2021 - $462,679 (includes carryover)
   2022 - $298,379
   2023 - $298,379

c. The total amount spent of LIURP dollars for UGI Electric:

   2020 - $86,821
   2021 - $168,097
   2022 - $258,230
   2023 - $34,303 (Year to date 02/28/23)

d. Not applicable. The LIURP budget was not exhausted in the previously mentioned years.

Prepared by or under the supervision of: Daniel V. Adamo

I&E Statement No. 2-SR
Witness: Christopher Keller
NON-PROPRIETARY

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – ELECTRIC DIVISION

Docket No. R-2022-3037368

Surrebuttal Testimony

of

Christopher Keller

Bureau of Investigation and Enforcement

Concerning:

Operating and Maintenance Expenses
Cash Working Capital

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<u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher Keller. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME CHRISTOPHER KELLER WHO SUBMITTED THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 2 AND I&E EXHIBIT NO. 2 AND THE REBUTTAL TESTIMONY CONTAINED IN I&E STATEMENT NO. 2-R AND I&E EXHIBIT NO. 2-R?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of UGI Utilities, Inc. – Electric Division (UGI Electric or Company) witnesses Christopher R. Brown (UGI Statement No. 1-R), Tracy A. Hazenstab (UGI Electric Statement No. 2-R), and Vivian K. Ressler (UGI Electric Statement No. 3-R).

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 2-SR contains schedules that support my surrebuttal testimony. In this surrebuttal testimony, I will also make references to my direct testimony and its accompanying exhibit (I&E Statement No. 2 and I&E Exhibit No. 2).

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS AS CONTAINED IN THIS SURREBUTTAL TESTIMONY.

A. The following table summarizes my recommended adjustments to the Company's updated claims in UGI Electric Exhibit A – Fully Projected (Rebuttal), Schedule A-1.

	Company Claim in Rebuttal	I&E Adjustment	I&E Recommended Allowance
O&M Expenses:			
{BEGIN PROPRIETARY}			
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
{END PROPRIETARY}			
Advertising Expense	$113,000	($54,000)	$59,000
Total O&M Expense Adjustments		($779,800)	
Rate Base Adjustments:			
Cash Working Capital	$11,437,000	($58,623)	$11,378,377
Total Rate Base Adjustments		($58,623)	

<u>**STOCK OPTIONS AND RESTRICTED STOCK AWARDS**</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR STOCK OPTIONS AND RESTRICTED STOCK AWARDS.

A. In direct testimony, I recommended disallowance of UGI Electric's entire claim of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** for stock options and restricted stock awards.. My recommendation was based on stock-based compensation being based on achieving financial goals and targets that serve primarily to benefit shareholders that should not be funded by the ratepayers as financial goals do not assist in providing safe and reliable service to ratepayers (I&E Statement No. 2, pp. 3-5).

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION FOR STOCK OPTIONS AND RESTRICTED STOCK AWARDS?

A. Yes. Company witnesses Christopher R. Brown and Vivian K. Ressler disagree with my stock options and restricted stock awards recommendation. Mr. Brown references the 2018 UGI Electric base rate case, where the Commission approved the Company's claim for incentive compensation such as stock options and restricted stock awards, to support his argument that the Company's claim for stock options and restricted stock awards should be included. Mr. Brown asserts that ratepayers benefit from incentive compensation programs such as stock options and restricted stock awards (UGI Electric Statement No. 1-R, pp. 3-4).

Ms. Ressler asserts that my recommendation should be rejected as the Company is entitled to recover in rates all expenses reasonably necessary to provide service. Ms. Ressler states that these incentive compensation programs act as an incentive to retain employees and that Company compensates its employees consistent with industry standards. Ms. Ressler asserts that if the Company did not have this type of compensation, the Company's base salaries would likely have to be higher. Ms. Ressler also disagrees with my recommendation because incentive compensation programs such as stock options and restricted stock awards should be evaluated as a whole when determining whether the plan goals benefit customers as indicated by the Commission in the Company's last base rate case. Ms. Ressler references Aqua Pennsylvania, Inc.'s most recent base rate case in support of her argument. Additionally, Ms. Ressler asserts that the Company is not required to demonstrate that its incentive compensation plans benefit customers. Ms. Ressler also points out my incorrect quote regarding the 2021 Columbia Gas of Pennsylvania, Inc. (Columbia Gas) base rate case. Finally, she states that circumstances in the above referenced Columbia Gas base rate case do not apply in this proceeding as Columbia Gas withdrew its claim and any reliance on that proceeding should be disregarded (UGI Electric Statement No. 3-R, pp. 9-15).

Q. DO YOU AGREE WITH MS. RESSLER'S ASSERTION THAT YOU MISQUOTED THE COMMISSION'S ORDER FOR THE 2021 COLUMBIA GAS BASE RATE CASE?

A. Yes. Ms. Ressler is correct that I misquoted the Commission's Order for the 2021 Columbia Gas base rate case. However, it should be noted that in that Commission Order, although Columbia Gas withdrew its claim for stock awards, the Commission agreed with the Administrative Law Judge's (ALJ's) recommended decision to disallow the full amount of stock awards expense as shareholders benefit from incentive compensation linked to financial goals and not ratepayers and ratepayers should not pay for the cost of incentive compensation based on achieving financial goals as it would not be just and reasonable,

> The ALJ noted that the OCA proposed an elimination of the $2,300,000 stock rewards expense from the O&M expenses. The

> ALJ agreed with the OCA that stock rewards and the appreciation of common stock are a shareholder-oriented goal, not a customer service-oriented goal. R.D. at 109 (citing OCA St. 2 at 12). The ALJ reasoned that higher earnings for the Company will come from higher rates which will increase the value of the Company's common stock. The ALJ agreed with the OCA's argument that shareholders, not ratepayers, should bear the cost of any incentive program because, if the incentive program succeeds, Columbia's earnings and common stock values will rise. *Id.* The ALJ recommended that the Commission determine that increases to common stock valuations are a shareholder benefit for which the shareholders should bear the cost. The ALJ concluded that approving the incentive program as an element of the rate base expenses would not lead to a reasonable and just rate. R.D. at 109…
>
> We also agree with the ALJ's recommendation to disallow the $2,300,000 of stock rewards expense from the FPFTY O&M expenses. We note that Columbia has voluntarily withdrawn its claim regarding the stock compensation portion of its incentive compensation program. *See* CG Exc. at 2-3.[1]

Q. DO YOU AGREE WITH MR. BROWN'S AND MS. RESSLER'S RESPONSES TO YOUR RECOMMENDATION TO DISALLOW THE COMPANY'S CLAIM FOR STOCK OPTIONS AND STOCK REWARDS?

A. No. The value of stock options and restricted stock awards are based on achieving financial goals that are shareholder-oriented goals. Incentive compensation programs such as stock options and restricted stock awards permitted for recovery from ratepayers should be directly linked to the benefit of ratepayers such as providing safe and reliable service.

Mr. Brown's claim that the achievement of financial goals or targets benefits ratepayers is speculative and unsupported because there are no measurable or quantifiable benefits accruing directly to ratepayers specifically attributable to stock options and

[1] *Pa. PUC v. Columbia Gas,* Docket No. R-2020-3018835, Opinion and Order, pp. 73-75 (Order Entered February 19, 2021).

restricted stock awards.

Therefore, the Company's stock options and restricted stock awards claim should not be funded by ratepayers. Allowing this claim in rates would result in higher rates and revenues at the expense of ratepayers, while providing a benefit to the parent company and shareholders' financial goals. It is not obvious how stock options and restricted stock awards attributable to financial goals directly relate to providing safe and reliable service to ratepayers. Therefore, all costs associated with stock options and restricted stock awards should be paid for by shareholders, and not by ratepayers, as it is directly linked to the benefit of shareholders.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR STOCK OPTIONS AND RESTRICTED STOCK AWARDS?

A. No. I continue to recommend disallowance of UGI Electric's entire claim of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** for stock options and restricted stock awards for the reasons stated above and in my direct testimony.

<u>INCENTIVE COMPENSATION AND EXECUTIVE BONUS PLAN</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR INCENTIVE COMPENSATION AND THE EXECUTIVE BONUS PLAN.

A. In direct testimony, I recommended an allowance of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** for incentive compensation and the executive bonus plan, or a reduction of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** to the Company's claim. My recommendation was based on removing the portion attributable to achieving financial goals and targets that serves primarily to benefit shareholders, and that it should not be funded by ratepayers as financial goals do not assist in providing safe and reliable service (I&E Statement No. 2, pp. 5-8).

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION FOR INCENTIVE COMPENSATION AND THE EXECUTIVE BONUS PLAN?

A. Yes. Company witnesses Christopher R. Brown and Vivian K. Ressler disagree with my incentive compensation and the executive bonus plan recommendation. Again, Mr. Brown references the 2018 UGI Electric base rate case, where the Commission approved the Company's claim for incentive compensation, to support his argument that the Company's entire claim for incentive compensation and the executive bonus plan should be accepted. Mr. Brown asserts that ratepayers benefit from providing incentive compensation and the executive bonus plan (UGI Electric Statement No. 1-R, pp. 3-4).

Ms. Ressler asserts that my recommendation should be rejected as the Company is entitled to recover in rates all expenses reasonably necessary to provide service. Ms. Ressler states that these incentive compensation programs act as an incentive to retain employees and that Company compensates its employees consistent with industry standards. Ms. Ressler asserts that if the Company did not have this type of compensation, the Company's base salaries would likely have to be higher. Ms. Ressler also disagrees with my recommendation because incentive compensation programs that include such components as the Company's incentive compensation and the executive bonus plan should be evaluated as a whole when determining whether the plan goals benefit customers as indicated by the Commission in the Company's last base rate case. Ms. Ressler also references Aqua Pennsylvania, Inc.'s most recent base rate case in support of her argument. Additionally, Ms. Ressler asserts that the Company is not required to demonstrate that its incentive compensation plan and executive bonus plan benefit customers. Ms. Ressler points out my incorrect quote regarding the Commission Order for the 2021 Columbia Gas base rate case. Finally, Ms. Ressler states that circumstances in the above reference Columbia Gas base rate case do not apply in this proceeding as Columbia Gas withdrew its claim, and any reliance on that proceeding should be disregarded (UGI Electric Statement No. 3-R, pp. 9-15).

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A. Yes. Ms. Ressler is correct that I misquoted the Commission's Order for the 2021 Columbia Gas base rate case. However, it should be noted that , although Columbia Gas withdrew its claim for stock awards, the Commission agreed with the ALJ's recommended decision to disallow the full amount of stock awards expense as shareholders benefit from incentive compensation linked to financial goals and not ratepayers, and that ratepayers should not pay for the cost of incentive compensation based on achieving financial goals as it would not be just and reasonable,

> The ALJ noted that the OCA proposed an elimination of the $2,300,000 stock rewards expense from the O&M expenses. The ALJ agreed with the OCA that stock rewards and the appreciation of common stock are a shareholder-oriented goal, not a customer service-oriented goal. R.D. at 109 (citing OCA St. 2 at 12). The ALJ reasoned that higher earnings for the Company will come from

> higher rates which will increase the value of the Company's common stock. The ALJ agreed with the OCA's argument that shareholders, not ratepayers, should bear the cost of any incentive program because, if the incentive program succeeds, Columbia's earnings and common stock values will rise. *Id.* The ALJ recommended that the Commission determine that increases to common stock valuations are a shareholder benefit for which the shareholders should bear the cost. The ALJ concluded that approving the incentive program as an element of the rate base expenses would not lead to a reasonable and just rate. R.D. at 109…
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> We also agree with the ALJ's recommendation to disallow the $2,300,000 of stock rewards expense from the FPFTY O&M expenses. We note that Columbia has voluntarily withdrawn its claim regarding the stock compensation portion of its incentive compensation program. *See* CG Exc. at 2-3.[2]

Q. DO YOU AGREE WITH MR. BROWN'S AND MS. RESSLER'S RESPONSES TO YOUR RECOMMENDED ADJUSTMENT TO THIS EXPENSE?

A. No. My recommended adjustment to incentive compensation and the executive bonus plan is based on an amount related to achieving financial goals that are shareholder-oriented goals. The amount permitted for recovery in rates should be directly linked to the benefit of ratepayers such as providing safe and reliable service.

Mr. Brown's claim that the achievement of financial goals or targets benefits ratepayers is speculative and unsupported because there are no measurable or quantifiable benefits accruing directly to ratepayers specifically attributable to the Company's incentive compensation and executive bonus plan.

Therefore, the portion of the incentive compensation and the executive bonus plan claim that is attributable to achieving financial goals should not be funded by ratepayers. Allowing this claim in rates would result in higher rates and revenues at the expense of

[2] *Pa. PUC v. Columbia Gas,* Docket No. R-2020-3018835, Opinion and Order, pp. 73-75 (Order Entered February 19, 2021).

ratepayers, while providing a benefit to the parent company and shareholders' financial goals. It is not obvious how the portion of the Company's incentive compensation and executive bonus plan that is attributable to financial goals directly relates to providing safe and reliable service to ratepayers. Therefore, the portion of the incentive compensation and the executive bonus plan claim that is attributable to achieving financial goals should be paid for by shareholders, and not by ratepayers, as it is directly linked to the benefit of shareholders.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR INCENTIVE COMPENSATION AND THE EXECUTIVE BONUS PLAN?

A. No. I continue to recommend an allowance of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** for incentive compensation and the executive bonus plan, or a reduction of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** to the Company's claim for the reasons stated above and in my direct testimony.

DIRECTORS' EQUITY COMPENSATION

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR DIRECTORS' EQUITY COMPENSATION.

A. In direct testimony, I recommended disallowance of UGI Electric's entire claim of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** for directors' equity compensation. My recommendation was based on stock-based compensation being based on achieving financial goals and targets that serve primarily to benefit shareholders that should not be funded by the ratepayers as financial goals do not assist in providing safe and reliable service to ratepayers (I&E Statement No. 2, pp. 9-11).

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION FOR DIRECTORS' EQUITY COMPENSATION?

A. Yes. Company witnesses Christopher R. Brown and Vivian K. Ressler disagree with my directors' equity compensation recommendation. Mr. Brown references the 2018 UGI Electric base rate case, where the Commission approved the Company's claim for incentive compensation, to support his argument that the Company's claim for directors' equity compensation should be accepted. Mr. Brown asserts that ratepayers benefit from programs such as directors' equity compensation (UGI Electric Statement No. 1-R, pp. 3-4).

Ms. Ressler asserts that my recommendation should be rejected as the Company is entitled to recover in rates all expenses reasonably necessary to provide service. Ms. Ressler states that such programs act as an incentive to retain employees and that Company compensates its employees consistent with industry standards. Ms. Ressler asserts that if the Company did not have this type of compensation, its base salaries would likely have to be higher. Ms. Ressler also disagrees with my recommendation because incentive compensation programs, which include such items as directors' equity compensation, should be evaluated as a whole when determining whether the plan goals benefit customers as indicated by the Commission in the Company's last base rate case. Ms. Ressler also references Aqua Pennsylvania, Inc.'s most recent base rate case in support of her argument. Additionally, Ms. Ressler asserts the Company is not required to demonstrate that its incentive compensation plans benefit customers. Ms. Ressler also points out my incorrect quote regarding the Commission Order for the 2021 Columbia Gas base rate case. Finally, she states that circumstances in the above reference Columbia Gas base rate case do not apply in this proceeding as Columbia Gas withdrew its claim, and any reliance on that proceeding should be disregarded (UGI Electric Statement No. 3-R, pp. 9-15).

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> The ALJ noted that the OCA proposed an elimination of the \$2,300,000 stock rewards expense from the O&M expenses. The ALJ agreed with the OCA that stock rewards and the appreciation of common stock are a shareholder-oriented goal, not a customer service-oriented goal. R.D. at 109 (citing OCA St. 2 at 12). The ALJ reasoned that higher earnings for the Company will come from higher rates which will increase the value of the Company's common stock. The ALJ agreed with the OCA's argument that shareholders, not ratepayers, should bear the cost of any incentive program because, if the incentive program succeeds, Columbia's earnings and common stock values will rise. *Id.* The ALJ recommended that the Commission determine that increases to

> common stock valuations are a shareholder benefit for which the shareholders should bear the cost. The ALJ concluded that approving the incentive program as an element of the rate base expenses would not lead to a reasonable and just rate. R.D. at 109…
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> We also agree with the ALJ's recommendation to disallow the $2,300,000 of stock rewards expense from the FPFTY O&M expenses. We note that Columbia has voluntarily withdrawn its claim regarding the stock compensation portion of its incentive compensation program. *See* CG Exc. at 2-3.[3]

Q. DO YOU AGREE WITH MR. BROWN'S AND MS. RESSLER'S RESPONSES TO YOUR RECOMMENDATION?

A. No. The value of directors' equity compensation is based on achieving financial goals that are shareholder-oriented. Incentive compensation programs such as directors' equity compensation permitted for recovery from ratepayers should be directly linked to the benefit of ratepayers, such as providing safe and reliable service.

Mr. Brown's claim that achieving financial goals or targets benefits ratepayers is speculative and unsupported because there are no measurable or quantifiable benefits accruing directly to ratepayers specifically attributable to directors' equity compensation.

Therefore, the Company's directors' equity compensation claim should not be funded by ratepayers. Allowing this claim in rates would result in higher rates and revenues at the expense of ratepayers, while providing a benefit to the parent company and shareholders' financial goals. It is not obvious how directors' equity compensation attributable to financial goals directly relates to providing safe and reliable service to ratepayers. Therefore, all costs associated with directors' equity compensation should be

[3] *Pa. PUC v. Columbia Gas,* Docket No. R-2020-3018835, Opinion and Order, pp. 73-75 (Order Entered February 19, 2021).

paid for by shareholders, and not by ratepayers, as they are directly linked to the benefit of shareholders.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR DIRECTORS' EQUITY COMPENSATION?

A. No. I continue to recommend disallowance of UGI Electric's entire claim of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** for directors' equity compensation for the reasons stated above and in my direct testimony.

<u>ADVERTISING EXPENSE</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR ADVERTISING EXPENSE.

A. In direct testimony, I recommended an allowance of $59,000 for distribution advertising expense or a reduction of $54,000 ($113,000 - $59,000) to the Company's distribution claim. This was determined by starting with a total (transmission and distribution) recommended advertising expense of $74,000, which was further broken down to the amount allocated to transmission of $15,000 and the amount allocated to distribution of $59,000. This resulted in a total reduction of $67,000 ($141,000 - $74,000) to the Company's total claim, which was broken down to the amount allocated to transmission of $13,000 and the amount allocated to distribution of $54,000.

My recommendation was based on a reduction to the historic test year amount of the Company's claimed other advertising expense , as the increase to the FPFTY claim is primarily for event sponsorships, builder meetings, tradeshows, and arena signage. These types of advertising should not be paid for by ratepayers as they are more representative of goodwill advertising or promotional advertising, that would provide little, if any, benefit to ratepayers. Ratepayers should not be required to fund the Company's decision to pay for such promotional advertising (I&E Statement No. 2, pp. 11-15).

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION FOR ADVERTISING EXPENSE?

A. Yes. Company witness Vivian K. Ressler disagrees with my advertising expense recommendation. Ms. Ressler asserts that I propose too narrow of a standard for determining whether my adjustment to advertising expense can be recovered in rates. Ms. Ressler states that she was advised by counsel that a public utility is not required to show that advertising has to benefit customers, but must be reasonable prudent, and meet one of the criteria listed in 66 Pa. C.S. § 1316(a). Ms. Ressler states that advertising expense can be recovered in rates if it provides information regarding safety, rate changes, means of reducing of bills, load management or energy conservation, or is for the promotion of community service or economic development. Ms. Ressler states that the Company uses sponsorships and advertising to connect with communities where it provides service. Ms. Ressler states the advertising expense related to chambers of commerce and economic development alliances help promote economic development (UGI Electric Statement No. 3-R, pp. 24-26).

Q. DO YOU AGREE WITH MS. RESSLER'S RESPONSE THAT THE ADVERTISING COSTS ASSOCIATED WITH SPONSORSHIPS AND ADVERTISING RELATED TO CHAMBERS OF COMMERCE AND ECONOMIC DEVELOPMENT ALLIANCES BENEFIT RATEPAYERS?

A. No. Ms. Ressler states that the sponsorships and related advertising are a way for UGI Electric to connect with the community it serves, where customers can connect with Company and receive information about billing, customer programs, safety, or utility service (UGI Electric Statement No. 3-R, p. 25).

While I agree with Ms. Ressler that the type of advertising shown in I&E Exhibit No. 2, Schedule 3 may possibly benefit ratepayers in providing safe and reliable service, as I stated in my direct testimony, not all attendees at these events are UGI Electric ratepayers, and many UGI Electric ratepayers may never attend these events. Therefore, this advertising is not directly targeted to ratepayers.

Furthermore, the Company's partnerships with a charity such as the United Way for a children's book drive or the Greater Wyoming Valley Chamber of Commerce for the 2023 Young Professionals Conference may help develop a presence in the community where customers can receive information such as billing, customer programs, safety, or utility services, recruit new employees, and promote economic development. However, as stated in my direct testimony, if the Company is spending money in an attempt to benefit the overall community in some way, it is more representative of a charitable contribution (I&E Statement No. 2, p. 14, lines 4-7). Ratepayers who do not support certain charities or other organizations that presumably benefit the overall community, have no option to remove the portion of their bill attributable to the Company's sponsorships of certain charities or organizations. So, even if the Company represents these payments as safety and e-billing promotions, there are more effective and likely less costly ways to more directly reach the ratepaying community (I&E Statement No. 2, p. 14, lines 9-11).

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR ADVERTISING EXPENSE?

A. No. I continue to recommend an allowance of $59,000 for distribution advertising expense or a reduction of $54,000 ($113,000 - $59,000) to the Company's distribution claim for all of the reasons discussed above.

<u>CASH WORKING CAPITAL</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR CASH WORKING CAPITAL.

A. In direct testimony, I recommended a total allowance $11,389,408 or a decrease of $77,477 ($11,466,885 - $11,389,408) to the Company's claim (I&E Exhibit No. 2, Schedule 5, p. 1). My recommendation was based on adjustments to O&M expenses as discussed in I&E witness Vanessa Okum's direct testimony (I&E Statement No. 1) and in my direct testimony (I&E Statement No. 2, pp. 15-18).

Q. DID THE COMPANY RESPOND TO YOUR CWC RECOMMENDATION?

A. Yes. Company witness Tracy A. Hazenstab disagrees with my O&M adjustments used to determine my cash working capital recommendation (UGI Electric Statement No. 2-R, pp. 19-21).

Q. DID THE COMPANY PROVIDE AN UPDATED CWC CLAIM?

A. Yes. The Company's updated claim for CWC is $11,437,000 (UGI Electric Exhibit A – Fully Projected (Rebuttal), Schedule C-4, p. 1, line 5).

Q. DO YOU HAVE AN UPDATE TO YOUR CWC RECOMMENDATION DUE TO THE I&E RECOMMENDED ADJUSTMENTS TO O&M EXPENSES?

A. Yes. As stated in direct testimony, all O&M expense adjustments that are cash-based expense claims are included when determining the Company's overall CWC requirement. Therefore, I have included cash-based O&M recommendations when computing the overall recommended CWC allowance.

Q. SUMMARIZE WHERE EACH OF THE RECOMMENDED O&M EXPENSE ADJUSTMENTS ARE REFLECTED IN THE CWC COMPUTATIONS.

A. <u>Other Expenses (less uncollectibles) – Expense Lag Days</u>:

The following recommended adjustments (I&E Statement No. 1-SR, p. 2 and I&E Statement No. 2-SR, p. 3) are reflected in the Other Expenses (less Uncollectibles) Expense Lag Days calculation (I&E Exhibit No. 2-SR, Schedule 1, p. 1, line 5): rate case expense adjustment of $77,400, stock options and restricted stock awards adjustment of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}**, incentive compensation and executive bonus plan adjustment of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}**, directors' equity compensation adjustment of **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}**, and advertising expense adjustment of $84,000 as discussed above and in I&E Statement No. 1, resulting in a total decrease of $857,200 to the Other Expenses Lag Days calculation (I&E Exhibit No. 2-SR, Schedule 1, p. 2).

<u>Summary of I&E-Updated Recommended CWC Allowance</u>:

Q. BASED ON THE ABOVE TESTIMONY, WHAT IS YOUR UPDATED RECOMMENDED ALLOWANCE FOR CWC?

A. Based on reflecting all of I&E's recommended adjustments as discussed above, my updated recommendation for CWC is an allowance of $11,378,377 or a decrease of $58,623 ($11,437,000 - $11,378,377) to the Company's updated claim (I&E Exhibit No. 2-SR, Schedule 1, p. 1, line 14).

Q. IS YOUR UPDATED RECOMMENDATION FOR CWC A FINAL RECOMMENDED ALLOWANCE?

A. No. As stated in my direct testimony, all adjustments to the Company's claims must be continually brought together in the Administrative Law Judge's Recommended Decision and again in the Commission's Final Order. This process, known as iteration, effectively prevents the determination of a precise calculation until all adjustments have been made to the Company's claims.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Exhibit No. 2-SR
Witness: Christopher Keller

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – ELECTRIC DIVISION

Docket Nos. R-2022-3037368

Exhibit to Accompany

the

Direct Testimony

of

Christopher Keller

Bureau of Investigation and Enforcement

Concerning:

Operating and Maintenance Expenses
Cash Working Capital

Summary of Working Capital

		[1]	[2]		[3]	[4]	[5]
Line #	Description	Reference	Test Year Expenses		Factor	Number of (Lead) / Lag Days [2] * [3]	Totals
WORKING CAPITAL REQUIREMENT							
1	REVENUE LAG DAYS	Page 3					59.56
2	EXPENSE LAG DAYS	Page 4					
3	Payroll	Sch D-7	$ 6,121,000		12.00	$ 73,452,000	
4	Purchased Power Costs	Sch D-6	91,176,000		33.30	3,035,741,390	
5	Other Expenses	L 19 - L 2 to L 4	25,701,800	(a)	30.76	790,587,368	
6	Total	Sum (L 3 to L 5)	$ 122,998,800			$ 3,899,780,758	
7	O & M Expense Lag Days	L6, C 4 / C 2					31.71
8	Net (Lead) Lag Days	L 1 - L 7					27.85
9	Operating Expenses Per Day	L 6, C 2 / 365					$ 336,983
10	Working Capital for O & M Expense	L 8 * L 9					$ 9,386,377
11	Interest Payments	Page 7					(301,000)
12	Tax Payment Lag Calculations	Page 8					261,000
13	Prepaid Expenses	Page 9					2,032,000
14	Total Working Capital Requirement	Sum (L 10 to L 13)					$ 11,378,377
(a)	Ref: I&E Exhibit No. 2-SR, Schedule 1, p. 2						

UGI Utilities, Inc. - Electric Division
Cash Working Capital Other Expenses Adjustment
For the Twelve Months Ended September 30, 2024

		I&E Recommendded Adjustment
1	Rate Case Expense	(77,400)
2	Stock Options and Restricted Stock Awards	(497,000)
3	Incentive Compensationa and Executive Bonus Plan	(192,800)
4	Directors' Equity Compensation	(36,000)
5	Advertising Expense	(54,000)
6	Total	(857,200)

Ref: I&E Statement No. 1-SR, p. 2 and I&E Statement No. 2-SR, p. 3

I&E Statement No. 3
Witness: D. C. Patel

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI Utilities, Inc. - Electric Division

Docket No. R-2022-3037368

Direct Testimony

of

D. C. Patel

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

TABLE OF CONTENTS

<u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is D. C. Patel, and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. WHAT IS YOUR EDUCATION AND PROFESSIONAL EXPERIENCE?

A. An outline of my education and employment experience is set forth in the attached Appendix A.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for representing the public interest in rate and other proceedings before the Commission. I&E's analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires balancing the interests of ratepayers, the regulated utility company, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to address the rate of return, including capital structure, cost of long-term debt, the cost of equity, and the overall fair rate of return in the base rate filing of UGI Utilities, Inc. - Electric Division (UGI Electric or Company) for the fully projected future test year (FPFTY) ending September 30, 2024.

Q. DOES YOUR DIRECT TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 3 contains schedules that support my direct testimony.

BACKGROUND

Q. WHAT IS THE GENERAL DEFINITION OF RATE OF RETURN IN THE CONTEXT OF A BASE RATE CASE?

A. The rate of return is one of the components of the revenue requirement formula. Rate of return is the amount of revenue an investment generates in the form of net income and is usually expressed as a percentage of the amount of capital invested over a given period of time.

Q. WHAT IS THE REVENUE REQUIREMENT FORMULA?

A. The revenue requirement formula used in base rate cases is as follows:

$$RR = E + D + T + (RB \times ROR)$$

Where:

RR	=	Revenue Requirement
E	=	Operating Expenses
D	=	Depreciation Expense
T	=	Taxes

RB = Rate Base

ROR = Overall Rate of Return

In the above formula, the rate of return is expressed as a percentage. The calculation of that percentage is independent of the determination of the appropriate rate base value for ratemaking purposes. As such, the appropriate and reasonable total dollar return is dependent upon the proper computation of the rate of return and the proper valuation of the Company's rate base.

Q. WHAT CONSTITUTES A FAIR AND REASONABLE OVERALL RATE OF RETURN?

A. A fair and reasonable overall rate of return is one that will allow the utility an opportunity to recover those costs prudently incurred for all classes of capital used to finance the rate base during the prospective period in which its rates will be in effect.

The *Bluefield Water Works & Improvements Co. v. Public Service Comm. of West Virginia,* 262 U.S. 679, 692-93 (1923), and the *Federal Power Commission et al v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) cases set forth the principles that are generally accepted by regulators throughout the country as the appropriate criteria for measuring a fair rate of return:

1. A utility is entitled to a return similar to that being earned by other enterprises with corresponding risks and uncertainties, but not as high as those earned by highly profitable or speculative ventures.
2. A utility is entitled to a return level reasonably sufficient to assure financial soundness.

3. A utility is entitled to a return sufficient to maintain and support its credit and raise necessary capital.

4. A fair return can change (increase or decrease) along with economic conditions and capital markets.

Q. EXPLAIN HOW THE OVERALL RATE OF RETURN IS TRADITIONALLY CALCULATED IN BASE RATE PROCEEDINGS.

A. In base rate proceedings, the overall rate of return is traditionally calculated using the weighted average cost of capital method. To calculate the weighted average cost of capital, a company's capital structure must first be determined by comparing the percentage of each capitalization component, which has a financed rate base, to the total capital. Next, the effective cost rate of each capital structure component must be determined. The historical component of the cost rate of debt can be computed accurately, and any future debt issuances are based on estimates. The cost rate of common equity is not fixed and is more difficult to measure. Because of this difficulty, a proxy group of utilities engaged in a similar business is used as discussed later in this testimony. Then, each capital structure component percentage is multiplied by its corresponding effective cost rate to determine the weighted capital component cost rate. The table in the *"I&E Position"* section below demonstrates the interaction of each capital structure component and its corresponding effective cost rate. Finally, the sum of the weighted cost rates produces the overall rate of return. This overall rate of return is multiplied by the rate base to determine the return portion of a company's revenue requirement.

COMPANY'S RATE OF RETURN CLAIM

Q. WHO IS THE COMPANY'S RATE OF RETURN WITNESS?

A. Paul R. Moul is the primary witness addressing the rate of return. Throughout his direct testimony, Mr. Moul provides his analysis for the claimed capital structure, cost of common equity, and overall rate of return for UGI Electric (UGI Electric Statement No. 9, pp. 1-43).

Q. PLEASE SUMMARIZE MR. MOUL'S RECOMMENDATIONS FOR THE COMPANY'S RATE OF RETURN CLAIM.

A. Mr. Moul recommends the following rate of return for the Company based on its FPFTY ending September 30, 2024 (UGI Electric Statement No. 9, p. 2, line 6):

Type of Capital	Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	45.41%	4.35%	1.98%
Common Equity	54.59%	11.30%	6.17%
Total	**100.00%**		**8.15%**

I&E POSITION

Q. PLEASE SUMMARIZE YOUR RATE OF RETURN RECOMMENDATION FOR THE COMPANY.

A. I recommend the following rate of return for the Company (I&E Exhibit No. 3, Schedule 1):

Type of Capital	Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	45.41%	4.35%	1.98%
Common Equity	54.59%	8.76%	4.78%
Total	**100.00%**		**6.76%**

PROXY GROUP

Q. WHAT IS A PROXY GROUP AS USED IN BASE RATE CASES?

A. A proxy group is a set of companies that have similar traits as compared to the subject utility. This group of companies acts as a benchmark for determining the subject utility's rate of return in a base rate case.

Q. WHAT ARE THE REASONS FOR USING A PROXY GROUP?

A. A proxy group's cost of equity is used as a benchmark to satisfy the long-established guideline of utility regulation that seeks to provide the subject utility with the opportunity to earn a return similar to that of enterprises with corresponding risks and uncertainties.

A proxy group is typically utilized since the use of data exclusively from one company may be less reliable. The lower reliability occurs because the data for one company may be subject to events that can cause short-term anomalies in the marketplace. The rate of return on common equity for a single company could become distorted in these circumstances and would therefore not be representative of similarly situated companies. Therefore, a proxy group has the effect of smoothing out potential anomalies associated with a single company.

Q. WHAT CRITERIA DID YOU USE IN SELECTING YOUR ELECTRIC UTILITY PROXY GROUP?

A. The criteria for my proxy group was designed to select companies that are representative of UGI Electric. I applied the following criteria to Value Line's "Electric Utility (East, West, and Central Group)" company group:

1. Fifty percent or more of the company's revenues must be generated from the regulated electric utility industry.
2. The company's stock must be publicly traded.
3. Investment information for the company must be available from more than one source, which includes Value Line.
4. The company must not be currently involved in an announced merger or the target of an acquisition.
5. The company must have four consecutive years of historic earnings data.
6. The company must be operating in a state that has a deregulated electric utility market.

Q. WHAT CRITERIA DID MR. MOUL USE IN SELECTING THE COMPANIES THAT MAKE UP HIS ELECTRIC (PROXY) GROUP?

A. Mr. Moul states that his proxy group consist of electric companies that (1) have publicly traded common stock, (2) are contained in *The Value Line Investment Survey* and are classified in the Electric Utility East Group, (3) are not currently the target of a merger or acquisition, and (4) are not engaged in the construction of a nuclear generating plant. Based on this list of criteria, he eliminates two companies, Southern Company (SO) and Unitil Corporation (UTL) from the "East Group" electric utilities contained in the Value Line's Investment Survey (UGI Electric Statement No. 9, p. 5, lines 6-9).

Q. WHAT PROXY GROUP DID MR. MOUL USE IN HIS ANALYSIS?

A. Mr. Moul's Electric Group consists of the following ten companies from the East Group of Value Line's Investment Survey (UGI Electric Exhibit B, p. 6, Schedule 3, p. 2):

Company	Stock Ticker
AVANGRID, Inc.	AGR
Consolidated Edison, Inc.	ED
Dominion Energy, Inc.	D
Duke Energy Corporation	DUK
Eversource Energy	ES
Exelon Corporation	EXC
FirstEnergy Corporation	FE
NextEra Energy, Inc.	NEE
PPL Corporation	PPL
Public Service Enterprise Group, Inc.	PEG

Q. WHAT PROXY GROUP DID YOU USE IN YOUR ANALYSIS?

A. I have included the following twelve companies from the East, West, and Central Groups of Value Line's Investment Survey in my proxy group based on criteria described above:

Company	Stock Ticker
IDACORP, Inc.	IDA
Portland General Electric Company	POR
Dominion Energy, Inc.	D
Duke Energy Corporation	DUK
Eversource Energy	ES
FirstEnergy Corporation	FE
PPL Corporation	PPL
Public Service Enterprise Group, Inc.	PEG
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
CMS Energy Corporation	CMS
Entergy Corporation	ETR

Q. DO YOU AGREE WITH MR. MOUL'S ELECTRIC PROXY GROUP?

A. Not entirely. Mr. Moul relies on Value Line's East Group utility companies while I use Value Line's East, West, and Central groups utility companies. Mr. Moul's Electric Group includes six of the companies I selected and excludes another six companies from my proxy group of twelve companies. I have not included four of the companies in my proxy group that Mr. Moul uses in his proxy group of ten companies.

Q. PLEASE IDENTIFY THE FOUR COMPANIES MR. MOUL HAS INCLUDED THAT YOU DO NOT AND EXPLAIN WHY YOU HAVE EXCLUDED THEM FROM YOUR PROXY GROUP.

A. The four companies Mr. Moul includes in his Electric Group that I exclude from my proxy group are AVANGRID, Inc., Consolidated Edison, Inc., Exelon Corporation, and NextEra Energy, Inc. as these companies did not meet my criterion for determining the proxy group. First, AVANGRID and Consolidated Edison are currently involved in an announced merger/acquisition of significant value. Second, Exelon does not meet my criterion that fifty percent or more of the company's revenues must be generated from the regulated electric distribution utility because approximately 54% of Exelon's total revenue is generated from the unregulated power generation business. This is important because revenues represent the percentage of cash flow a company receives from each business line related to providing goods or services. If less than fifty percent of revenues come from the regulated electric sector, such companies are not comparable to the subject utility as they do not provide a similar level of regulated business. Lastly, I excluded NextEra Energy because it is not operating in a state that has a deregulated electric utility market. Considering the above, I have excluded these four companies in my proxy group.

CAPITAL STRUCTURE

Q. WHAT IS A CAPITAL STRUCTURE?

A. A capital structure represents how a utility has financed its rate base with different sources of funds. The primary sources of funding are long-term debt and common equity.

Q. WHAT IS THE COMPANY'S CLAIMED CAPITAL STRUCTURE?

A. The Company's claim for the FPFTY capital structure is summarized in the table below (UGI Electric Statement No. 9, p. 17, lines 17-19 and UGI Electric Exhibit A, Schedule B-7 and Exhibit B, p. 10, Schedule 5):

Type of Capital	Capitalization Ratio
Long-Term Debt	45.41%
Short-Term Debt	0.00%
Common Equity	54.59%
Total	**100.00%**

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIMED CAPITAL STRUCTURE?

A. Mr. Moul states that the Company's capitalization and capital structure ratios reflect: (1) sinking fund payments of $6.250 million in the future test year (FTY) ending September 30, 2023 and the FPFTY on the Senior Notes due in 2027; (2) the issuance of $225 million of long-term debt in the FPFTY; and (3) the Company's projection of retained earnings at the end of the FTY and FPFTY (UGI Electric Statement No. 9, p. 15, lines 20-23). Mr. Moul ultimately reasons that since rate setting is prospective, the rate of return should consider conditions that will exist during the period of time the proposed rates are to be effective. Therefore, he adopts the Company's capital structure ratios at the end of the FPFTY of 45.41% long-term debt and 54.59% common equity (UGI Electric Statement No. 9, p. 17, lines 16-19). He opines that these ratios are within the ranges indicated for his Electric Group and further notes that due to the small size of UGI Utilities, Inc. (Gas and Electric combined) and UGI Electric (standalone), less debt and more equity would be appropriate and an equity ratio in the upper end of the range would be warranted (UGI Electric Statement No. 9, p. 17, lines 19-22).

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S CAPITAL STRUCTURE?

A. I recommend using the Company's claimed capital structure as presented in the table above.

Q. WHAT IS THE BASIS FOR YOUR CAPITAL STRUCTURE RECOMMENDATION?

A. Although I believe a capital structure of 50% long-term debt and 50% common equity is optimal when trying to balance the financial integrity of a utility, as well as trying to control costs to ratepayers, I recommend using the Company's claimed capital structure as it falls within the range of my proxy group's 2021 (most recently available) capital structures. The most recent five-year (2017-2021) average range contains individual company capital structure ratios from 43.07% to 75.67% long-term debt and 24.27% to 56.93% common equity, with an overall five-year average of 57.21% long-term debt and 42.46% common equity (I&E Exhibit No. 3, Schedule 2).

Mr. Moul states that in order to avoid double counting the amount of short-term debt that finances the Company's construction work in progress (CWIP), those amounts should be removed from the average short-term debt amounts for rate case purposes. Further, he states that for the FPFTY, the CWIP balances approximately offset the average amount of short-term debt. Therefore, the de- minimis remaining amount of short-term debt is removed from the capital structure for the FPFTY (UGI Electric Statement No. 9, p. 17, lines 9-13).

I accept the use of the Company's recommended capital structure. However, it is worth noting that the Company's FPFTY claimed equity ratio of 54.59% is well above the proxy group's average equity ratio of 42.46% and near the highest end of 56.93%. In fact, ten of the twelve companies in my proxy group have a capital structure wherein the equity ratio is less than 50% for the most recent five-years (2017-2021) (I&E Exhibit No. 3, Schedule 2). Mr. Moul concedes that a firm with a higher common equity ratio has lower financial risk, while a firm with a lower common equity ratio has higher financial risk (UGI Electric Statement No. 9, p. 12, lines 11-13). Additionally, he states that the FPFTY capital structure of the Company in this case is within the range of his Electric (Proxy) Group both historically and prospectively based upon the Value Line forecasts (UGI Electric Statement No. 9, p.

12, lines 15-17). I believe this equity heavy capital structure must be recognized considering UGI Electric's historic actual capital structure (2017-2021) (UGI Electric Exhibit B, p. 3 - Schedule 2, p. 1) and the current market interest rate for borrowing.

Q. PLEASE CONTINUE.

A. Considering the Company's overall financial risk, as an example if the Company were to employ a 50% long-term debt and 50% common equity capital structure in its cost of capital while maintaining its claimed return on equity and rate base, the table below illustrates the approximate cost savings to ratepayers.

UGI ELECTRIC - CLAIMED CAPITAL STRUCTURE			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost**
Long-Term Debt	45.41%	4.35%	1.98%
Common Equity	54.59%	11.30%	6.17%
	100.00%		**8.15%**
50/50 OPTIMAL CAPITAL STRUCTURE			
Long-Term Debt	50.00%	4.35%	2.17%
Common Equity	50.00%	11.30%	5.65%
	100.00%		**7.82%**
Difference in the Overall Rate of Return (8.15% - 7.82% = 0.33%)			0.33%
Impact Prior to Gross Up (Claimed Rate Base* x Difference in the Overall Rate of Return) ($172,242,000 x 0.0033)			$568,399
Gross Revenue Conversion Factor**			1.513583
Total Impact to Ratepayers ($568,399 x 1.513583)			**$860,319**

* UGI Electric Exhibit A, Schedule C-1 (FPFTY).
** UGI Electric Exhibit A, Schedule D-35 (FPFTY).

In this example, if the Company were to employ a 50/50 capital structure and make no change to the requested return on equity (which I do not agree with as discuss in more detail below), the cost savings to ratepayers would be $860,319. While I understand achieving and maintaining an exact 50/50 capital structure is not always feasible, this example is intended to demonstrate UGI Electric's financial security as compared to its peers and prove that Mr. Moul's various "add-ons" to his cost of equity calculations are unnecessary.

COST OF LONG-TERM DEBT

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S COST RATE OF LONG-TERM DEBT?

A. I recommend using the Company's claimed long-term debt cost rate of 4.35% for the FPFTY (UGI Electric Statement No. 9, p. 2, line 6 and p.18, lines 22-23 and UGI Electric Exhibit A, Schedule B-7).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO USE THE COMPANY'S CLAIMED COST RATE OF LONG-TERM DEBT?

A. The Company's claimed cost rate of long-term debt appears reasonable, especially when considering recent inflation and rising interest rates. Mergent Bond Record's A-Rated Public Utility Bond Yields have increased 187 basis points from 3.33% in January 2022 to 5.20% in January 2023. Additionally, the Company's debt cost rate is within the high and low (5.07% - 3.18%) range of my proxy group implied debt cost rate (I&E Exhibit No. 3, Schedule 3). Given this sharp upward trend and proxy group debt cost rate, I believe that the Company's claim is representative of the utility industry.

<u>COST OF COMMON EQUITY</u>

<u>COMMON METHODS</u>

Q. WHAT METHODS ARE COMMONLY PRESENTED BY UTILITIES IN DETERMINING THE COST OF COMMON EQUITY?

A. Four methods commonly presented to estimate the cost of common equity are the Discounted Cash Flow (DCF), the Capital Asset Pricing Model (CAPM), the Risk Premium (RP) Method, and the Comparable Earnings (CE) Method.

Q. WHAT IS THE THEORETICAL BASIS FOR THE DCF METHOD?

A. The DCF method is the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows. The DCF method assumes that investors evaluate stocks in the traditional economic framework, which maintains that the value of a financial asset is determined by its earning power, or its ability to generate future cash flows.

Q. WHAT IS THE THEORETICAL BASIS FOR THE CAPM?

A. The CAPM describes the relationship of a stock's investment risk and its market rate of return. It identifies the rate of return investors expect so that it is comparable with returns of other stocks of similar risk. This method hypothesizes that the investor-required return on a company's stock is equal to the return on a "risk free" asset plus an equity premium reflecting the company's investment risk. In the CAPM, two types of risk are associated with a stock: (1) firm-specific risk (unsystematic risk); and (2) market risk (systematic risk), which is measured by a firm's beta. The CAPM allows investors to receive a return only for bearing systematic risk. Unsystematic risk is assumed to be diversified away, and therefore, does not earn a return.

Q. WHAT IS THE THEORETICAL BASIS FOR THE RP METHOD?

A. The theoretical basis for the RP method is a simplified version of the CAPM. The RP method's theory is that common stock is riskier than debt, thus, investors require a higher expected return on stocks than bonds. In the RP approach, the cost of equity is made up of the cost of debt and a risk premium. While the CAPM uses the market risk premium, it also directly measures the systematic risk of a company or proxy group using beta. The RP method does not measure the specific risk of a company.

Q. WHAT IS THE THEORETICAL BASIS FOR THE CE METHOD?

A. The CE method utilizes the concept of opportunity cost. This means that investors will likely dedicate their capital to the investment offering the highest return with similar risk to alternative investments. Unlike the DCF, CAPM, and the RP methods, the CE method is not market-based and relies upon historic accounting data. The most problematic issue with the CE method is determining what constitutes comparable companies.

<u>I&E RECOMMENDED METHOD TO EMPLOY</u>

Q. WHAT METHOD DO YOU RECOMMEND TO DETERMINE AN APPROPRIATE COST OF COMMON EQUITY FOR UGI ELECTRIC?

A. I recommend using the DCF method as the primary method to determine the cost of common equity. Additionally, I provide a CAPM analysis to be used as a comparison, not as a check, to the DCF results. The Commission has historically relied mostly upon the DCF results in base rate proceedings, including as recently as 2017, 2018, 2020, and 2021.[1]

Q. PLEASE EXPLAIN WHY YOU CHOSE TO EMPLOY THE DCF TO DETERMINE YOUR RECOMMENDED RETURN ON EQUITY.

A. I recommend using the DCF for a variety of reasons. The DCF is appealing to investors since it is based upon the concept that the receipt of dividends in addition to expected appreciation is the total return requirement determined by the market.[2] The use of a growth rate and expected dividend yield are also strengths of the DCF, as this recognizes the time value of money and is forward-looking. The use of the utilities' own, or in this case the proxy group's, stock prices and growth rates directly in the

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[1] *Pa. PUC v. City of DuBois – Bureau of Water*; Docket No. R-2016-2554150 (Order Entered March 28, 2017). *See generally* Disposition of Cost Rate Models, pp. 96-97; *Pa. PUC v. UGI Utilities, Inc. – Electric Division,* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Cost of Common Equity, p. 119; *Pa. PUC v. Wellsboro Electric Company,* Docket No. R-2019-3008208 (Order Entered April 29, 2020). *See generally* Disposition of Primary Methodology to Determine ROE, pp. 80-81; *Pa. PUC v. Citizens Electric Company of Lewisburg, PA,-* Docket No. R-2019-3008212 (Order Entered April 29, 2020). *See generally* Disposition of Cost of Common Equity, pp. 91-92; *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.,* Docket No. R-2020-3018835 (Order Entered February 19, 2021). *See generally* Disposition of Cost of Common Equity, p. 131.

[2] David C. Parcell, "The Cost of Capital – A Practitioner's Guide," 2010 Edition, p. 151.

calculation also causes the DCF to be industry and company specific. Finally, the current inflationary and economic trends are most certainly reflected in a stock's price, which is used in determining the dividend yield by analysts who generate forecasted earnings growth rates. Therefore, the DCF contains the most up-to-date projected information of any model and is the superior method for determining the rate of return for the current economic market because it measures the cost of equity directly.

Q. PLEASE EXPLAIN WHY YOU CHOSE TO USE THE CAPM AS A COMPARISON TO THE DCF IN YOUR ANALYSIS.

A. I have included a CAPM analysis only as a comparison, and not as a basis, for my recommendation because both the CAPM and the DCF include inputs that allow the results to be specific to the utility industry. However, the CAPM is based on the performance of U.S. Treasury bonds and the performance of the market as measured through the S&P 500 and is company-specific only through the use of beta. Beta reflects a stock's volatility relative to the overall market, thereby incorporating an industry-specific aspect to the CAPM, but only as a measure of how reactive the industry is compared to the market as a whole. Although changes in the utility industry are more likely to be accurately reflected in the DCF, which uses the companies' actual prices, dividends, and growth rates, I have also included the results of my CAPM analysis because changes in the market, whether as a whole or specific to the utility industry, affect the outcome of each method in different ways. Though I have provided the results of my CAPM analysis as a comparison, and not as a check, it does have several disadvantages and should not be given comparable weight to the DCF.

Q. EXPLAIN THE DISADVANTAGES OF THE CAPM.

A. The CAPM, and the RP method by virtue of its similarities to the CAPM, give results that indicate to an investor what the equity cost rate should be if current economic and regulatory conditions are the same as those present during the historical period in which the risk premiums were determined. This is because beta, which is the only company-specific variable in the CAPM model, measures the *historical* volatility of a stock compared to the *historical* overall market return. Reliance on historical values is especially problematic now given the recent impact of the COVID-19 pandemic on economic conditions. Although, the CAPM and RP results can be useful to investors in making buy and sell decisions within their portfolios, the DCF method is the superior method for determining the rate of return for the current economic market and measuring the cost of equity directly. The CAPM and the RP methods are less reliable indicators because they measure the cost of equity indirectly and risk premiums vary depending on the debt and equity being compared. Also, regulators can never be certain that economic and regulatory conditions underlying the historical period during which the risk premiums were calculated are the same today or will be the same in the future. This is a very important point considering the fact that the Company's cost of equity is determined for the FPFTY when the new rates will be effective prospectively.

Q. IS THERE ANY ACADEMIC EVIDENCE THAT QUESTIONS THE CREDIBILITY OF THE CAPM MODEL?

A. Yes. An article, "Market Place; A Study Shakes Confidence in the Volatile-Stock Theory," which appeared in the *New York Times* on February 18, 1992, summarized a CAPM study conducted by professors Eugene F. Fama and Kenneth R. French.[3] Their study examined the importance of beta, CAPM's risk factor, in explaining returns on common stock. In CAPM theory a stock with a higher beta should have a higher expected return. However, they found that this model did not do well in predicting actual returns and suggested the use of more elaborate multi-factor models.

A more recent article, "The Capital Asset Pricing Model: Theory and Evidence," which appeared in the *Journal of Economic Perspectives,* states that "the attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor, and is poor enough to invalidate the way it is used in applications."[4] As a result, I conclude that the CAPM's relevance to the investment decision making process does not carry over into the regulatory rate setting process.

Q. PLEASE EXPLAIN WHY YOU HAVE CHOSEN TO EXCLUDE THE RP METHOD FROM YOUR ANALYSIS.

A. The RP method is excluded because it is a simplified version of the CAPM and is

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[3] Berg, Eric N. "Market Place; A Study Shakes Confidence in the Volatile-Stock Theory" *The New York Times*, 18 Feb 1992: *nytimes.com* Web. 23 Mar 2016.

[4] Fama, Eugene F. and French, Kenneth R., "The Capital Asset Pricing Model: Theory and Evidence." *Journal of Economic Perspectives* (2004): Volume 18, Number 3, pp. 25-46.

subject to the same faults explained above. Most importantly, unlike the CAPM, the RP method does not recognize company-specific risk through beta.

Q. EXPLAIN WHY YOU HAVE CHOSEN TO EXCLUDE THE CE METHOD IN YOUR ANALYSIS.

A. The CE method is excluded because the choice of which companies are comparable is highly subjective, and it is debatable whether historic accounting values are representative of the future. Moreover, its historical usage in this regulatory forum has been minimal.

Q. ARE THERE ANY RECENT COMMISSION ORDERS THAT DEVIATE FROM THE HISTORICAL USE OF THE DCF AS THE PRIMARY METHOD IN DETERMINING A COMPANY'S RETURN ON EQUITY?

A. Yes. The Commission indicated in the most recent Aqua Pennsylvania, Inc. (Aqua) base rate case order that its method "for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies"[5] and that "I&E's DCF and CAPM produce a range of reasonableness for the ROE…,"[6] which deviates from the historical Commission practice of primarily relying on the DCF.

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5 *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 154 (Order entered May 16, 2022).

6 *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 178 (Order entered May 16, 2022).

Q. SHOULD THE COMMISSION'S USE OF THE CAPM AS A CEILING FOR A "RANGE OF REASONABLENESS" APPLY IN THIS PROCEEDING?

A. No. In a report issued by Regulatory Research Associates, a group within S&P Global Market Intelligence,[7] Aqua's return on equity of 10.00% is stated as being above the national average for water utility base rate cases and above the Distribution System Improvement Charge (DSIC) authorized by the Commission of 9.80%[8] for water and wastewater utilities based on a period ended March 31, 2022. This DSIC rate has since dropped 5 basis points to 9.75%.[9] The above referenced report also states that the average return on equity for water utility base rate cases that have been completed during the first four months of 2022 was 9.63% and for the last twelve months ended April 30, 2022, was 9.53%, which are well below the 10.00% return on equity authorized by the Commission for Aqua. Although this is related to the water utility industry only, it demonstrates the problem associated with using the CAPM as a ceiling for determining a utility's return on equity.

Additionally, as I explained above, the CAPM should not be used as a primary method, and it should only be used as a comparison and not as a check of the DCF or to establish a "reasonable range" due to the concerns stated above. Also, as demonstrated below, the use of the CAPM in this proceeding would result in a

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[7] Regulatory Research Associates, "Commission authorizes management performance bonus for Aqua Pennsylvania," *S&P Global Market Intelligence*, May 16, 2022. CIQ Pro: RRA Regulatory Focus: Commission authorizes management performance bonus for Aqua Pennsylvania (spglobal.com) (Accessed February 22, 2023).

[8] PA Public Utility Commission, Bureau of Technical Utility Services Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended March 31, 2022, approved at Public Meeting on August 4, 2022 at Docket No. M-2022-3033561.

[9] PA Public Utility Commission, Bureau of Technical Utility Services Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended September 30, 2022, approved at Public Meeting on February 9, 2023 at Docket No. M-2022-3037661.

significant burden to ratepayers during a time of increasing levels of inflation and economic decline. Therefore, I disagree with providing the CAPM comparable weight to the DCF method.

SUMMARY OF THE COMPANY'S RESULTS

Q. WHAT ARE THE RESULTS OF THE COMPANY'S COST OF EQUITY ANALYSES?

A. Mr. Moul employs the DCF, CAPM, RP, and CE methods in analyzing the Company's cost of equity and produces the results as shown in the table below (UGI Electric Statement No. 9, p. 6, line 11):

DCF	10.45%
CAPM	15.95%
RP	11.75%
CE	13.10%

He made several adjustments to his results, which include consideration of risk, leverage, inflated beta, and size adjustment (UGI Electric Exhibit B, p. 2, Schedule 1, p. 2). Ultimately, Mr. Moul determines the cost of equity by averaging DCF and RP results that provide a return of 11.10% (10.45% + 11.75% = 22.20% ÷ 2 = 11.10%) and then adds 20 basis points (0.20%) for recognition of exemplary/strong management performance, which result in his recommended cost of equity of 11.30% (UGI Electric Statement No. 9, p. 6, lines 13-16). He then argues that his recommended higher equity rate of return is warranted in order to obtain new capital to support an expanded construction program and retain existing capital, and to satisfy investors' requirements (UGI Electric Statement No. 9, p. 6, lines 20-21 through p. 7, line 1).

I&E RECOMMENDATION

Q. WHAT IS YOUR RECOMMENDED COST OF COMMON EQUITY FOR UGI ELECTRIC?

A. Based upon my analysis, I recommend a common equity cost rate of 8.76% (I&E Exhibit No. 3, Schedule 4).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation uses the DCF method. As explained herein, I used my CAPM result only to present to the Commission a comparison to my DCF result. My DCF analysis uses a spot dividend yield, a 52-week dividend yield, and earnings growth forecasts (I&E Exhibit No. 3, Schedule 4).

DISCOUNTED CASH FLOW

Q. PLEASE EXPLAIN YOUR DCF ANALYSIS.

A. My analysis employs the constant growth DCF model as portrayed in the following formula:

$$K = D_1/P_0 + g$$

Where:

K = Cost of equity

D_1 = Dividend expected during the year

P_0 = Current price of the stock

g = Expected growth rate

When a forecast of D_1 is not available, D_0 (the current dividend) must be adjusted by one half of the expected growth rate to account for changes in the dividend paid in period one. As forecasts for each company in my proxy group were available from Value Line, no dividends were adjusted for the purpose of my analysis.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE DIVIDEND YIELDS USED IN YOUR DCF ANALYSIS.

A. A representative dividend yield must be calculated over a time frame that avoids the problems of both short-term anomalies and stale data series. For my DCF analysis, the dividend yield calculation places equal emphasis on the most recent spot and the 52-week average dividend yields. The following table summarizes my dividend yield computations for the proxy group (I&E Exhibit No. 3, Schedule 5):

Proxy Group – Average Dividend Yields	
(a) Spot Dividend Yield	3.69%
(b) 52-week Average Dividend Yield	3.52%
(c) Average ((a +b) ÷ 2)	3.61%

Q. WHAT INFORMATION DID YOU RELY UPON TO DETERMINE YOUR EXPECTED GROWTH RATE?

A. I have used five-year projected earnings growth rate estimates from Yahoo! Finance, Zacks, and Value Line.

Q. WHAT WERE THE RESULTS OF YOUR FORECASTED EARNINGS GROWTH RATES?

A. The expected average growth rates for my electric proxy group ranged from 3.50% to 7.76% with an overall average of 5.15% (I&E Exhibit No. 3, Schedule 6). In calculating the average growth rate I removed outlier growth rates: (1) the negative growth rate (-2.42%) of FirstEnergy Corp.; and (2) an extraordinary double digit growth rate (17.47%) of PPL Corp. projected by Yahoo Finance, to avoid distorting the growth rate.

Q. WHAT IS THE RESULT OF YOUR DCF ANALYSIS BASED ON YOUR RECOMMENDED DIVIDEND YIELD AND GROWTH RATE?

A. The results of my DCF analysis are calculated as follows (I&E Exhibit No. 3, Schedule 4):

K	**=**	**D_1/P_0**	**+**	**g**
8.76%	=	3.61%	+	5.15%

CAPITAL ASSET PRICING MODEL

Q. PLEASE EXPLAIN YOUR CAPM ANALYSIS.

A. My analysis employs the traditional CAPM as portrayed in the following formula:

$$K = R_f + \beta(R_m - R_f)$$

Where:

K	=	Cost of equity
R_f	=	Risk-free rate of return
R_m	=	Expected rate of return on the overall stock market
β	=	Beta measures the systematic risk of an asset

Q. WHAT IS BETA AS EMPLOYED IN YOUR CAPM ANALYSIS?

A. Beta is a measure of the systematic risk of a stock in relation to the rest of the stock market. A stock's beta is estimated by calculating the linear regression of a stock's return against the return on the overall stock market. The beta of a stock with a price pattern identical to that of the overall stock market will equal one. A stock with a price movement that is greater than the overall stock market will have a beta that is greater than one and would be described as having more investment risk than the market. Conversely, a stock with a price movement that is less than the overall stock market will have a beta of less than one and would be described as having less investment risk than the overall stock market.

Q. HOW DID YOU DETERMINE YOUR BETA FOR YOUR CAPM ANALYSIS?

A. In estimating an equity cost rate for my proxy group, I used the average of the betas for the companies as provided in the Value Line Investment Survey. The average beta for my proxy group is 0.86 (I&E Exhibit No. 3, Schedule 7).

Q. WHAT RISK-FREE RATE OF RETURN HAVE YOU USED FOR YOUR FORECASTED CAPM ANALYSIS?

A. I have chosen to use the risk-free rate of return (R_f) from the projected yield on 10-year Treasury Notes. While the yield on the short-term T-Bill is a more theoretically correct parameter to represent a risk-free rate of return, it can be extremely volatile. The volatility of short-term T-Bills is directly influenced by Federal Reserve policy. At the other extreme, the 30-year Treasury Bond exhibits more stability but is not risk-free. Long-term Treasury Bonds have substantial maturity risk associated with market risk and the risk of unexpected inflation. Long-term treasuries normally offer higher yields to compensate investors for these risks. As a result, I used the yield on the 10-year Treasury Note because it mitigates the shortcomings of the 30-year Treasury Bond. Additionally, the Commission has historically agreed with I&E and recognized the 10-year Treasury Note as the superior measure of the risk-free rate of return.[10]

The forecasted yield on the 10-year Treasury Note, as seen in Blue Chip Financial Forecasts, is trending downward from 3.70% in the second quarter of 2023 to 3.40% in the second quarter of 2024, and it is forecasted to be an average of 3.60% for the five-year period from 2024 to 2028. For my CAPM analysis, I used 3.58%,

[10] *Pa. PUC v. UGI Utilities, Inc. – Electric Division,* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Capital Asset Pricing Model (CAPM), p. 99.

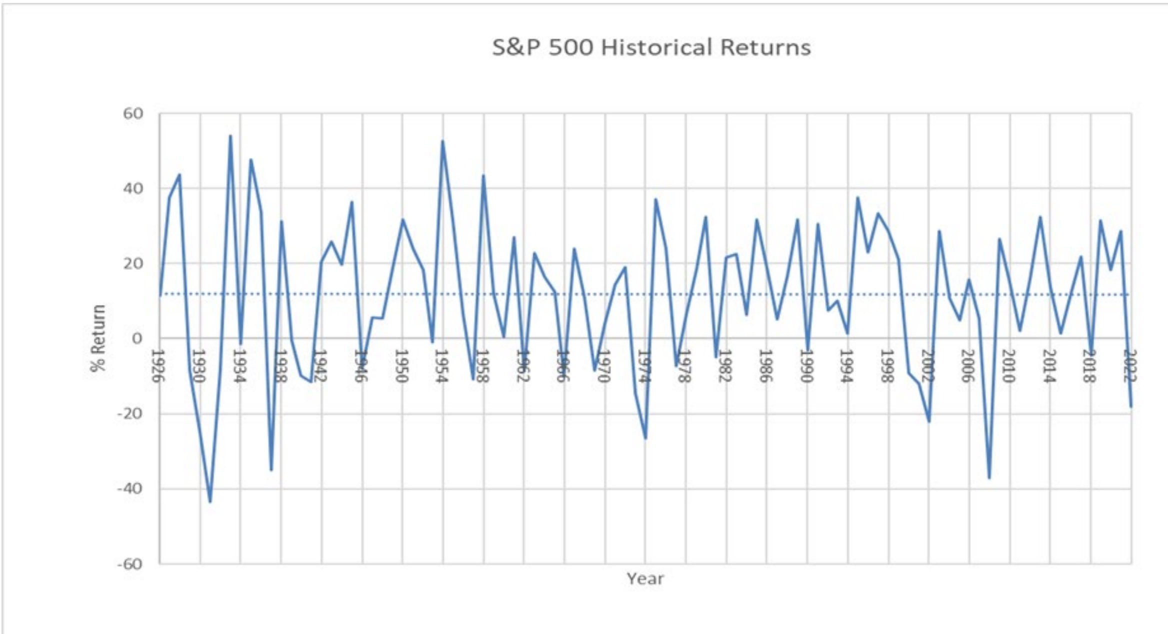
which is the average of all the yield forecasts I observed (I&E Exhibit No. 3, Schedule 8).

Q. HOW DID YOU DETERMINE THE ESTIMATED RETURN ON THE OVERALL STOCK MARKET EMPLOYED IN YOUR CAPM ANALYSIS?

A. To arrive at an estimated return on the overall stock market, I observed Value Line's approximately 1700 stocks and the historical returns of the S&P 500. Value Line expects its universe of approximately 1700 stocks to have an average yearly return of 13.68% over the next three to five years based on a forecasted dividend yield of 2.10% and a yearly index appreciation of 55% (I&E Exhibit No. 3, Schedule 9). The S&P 500 Index has an average return of 12.01% over the past 97 years (I&E Exhibit No. 3, Schedule 10). I have averaged these two figures, which results in an estimated or expected market return of 12.85% ((13.68% + 12.01%) ÷ 2) (I&E Exhibit No. 3, Schedule 9).

Q. DID I&E RECENTLY CHANGE ITS APPROACH TO ESTIMATE A RETURN ON THE OVERALL STOCK MARKET COMPARED TO PRIOR PROCEEDINGS?

A. Yes. In the most recent base rate proceeding of National Fuel Gas Distribution Corporation at Docket No. R-2022-3035730, I&E included S&P 500 historical returns for calculating the estimated overall market return for a few reasons. The sources historically employed, such as Yahoo! Finance and Morningstar, no longer offer projected growth rates for the S&P 500 to pair with projected dividend yields as they have in the recent past. Additionally, the trendline for the returns over the past 97 years has been relatively flat and stable as shown below.



Therefore, it is reasonable to utilize this data in calculating the expected overall market return. Notably, Mr. Moul similarly employs the historical S&P 500 returns in his CAPM analysis (UGI Electric Exhibit B, p. 25, Schedule 13, p. 2).

Q. WHAT IS THE COST OF EQUITY RESULT FROM YOUR CAPM ANALYSIS?

A. The result of my analysis is as follows (I&E Exhibit No. 3, Schedule 11):

K	**=**	**Rf**	**+**	**β(Rm – Rf)**
11.55%	=	3.58%	+	0.86 (12.85% - 3.58%)

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING YOUR CAPM ANALYSIS?

A. Yes. As discussed above, my recommended cost of equity is based upon my DCF analysis. I only present a CAPM analysis to the Commission as a comparison and not for recommendation purposes as the inputs are highly subjective, and other than beta, not company or industry specific.

Q. IS IT NECESSARY TO APPLY THE CAPM WITH SIMILAR WEIGHT TO THE DCF WHEN DETERMINING A SPECIFIC RETURN ON EQUITY DUE TO RECENT INFLATIONARY TRENDS?

A. No. My use of the DCF as a primary method already sufficiently considers inflationary trends in determining an appropriate return on equity. As mentioned above, the DCF includes a spot stock price in the dividend yield calculation and analysts who generate forecasted earnings growth almost certainly take inflation into consideration, so it contains the most up-to-date projected information of any model. In other words, the inputs of the DCF capture all known economic factors, including inflation.

Q. DID YOU QUANTIFY THE NUMBER OF BASIS POINTS BETWEEN YOUR DCF AND CAPM RESULTS TO ILLUSTRATE THE FINANCIAL IMPACT BETWEEN USING EACH MODEL?

A. Yes. The difference between my DCF and CAPM analysis is 279 basis points (CAPM result of 11.55% - DCF result of 8.76% = 2.79%). As demonstrated below, relying on the results of the CAPM is unnecessary and creates undue hardship for UGI Electric's ratepayers.

Q. BASED ON THE COMPANY'S AS-FILED RATE BASE AND CLAIMED CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 279 BASIS POINTS TO THE COST OF EQUITY BASED ON THE DIFFERENCE IN RESULTS BETWEEN YOUR CAPM ANALYSIS (11.55%) AND YOUR DCF ANALYSIS (8.76%)?

A. The example below illustrates the impact of 279 additional basis points to the Company's cost of equity if the results of my CAPM analysis, rather than my DCF results, were applied to the Company's total claimed rate base and capital structure.

UGI Electric's Claimed Equity Percentage of Capital Structure*	54.59%
Difference in Return on Equity between I&E's CAPM and DCF Analysis (11.55 – 8.76% = 2.79%)	2.79%
Claimed Rate Base**	$172,242,000
Impact Prior to Gross Up (0.5459 x 0.0279 x $172,242,000)	$2,623,351
Gross Revenue Conversion Factor***	1.513583
Total Impact to Ratepayers ($2,623,351 x 1.513583)	**$3,970,659**

*UGI Electric Exhibit A, Schedule B-7.
** UGI Electric Exhibit A, Schedule C-1.
*** UGI Electric Exhibit A, Schedule D-35.

In this example, an addition of 279 basis points (2.79%) to the cost of equity (if the CAPM result was used instead of the DCF result) would burden ratepayers to fund an additional amount of $3,970,659 annually to cover the increase of the inflated rate of return along with the associated impact resulting from increases to income taxes, gross receipts tax, and uncollectibles.

Q. DOES THE DEMONSTRATED FINANCIAL IMPACT THAT RATEPAYERS WOULD BEAR TO FUND AN ADDITIONAL $3,970,659 ANNUALLY DEMONSTRATE THAT IT IS INAPPROPRIATE TO USE THE CAPM TO ESTABLISH A "ZONE OF REASONABLENESS" IN THIS PROCEEDING?

A. Yes, in my opinion it is inappropriate to use the CAPM as the top end of a range as was done by the Commission in the recent Aqua rate proceeding to determine a return on equity. Contrary to the 279-basis point spread in this proceeding, as illustrated above, the spread between the DCF and the CAPM in the Aqua proceeding was more modest at 99 basis points.[11] In this proceeding, with a 279 basis-point impact, the burden would be far more onerous for ratepayers and would be unwarranted and inappropriate. In my opinion, and as demonstrated by my analysis, any amount granted above the DCF rate (8.76% based on my recommendation) places an inappropriate burden on ratepayers.

<u>CRITIQUE OF MR. MOUL'S PROPOSED COST OF EQUITY</u>

Q. DO YOU AGREE WITH MR. MOUL'S PROPOSED COST OF EQUITY?

A. No. I disagree with Mr. Moul's proposed cost of equity analysis for several reasons. First, I disagree with the weights given to the results of Mr. Moul's CAPM, RP, and

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[11] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 178 (Order entered May 16, 2022).

CE analyses in his recommendation. Second, I take issue with certain aspects of Mr. Moul's risk analysis of UGI Electric. Third, I disagree with his application of the DCF including the forecasted growth rate and leverage adjustment he uses. Fourth, I do not agree with his use of the 30-year Treasury Bond in place of the 10-year Treasury Note, his inclusion of a size adjustment, and use of an inflated beta in his CAPM analysis. Finally, I disagree with Mr. Moul's recommendation to include an adjustment to the cost of equity for recognition of management performance.

<u>WEIGHTS GIVEN TO THE CAPM, RP, AND CE METHODS</u>

Q. DO YOU AGREE WITH MR. MOUL'S RELIANCE ON THE CAPM, RP, AND CE MODELS?

A. No. I am not opposed to providing the Commission the results of the CAPM methodology for a point of comparison to the results of the DCF calculation. However, I am opposed to giving the CAPM, RP, and CE considerable weight. For the reasons previously discussed in this testimony, including my reference to recent Commission orders, it is inappropriate to give the RP model similar weight to the DCF as Mr. Moul has done in creating his recommended cost of equity by averaging DCF and RP results (UGI Electric Statement No. 9, p. 6, lines 13-15). As discussed above, the CAPM measures the cost of equity indirectly and can be manipulated by the time period chosen. Since the RP is a simplified version of the CAPM, it suffers these same flaws; therefore, consideration or affording equal weight to the RP result and DCF result produces an inappropriate inflated cost of equity. Additionally, Mr. Moul's response to I&E-RE-4-D(A) does not provide convincing support for averaging the RP and DCF results to determine the cost of equity in light of the same flaws as discussed earlier for the CAPM model (I&E Exhibit No. 3, Schedule 12).

Q. DO YOU AGREE WITH MR. MOUL'S USE OF THE CE METHOD?

A. No. The companies in Mr. Moul's analysis are not utilities; therefore, they are too dissimilar to be used in a CE analysis. The companies (non-regulated and non-utilities) in Mr. Moul's CE proxy group are simply not comparable to electric utilities in terms of diverse business segments and different types of business risk and financial risk profile (UGI Electric Exhibit B, pp. 27-28, Schedule 14, pp. 1-2). Electric distribution companies are monopolies that are subject to very little competition if any at all. Due to this minimal competition, regulated utilities in general have very low business risk and can maintain higher financial risk profiles by employing more leverage. Conversely, since the companies in Mr. Moul's CE proxy group (UGI Electric Exhibit B, pp. 27-28, Schedule 14, pp. 1-2) operate in an unregulated competitive environment with a higher level of business risk, they must maintain lower financial risk profiles by employing a smaller amount of leverage.

Further, in his CE analysis, Mr. Moul states, "I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach" (UGI Electric Statement No. 9, p. 42, lines 14-16). I do not believe this arbitrary use of 20% is justified, as I am unaware of any electric utility company that has been granted a Commission authorized return or regularly earns a 20% or greater return on equity.

<u>RISK ANALYSIS</u>

Q. PLEASE SUMMARIZE MR. MOUL'S CLAIMS REGARDING THE RISK FACTORS THE COMPANY FACES.

A. Mr. Moul describes the Company's claimed risk factors and his risk analysis in two sub-sections. In first sub-section labeled "Electric Utility Risk Factors," Mr. Moul discusses various electric business risks such as the potential for by-pass due to development of micro-turbines, commercialization of fuel cells, wind and solar power, and the creation of micro-grids resulting in decline in transmission and distribution revenues. He also briefly discusses replacement of aging infrastructure and the Company's construction program (UGI Electric Statement No. 9, pp. 7-9).

In second sub-section labeled "Fundamental Risk Analysis," he describes the *quantitative* risk factors. Mr. Moul discusses the Company's credit quality, as well as many different financial metrics including size, market ratios, common equity ratios, return on book equity, operating ratios, pre-tax interest coverage, quality of earnings, internally generated funds (IGF), and betas and how they are comparable for UGI Utilities (Gas and Electric Divisions combined) with his Electric Group and S&P Public Utilities (UGI Electric Statement No. 9, pp. 11-14).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S CLAIMED RISK OF BY-PASS FOR UGI ELECTRIC?

A. Mr. Moul discusses potential business by-pass risk in general and does not quantify potential revenue decline for UGI Electric due to by-pass risk. Most companies in the electric utility sector face similar or universal risks of competition with other suppliers. Mr. Moul concedes that all members/utilities of his electric group are subject to all these by-pass risks (I&E Exhibit No. 3, Schedule 13). In this regard, the companies within my proxy group provide a good measurement of the risk associated with competition from alternate suppliers.

Q. WHAT IS MR. MOUL'S CLAIM REGARDING ADDITIONAL RISK DUE TO THE COMPANY'S CONSTRUCTION PROGRAM?

A. Mr. Moul states that under LTIIP, the Company is investing substantial capital to maintain and upgrade existing facilities in its service territory and to meet growth. The Company expects to incur the total capital expenditures (transmission and distribution) of approximately $131.59 million over the next five years (2023-2027). Therefore, he believes that a reasonable return is a key to a financial profile that will allow for the attraction of capital on reasonable terms to fund these expenditures (UGI Electric Statement No. 9, p. 8, lines 15-18 and p. 9, lines 2-4).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S CLAIM REGARDING THE COMPANY'S CONSTRUCTION PROGRAM?

A. Every electric utility faces the same issues to maintain and upgrade its existing facilities in its service territory and to meet growth potential. As costs for upgrading or replacing facilities, UGI Electric, like any other regulated electric utility, has the option to file a base rate case at any time to address revenue inadequacy due to increasing costs, infrastructure upgradation/replacement program, or any other associated issues. Base rate cases allow a utility to recover its costs and provide it with the *opportunity* to earn a reasonable return on capital investments. Additionally, the Commission offers risk reducing mechanisms such as the DSIC and the FPFTY to reduce any regulatory lag in recovery of infrastructure investment or other unforeseen expenditures. It should be noted that these mechanisms were not designed to eliminate the need for periodic base rate case filings, but only to mitigate regulatory lag and support increasing infrastructure upgradation or replacement needs.

It is important to note that the proposed capital expenditures program of approximately $131.59 million over next five years (2023-2027) is not new for the Company because the Company has been regularly making capital expenditures and it has become normal business activity per the Company's historic actual capital expenditures ($110.38 million for 2018-2022) as shown in the table below (I&E Exhibit No. 3, Schedule 14, p. 2):

2018	$19.11 million
2019	$23.70 million
2020	$18.85 million
2021	$20.78 million
2022	$27.94 million
Total	**$110.38 million**

Q. ACCORDING TO MR. MOUL, WHAT ADDITIONAL FACTORS INFLUENCED HIS COST OF EQUITY ANALYSIS?

A. Mr. Moul states that his cost of equity analysis reflects the high levels of inflation, which have an impact on the level of economic activity, the cost of capital, particularly the interest cost of debt (UGI Electric Statement No. 9, p. 2, lines 16-19). He suggests that the Company faces increased risk of throughput due to inflation, pandemic-related supply disruptions, and consistent increases in interest rates (UGI Electric Statement No. 9, pp. 2-3).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S CLAIMS REGARDING THE VARIOUS ECONOMIC AND FINANCIAL RISKS HE MENTIONS?

A. The universal financial and economic risks referenced by Mr. Moul affect the entire electric utility industry; therefore, UGI Electric faces the same exposure to these issues as do all the other companies in our proxy groups. Investors voluntarily buy and hold stocks in electric utility companies, indicating they are aware of these risks and the returns, and the stock prices do reflect financial and economic risks utility companies are facing. My recommended cost of equity for UGI Electric is adequately measured by my proxy group and adequately compensates investors for these risks.

Q. PLEASE DISCUSS THE CLAIMS MR. MOUL MAKES REGARDING QUANTITATIVE RISK FACTORS IN THE SECTION HE LABELS "FUNDAMENTAL RISK ANALYSIS."

A. Mr. Moul states that it is necessary to establish a company's relative risk position within its industry through an analysis of quantitative and qualitative factors. In this section, Mr. Moul uses various financial metrics to compare UGI Utilities (Gas and Electric Divisions combined) to the S&P Public Utilities Index and his Electric Group (UGI Electric Statement No. 9, pp. 11-14).

Q. WHAT ARE YOUR COMMENTS REGARDING MR. MOUL'S "FUNDAMENTAL RISK ANALYSIS?"

A. Two of the points he examines, size risk and betas, are discussed and disputed elsewhere in my direct testimony. Throughout the remainder of his "fundamental risk analysis," Mr. Moul makes several statements to indicate that UGI Electric has no more of a risk than any other company in his Electric Group.

First, although UGI Electric is not individually rated by credit rating agencies, Mr. Moul notes that Moody's Investors Service (Moody's) offers a long-term issuer credit quality rating of A3 to UGI Utilities (Gas and Electric Divisions), which is same as the average A3 credit rating of his Electric Group and the S&P Public Utilities Index (UGI Electric Statement No. 9, p. 11, lines 3-6). This rating signifies medium-level investment grade with low credit risk. Additionally, S&P Global Ratings offers corporate credit ratings of BBB+ for the S&P Public Utilities Index. These ratings are categorized as investment grade and imply an adequate/strong capability to meet financial commitments. From this information, we can extrapolate that Mr. Moul's Electric Group, which is used to develop his return on equity recommendation, possesses low financial risk.

Second, while discussing common equity ratios, Mr. Moul notes that the five-year average common equity ratios, based on permanent capital based on book value, were 45.2% for the Electric Group and 41.0% for the S&P Public Utilities (UGI Electric Statement No. 9, p. 12, lines 13-15). These ratios are much lower than the 54.59% he is recommending for UGI Electric in this proceeding, which indicates lower financial risk. Additionally, Mr. Moul acknowledges that a firm with a higher common equity ratio has lower financial risk, while a firm with a lower common equity ratio has higher financial risk (UGI Electric Statement No. 9, p. 12, lines 11-13).

Third, pertaining to operating ratios, Mr. Moul affirms that the five-year average operating ratios were 77.5% for the UGI Utilities (Gas and Electric Divisions), 78.6% for the Electric Group, and 79.8% for the S&P Public Utilities (UGI Electric Statement No. 9, p. 13, lines 8-10). As Mr. Moul explains, the operating ratio (operating margin/measure of profitability) illustrates the percentage of revenues consumed by operating expenses, depreciation, and taxes. The higher the operating ratio is, the lower the operating margin and vice versa (UGI Electric Statement No. 9, p. 13, Footnote 3). As shown above, UGI Electric, the Electric Group, and the S&P Public Utilities Index all have comparable operating ratios indicating similar risk levels (UGI Electric Statement No. 9, p. 13, lines 9-10).

Fourth, regarding the interest coverage, he explains that excluding the Allowance for Funds Used During Construction, the five-year average pre-tax interest coverage was 4.89 times for UGI Utilities (Gas and Electric Divisions), 3.00 times for the Electric Group, and 2.97 times for the S&P Public Utilities. Mr. Moul acknowledges that "[t]he higher interest coverage for UGI Utilities (Gas and Electric Divisions) suggests lower credit risk, although its bond rating is similar to the other group" (UGI Electric Statement No. 9, p. 13, lines 17-19). He also states that higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness (UGI Electric Statement No. 9, p. 13, lines 13-15).

Fifth, related to quality of earnings, Mr. Moul concludes, "[q]uality of earnings has not been a significant concern for UGI Utilities (Gas and Electric Divisions) and the Electric Group (UGI Electric Statement No. 9, p. 13, lines 23-24).

Finally, Mr. Moul's provided data reflects that UGI Utilities (Gas and Electric Divisions) has a significantly higher level of internally generated funds (IGF) as compared to his Electric Group and the S&P Public Utilities, and he notes that IGF represent a key measure of credit strength. He reveals that the historical five-year average percentage of IGF to construction expenditures are 73.7%, 68.3%, and 66.0% for UGI Utilities (Gas and Electric Divisions), the Electric Group, and the S&P Public Utilities, respectively (UGI Electric Statement No. 9, p. 14, lines 3-6). Mr. Moul's own data for IGF indicates the superior credit strength for UGI Utilities (Gas and Electric Divisions).

Q. PLEASE CONTINUE.

A. Mr. Moul summarizes his fundamental risk analysis by stating that the investment risk of UGI Utilities (Gas and Electric Divisions) parallels that of the Electric Group in certain respects and UGI Utilities has lower risk as shown by its higher common equity and higher interest coverages, operating ratios, quality earnings, and its IGF to construction ratio indicates comparable risk to the Electric Group (UGI Electric Statement No. 9, p. 14, lines 17, 19-20). On balance, the cost of equity for the Electric Group would fairly represent the Company's cost of equity for this case (UGI Electric Statement No. 9, p. 15, lines 1-3). Overall, through his own analysis and testimony, Mr. Moul substantiates that the Company has a very similar risk as compared to that of his Electric Group; therefore, any additional consideration for the Company's risk profile is unnecessary and unfair.

COST OF EQUITY ADJUSTMENTS

INFLATED GROWTH RATES USED IN DCF ANALYSIS

Q. WHAT GROWTH RATE HAS MR. MOUL USED IN HIS DCF ANALYSIS?

A. Mr. Moul has chosen a growth rate of 6.00% (UGI Electric Exhibit B, p. 2, Schedule 1, p. 1).

Q. WHAT IS THE BASIS FOR MR. MOUL'S GROWTH RATE?

A. Mr. Moul indicates that Schedule 9 of his exhibit shows the prospective five-year earnings per share growth rates projected for the Electric Group to be 6.25% from IBES/First Call, 5.89% from Zacks, and 4.83% from Value Line (UGI Electric Exhibit B, p. 17, Schedule 9). Although the average of his sources for the growth rate is 5.66% ((6.25% + 5.89% + 4.83%) ÷ 3), Mr. Moul chooses to use a 6.00% growth rate claiming this growth rate is a reasonable estimate of investor-expected growth for the Electric Group because it falls within the 4.83% to 6.25% growth rate range. Additionally, he opines that DCF growth rates should not be established by mathematical formulation (UGI Electric Statement No. 9, p. 26, lines 18-20). He also opines that the reasonableness of his chosen growth rate is justified by investor-expected growth for the Electric Group and continuation of electric utility infrastructure spending (UGI Electric Statement No. 9, p. 26, lines 20-21 and lines 23-24).

Q. DO YOU AGREE WITH MR. MOUL'S GROWTH RATE ANALYSIS?

A. No. Contrary to Mr. Moul's belief that DCF growth rates *should not* be established by mathematical formulation, any alternative is subjective and introduces additional and unnecessary bias and should be avoided when possible. The use of a higher growth rate of 6.00% than the average growth rate of 5.66% of his proxy group ignores the fact that analysts making earnings per share growth forecasts are already aware of the economic conditions and the state of the electric utility industry. The reasons Mr. Moul has given for choosing a growth rate above the calculated average are factors that are already included in the earnings per share growth forecasts; thus, choosing a growth rate higher than the average of his proxy group would account for the same factors twice.

Mr. Moul concedes in his response to I&E-RR-10-D that "[t]he growth rates published by IBES/FirstCall, Zacks, and Value Line are assumed to consider all factors that they believe impact future growth, which for the members of the Electric Group would include growth associated with infrastructure spending" (I&E Exhibit No. 3, Schedule 15).

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING THE RESULTS OF MR. MOUL'S PROJECTED GROWTH RATES?

A. Yes. While the five-year projected growth rates can be used in analyses, one must be aware that analysts' estimates may be biased. This bias has been observed in literature. An article authored by Professors Ciciretti, Dwyer, and Hasan in 2009 observed strong support of earnings forecasts being higher than actual earnings.[12] In spring of 2010, McKinsey on Finance presented an article reporting that after a decade of stricter regulation analysts' forecasts are still overly optimistic.[13]

Analysts' estimates are an attempt to forecast future cash flows and thus expected earnings growth. However, it should be kept in mind that prudent judgment must be exercised as to the sustainability of forecasted growth rates with respect to the base earnings. If the base year earnings are abnormally high, the growth rates from which they are calculated will be biased downward. Similarly, if the base year earnings are abnormally low, the growth rates from which they are calculated will be biased upward. As a result, it is typically necessary to employ a methodology to smooth out the abnormally high or low base year earnings.

In summary, since analysts' projected growth forecasts are most often overly optimistic, there is no need to arbitrarily and non-formulaically increase the growth rate estimate by 0.44% (6.00% - 5.66%) over the average growth value as is done by Mr. Moul in his DCF analysis.

LEVERAGE ADJUSTMENT APPLIED TO DCF ANALYSIS

Q. HAS MR. MOUL MADE ANY ADDITIONAL ADJUSTMENTS TO THE RESULT OF HIS DCF ANALYSIS?

A. Yes. Mr. Moul proposes to make a 97-basis point (0.97%) "leverage" adjustment to

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[12] Ciciretti, Rocco; Dwyer, Gerald R; and Iftekhan Hasan. "Investment Analysts' Forecasts of Earnings" Federal Reserve Bank of St. Louis *Review*, September/October 2009, 91 (5, part 2) pp. 545-67.

[13] Goedhart, Marc J; Raj, Rishi; and Abhishek Saxena. "Equity analyst: Still too bullish" McKinsey on Finance Number 35 Spring 2010, pp. 14-17.

the results of his DCF analysis to account for applying a market-determined cost of equity to a book value capital structure (UGI Electric Exhibit B, p. 2, Schedule 1, p. 2)

Q. WHAT IS FINANCIAL LEVERAGE?

A. Financial leverage is the use of debt capital to supplement equity capital. A firm with significantly more debt than equity is considered highly leveraged.

Q. WHAT IS A MARKET-TO-BOOK (M/B) RATIO?

A. A market-to-book ratio is used to evaluate a public firm's equity value by comparing the market value and book value of a company's equity. One way of doing this is to divide the current price per share of stock by the book value per share. A M/B result of above one (1) is desired.

Q. HAS MR. MOUL PROPOSED TO ADJUST HIS CAPITAL STRUCTURE AND THE RESULT OF HIS DCF ANALYSIS TO RECOGNIZE HOW THE COMPANY IS LEVERAGED?

A. No. Mr. Moul does not propose to change the capital structure of the utility (a leverage adjustment), nor does he propose to apply the market-to-book ratio to the DCF model (a market-to-book adjustment). Instead, Mr. Moul proposes to make an adjustment to account for applying the market value cost rate of equity to the book value of the utility's capital structure. I am not aware of any term in academic journals, textbooks, or other literature that describes this type of adjustment.

Q. WHAT IS THE BASIS FOR MR. MOUL'S PROPOSED LEVERAGE ADJUSTMENT?

A. As stated above, Mr. Moul theorizes that in order to make the DCF results relevant to a book value capital structure, the market-derived cost of equity needs to be adjusted to account for this difference in financial risk (UGI Electric Statement No. 9, p. 27, lines 17-19). Mr. Moul opines that financial risk difference arises because a market-valued capitalization contains more equity and less debt than a book-value capitalization, and therefore, has less risk than the book-value capitalization (UGI Electric Statement No. 9, p. 27, lines 11-14).

Q. HOW DOES MR. MOUL CALCULATE THE LEVERAGE ADJUSTMENT USED IN HIS DCF ANAYSIS?

A. Mr. Moul simply states,

> I know of no means to mathematically solve for the 0.97% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.97% adjustment is merely a convenient way to compare the 10.45% return computed using the Modigliani & Miller formulas to the 9.48% return generated by the DCF model based on a market-value capital structure (UGI Electric Statement No. 9, p. 30, lines 11-16).

Q. DO YOU AGREE WITH MR. MOUL'S "LEVERAGE ADJUSTMENT"?

A. No. Mr. Moul's adjustment is inappropriate for a couple of reasons, including the characterization of financial risk difference and its inconsistency with the Commission precedent.

Q. EXPLAIN HOW RATING AGENCIES ASSESS FINANCIAL RISK.

A. Rating agencies assess financial risk based on a company's booked debt obligations and the ability of its cash flow to cover the interest payments on those obligations. The agencies use a company's financial statements for their analysis, not the market value of capital structure. The income statement reflects the financial risk of a company because it represents the performance of the company over a certain period. A change in the market value of the stock is not reflected in the income statement nor is a change in market value capital structure reflected in the book value capital structure unless treasury stock is purchased. It is a company's financial statements that affect the market value of the stock, and therefore, the financial statements and the book value capital structure are relied upon in an analysis such as that followed by rating agencies.

Q. DO YOU BELIEVE MR. MOUL'S CHARACTERIZATION OF FINANCIAL RISK DIFFERENCE SUPPORTS HIS LEVERAGE ADJUSTMENT IN THE DCF RESULT FOR THE BOOK VALUE OF STOCK USED IN THE CAPITALIZATION RATIO INSTEAD OF MARKET VALUE OF STOCK?

A. No. The market capitalization of equity stock can go up and down depending on the current stock price which can be tied to investor sentiment/emotions and may not be an accurate representation of a company's actual capital structure which changes only when financing actions are taken. Wild swings in stock price immediately impact the market value capitalization, but not the Company's book value.

Market capitalization refers to how much a company is worth as determined by the stock market, which is a quick and easy method for estimating a company's value by extrapolating what the market thinks it is worth for publicly traded companies. Market capitalization does not measure the true equity value of a company. Only a thorough analysis of a company's fundamentals can provide a true value of a company. It is inadequate to value a company in this way because the market price on which it is based does not necessarily reflect how much a piece of the business is worth. Stocks are often over or undervalued by the market, meaning the market price determines only how much the market is willing to pay for its stocks.

Most importantly, as discussed in the capital structure section, the Company is benefitting from a much more equity heavy capital structure than most of its peers. Mr. Moul concedes that a firm with a higher common equity ratio has lower financial risk, while a firm with a lower common equity ratio has higher financial risk (UGI Electric Statement No. 9, p. 12, lines 11-13). As a result of the equity heavy capital structure, the Company and shareholders ultimately benefit greatly in revenue from customers and the correspondingly higher rate of return. Therefore, Mr. Moul’s 97-basis point (0.97%) leverage adjustment to his DCF result (9.48% + 0.97% = 10.45%) based on financial risk difference due to market-to-book capitalization ratio (metric) is inappropriate and unsupported, causing an inflated return on equity and overall rate of return.

Q. WHAT ARE THE MOST RECENT COMMISSION DECISIONS REGARDING A LEVERAGE ADJUSTMENT?

A. The following cases are the most recent instances where the Commission has addressed the use of a "leverage adjustment." In these cases, this adjustment has been rejected.

First, in *Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.*, at Docket No. R-00072711 (Order Entered July 31, 2008), pp. 38-39, the Commission rejected the ALJ's recommendation for a leverage adjustment stating, "[t]he fact that we have granted leverage adjustments in the past does not mean that such adjustments are indicated in all cases." In this proceeding, the Commission determined that there was no viable support for an upwards adjustment to compensate for any perceived risk.

Second, in *Pennsylvania Public Utility Commission, et al v. City of Lancaster – Bureau of Water*, at Docket No. R-2010-2179103 (Order Entered July 14, 2011), p. 101, the Commission agreed with the I&E position and stated, "any adjustment to the results of the market based DCF are unnecessary and will harm ratepayers. Consistent with our determination in *Aqua 2008* there is no need to add a leverage adjustment. . ."

Third, in *Pennsylvania Public Utility Commission, et al v. UGI Utilities, Inc. – Electric Division*, at Docket No. R-2017-2640058 (Order Entered October 25, 2018), pp. 93-94, the Commission agreed with the I&E position and stated, "we conclude that an artificial adjustment in this proceeding is unnecessary and contrary to the public interest. Accordingly, we decline to include a leverage adjustment in our calculation of the DCF cost of equity."

Fourth, in *Pennsylvania Public Utility Commission, et. al v. Columbia Gas of Pennsylvania, Inc*., at Docket R-2020-3018835 (Order Entered February 19, 2021), pp. 137-141, the Commission adopted the ALJ's recommendation to use I&E's DCF methodology, which excluded Columbia's application of a leverage adjustment.

Fifth, in *Pennsylvania Public Utility Commission, et. al v. PECO Energy Company – Gas Division*, at Docket R-2020-3018929 (Order Entered June 22, 2021, Public Version), pp. 172-173, the Commission adopted the ALJ's recommendation to use I&E's DCF methodology, which excluded PECO's application of a leverage adjustment.

Finally, in the most recent case of *Pennsylvania Public Utility Commission, et. al v. Aqua Pennsylvania, Inc.*, at Docket R-2021-3027385 (Order Entered June 22, 2021), pp. 154-155, the Commission adopted the ALJ's recommendation to use I&E's DCF methodology, which excluded Aqua's application of a leverage adjustment.

Q. BASED ON THE COMPANY'S AS-FILED RATE BASE AND CLAIMED CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 97 BASIS POINTS FOR MR. MOUL'S LEVERAGE ADJUSTMENT TO THE COST OF EQUITY?

A. The example below illustrates the impact of 97 additional basis points for the leverage adjustment to the Company's cost of equity in DCF analysis.

UGI Electric's Claimed Equity Percentage of Capital Structure*	54.59%
Additional Basis Points to the Calculated Cost of Equity for a "Leverage Adjustment"	0.97%
Claimed Rate Base**	$172,242,000
Impact Prior to Gross Up (0.5459 x 0.0097 x $172,242,000)	$912,061
Gross Revenue Conversion Factor***	1.513583
Total Impact to Ratepayers ($912,061 x 1.513583)	**$1,380,480**

*UGI Electric Exhibit A, Schedule B-7.
** UGI Electric Exhibit A, Schedule C-1.
*** UGI Electric Exhibit A, Schedule D-35.

In this example, an addition of 97 basis points for the leverage adjustment to the cost of equity would force ratepayers to fund an unwarranted additional amount of $1,380,480 annually to cover the increase of the inflated rate of return along with the associated impact resulting from increases to income taxes, gross receipts tax, and uncollectibles.

Q. SUMMARIZE YOUR RECOMMENDATION REGARDING THE PROPOSED LEVERAGE ADJUSTMENT.

A. I recommend that Mr. Moul's proposed 97-basis point leverage (0.97%) adjustment applied to his DCF analysis be rejected because the true financial risk is a function of the amount of interest expense and capital structure information provided to investors through Value Line is that of book values and not market values. This demonstrates that investors base their decisions on book value debt and equity ratios for regulated utilities; therefore, no adjustment is needed. Mr. Moul's proposed adjustment serves only to manipulate the DCF's market-based methodology and causes undue harm to ratepayers as illustrated above.

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING MR. MOUL'S DCF CALCULATION?

A. Yes. While I am not directly disputing Mr. Moul's adjusted historic six-month average dividend yield, it is important to recognize that, as cited above, the Commission has recently agreed with I&E's DCF methodology which includes the appropriate calculation of dividend yields. Although it is acceptable to adjust historical dividend yields as Mr. Moul has done, it is preferable to use forecasted dividends to calculate the dividend yields when available, such as the ones offered by Value Line that I have employed.

Q. WHAT WOULD MR. MOUL'S DCF RESULT BE WITHOUT ANY ADJUSTMENTS?

A. Without Mr. Moul's use of inflated growth rate of 6.00% and a leverage adjustment of 0.97%, his DCF would consist of an adjusted dividend yield of 3.48% (UGI Electric Exhibit B, p. 15, Schedule 7) and an average growth rate of 5.66% ((6.25% + 5.89% +4.83%) ÷ 3) (UGI Electric Exhibit B, p. 17, Schedule 9), which results in a 9.14% (3.48% + 5.66%) cost of equity. This result is higher than my DCF result of 8.76% (I&E Exhibit No. 3, Schedule 4), however, it is closer than his originally calculated and inappropriately inflated result of 10.45% (3.48% + 6.00% + 0.97%) (UGI Electric Exhibit B, p. 2, Schedule 1, p. 2).

RISK-FREE RATE OF RETURN

Q. HOW HAS MR. MOUL CALCULATED HIS RISK-FREE RATE FOR USE IN HIS CAPM MODEL?

A. Mr. Moul's calculation of his risk-free rate is similar to mine. He considers Treasury yield estimates published by Blue Chip Financial Forecasts over the next six quarters, from the time of his analysis, as well as long-range, five-year averages. However, he uses the 30-year Treasury Bond while I employ the 10-year Treasury Note. I use a long-range, five-year average, future data point accounting for years 2024-2028 predictions and Mr. Moul uses two future data points accounting for not only years 2023-2027, but he also includes an estimate for years 2028-2032. His analysis results in a 4.00% risk-free rate (UGI Electric Statement No. 9, p. 38, lines 3-12 and UGI Electric Exhibit B, p. 25, Schedule 13, p. 2), which is higher than my calculated average risk-free rate of 3.58% (I&E Exhibit No. 3, Schedule 8).

Q. WHAT COMMENTS DO YOU HAVE REGARDING MR. MOUL'S CALCULATION OF THE RISK-FREE RATE?

A. I disagree with Mr. Moul's method and inputs to determine the risk-free rate. I must reiterate my earlier statements that long-term 30-year Treasury Bonds have substantial maturity risk associated with the market risk and the risk of unexpected inflation and normally offer higher yields to compensate investors for these risks. Using the 10-year Treasury Note is more appropriate to balance the short-term volatility risk and the long-term inflation risk.

The Commission has recognized the 10-year Treasury Note as the superior measure for the risk-free rate by stating the following,[14]

> We agree with I&E and the ALJs that using the yield on the 10-year Treasury Note provides a better measure of the risk-free rate of return than using the yield on the 30-year Treasury Bond, as recommended by UGI. In our view, using the 10-year Treasury Note balances the shortcomings of the short-term T-Bill and the 30-year Treasury Bond. Although long-term Treasury Bonds have less risk of being influenced by federal policies, they have substantial maturity risk associated with the market risk. In addition, long-term Treasury Bonds bear the risk of unexpected inflation.

Additionally, the further out into the future one projects, the less reliable the information becomes. Providing the projection for 2028-2032 is an unreliable measure and this should not be included in determining the risk-free rate. The Company's FPFTY will end on September 30, 2024, and, in my opinion, comparing an estimated risk-free rate that is up to eight years beyond the FPFTY is unreasonable and unnecessary.

<u>INFLATED BETAS USED IN CAPM ANALYSIS</u>

Q. HOW HAS MR. MOUL INFLATED THE BETAS EMPLOYED IN HIS CAPM ANALYSIS?

A. Mr. Moul uses the same logic for inflating his CAPM value line betas of his Electric Group average beta of 0.88 to 1.08 that he uses to enhance his CAPM returns, through

[14] *Pa. PUC v. UGI Utilities, Inc. – Electric Division,* Docket No. R-2017-2640058 (Order entered October 25, 2018), p. 99 (Disposition of Capital Asset Pricing Model (CAPM)).

a financial risk or "leverage" adjustment (UGI Electric Statement No. 9, p. 36, lines 2-21 and UGI Electric Exhibit B, p. 18, Schedule 10).

Q. DO YOU AGREE WITH MR. MOUL'S USE OF ADJUSTED OR LEVERAGED BETAS?

A. No. Such enhancements are unwarranted for beta in a CAPM analysis for the same reasons that the "leverage" adjustment is unwarranted for DCF results as discussed earlier.

Additionally, if the unadjusted *Value Line* betas do not reflect an accurate investment risk as Mr. Moul contends, the question naturally arises as to why *Value Line* does not publish betas that are adjusted for leverage. Until this type of adjustment is demonstrated in the academic literature to be valid, such leverage adjusted betas in a CAPM model should be rejected.

Finally, as described in my CAPM analysis above, a stock with a price movement that is greater than the overall stock market will have a beta that is greater than one and would be described as having more investment risk than the market. Due to being regulated and the monopolistic nature of utilities, very rarely do they have a beta equal to or greater than one. Therefore, in this case, to apply an adjusted beta of 1.08 to the entire industry or electric proxy group is irrational and unsupported.

SIZE ADJUSTMENT APPLIED TO CAPM ANALYSIS

Q. PLEASE EXPLAIN MR. MOUL'S PROPOSED SIZE ADJUSTMENT IN CAPM ANALYSIS.

A. Mr. Moul adds 102 basis points to his CAPM indicated cost of common equity because he believes that as the size of a firm decreases, its risk and required return increases. Mr. Moul relies upon technical literature including a Fama and French study entitled "The Cross-Section of Expected Stock Returns," an article published in Public Utilities Fortnightly entitled "Equity and the Small-Stock Effect," and the Stocks, Bonds, Bills, and Inflation Yearbook (UGI Electric Statement No. 9, p. 39, lines 5-18 and UGI Electric Exhibit B, p. 26, Schedule 13, p. 3).

Q. DO YOU AGREE WITH MR. MOUL'S SIZE ADJUSTMENT?

A. No. Mr. Moul's proposed size adjustment is unnecessary because the technical literature he cites supporting investment adjustments relating to the size of a company is not specific to the utility industry and, therefore, has no relevance in this proceeding.

Q. IS THERE ACADEMIC EVIDENCE THAT SUPPORTS YOUR CONCLUSION THAT THE SIZE ADJUSTMENT FOR RISK IS NOT APPLICABLE TO UTILITY COMPANIES?

A. Yes. In the article "Utility Stocks and the Size Effect: An Empirical Analysis," Dr. Annie Wong concludes,

> The objective of this study is to examine if the size effect exists in the utility industry. After controlling for equity values, there is some weak evidence that firm size is a missing factor from the CAPM for the industrial but not for utility stocks. This implies that although the size phenomenon has been strongly documented for the industrials, the findings suggest that there is no need to adjust for the firm size in utility rate regulation.[15]

UGI Electric presents no evidence to support application of a non-utility study regarding a size adjustment for risk to a utility setting. Absent any credible article to refute Dr. Wong's findings, Mr. Moul's size adjustment to his CAPM results should be rejected.

Additionally, the Commission has rejected the application of a size adjustment to the CAPM cost of equity calculation in UGI Electric's 2017 base rate case, where the Commission agreed that the same literature the Company cites is not specific to the utility industry.[16]

Q. BASED ON THE COMPANY'S CLAIMED RATE BASE AND CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 102 BASIS POINTS FOR MR. MOUL'S SIZE ADJUSTMENT TO THE COST OF EQUITY?

A. The example below illustrates the impact of 102 additional basis points (1.02%) for

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15 Dr. Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis," *Journal of Midwest Finance Association* 1993, pp. 95-101.

16 *Pa. PUC v. UGI Utilities, Inc. – Electric Division,* Docket No. R-2017-2640058 (Order Entered October 25, 2018), p. 100 (Disposition of Cost of Common Equity).

the size adjustment to the Company's cost of equity in CAPM analysis:

UGI Electric's Claimed Equity Percentage of Capital Structure*	54.59%
Additional Basis Points to the Calculated Cost of Equity for a "Size Adjustment"	1.02%
Claimed Rate Base**	$172,242,000
Impact Prior to Gross Up (0.5459 x 0.0102 x $172,242,000)	$959,074
Gross Revenue Conversion Factor***	1.513583
Total Impact to Ratepayers ($959,074 x 1.513583)	**$1,451,638**

*UGI Electric Exhibit A, Schedule B-7.
** UGI Electric Exhibit A, Schedule C-1.
*** UGI Electric Exhibit A, Schedule D-35.

In this example, an addition of 102 basis points for the size adjustment to the cost of equity would force ratepayers to fund an unwarranted additional amount of $1,451,638 annually to cover the increase of the overstated rate of return along with the associated impact resulting from increases to income taxes, gross receipts tax, and uncollectibles.

Q. WHAT WOULD MR. MOUL'S CAPM RESULT BE WITHOUT HIS SIZE ADJUSTMENT AND INFLATED BETAS?

A. Mr. Moul's CAPM result would be 12.91%. This is 304 basis points (3.04%) lower than his originally calculated 15.95% result (UGI Electric Exhibit B, p. 2, Schedule 1, p. 2) and 136 basis points higher than my CAPM result of 11.55% (I&E Exhibit No. 3, Schedule 11). The calculation is repeated below without Mr. Moul's unnecessary adjustments in beta and size adjustment:

Rf	**+**	***β***	**x**	***(Rm – Rf)***	**+**	***Size***	**=**	***k***
4.00%	+	0.88	x	10.12%	+	0%	=	**12.91%**

MANAGEMENT PERFORMANCE

Q. DISCUSS THE COMPANY'S CLAIMS SPECIFIC TO MANAGEMENT PERFORMANCE.

A. Mr. Moul proposes that 20 basis points (0.20%) be added to his calculated/recommended cost of equity of 11.10% in recognition of the Company's strong management performance, which results in the recommended cost of equity of 11.30% (UGI Electric Statement No. 9, p. 1, lines 19-21). He primarily relies upon the direct testimony of Company witness Christopher R. Brown, VP and General Manager of Rates and Supply (UGI Electric Statement No. 1) to support the consideration of additional basis points for UGI Electric's management performance (UGI Electric Statement No. 9, p. 2, lines 9-14).

Q. WHAT INFORMATION DOES MR. BROWN PROVIDE TO SUPPORT THE COMPANY'S CLAIM OF STRONG MANAGEMENT PERFORMANCE?

A. Mr. Brown claims that UGI Electric has exhibited exceptional management performance demonstrated by its efforts which include the Company's High Standards for Electric Reliability, Consistent Performance on Long-Term Infrastructure Improvement Targets, Energy Efficiency and Conservation Plan, Enhanced Customer-Service Offerings and Continued Information Technology System Replacements, Safety Focus, and Community Support (UGI Electric Statement No. 1, pp. 12-16). He reasons that the above-described initiatives, as well as the operating factors demonstrate the role of exceptional management performance in UGI Electric's commitment to, and focus on, providing safe, reliable, and quality distribution service to its customers (UGI Electric Statement No. 1, p. 16, lines 5-8).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIMS REGARDING MANAGEMENT PERFORMANCE?

A. No. First, many of the topics presented by the Company witnesses fall within the categories of reliability, customer satisfaction, and safety that are required of every public utility company under 66 Pa C.S.A. §1501, and the program successes he cites are almost entirely directly funded by ratepayers. Additionally, the Company passes capital expenditures related to infrastructure improvements onto ratepayers via base rates, or it can utilize a DSIC for capital expenditure recovery. Second, there is no set criteria or measurement for claiming exemplary/superior management performance for a utility company that makes it eligible for an additional basis-point adder in the cost of equity claim. Lastly, if the Company is effective at controlling operating and maintenance expenses due to prudent operation management policy, then those savings should flow through to ratepayers and/or investors. These savings would likely be offset by the addition of basis points for management performance as ratepayers would have to fund the additional costs. This defeats the purpose of any cost cutting measures to benefit ratepayers.

Q. ARE YOU AWARE OF ANY COMPANIES THAT HAVE RECENTLY RECEIVED ADDITIONAL BASIS POINTS IN RECOGNITION OF MANAGEMENT PERFORMANCE?

A. Yes. Most recently, the Commission awarded Aqua an addition of 25 basis points (0.25%) for its management performance efforts.[17] However, it is important to recognize that this addition was based specifically on Aqua rescuing troubled water and wastewater systems at the Commission's request. The Commission stated:[18]

> We specifically recognize Aqua's efforts and willingness to quickly provide emergency aid to various water and wastewater systems that needed substantial improvement. Aqua has often provided this emergency aid on short notice and at the request of the Commission or other parties to protect the public from egregious health and safety threats and to protect the Commonwealth's drinking water resources from catastrophic damage.

Q. DOES THE COMMISSION'S PAST ISSUANCE OF ADDITIONAL EQUITY POINTS TO RECOGNIZE MANAGEMENT PERFORMANCE MEAN THAT UGI ELECTRIC SHOULD ALSO RECEIVE AN ADJUSTED RETURN ON EQUITY?

A. No. The award of additional basis points in equity return to recognize management performance should be done on a case-by-case basis. The situation in the Aqua proceeding, as discussed, above was very specific to Aqua rescuing troubled water

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17 *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 168-173 (Order entered May 16, 2022).

18 *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, p. 169 (Order entered May 16, 2022).

and wastewater systems and preventing health and safety concerns regarding drinking water. This scenario does not apply to UGI Electric.

Q. BASED ON THE COMPANY'S FILED RATE BASE AND CLAIMED CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 20 BASIS POINTS FOR THE CONSIDERATION OF MANAGEMENT PERFORMANCE TO THE COST OF EQUITY?

A. The example below illustrates the impact of 20 additional basis points (0.20%) for the consideration of management performance to the Company's claimed cost of equity:

UGI Electric's Claimed Equity Percentage of Capital Structure*	54.59%
Additional Basis Points to the Calculated Cost of Equity for a "Management Performance Adjustment"	0.20%
Claimed Rate Base**	$172,242,000
Impact Prior to Gross Up (0.5459 x 0.0020 x $172,242,000)	$188,054
Gross Revenue Conversion Factor***	1.513583
Total Impact to Ratepayers ($188,054 x 1.513583)	**$284,635**

*UGI Electric Exhibit A, Schedule B-7.
** UGI Electric Exhibit A, Schedule C-1.
*** UGI Electric Exhibit A, Schedule D-35.

In this example, an addition of 20 basis points to the cost of equity in consideration of management performance would force ratepayers to fund an unwarranted additional amount of $284,635 annually to cover the increase of the inflated rate of return along with the associated impact resulting from increases to income taxes, gross receipts tax, and uncollectibles.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE CONSIDERATION OF ADDITIONAL BASIS POINTS FOR THE COMPANY'S MANAGEMENT PERFORMANCE?

A. Ultimately, as alluded to above, true strong management performance is earning a higher return through efficient use of resources and cost cutting measures. The greater net income resulting from cost savings and true efficiency in management and operations should be passed on to both ratepayers and shareholders. I do not believe UGI Electric, or any utility, should be gifted additional basis points for doing what is required to provide adequate, efficient, safe, and reliable utility service under 66 Pa C.S.A. §1501, nor should it claim basis points for programs such as its energy efficiency and conservation program that are entirely funded by ratepayers.

For these reasons, I recommend that any addition of basis points to the cost of equity for management performance be disallowed.

<u>OVERALL RATE OF RETURN RECOMMENDATION</u>

Q. WHAT IS THE COMPANY'S PROPOSED COSTS OF DEBT AND EQUITY, AND OVERALL RATE OF RETURN?

A. The Company recommends costs of debt and equity of 4.35% and 11.30% respectively and an overall weighted rate of return of 8.15% (UGI Electric Exhibit B, p. 1, Schedule 1, p. 1).

Q. WHAT IS I&E'S RECOMMENDED COSTS OF DEBT AND EQUITY, AND OVERALL RATE OF RETURN?

A. I&E Exhibit No. 3, Schedule 1, summarizes appropriate costs of debt and equity of

4.35% and 8.76% respectively with an overall weighted rate of return for UGI Electric of 6.76%.

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING THE COMPANY'S PROPOSED RETURN ON EQUITY?

A. Yes. First, a report issued by Regulatory Research Associates, a group within S&P Global Market Intelligence,[19] illustrates that UGI Electric's 11.30% requested return on equity is a significant 176 basis points (1.76%) higher than the average return on equity of 9.54% of all electric utility rate cases decided by the utility Commissions/Boards throughout the United States in 2022. It is also important to note here that Pennsylvania is a deregulated state, which would indicate less risk.

Second, when asked, Mr. Moul indicates that he was unaware if any electric distribution utilities throughout the United States were granted a Commission authorized return of 11.30% or higher cost of common equity in the past two years (I&E Exhibit No. 3, Schedule 16).

Third, the Company's requested return on common equity is 185 basis points (1.85%) higher than the Commission's approved DSIC rate of 9.45% (Q3- 2022 Quarterly Earnings Summary Report)[20] for electric distribution companies. The DSIC rate is designed to encourage its use and to incentivize accelerated infrastructure improvements/upgrades to bring the existing aging infrastructure closer

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[19] Regulatory Research Associates, "Major Energy Rate Case Decision in the US – January-December 2022," *S&P Global Market Intelligence*, RRA Regulatory Focus - February 2023, p. 3.

[20] Pa PUC Report on the Quarterly Earnings of Jurisdictional Utilities – September 30, 2022, at Docket No. M-2022-3037661 approved at the public meeting held on February 9, 2023, p. 15.

to meeting safety and reliability requirements in between base rate filings. Additionally, the DSIC rate establishes a benchmark above which a utility company is considered "overearning." As such, the DSIC rate does not serve as a proper measurement of a subject utility's cost of equity in a rate case proceeding. To suggest the cost of equity must be at or in this case, drastically above the DSIC rate in this base rate proceeding is inappropriate and not in the public interest.

Finally, while I am aware of the rising costs of capital due to the after-effects of the pandemic and the increased levels of inflation, I believe it is important not to overburden ratepayers. While the economy is in decline, UGI Electric is requesting a record return on equity to apply to its equity heavy capital structure and expanding rate base. As detailed in the various charts above, the effect of Mr. Moul's adjustments to the market-determined cost of common equity are an enormous burden to ratepayers and are completely unwarranted and unnecessary. Although they are not cumulative, the dollar impact to ratepayers for each of the disputed adjustments is summarized below:

Leverage Adjustment	$1,380,480
Size Adjustment	$1,451,638
Management Performance	$284,635

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

D.C. PATEL

PROFESSIONAL EXPERIENCE AND EDUCATION

EXPERIENCE:

- Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania
  June 2015 to present.
  Fixed Utility Financial Analyst, Bureau of Investigation and Enforcement
- Pennsylvania Insurance Department, Harrisburg, Pennsylvania
  March 2013 - June 2015
  Insurance Company Financial Analyst, Bureau of Company Licensing & Financial Analysis
- Pennsylvania Department of Revenue, Harrisburg, Pennsylvania
  November 2010 - March 2013
  Accounting Assistant, Bureau of Corporation Taxes (Accounting)
- Hersha Hospitality Management, Harrisburg, Pennsylvania
  June 2007 - November 2010
  Staff Accountant (Taxes), Accounting Department
- Corporate Experience-India
  February 1987 - April 2007
  Worked as Company Secretary for three different companies during this period, which were listed on the Stock Exchanges.

EDUCATION/CERTIFICATION:

- Gujarat State University, Ahmedabad, India:
  - Bachelor of Commerce (Major concentration: Accounting)
    June 1980 - April 1983
  - Bachelor of Law
    June 1983 - December 1988
- The Institute of Company Secretaries of India, New Delhi, India:
  - Post Graduate Professional Degree: Company Secretary
    June 1983 - December 1985

RATE CASE TRAINING:

- Attended 37th Western NARUC Utility Rate School in May 2016

WORKED ON THE FOLLOWING CASES (Testimony not required):

- R-2022-3032167 - Columbia Gas of Pennsylvania, Inc. (Green Path Rider)
- R-2022-3031172 - Columbia Gas of Pennsylvania, Inc. (1307(f))
- M-2018-2640802 and 2640803 - Pittsburgh Water and Sewer Authority (Compliance Plan Stage 2)
- R-2021-3024349 - Columbia Gas of Pennsylvania, Inc. (1307(f))
- M-2018-2640802 and 2640803 - Pittsburgh Water and Sewer Authority (Compliance Plan Stage 2)
- R-2021-3023541 - National Fuel Gas Distribution Corporation (§ 1307(f))
- A-2020-3020178 - PA American Water Co.-Valley Township-Wastewater (1329)
- A-2020-3019859 - PA American Water Co.-Valley Township-Water (1329)
- A-2020-3021460 - PA American Water Co.-Upper Pottsgrove-Wastewater (1329)
- U-2020-3015258 - Pittsburgh Water and Sewer Authority
- R-2020-3019661 - PECO Energy Co. - Gas Operations (1307(f))
- R-2019-3008255 - Columbia Gas of Pennsylvania, Inc. (1307(f))
- R-2018-3001568 - PECO Energy Co. - Gas Operations (1307(f))
- R-2018-3000253 - Columbia Gas of Pennsylvania, Inc. (1307(f))
- A-2017-2629534 - PPL Electric Utilities (Restructuring Plan)
- R-2017-2631441 - Reynolds Water Co.
- R-2017-2602611 - PECO Energy Co. - Gas Operations (1307(f))
- R-2016-2567893 - Andreassi Gas Co.
- R-2016-2525128 - Columbia Water Co. - Marietta Division
- R-2015-2479962 - Corner Water Supply and Service Corporation
- R-2015-2479955 - Allied Utility Services, Inc.
- R-2015-2493905 - Sands, Inc.

SUBMITTED TESTIMONY IN THE FOLLOWING CASES:

- A-2022-3034143 Aqua Pennsylvania, Inc. - Borough of Shenandoah (Water System) (1329)
- R-2022-3031672 and R-2022-3031673 - PA American Water Co.
- R-2022-3031211 - Columbia Gas of Pennsylvania, Inc.
- A-2021-3024681 - PA American Water Co. - York City Sewer Authority/City of York Wastewater (1329)
- A-2021-3024267 - Aqua Pennsylvania Wastewater, Inc. - Lower Makefield (WW) (1329)
- R-2021-3024601 - PECO Energy Co. - Electric Operations
- R-2021-3024773 et al. - Pittsburgh Water and Sewer Authority
- M-2018-2640802 and M-2018-2640803 - Pittsburgh Water and Sewer Authority (Compliance Plan – II)
- A-2020-3019634 - PA American Water Co. - Royersford Wastewater (1329)
- R-2020-3018921 - PECO Energy Co. - Gas Operations
- R-2020-3017951 et al. - Pittsburgh Water and Sewer Authority
- R-2020-3018993 - Columbia Gas Pennsylvania, Inc. (1307(f))
- R-2019-3008208 - Wellsboro Electric Company
- R-2019-3008212 - Citizens Electric Company of Lewisburg, PA

- A-2019-3008491 - Aqua Pennsylvania Wastewater, Inc.
- R-2018-3006814 - UGI Utilities, Inc. (Gas Division)
- M-2018-2640802 and 2640803 - Pittsburgh Water and Sewer Authority
- R-2018-3002645 and 3002647 - Pittsburgh Water and Sewer Authority
- R-2018-3000834 - Suez Water Pennsylvania, Inc.
- R-2018-2647577 - Columbia Gas of Pennsylvania, Inc.
- R-2017-2595853 - Pennsylvania American Water Co.
- P-2016-2526627 - PPL Electric Utilities Corp. (DSP IV)
- R-2016-2529660 - Columbia Gas of Pennsylvania, Inc.
- R-2016-2554150 - City of DuBois - Bureau of Water
- R-2016-2580030 - UGI Penn Natural Gas, Inc.

I&E Exhibit No. 3
Witness: D. C. Patel

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI Utilities, Inc. - Electric Division

Docket No. R-2022-3037368

Exhibit to Accompany

the

Direct Testimony

of

D. C. Patel

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

I&E Exhibit No. 3
Schedule 1

I&E
Summary of Cost of Capital

Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost**
UGI Utilities Inc. - Electric Division			
Long-Term Debt	45.41%	4.35%	1.98%
Common Equity	54.59%	8.76%	4.78%
Total	100.00%		6.76%

I&E Exhibit No. 3
Schedule 2

Proxy Group Capital Structure

	2021		2020		2019		2018		2017		Average
IDACORP Inc.											
Long-term Debt	$ 2,000.640	42.85%	$ 2,000.414	43.86%	$ 1,736.659	41.34%	$ 1,834.788	43.63%	$ 1,746.123	43.68%	43.07%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	2,668.436	57.15%	2,559.980	56.14%	2,464.628	58.66%	2,370.360	56.37%	2,251.385	56.32%	56.93%
	4,669.076	100.00%	4,560.394	100.00%	4,201.287	100.00%	4,205.148	100.00%	3,997.508	100.00%	100.00%
Portland General Electric Company											
Long-term Debt	3,580.000	56.94%	3,051.000	53.87%	2,775.000	51.71%	2,225.000	47.03%	2,475.000	50.60%	52.03%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	2,707.000	43.06%	2,613.000	46.13%	2,591.000	48.29%	2,506.000	52.97%	2,416.000	49.40%	47.97%
	6,287.000	100.00%	5,664.000	100.00%	5,366.000	100.00%	4,731.000	100.00%	4,891.000	100.00%	100.00%
Dominion Energy Inc.											
Long-term Debt	37,890.000	56.71%	34,473.000	56.90%	34,266.000	51.71%	31,144.000	60.77%	30,948.000	64.35%	58.09%
Preferred Stock	3,393.000	5.08%	2,387.000	3.94%	2,387.000	3.60%	-	0.00%	-	0.00%	2.52%
Common Equity	25,525.000	38.21%	23,730.000	39.16%	29,607.000	44.68%	20,107.000	39.23%	17,142.000	35.65%	39.39%
	66,808.000	100.00%	60,590.000	100.00%	66,260.000	100.00%	51,251.000	100.00%	48,090.000	100.00%	100.00%
Duke Energy Corporation											
Long-term Debt	61,522.000	55.52%	56,965.000	54.29%	56,417.000	54.65%	51,123.000	53.85%	49,035.000	54.02%	54.46%
Preferred Stock	1,962.000	1.77%	1,962.000	1.87%	1,962.000	1.90%	-	0.00%	-	0.00%	1.11%
Common Equity	47,334.000	42.71%	46,002.000	43.84%	44,860.000	43.45%	43,817.000	46.15%	41,739.000	45.98%	44.43%
	110,818.000	100.00%	104,929.000	100.00%	103,239.000	100.00%	94,940.000	100.00%	90,774.000	100.00%	100.00%
Eversource Energy											
Long-term Debt	17,569.879	54.62%	15,726.088	52.79%	14,360.350	53.21%	12,832.074	52.77%	11,775.889	51.51%	52.98%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	14,599.844	45.38%	14,063.566	47.21%	12,629.994	46.79%	11,486.817	47.23%	11,086.242	48.49%	47.02%
	32,169.723	100.00%	29,789.654	100.00%	26,990.344	100.00%	24,318.891	100.00%	22,862.131	100.00%	100.00%
FirstEnergy Corporation											
Long-term Debt	22,519.000	72.19%	22,394.000	75.58%	19,859.000	74.01%	17,751.000	72.26%	21,115.000	84.33%	75.67%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	71.000	0.29%	-	0.00%	0.06%
Common Equity	8,675.000	27.81%	7,237.000	24.42%	6,975.000	25.99%	6,743.000	27.45%	3,925.000	15.67%	24.27%
	31,194.000	100.00%	29,631.000	100.00%	26,834.000	100.00%	24,565.000	100.00%	25,040.000	100.00%	100.00%
PPL Corporation											
Long-term Debt	10,713.000	43.84%	21,623.000	61.79%	20,799.000	61.55%	20,069.000	63.26%	19,847.000	64.84%	59.06%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	13,723.000	56.16%	13,373.000	38.21%	12,991.000	38.45%	11,657.000	36.74%	10,761.000	35.16%	40.94%
	24,436.000	100.00%	34,996.000	100.00%	33,790.000	100.00%	31,726.000	100.00%	30,608.000	100.00%	100.00%
Public Service Enterprise Group Inc.											
Long-term Debt	15,410.000	51.63%	14,748.000	47.99%	14,016.000	48.16%	13,168.000	47.81%	12,068.000	46.57%	48.43%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	14,438.000	48.37%	15,984.000	52.01%	15,089.000	51.84%	14,377.000	52.19%	13,847.000	53.43%	51.57%
	29,848.000	100.00%	30,732.000	100.00%	29,105.000	100.00%	27,545.000	100.00%	25,915.000	100.00%	100.00%
Ameren Corporation											
Long-term Debt	12,562.000	56.43%	11,078.000	55.35%	8,944.000	52.60%	7,859.000	50.74%	7,094.000	49.68%	52.96%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	9,700.000	43.57%	8,938.000	44.65%	8,059.000	47.40%	7,631.000	49.26%	7,184.000	50.32%	47.04%
	22,262.000	100.00%	20,016.000	100.00%	17,003.000	100.00%	15,490.000	100.00%	14,278.000	100.00%	100.00%
American Electric Power Company Inc.											
Long-term Debt	31,989.600	58.73%	29,855.800	59.18%	26,110.600	57.03%	21,881.700	53.44%	19,658.400	51.79%	56.03%
Preferred Stock	43.300	0.08%	45.200	0.09%	42.900	0.09%	39.400	0.10%	11.900	0.03%	0.08%
Common Equity	22,433.200	41.19%	20,550.900	40.73%	19,632.200	42.88%	19,028.400	46.47%	18,287.000	48.18%	43.89%
	54,466.100	100.00%	50,451.900	100.00%	45,785.700	100.00%	40,949.500	100.00%	37,957.300	100.00%	100.00%
CMS Energy Corporation											
Long-term Debt	12,115.000	64.63%	13,715.000	71.39%	12,064.000	70.62%	10,684.000	69.20%	9,214.000	67.48%	68.66%
Preferred Stock	224.000	1.19%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.24%
Common Equity	6,407.000	34.18%	5,496.000	28.61%	5,018.000	29.38%	4,755.000	30.80%	4,441.000	32.52%	31.10%
	18,746.000	100.00%	19,211.000	100.00%	17,082.000	100.00%	15,439.000	100.00%	13,655.000	100.00%	100.00%
Entergy Corporation											
Long-term Debt	25,053.255	68.28%	21,429.544	66.23%	17,313.378	62.87%	15,538.681	63.73%	14,337.274	64.21%	65.06%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	11,637.284	31.72%	10,926.142	33.77%	10,223.675	37.13%	8,844.305	36.27%	7,992.515	35.79%	34.94%
	36,690.539	100.00%	32,355.686	100.00%	27,537.053	100.00%	24,382.986	100.00%	22,329.789	100.00%	100.00%

Five-Year Average Capital Structure					
Long-term Debt	57.21%	Maximum	75.67%	Minimum	43.07%
Preferred Stock	0.33%				
Common Equity	42.46%	Minimum	24.27%	Maximum	56.93%
	100.00%				

Source: Compustat ($ in millions)

	2021		
	Interest Charges	Long-Term Debt	Debt Cost
IDACORP Inc.	$ 98.69	$ 2,000.64	4.93%
Portland General Electric Company	$ 145.00	$ 3,580.00	4.05%
Dominion Energy Inc.	$ 1,471.00	$ 37,890.00	3.88%
Duke Energy Corporation	$ 2,344.00	$ 61,522.00	3.81%
Eversource Energy	$ 600.73	$ 17,569.88	3.42%
FirstEnergy Corporation	$ 1,141.00	$ 22,519.00	5.07%
PPL Corporation	$ 529.00	$ 10,713.00	4.94%
Public Service Enterprise Group Inc.	$ 571.00	$ 15,410.00	3.71%
Ameren Corporation	$ 400.00	$ 12,562.00	3.18%
American Electric Power Company Inc.	$ 1,252.90	$ 31,989.60	3.92%
CMS Energy Corporation	$ 503.00	$ 12,115.00	4.15%
Entergy Corporation	$ 863.71	$ 25,053.26	3.45%

Implied Interest Cost Rate	Range:	Low	3.18%
		High	5.07%
		Average	4.04%

Source: Compustat

Mergent Bond Record
A-Rated Public Utility Bond Yields

Month	Yield
Jan-22	3.33%
Feb-22	3.68%
Mar-22	3.98%
Apr-22	4.32%
May-22	4.75%
Jun-22	4.86%
Jul-22	4.78%
Aug-22	4.76%
Sep-22	5.28%
Oct-22	5.88%
Nov-22	5.75%
Dec-22	5.28%
Jan-23	5.20%
Jan-00	4.76%

Source: Mergent Bond Record
2/1/2023

I&E Exhibit No. 3
Schedule 4

Expected Market Cost Rate of Equity

Using Data for the Proxy Group of Electric Companies
5-Year Forecasted Growth Rates

	Time Period	Adjusted Dividend Yield (1)	Growth Rate (2)	Expected Return on Equity (3=1+2)
(1)	52-Week Average Ending: February 15, 2023	3.52%	5.15%	8.67%
(2)	Spot Price Ending: February 15, 2023	3.69%	5.15%	8.84%
(3)	Average:	3.61%	5.15%	8.76%

Sources: Value Line February 15, 2023
Barron's February 15, 2023

I&E Exhibit No. 3
Schedule 5

Dividend Yields of the Proxy Group

Company Symbol	IDACORP Inc. IDA	Portland General Electric Company POR	Dominion Energy Inc. D	Duke Energy Corporation DUK	Eversource Energy ES
Div	3.25	1.88	2.75	4.06	2.71
52-wk low	93.53	41.58	57.18	83.76	70.54
52-wk high	118.92	57.03	88.78	116.33	94.63
Spot Price	100.99	47.07	58.06	99.47	78.89
Spot Div Yield	3.22%	3.99%	4.74%	4.08%	3.44%
52-wk Div Yield	3.06%	3.81%	3.77%	4.06%	3.28%
Average	3.14%	3.90%	4.25%	4.07%	3.36%

Company Symbol	FirstEnergy Corporation FE	PPL Corporation PPL	Public Service Enterprise Group Inc. PEG	Ameren Corporation AEE	American Electric Power Company Inc. AEP
Div	1.56	0.96	2.28	2.52	3.35
52-wk low	35.22	23.47	52.51	73.28	80.30
52-wk high	48.85	31.74	75.61	99.20	105.60
Spot Price	40.17	28.54	61.16	85.20	90.48
Spot Div Yield	3.88%	3.36%	3.73%	2.96%	3.70%
52-wk Div Yield	3.71%	3.48%	3.56%	2.92%	3.60%
Average	3.80%	3.42%	3.64%	2.94%	3.65%

Company Symbol	CMS Energy Corporation CMS	Entergy Corporation ETR
Div	1.94	4.30
52-wk low	52.41	94.94
52-wk high	73.76	126.82
Spot Price	61.16	106.09
Spot Div Yield	3.17%	4.05%
52-wk Div Yield	3.08%	3.88%
Average	3.12%	3.97%

	Average
Spot Div Yield	**3.69%**
52-wk Div Yield	**3.52%**
Average	**3.61%**

Source:	Barron's	February 15, 2023
	Value Line	February 15, 2023

I&E Exhibit No. 3
Schedule 6

Five-Year Growth Estimate Forecast for the Proxy Group (Actual)

Company	Symbol	Yahoo	Zacks	Value Line	Average
		Source			
IDACORP Inc.	IDA	2.70%	3.40%	4.50%	3.53%
Portland General Electric Company	POR	1.39%	5.30%	5.00%	3.90%
Dominion Energy Inc.	D	6.42%	4.80%	4.00%	5.07%
Duke Energy Corporation	DUK	5.47%	5.40%	5.00%	5.29%
Eversource Energy	ES	5.74%	6.50%	6.50%	6.25%
FirstEnergy Corporation	FE	NA	6.40%	3.00%	4.70%
PPL Corporation	PPL	NA	NA	3.50%	3.50%
Public Service Enterprise Group Inc.	PEG	3.80%	2.40%	4.50%	3.57%
Ameren Corporation	AEE	6.26%	6.90%	6.50%	6.55%
American Electric Power Company Inc.	AEP	6.23%	6.10%	6.50%	6.28%
CMS Energy Corporation	CMS	8.77%	8.00%	6.50%	7.76%
Entergy Corporation	ETR	6.19%	6.00%	4.00%	5.40%
Average:					**5.15%**

Source:
Internet
February 15, 2023

Proxy Group Company	Beta
IDACORP Inc.	0.80
Portland General Electric Company	0.85
Dominion Energy Inc.	0.80
Duke Energy Corporation	0.85
Eversource Energy	0.90
FirstEnergy Corporation	0.85
PPL Corporation	1.05
Public Service Enterprise Group Inc.	0.90
Ameren Corporation	0.85
American Electric Power Company Inc.	0.75
CMS Energy Corporation	0.80
Entergy Corporation	0.95
Average beta for CAPM	**0.86**

Source:
Value Line
February 15, 2023

I&E Exhibit No. 3
Schedule 8

Risk-Free Rate 10-Year Treasury Note	Yield
2Q 2023	3.70
3Q 2023	3.70
4Q 2023	3.60
1Q 2024	3.50
2Q 2024	3.40
5-Yr (2024-2028) Average	3.60
Average	**3.58**

Source:
Blue Chip
2/1/2023 & 12/2/2022

I&E Exhibit No. 3
Schedule 9

Required Rate of Return on Market as a Whole Forecasted

	Dividend Yield	+	Growth Rate	=	Expected Market Return
Value Line Estimate	2.10%		11.58%	(a)	13.68%
S&P 500 Historical Return					12.01%
Average Expected Market Return				=	12.85%

(a) Value Line forecast for the 3 to 5 year index appreciation is 55%
((1+55%)^.25)-1)

Sources:

Value Line Dividend Yield	2/10/2023	2.10%
Valueline Appreciation Potential	2/10/2023	55%
S&P 500 Historical Return Tab	2/16/2023	12.01%

S&P 500 Historical Return

Year	Return
2022	-18.11
2021	28.71
2020	18.4
2019	31.49
2018	-4.38
2017	21.83
2016	11.96
2015	1.38
2014	13.69
2013	32.39
2012	16
2011	2.11
2010	15.06
2009	26.46
2008	-37
2007	5.49
2006	15.79
2005	4.91
2004	10.88
2003	28.68
2002	-22.1
2001	-11.89
2000	-9.1
1999	21.04
1998	28.58
1997	33.36
1996	22.96
1995	37.58
1994	1.32
1993	10.08
1992	7.62
1991	30.47
1990	-3.1
1989	31.69
1988	16.61
1987	5.25
1986	18.67
1985	31.73
1984	6.27
1983	22.56
1982	21.55
1981	-4.91
1980	32.42
1979	18.44
1978	6.56
1977	-7.18
1976	23.84
1975	37.2
1974	-26.47
1973	-14.66

1972	18.98
1971	14.31
1970	4.01
1969	-8.5
1968	11.06
1967	23.98
1966	-10.06
1965	12.45
1964	16.48
1963	22.8
1962	-8.73
1961	26.89
1960	0.47
1959	11.96
1958	43.36
1957	-10.78
1956	6.56
1955	31.56
1954	52.62
1953	-0.99
1952	18.37
1951	24.02
1950	31.71
1949	18.79
1948	5.5
1947	5.71
1946	-8.07
1945	36.44
1944	19.75
1943	25.9
1942	20.34
1941	-11.59
1940	-9.78
1939	-0.41
1938	31.12
1937	-35.03
1936	33.92
1935	47.67
1934	-1.44
1933	53.99
1932	-8.19
1931	-43.34
1930	-24.9
1929	-8.42
1928	43.61
1927	37.49
1926	11.62
Average	**12.01381**

Source: Accessed on 2/16/2023
https://www.slickcharts.com/sp500/returns#google_vignette

CAPM with forecasted return

Re		Required return on individual equity security
Rf		Risk-free rate
Rm		Required return on the market as a whole
Be		Beta on individual equity security
Re	=	Rf+Be(Rm-Rf)
Rf	=	3.58
Rm	=	12.85
Be	=	0.86
Re	=	**11.55**

Sources: Value Line February 15, 2023
Blue Chip 2/1/2023 & 12/2/2022

UGI Utilities, Inc. - Electric Division
Docket No. R-2022-3037368
UGI Electric 2023 Base Rate Case
Responses to I&E (RR-1-D thru RR-20-D)
Delivered on February 24, 2023

I&E-RR-4-D

Request:

Reference UGI Electric Statement No. 9, p. 6, lines 13-15:

A. Explain why Mr. Moul chose an average of DCF (10.45%) and Risk Premium (11.75%) results to determine the indicated cost of equity of 11.10%.

B. State whether Mr. Moul believes the CAPM result is appropriate to consider in determining a fair cost of equity rate. If the response is yes, explain why he ignored the CAPM result.

Response:

A. Both the results of DCF and Risk Premium are widely recognized measures of the cost of equity and, therefore, require weight in the determination of the cost of equity. The other measures, i.e., CAPM and Comparable Earnings are equally valid.

B. CAPM is a valid measure of the cost of equity. Mr. Moul did not ignore the results of the CAPM.

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

I&E-RR-5-D

Request:

Reference UGI Electric Statement No. 9, p. 7, lines 15-19. Identify the companies in Mr. Moul's Electric Group that are not susceptible to business risks due to micro-turbines, potential commercialization of fuel cells, development of wind and solar power, and the creation of micro-grids, which create potential for bypass and the resulting declines in transmission and distribution revenues.

Response:

All members of the Electric Group are subject to these factors, but to varying degrees.

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

UGI Utilities, Inc. - Electric Division
Docket No. R-2022-3037368
UGI Electric 2023 Base Rate Case
Responses to I&E (RR-1-D thru RR-20-D)
Delivered on February 24, 2023

I&E-RR-7-D

Request:

Reference UGI Electric Statement No. 9, p. 8, lines 15-18 concerning the proposed capital expenditures (transmission and distribution) over next five years (2023-2027), provide the actual dollar amount of capital expenditures made in 2018, 2019, 2020, 2021 and 2022.

Response:

Please see Attachment I&E-RR-7-D.

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

UGI Utilities, Inc. - Electric Division
Actual Capital Expenditures[1]
for 12 Months Ended September 30,

	2018	2019	2020	2021	2022
Distribution	$ 14,490,933	$ 13,887,866	$ 13,709,264	$ 13,532,502	$ 17,605,907
General (IT, Tools, Fleet & Building & Grounds)	282,801	1,810,397	837,240	1,209,769	2,680,232
Transmission	4,342,050	7,999,871	4,308,743	6,037,863	7,651,589
	$ 19,115,784	$ 23,698,133	$ 18,855,247	$ 20,780,135	$ 27,937,727

[1] *Amounts shown are prior to any allocations*

I&E-RR-10-D

Request:

Reference UGI Electric Statement No. 9, p. 26, lines 18-24 and UGI Exhibit B, Schedule 9, where Mr. Moul suggests a 6.00% five-year projected growth rate, which is notably above his Electric Group's average growth rate of 5.66% [(6.25 + 5.89 + 4.83) ÷ 3], is appropriate due to investor-expected growth for the Electric Group as well as expected continuation of electric utility infrastructure spending:

A. Explain whether Mr. Moul believes that the analysts at IBES/First Call, Zacks, and Value Line consider these expectations when formulating their five-year growth projections.

B. Explain whether Mr. Moul believes that all companies in his Electric Group would benefit from the same expectations.

Response:

A. The growth rates published by IBES/FirstCall, Zacks and Value Line are assumed to consider all factors that they believe impact future growth, which for the members of the Electric Group would include growth associated with infrastructure spending. IBES/First Call and Zacks are consensus growth rates that are obtained from a survey of analysts, and as such, the assumptions reflected in the consensus are not revealed by the published growth rates. Hence, there is no ability to determine the weight that an individual analyst assigns to infrastructure spending for each member of the Electric Group. Value Line does reveal the underlying data that supports its growth rates.

B. It cannot be established that "all companies" are affected equally by infrastructure spending, as infrastructure spending varies across the members of the Electric Group. Regardless, there is widespread support for the proposition that infrastructure spending has been ramping up in recent years for the electric utility industry.

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

I&E-RR-17-D

Request:

Reference UGI Electric Statement No. 9, pp. 42-43:

A. State whether Mr. Moul is aware of any electric distribution utilities throughout the United States that have been granted a Commission authorized 11.30% or higher cost of common equity in a base rate case in the past two years.

B. If the answer to Part A is yes, identify which company/companies have been authorized such cost of common equity and in what jurisdiction.

Response:

A. Mr. Moul is not aware of any electric distribution utilities throughout the United States that have been granted a Commission authorized 11.30% or higher cost of common equity in a base rate case in the past two years. However, Mr. Moul does not believe the Commission Opinions of the last two years are reasonable indicators of current market conditions.

B. See the response to (A) above.

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

I&E Statement No. 3-SR
Witness: D. C. Patel

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI Utilities, Inc. - Electric Division

Docket No. R-2022-3037368

Surrebuttal Testimony

of

D. C. Patel

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

TABLE OF CONTENTS

<u>INTRODUCTION OF WITNESS</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is D.C. Patel, and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. ARE YOU THE SAME D. C. PATEL WHO IS RESPONSIBLE FOR THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 3 AND THE SCHEDULES IN I&E EXHIBIT NO. 3?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to address statements made in the rebuttal testimony of UGI Utilities, Inc. - Electric Division (UGI Electric or Company) witness Paul R. Moul (UGI Electric Statement No. 9-R) regarding rate of return topics including the cost of common equity and the overall fair rate of return that will be applied to the Company's rate base. In addition, I will address the management performance claim discussed by Company witness Christopher R. Brown (UGI Electric Statement No. 1-R).

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN ACCOMPANYING EXHIBIT?

A. No. However, I refer to my direct testimony and its accompanying exhibit in this surrebuttal testimony (I&E Statement No. 3 and I&E Exhibit No. 3).

SUMMARY OF MR. MOUL'S REBUTTAL TESTIMONY

Q. SUMMARIZE MR. MOUL'S RESPONSE IN REBUTTAL TESTIMONY TO YOUR RATE OF RETURN RELATED RECOMMENDATIONS.

A. Mr. Moul provides an update to his overall rate of return due to a revised cost of long-term debt (UGI Electric Statement No. 9-R, p. 14) and generally discusses his analysis for adequacy of rate of return on equity throughout his rebuttal testimony to justify his equity rate of return recommendation. He disputes my recommendations regarding an appropriate proxy group (UGI Electric Statement No. 9-R, pp. 14-16), my reliance on and application of the Discounted Cash Flow (DCF) Method (UGI Electric Statement No. 9-R, pp. 17-22), the DCF growth rate (UGI Electric Statement No. 9-R, pp. 22-23), and my recommended disallowance of his leverage adjustment to the DCF (UGI Electric Statement No. 9-R, pp. 29-31). He disputes my Capital Asset Pricing Model (CAPM) analysis and disagrees with the appropriate risk-free rate to use and my exclusion of a size adjustment in the CAPM analysis (UGI Electric Statement No. 9-R, pp. 34-38). Further, Mr. Moul, rejects my disagreement with his use of the Risk Premium (RP) and Comparable Earnings (CE) methods (UGI Electric Statement No. 9-R, pp. 41-43) and my recommended disallowance of additional basis points for management performance (UGI Electric Statement No. 9-R, p. 44). Finally, Mr. Moul suggests that the Commission-determined Distribution System Improvement Charge (DSIC) rates should serve as a benchmark cost of equity in this proceeding (UGI Electric Statement No. 9-R, pp. 18-19).

UPDATED OVERALL RATE OF RETURN

Q. DID THE COMPANY PROVIDE AN UPDATE TO ITS COST OF DEBT AND OVERALL RATE OF RETURN CLAIM IN REBUTTAL TESTIMONY?

A. Yes. The Company updated the fully projected future test year (FPFTY) cost of debt due to a higher forecast in the interest rate from 4.55% to 5.23% on the new issue of a $225,000,000 Senior Unsecured Note that will be issued later this year. As shown in the revised Schedule B-6, the FPFTY revised embedded cost of long-term debt is 4.44% (UGI Electric Exhibit A - Fully Projected – Rebuttal). This change increases the embedded cost of long-term debt by 0.09% (4.44% - 4.35%) from Mr. Moul's direct testimony. With this update, the overall rate of return increases from 8.15% to 8.19% as shown in the revised Schedule B-7 (UGI Electric Exhibit A - Fully Projected - Rebuttal and UGI Electric Statement No. 9-R, p. 14, lines 4-14). Company witness Tracy A. Hazenstab has adjusted the overall revenue requirement for this change as described above (UGI Electric Statement No. 2-R, p. 3, lines 21-28).

Q. PLEASE SUMMARIZE THE COMPANY'S UPDATED OVERALL RATE OF RETURN CLAIM.

A. Mr. Moul recommends the following updated overall rate of return to reflect an update in the embedded long-term debt cost for the FPFTY ending September 30, 2024 (UGI Electric Statement No. 9-R, p. 14, lines 9-13):

Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost Rate**
Long-Term Debt	45.41%	4.44%	2.02%
Common Equity	54.59%	11.30%	6.17%
Total	**100.00%**		**8.19%**

Q. DO YOU ACCEPT THE COMPANY'S UPDATED DEBT COST AND OVERALL RATE OF RETURN CLAIM?

A. No. I accept the updated debt cost rate of 4.44% but continue to disagree with the equity cost claim of 11.30% and overall rate of return of 8.19% as discussed throughout this testimony.

UPDATED ANALYSIS

Q. HAS THE COMPANY UPDATED ITS COST OF EQUITY?

A. No. Mr. Moul provides additional information to support his original cost of equity recommendation (UGI Electric Statement No. 9-R, pp. 4-8). However, his original cost of equity claim remains unchanged.

Q. SUMMARIZE MR. MOUL'S DISCUSSION THAT HE CLAIMS TO BE SUPPORTIVE OF HIS COST OF EQUITY RECOMMENDATION.

A. First, Mr. Moul states that the Commission has not set a return on equity on an original cost rate base that was less than 9% for an investor-owned utility in the past

40 years, and he asserts that the I&E recommended 8.76% equity return is not reasonable when the Commission approved 10.24% in the 2021 PECO Gas rate case, and 10.00% in the 2022 Aqua Pennsylvania rate case (UGI Electric Statement No. 9-R, pp. 4-5). Second, he stated there have been dramatic increases in inflation and interest rates throughout 2022 and 2023, prompting the Federal Open Market Committee to increase the federal funds rate consistently to combat inflation. Therefore, with the upward move in interest rates, he opines that an equity return above 10% is clearly warranted (UGI Electric Statement No. 9-R, p. 5, lines 8-9). He asserts that investors would view Pennsylvania regulation as less supportive of the Company at a time of high levels of capital investment and increasing capital costs if the Commission ignores inflation and interest costs in determining a return on equity (UGI Electric Statement No. 9-R, p. 5, lines 16-18).

Q. PLEASE RESPOND TO MR. MOUL'S ASSERTIONS.

A. First, it is inappropriate to compare and benchmark the Commission's approval of a higher return on equity in PECO Gas (natural gas) and Aqua Pennsylvania (water and wastewater) rate cases because both these utilities operate in separate business segments and have different business and financial risks that are not comparable with UGI Electric's business and financial risks. Second, I agree that the cost of capital has trended upward due to higher inflation and interest rates in 2021 and 2022. However, per Blue Chip Financial Forecasts of May 1, 2023, p. 2, the inflation rate (Consumer Price Index) has declined beginning Q3-2022 and forecasts for the next six quarters for the inflation are in the range of 2.3% - 3.4% as shown in the table below:

Historic Quarter	Inflation Rate	Forecast Quarter	Inflation Rate
Q2-2021	7.5%	Q2-2023	3.4%
Q3-2021	6.6%	Q3-2023	3.0%
Q4-2021	8.8%	Q4-2023	2.7%
Q1-2022	9.2%	Q1-2024	2.4%
Q2-2022	9.7%	Q2-2024	2.3%
Q3-2022	5.5%	Q3-2024	2.3%
Q4-2022	4.2%		
Q1-2023	3.8%		

Similarly, per Blue Chip Financial Forecasts of May 1, 2023, p. 2, the 10-Year Treasury Note interest rates for the Q2-2023 through Q3-2024 are forecasted to be in the range of 3.4% - 3.6% as compared to Q1-2023 interest rate of 3.65%. Therefore, Mr. Moul's claim for a higher equity return above 10% due to higher levels of inflation and interest rates is speculative and not supported by the information presented above. Additionally, Corporate Bond Yield Averages of A-rated Public Utility Bonds seem to have peaked in October 2022 at 5.88% and trended downward to 5.13% as of April 2023.[1]

Lastly, Mr. Moul's statement that investors would view Pennsylvania regulation as less supportive of the Company at a time of high levels of capital investment and increasing capital costs if the Commission ignores inflation and

1 Mergent Bond Record, May 2023, p. 18, Corporate Bond Yield Averages.

interest costs in determining the equity return is speculative and unsupported.

PROXY GROUP

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR PROXY GROUP.

A. Mr. Moul states that my exclusion of four electric utilities (AVANGRID, Inc., Consolidated Edison, Inc., Exelon Corporation, and NextEra Energy, Inc.) from the proxy group is unwarranted (UGI Electric Statement No. 9-R, p. 14, line 26 and p. 15, line 1). He argues that all companies in his proxy group have revenues, earnings, and assets equal or above the 50% threshold for all members of his Electric Group (UGI Electric Statement No. 9-R, p. 15, lines 7-9). He disagrees with my criteria for exclusion of utilities involved in merger and acquisition (M&A) transactions, particularly for AVANGRID, Inc. and Consolidated Edison, Inc. because, he opines, an M&A transaction does not impact stock prices significantly (UGI Electric Statement No. 9-R, p. 16, lines 10-20). Similarly, he disagrees with my exclusion of Next Era Energy, Inc. for not operating in a state that has electric deregulation (UGI Electric Statement No. 9-R, p. 16, lines 20-25).

Q. DO YOU AGREE WITH MR. MOUL'S ASSERTION THAT THE 50 PERCENT THRESHOLD OF REGULATED ASSETS TO TOTAL ASSETS IS AN APPROPRIATE CRITERION FOR DETERMINING THE PROXY GROUP?

A. No. Calculating the percentage of utility assets that make up the total assets of a company is not a reliable way to determine if a business is primarily a regulated utility. Assets are accounted for at the original cost minus depreciation, which means that the value of an asset depends on its age. Therefore, it is possible for the regulated utility segment of a company to have assets that are predominately depreciated. Although a utility may have assets that are significantly depreciated, it does not always indicate the level of business a company does. A company, or its parent company, can have most of its utility assets depreciated but still do more business as a utility than as another business.

Another reason that the percentage of utility business is not always accurately represented by using the percentage of utility assets to total assets is that there are differences between businesses in the amount of capital needed. Generally, a utility company requires a higher level of assets (asset value) to produce a comparatively small level of cash flow while another business may need only a small amount of assets to produce a large level of cash flow. Therefore, comparing the assets of an electric utility segment to the total assets of a company is not an appropriate criterion as it could be misleading.

Q. DO YOU AGREE WITH MR. MOUL'S PRESENTATION OF ADDITIONAL DATA ABOUT REGULATED EARNINGS AND ASSETS EXCEEDING THE 50 PERCENT THRESHOLD AS ADDITIONAL CRITERIA TO SUPPORT HIS PROXY GROUP?

A. No. It appears Mr. Moul presented additional criteria (earnings and assets) to rebut my exclusion of Exelon Corp. in the proxy group (UGI Electric Statement No. 9-R, p. 15, lines 7-10). My revenue criteria is specifically geared to regulated electric utility distribution revenues with a threshold exceeding 50%. Regarding Mr. Moul's assertion that I excluded Exelon improperly though it meets with my revenue criteria, I agree. I inadvertently overlooked the fact that Exelon recently divested from its generation operations as Mr. Moul notes (UGI Electric Statement No. 9-R, p. 15, footnote 1). However, Exelon should still be excluded from my proxy group as it did not meet my third criterion, which dictates investment information (five-year growth rate in this case) for the company must be available from Value line, and Value line did not project earning growth for Exelon.

Additionally, Mr. Moul admits that the ALJ in the Company's last rate case removed two companies from his proxy group because they failed to meet the 50% revenue threshold (UGI Electric Statement No. 9-R, p. 14). I reiterate that my regulated electric utility revenues criterion is appropriate and superior to Mr. Moul's analysis of additional criteria (earnings and assets), and this does not alter my proxy group selection. Revenue criterion is important because revenues represent the percentage of cash flow a company receives from each business line related to providing goods or services. If less than 50% of revenues come from the electric distribution sector, the companies are not comparable to the subject utility as they do not provide a similar level of regulated business (I&E Statement No. 3, p. 10).

Q. PLEASE REITERATE WHY YOU ELIMINATED AVANGRID, INC., CONSOLIDATED EDISON, INC., AND NEXTERA ENERGY, INC. FROM YOUR PROXY GROUP.

A. As explained in my direct testimony, AVANGRID and Consolidated Edison are currently involved in an announced merger/acquisition of significant value (I&E Statement No. 3, p. 10). Finally, NextEra Energy was excluded because it is not operating in a state that has a deregulated electric utility (I&E Statement No. 3, p. 10).

Q. DO YOU AGREE WITH MR. MOUL'S COMMENT THAT SINCE SIX COMPANIES IN MY PROXY GROUP OPERATE PREDOMINANTLY AS FULLY REGULATED INTEGRATED UTILITIES THIS WOULD DISQUALIFY THEM FOR MEMBERSHIP IN MY PROXY GROUP UNDER MY CRITERION NO. 6?

A. No. Mr. Moul states that American Electric Power, Dominion Energy, Duke, Entergy, Portland General Electric, and Xcel are not qualified for inclusion in my proxy group (UGI Electric Statement No. 9-R, p. 16, lines 20-24). In this context, I would like to clarify that Xcel is not included in my selected proxy group as it is involved in M&A activity. It is important to note that my proxy selection Criterion No. 6 requires that the company must be operating in *a state* that has a deregulated electric utility market (I&E Statement No. 3, p. 7). Mr. Moul's identified companies operate in at least one state that has a deregulated electric utility market; therefore, all five companies are properly qualified for inclusion in my proxy group. Additionally, Mr. Moul did not provide any support or analysis for his argument that the above five companies are not qualified for inclusion in my proxy group.

Q. DO YOU HAVE ANY CHANGES TO YOUR PROXY GROUP?

A. No. For the reasons discussed above, the percentage of revenue, involvement in

M&A transactions, value line investment information, and utility's operation in a deregulated state are important and appropriate criteria in addition to other criteria I utilized (I&E Statement No. 3, p. 7).

DISCOUNTED CASH FLOW

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR DCF ANALYSIS.

A. Mr. Moul agrees that results of the DCF analysis should be given weight, but he asserts that use of multiple methods provides a superior foundation to determine the cost of equity (UGI Electric Statement No. 9-R, p. 17, lines 5-6). He compares the DSIC rate determined by the Commission in the Quarterly Earnings Summary Reports to the rates calculated using market data (UGI Electric Statement No. 9-R, p. 18, lines 13-23). He then argues that the I&E recommended DCF return should be at least 9.82% (I&E calculated 8.76% + I&E Proxy Group DCF top range 10.88% = 19.64% ÷ 2) (UGI Electric Statement No. 9-R, p. 19, lines 11-14). He concludes that my DCF results is too low for two reasons: (1) there have been significant increases in interest rates and inflation since the pandemic; and (2) the DCF result is low compared to my CAPM result of 11.55% (UGI Electric Statement No. 9-R, p. 22, lines 2-4). He disagrees with my DCF result based on the outcomes of certain individual companies (UGI Electric Statement No. 9-R, p. 22, lines 11-18) and disputes my growth rate analysis (UGI Electric Statement No. 9-R, p. 23, lines 1-10). Finally, Mr. Moul disagrees with my recommendation to reject his leverage adjustment (UGI Electric Statement No. 9-R, pp. 29-31).

<u>EXCLUSIVE USE OF THE DCF</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR USE OF THE DCF.

A. Mr. Moul asserts that the use of more than one method provides a superior foundation for the cost of equity determination. He claims that the use of more than one method will capture the multiplicity of factors that motivate investors to commit their capital to a particular enterprise (UGI Electric Statement No. 9-R, p. 17, lines 5-10).

Q. WERE ANY METHODS OTHER THAN THE DCF EMPLOYED IN YOUR ANALYSIS?

A. Yes. Although my recommendation was based on the results of my DCF analysis, I also employed the CAPM as a comparison. For the reasons discussed in my direct testimony, the DCF method is the most reliable (I&E Statement No. 3, pp. 18-22). Although no one method can capture every factor that influences an investor, including the results of methods less reliable than the DCF, it does not make the end result more reliable or more accurate. In direct testimony, I cited several cases that illustrate that the methodology I employed is consistent with the methodology historically used by the Commission in base rate proceedings as recently as 2017, 2018, 2020, and 2021 (I&E Statement No. 3, p. 18).

Additionally, as indicated in my direct testimony (I&E Statement No. 3, p. 22), the Commission recently deviated from prior practice when it indicated in the 2022 Aqua Pennsylvania, Inc. (Aqua) rate case order that its method "for determining

Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies"[2] and that "I&E's DCF and CAPM produce a range of reasonableness for the ROE…".[3] This is why, in my direct testimony, I explain more fully why the CAPM should not be used as a primary method and continue to express those concerns in this proceeding as to why it should only be used as a comparison to, not a check of, the DCF (I&E Statement No. 3, pp. 18-21). Thus, I disagree with a method that provides the CAPM comparable weight to the DCF method.

Q. DID YOU USE THE CAPM RESULT FOR COMPARISON PURPOSES ONLY AND NOT AS CHECK?

A. Yes. I&E has been consistent in basing its cost of equity recommendations on the DCF model. Additionally, I&E provides a CAPM analysis as it has historically been the preference of the Commission to view both the DCF and CAPM analysis in base rate proceedings. I&E has consistently provided the CAPM analysis as a comparison and not a check for the reasons discussed in my direct testimony (I&E Statement No. 3, pp. 19-20). Further, regardless of which language is used, I stand firmly on my recommendation that the CAPM should not be given comparable weight to the DCF method.

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2 *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 154 (Order entered May 16, 2022).

3 *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 178 (Order entered May 16, 2022).

DSIC RATES

Q. SHOULD THE COMMISSION CONSIDER THE AUTHORIZED DSIC RATE ESTABLISHED IN THE QUARTERLY EARNINGS SUMMARY REPORTS AS AN APPROPRIATE MEASURE TO DETERMINE THE COST OF EQUITY IN THIS PROCEEDING?

A. No. Mr. Moul's comparison between the I&E recommended return on equity in this proceeding and the Commission's DSIC rate is misguided. My understanding is that the DSIC rate is designed to encourage its use and to incentivize accelerated pipeline replacement and infrastructure upgrades to bring aging infrastructure closer to meeting safety and reliability requirements in between base rate filings. To suggest that the cost of equity must be at or above the DSIC rate in this base rate proceeding is inappropriate and not in the public interest. Additionally, the DSIC rate establishes a benchmark above which a utility company is considered "overearning" and ineligible for use of the DSIC mechanism. As such, the DSIC rate should not serve as a proper measurement of a subject utility's cost of equity in a base rate proceeding since the DSIC rate is routinely higher than any return on equity approved in such base rate proceedings. In fact, 66 Pa. C.S. § 1358(b)(3) states the following,

> The distribution system improvement charge shall be reset at zero if, in any quarter, data filed with the commission in the utility's most recent annual or quarterly earnings report show that the utility will earn a rate of return that would exceed the allowable rate of return used to calculate its fixed costs under the distribution system improvement charge.

Finally, the DSIC mechanism serves to lower a utility's risk because it reduces the lag time in the recovery of a company's capital outlays. DSIC spending requires preapproval of eligible plant via a Long-Term Infrastructure Improvement Plan, so there is little question as to the prudence of those expenditures.

Q. ARE THERE ANY INSTANCES YOU ARE AWARE OF WHERE THE COMMISSION GRANTED A RETURN ON EQUITY THAT WAS HIGHER THAN THE MOST RECENTLY PUBLISHED DSIC RATE?

A. Yes. In the 2021 Aqua base rate case, the Commission awarded that company a return on equity of 10.00%,[4] which was higher than the published DSIC rate for water and wastewater utilities of 9.80%[5] around that same period.

Q. ARE THERE ANY POTENTIAL PROBLEMS WITH AWARDING A RETURN ON EQUITY THAT IS EQUAL TO OR HIGHER THAN THE DSIC RATE?

A. Yes. First, if a company achieves the awarded return that is above the DSIC rate, it eliminates the possibility for the utility to utilize the DSIC mechanism until its earnings fall below the DSIC rate. Further, if a company believes it will receive a return higher than the DSIC rate in a litigated base rate proceeding, it will remove the incentive to use the DSIC mechanism between rate filings and may encourage the more frequent filing of base rate cases. Additionally, it may encourage litigation as

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[4] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 178 (Order entered May 16, 2022).

[5] PA Public Utility Commission, Bureau of Technical Utility Services Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended December 31, 2021, approved at Public Meeting on June 16, 2022, at Docket No. M-2022-3032405.

opposed to settlement of cases, since companies may improperly believe this is the new norm, which will increase rate case costs to customers.

Therefore, in my opinion, the DSIC rate should generally be an incentive rate that is higher than a return on equity percentage granted in a base rate proceeding, and I am anticipating that the Commission decision identified above is not indicative of "the new normal."

Q. WERE THERE ANY SPECIAL CIRCUMSTANCES THAT CAUSED THE COMMISSION'S GRANTED RETURN ON EQUITY FOR AQUA TO EXCEED THAT OF THE MOST RECENTLY AVAILABLE DSIC RATE?

A. Yes. The Commission granted 25 basis points for management effectiveness,[6] which caused the return on equity of 9.75% to go up to 10.00%, thereby exceeding the effective DSIC rate at that time of 9.80% for water and wastewater. I will address management performance in a separate section of testimony below.

<u>EVALUATING THE DCF BASED ON INDIVIDUAL RESULTS</u>

Q. SUMMARIZE MR. MOUL'S RESPONSE IN REBUTTAL TESTIMONY REGARDING THE RESULTS OF YOUR DCF.

A. Mr. Moul argues that the I&E recommended DCF return should be at least 9.82% (I&E calculated 8.76% + I&E Proxy Group DCF top range 10.88% = 19.64% ÷2) (UGI Electric Statement No. 9-R, p. 19, lines 11-14). In this calculation, Mr. Moul

[6] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 178 (Order entered May 16, 2022).

tries to support his recommended DCF result of 9.48% (and 10.45% with a leverage adjustment of 0.97%) by pointing to the top DCF result (10.88%) of one company (CMS Energy Corp.) of my proxy group and includes this result with my average DCF result (8.76%) of the proxy group to reach an unrealistic and unsupported DCF result of 9.82%. Mr. Moul attempts to ignore the lower range (that falls below the DCF average of 8.76%) DCF results of my proxy group utilities (IDACORP 6.67%, PPL Corp 6.92%, Public Service Enterprise 7.21%, and Portland General Electric 7.80%) by stating that these companies fail to provide a sufficient spread over the yield on A-rated public utility bonds (UGI Electric Statement No. 9-R, p. 22, lines 11-17).

<u>GROWTH RATE</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR GROWTH RATES.

A. Mr. Moul argues that the 3.50% growth rate for PPL Corporation, 3.53% for IDACORP, 3.57% for Public Service Enterprise Group, and 3.90% for Portland General Electric are outliers attributed to the Yahoo! Finance low growth rate projections (UGI Electric Statement No. 9-R, p. 23, lines 4-8). He then states that looking at the Value Line data presented on Schedule 6 of I&E Exhibit No. 3, the growth rate averages 5.91%. Applying this growth rate result, the DCF result would be 9.56% (dividend yield 3.65% + growth rate 5.91%) (UGI Electric Statement No. 9-R, p. 23, lines 8-10).

Q. DO YOU AGREE WITH MR. MOUL'S RECALCULATION OF YOUR DCF RESULTS BASED ON REMOVING THE YAHOO! FINANCE AND ZACKS GROWTH RATE ESTIMATES?

A. No. Mr. Moul's calculated average growth rate of 5.91% based on Value line data is incorrect, which in fact averages to 4.96%, lower than my recommended growth rate of 5.15% (I&E Exhibit No. 3, Schedule 6). Additionally, his dividend yield of 3.65% is not correct as opposed to my dividend yield of 3.61%. Therefore, I disagree with his recalculated DCF result of 9.56% (dividend yield 3.65% + growth rate 5.91%).

Mr. Moul's decision to ignore the Yahoo! Finance low growth rates serves to inflate the DCF result, but his argument lacks objective rationale and defeats the purpose of using a proxy group. Mr. Moul himself states, "The principal purpose of assembling a barometer group is to avoid relying on data for a single company that may not be representative and to thereby smooth out any abnormalities" (UGI Electric Statement No. 9-R, p. 22, lines 6-8). This acknowledgement is counterintuitive to his suggestion to remove the Yahoo! Finance and Zacks growth estimates from my analysis. Ironically, and worth noting, Mr. Moul employs the very same growth estimates from sources he is criticizing in his own proxy group and analysis (UGI Electric Exhibit B, p. 17, Schedule 9).

Finally, while he takes issue with my proxy group companies' low growth rate estimates as noted above, he is not concerned with outlier growth estimates that are included in his growth rate analysis: (1) I/B/E/S First Call outlier growth estimates for PPL Corp 17.41% and NextEra Energy 9.35%; and (2) Zacks outlier growth estimates for NextEra Energy 9.70% when determining his average growth rate estimate of 6.00%.

<u>LEVERAGE ADJUSTMENT</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING HIS LEVERAGE ADJUSTMENT.

A. First, Mr. Moul states that credit rating agencies do not measure the market-required cost of equity for a company, nor are they concerned with how it is applied in the rate-setting context. Rather, the credit rating agencies are only concerned with the interests of lenders and the timely payment of principal and interest by companies (UGI Electric Statement No. 9-R, p. 29, lines 24-26). Then, Mr. Moul questions my references to prior Commission orders rejecting a leverage adjustment (UGI Electric Statement No. 9-R, pp. 30-31).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S REBUTTAL TESTIMONY CONCERNING CREDIT RATING AGENCIES?

A. Mr. Moul has actually supported my argument that his proposed leverage adjustment is not needed by stating that the credit rating agencies are only concerned with the timely payment of principal and interest by utilities. Mr. Moul's stated need for the leverage adjustment is based on his assertion that a financial risk difference arises because a market-value capitalization contains more equity and less debt than a book-value capitalization and therefore, has less risk than the book-value capitalization (UGI Electric Statement No. 9, p. 27, lines 11-14).

Financial risk does relate to the capital structure of a company, but it is created by the financing decisions (the use of debt or equity) and the amount of leverage or debt with which a company chooses to finance its assets. Financial risk and the book value capital structure of a company are represented in the financial statements, which are part of what is evaluated by rating agencies. Mr. Moul agrees with me that credit rating agencies use a company's booked debt obligations, found in the financial statements, in their analysis to assess financial risk and determine creditworthiness (UGI Electric Statement No, 9-R, p. 29, lines 20-23).

Q. SUMMARIZE MR. MOUL'S RESPONSE TO YOUR REFERENCE TO PRIOR COMMISSION ORDERS.

A. Mr. Moul refers to the discussion in my direct testimony about six recent cases where the Commission has rejected a "leverage adjustment." He explains that even though the Commission declined to make a "leverage adjustment" in a prior Aqua Pennsylvania case, it does not invalidate its use. Further, he states, "Notably, the Commission did not repudiate the leverage adjustment in the Aqua case, but instead arrived at an 11.00% return on equity for Aqua by including a separate return increment for management performance" (UGI Electric Statement No. 9-R, p. 30, lines 7-12). Next, Mr. Moul claims that the adjustment proposed in the City of Lancaster case was much different than what he proposes in this case (UGI Electric Statement No. 9-R, p. 30, lines 14-15). Regarding UGI Electric, Mr. Moul acknowledges that the Commission granted a "management performance increment" rather than a leverage adjustment when arriving at the allowed equity return (UGI

Electric Statement No. 9-R, p. 30, lines 21-23). As for the Columbia Gas case, Mr. Moul concedes that the Commission accepted I&E's return on equity recommendation, which did not include a leverage adjustment (UGI Electric Statement No. 9-R, p. 30, lines 23-25). Additionally, in the 2020 PECO Gas case, he argues that the Commission arrived at an equity return on the higher side without a leverage adjustment, therefore, no adjustment was warranted (UGI Electric Statement No. 9-R, p. 31, lines 3-5). Finally, in the 2021 Aqua case, Mr. Moul acknowledges that the Commission set the cost of equity without a leverage adjustment (UGI Electric Statement No. 9-R, p. 31, lines 6-8).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL REGARDING THE REFERENCED PRIOR COMMISSION ORDERS IN YOUR DIRECT TESTIMONY?

A. In this proceeding, Mr. Moul is recommending a 97-basis point "leverage adjustment." To be clear, the Commission did in fact refuse to accept the leverage adjustment in the Aqua case by stating "…we reject the ALJ's recommendation to allow a 65-basis point leverage adjustment."[7] The management performance points awarded to Aqua were case-specific and in no way related to the proposed leverage adjustment. Regarding the City of Lancaster case, the Commission did not reject the leverage adjustment based on the manner in which it was calculated, but rather, the Commission stated "…the ALJ's recommendation is in error as any adjustment to the

[7] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket No. R-00072711, pp. 38-39 (Order entered July 31, 2008).

results of the market based DCF as we have previously adopted are unnecessary and will harm ratepayers."[8] Regarding the UGI Electric case, the Commission concluded that "…an artificial adjustment in this proceeding is unnecessary and contrary to the public interest. Accordingly, we decline to include a leverage adjustment in our calculation of the DCF cost of equity."[9] Regarding the most recent Columbia Gas case, the Commission stated,

> … we have adopted the ALJ's recommendation to use I&E's DCF methodology utilizing I&E's dividend yield of 3.34% and growth rate of 6.52%. As noted above, the ALJ did not specify a recommended cost of equity for Columbia in their Recommended Decision. However, we note that I&E's methodology results in an ROE of 9.86%.[10]

The ALJ's Recommended Decision stated the following,

> The ALJ agrees with BIE's reasoning that Columbia Gas' calculated return on equity was flawed for five reasons: (1) the weights given to the results of the Company's CAPM, RP, and CE analyses; (2) certain aspects of Columbia's discussion of risk; (3) Columbia Gas' application of the DCF including the forecasted growth rate and leverage adjustment used; (4) Columbia's inclusion of a size adjustment, reliance on the 30-year Treasury Bond for the risk- free rate, and the use of a double-adjusted *beta* in the CAPM analysis; and (5) the Company's request for an additional 20 basis points for "strong management performance" is unjustified.[11]

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[8] *Pa. PUC v. City of Lancaster – Bureau of Water*; Docket No. R-2010-2179103, p. 101 (Order entered July 14, 2011).

[9] *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058, pp. 93-94 (Order entered October 25, 2018).

[10] *Pa. PUC v. Columbia Gas of Pennsylvania*; Inc. Docket No. R-2020-3018835, p. 141 (Order entered February 19, 2021).

[11] *Pa. PUC v. Columbia Gas of Pennsylvania*; Inc. Docket No. R-2020-3018835, Recommended Decision, pp. 184-185.

While the Company accepted I&E's DCF return without regard to the leverage adjustment or management performance in the last base rate case, in the Recommended Decision, the ALJ clearly rejected the Company's proposed leverage adjustment and the Commission agreed with the ALJ's Recommended Decision.

In the PECO Energy – Gas Division case, the Commission stated,

> … we have adopted the ALJ's recommendation to use I&E's DCF methodology and to use I&E's CAPM calculation as a check on the reasonableness of the DCF determined cost of equity. Therefore, we shall adopt the ALJ's recommended 10.24% cost of equity. In our view, this is an appropriate cost of equity for PECO given the record developed in this proceeding.[12]

In the Recommended Decision, the ALJ agreed with I&E's recommended cost of equity, which did not include a leverage adjustment.[13]

Finally, regarding the 2021 Aqua base rate case, the Commission did in fact reject the Company's proposed leverage adjustment as follows,

> We find I&E's arguments in opposition to the Company's position to be persuasive. For example, as I&E observed, credit rating agencies assess financial risk based upon a company's booked debt obligations and the ability of its cash flow to cover the interest payments on those obligations. The agencies use a company's financial statements, and not the company's market capital structure, in conducting their analysis. It is a company's financial statements that affect the market value of the stock, and, therefore, the financial statements and the book value capital structure are relied upon in an analysis such as that done by rating agencies. I&E St. 2 at 40; I&E St. 2-SR at 10. Accordingly, we find that the record in this proceeding supports rejecting the Company's requested leverage adjustment.[14]

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[12] *Pa. PUC v. PECO Energy Company – Gas Division*. Docket No. R-2020-3018929, p. 171 (Order entered June 22, 2021).

[13] *Pa. PUC v. PECO Energy Company – Gas Division*. Docket No. R-2020-3018929, Recommended Decision, p. 215.

[14] *Pa. PUC v. Aqua Pennsylvania, Inc*. Docket No. R-2021-3027385, pp. 166-167 (Order entered June 22, 2021).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S ASSERTION THAT INVESTORS DO NOT BASE THEIR DECISIONS ON BOOK VALUE, BUT RATHER THE RETURN THEY EXPECT TO EARN ON THE DOLLARS THEY INVEST?

A. Investors purchase securities such as stocks at market value as opposed to book value. In doing so, they accept the returns and associated risks implied by market prices. However, financial statements, which are based on book values, show the entirely true financial position of a company, providing the foundation for investment and financing decisions. For example, financial institutions such as banks lend money based on actual book values and not the current price of a stock. Further, almost all financial ratios used in financial analysis utilize at least one book value variable from either the income statement or the balance sheet.

Mr. Moul's assertion that investors are not concerned with some accounting value is unsupported. Clearly an investor takes the financial risk of the utility into consideration when determining a required return. In addition, the market capitalization information included in Value Line's reports and discussed by Mr. Moul is not the same as market value capital structure. Market capitalization refers to the number of shares outstanding multiplied by the current price. A market value capital structure refers to the ratio of market debt to market equity, which, to my knowledge, is not included in Value Line's reports. Therefore, Mr. Moul's contention that Value Line includes market capitalization data does not offer any support for his leverage adjustment.

Q. HAS YOUR RECOMMENDATION CHANGED FROM DIRECT TESTIMONY REGARDING MR. MOUL'S LEVERAGE ADJUSTMENT?

A. No. For the reasons discussed above, I continue to recommend that Mr. Moul's additional 97-basis point leverage adjustment included in the DCF result be rejected.

<u>**INFLATION**</u>

Q. DOES THE DCF ADEQUATELY FACTOR IN RECENT INFLATIONARY TRENDS?

A. Yes. My DCF calculation includes a spot stock price when determining the dividend yield, and analysts who generate forecasted earnings growth rates should take inflation and other economic factors into consideration as well. Therefore, it contains the most up-to-date projected information of any model. Thus, Mr. Moul's concerns of increasing inflation are adequately covered by use of the DCF as a primary model for determining an appropriate return on equity. Additionally, as discussed above, the inflation rate (per the Consumer Price Index) has declined, beginning Q3-2022 after reaching its peak of 9.70% in Q2-2022 and the inflation forecasts for the next six quarters are in the range of 2.3% - 3.4%.

<u>**CAPITAL ASSET PRICING MODEL**</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR APPLICATION OF THE CAPM.

A. Mr. Moul opines that my CAPM analysis understates the cost of equity for a few reasons, including my use of the yield on 10-year Treasury Notes for my risk-free rate, failure to use leverage adjusted betas, and rejection of his size adjustment (UGI Electric Statement No. 9-R, p. 35, lines 3-5). Each of these topics are discussed in more detail below.

RISK-FREE RATE

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR USE OF THE YIELD ON THE 10-YEAR U.S. TREASURY NOTE.

A. Mr. Moul claims that by using the 10-year Treasury Note, I introduced a systematic understatement of CAPM returns that can be traced to extraordinary monetary policy actions to deal with the recession created by the pandemic. He opines that his use of the yield on a 30-year U.S. Treasury Bond is more appropriate than my use of the yield on a 10-year Treasury Note because 30-year bonds are "more a reflection of investor sentiment of their required returns" and 10-year notes respond more to the policy initiatives of monetary officials (UGI Electric Statement No. 9-R, p. 35, lines 17-25). Additionally, he provides a recalculation of my risk-free rate to use in the CAPM formula (UGI Electric Statement No. 9-R, p. 36-37).

Q. DO YOU AGREE WITH MR. MOUL THAT USING THE YIELD OF A 30-YEAR U.S. TREASURY BOND IS MORE APPROPRIATE DUE TO A LONGER-TERM BOND BEING LESS SUSCEPTIBLE TO FEDERAL POLICY ACTIONS?

A. No. As explained in my direct testimony (I&E Statement No. 3, pp. 29-30), I chose the 10-year Treasury Note as it balances the shortcomings of the short-term T-Bill and the 30-year Treasury Bond. Although long-term Treasury Bonds have less risk of being influenced by federal policies, they have substantial maturity risk associated with the market risk. In addition, long-term treasury bonds bear the risk of unexpected inflation. As such, my choice of a 10-year Treasury Note is more appropriate. Additionally, as mentioned in my direct testimony, the Commission has recently agreed with I&E and recognized the 10-year Treasury Note as the superior measure of the risk-free rate of return.[15]

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR CALCULATION OF THE RISK-FREE RATE USED IN THE CAPM FORMULA.

A. Mr. Moul opines that I have incorrectly given the same weight to the yield on the 10-year Treasury Note for the first quarter of 2023 as I do for the entire five-year period encompassing 2024 to 2028. He then recalculates the risk-free rate by averaging the 10-year Treasury yield forecasts by year from 2024 through 2028 in a failed attempt to increase my calculated risk-free rate formula (UGI Electric Statement No. 9-R, p. 36, lines 4-13).

Q. DO YOU AGREE WITH MR. MOUL'S ANALYSIS OF YOUR RISK-FREE RATE?

A. No. Mr. Moul's new calculation proposes to give equal weight to each separate year

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[15] *Pa. PUC v. UGI Utilities, Inc. – Electric Division,* Docket No. R-2017-2640058, p. 99 (Order entered October 25, 2018).

from 2024 to 2028, which ultimately averages to 3.60% (I&E Exhibit No. 3, Schedule 8). The flaw with this approach is that the further out into the future one forecasts, the less reliable and more speculative the estimates become; therefore, to give the less reliable estimates equal weight would not be appropriate. It is more appropriate to weigh the quarters and years as I have done in my direct testimony (I&E Statement No. 3, pp. 29-30). My calculation provides a more accurate estimation of the risk-free rate during the FPFTY, as the further out one forecasts, the less reliable the information becomes.

More importantly, what Mr. Moul fails to recognize is that his recalculation of my risk-free rate of 3.58% and the risk-free rate he shows in his own calculation of 3.60% are very close. Therefore, his criticisms of my risk-free rate appear meaningless and carry no weight.

<u>LEVERAGE ADJUSTED BETAS</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE USE OF LEVERAGE ADJUSTED BETAS.

A. Mr. Moul simply claims that I failed to use leverage adjusted betas (UGI Electric Statement No. 9-R, p. 35). He does not offer an explanation beyond what he argued in his direct testimony.

Q. IS THE USE OF "LEVERAGE ADJUSTED BETAS" IN CAPM ANALYSIS APPROPRIATE?

A. No. Mr. Moul's adjustment only serves to inflate the result of his CAPM analysis, which I have discussed in greater detail in my direct testimony (I&E Statement No. 3, pp. 56-57). Value Line is a well-known and trusted source that both investors and the Commission rely upon; therefore, it is not necessary to make any type of adjustment to the Value Line betas. Additionally, it is worth mentioning again that a stock with a price movement that is greater than the overall stock market will have a beta that is greater than one and would be described as having more investment risk than the market. Due to being regulated and the monopolistic nature of utilities, very rarely do they have a beta equal to or greater than one. Therefore, in this case, to apply an adjusted beta of 1.08 to the entire industry or electric proxy group as Mr. Moul has done is completely irrational.

SIZE ADJUSTMENT

Q. SUMMARIZE YOUR DIRECT TESTIMONY REGARDING A SIZE ADJUSTMENT.

A. In direct testimony, I stated that Mr. Moul's 102-basis point CAPM size adjustment is unnecessary because none of the technical literature he cited in his direct testimony supporting investment adjustments is related to the size of a company specific to the utility industry (I&E Statement No. 3, pp. 58-60). In addition, I presented an article by Dr. Annie Wong that demonstrates that there is no need to make an adjustment for the size of a company in utility rate regulation. Further, I noted that the Commission has recently rejected the application of a size adjustment to the CAPM cost of equity calculation where it agreed that the same literature the Company cites is not specific to the utility industry.

Q. SUMMARIZE MR. MOUL'S RESPONSE IN REBUTTAL TESTIMONY REGARDING A SIZE ADJUSTMENT.

A. Mr. Moul states that enormous changes have occurred in the industry since the article "Utility Stocks and the Size Effect: An Empirical Analysis" by Dr. Annie Wong was published. He also references the Fama/French study, "The Cross-Section of Expected Stock Returns," to illustrate that his size adjustment is a separate factor from beta that helps to explain systematic risk and returns (UGI Electric Statement No. 9-R, pp. 37-38). He acknowledges that in the 2020 PECO Energy - Gas Division rate case (at Docket No. R-2020-3018929), both the ALJs and the Commission determined that an adjustment for size was not necessary in utility rate regulation (UGI Electric Statement No. 9-R, pp. 38, lines 18-19).

Q. DOES THE TIME THAT HAS ELAPSED SINCE AN ARTICLE WAS WRITTEN NECESSARILY INVALIDATE ITS RESULTS?

A. No. Although Mr. Moul states that enormous changes have occurred in the industry since the 1960s, he presents no evidence that these "changes" have caused the need for a size adjustment. To the contrary, Dr. Wong's study demonstrated that one does *not* need to be made in the regulated utility industry. As stated in my direct testimony, absent any credible article to refute Dr. Wong's findings, Mr. Moul's size adjustment to his CAPM results should be rejected.

Q. DOES THE FAMA/FRENCH STUDY REFUTE DR. WONG'S ARTICLE?

A. No. As stated in my direct testimony, Dr. Wong's article presents evidence that although a size effect may exist for industrial stocks, it does not exist for utility stocks. As the Fama/French study is not specific to utility stocks, it does not demonstrate that a size effect exists in the utility industry. In addition, the size effect that exists for industrial stocks varies to such an extent that it is difficult to predict. The difficulty in predicting the effect of size is demonstrated in the variance from year to year of the measurement of difference between the annual returns on the large and small-capitalization stocks of the NYSE/AMEX/NASDAQ in the Ibbotson *Stocks, Bonds, Bills & Inflation (SBBI): 2015 Yearbook*. As stated on page 100 of the SBBI Yearbook,

> While the largest stocks actually declined in 2001, the smallest stocks rose more than 30%. A more extreme case occurred in the depression-recovery year of 1933, when the difference between the first and 10th decile returns was far more substantial. The divergence in the performance of small-cap and large-cap stocks is evident. In 30 of the 89 years since 1926, the difference between the total returns of the largest stocks (decile 1) and the smallest stocks (decile 10) has been greater than 25 percentage points.

Page 109 states,

> In four of the last 10 years, large-capitalization stocks (deciles 1-2 of NYSE/AMEX/NASDAQ) have outperformed small-capitalization stocks (deciles 9-10). This has led some market observers to speculate that there is no size premium. But statistical evidence suggests that periods of underperformance should be expected.

Page 112 states,

> Because investors cannot predict when small-cap returns will be higher than large-cap returns, it has been argued that they do not expect higher rates of return for small stocks.

Q. WHAT IS YOUR RECOMMENDATION REGARDING MR. MOUL'S SIZE ADJUSTMENT?

A. I continue to recommend that his use of the 1.02% size adjustment be disallowed in calculating the CAPM.

Q. MR. MOUL HAS RECALCULATED YOUR CAPM RESULTS. DO YOU AGREE WITH HIS RECALCULATION?

A. No. Mr. Moul's recalculation (UGI Electric Statement No. 9-R, p. 37) is incorrect for several reasons. As stated in both my direct testimony and above, he used an inaccurate risk-free rate and an unnecessary size adjustment. Because of these factors, the recalculation of my CAPM results as Mr. Moul illustrates is unreliable and unnecessary.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING YOUR CAPM ANALYSIS?

A. Yes. My recommended cost of equity is primarily based upon my DCF analysis for the reasons explained above and in my direct testimony. I present a CAPM analysis to the Commission for comparison, not recommendation, purposes as the inputs are highly subjective, and other than beta, not company or industry specific.

<u>RISK PREMIUM</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE RISK PREMIUM METHOD.

A. Mr. Moul opines that the RP approach should be given serious consideration because it is straight-forward, understandable, and uses a company's own borrowing rate. He claims that it provides a direct and complete reflection of a utility's risk and return (UGI Statement No. 9-R, p. 41, lines 21-28). Mr. Moul also states that I make the assertion that the Risk Premium method does not measure the current cost of equity as directly as the DCF is similarly without foundation (UGI Statement No. 9-R, p. 42, lines 13-15).

Q. DO YOU AGREE WITH MR. MOUL THAT THE RP METHOD PROVIDES A DIRECT AND COMPLETE REFLECTION OF A UTILITY'S RISK AND RETURN?

A. No. The RP method produces an indirect measure when compared to the DCF method.

Q. PLEASE COMMENT ON THE INDIRECT MEASURE OF THE RP METHOD VERSUS THE MORE DIRECT MEASURE OF THE DCF METHOD.

A. Mr. Moul claims my statement that the Risk Premium method does not measure the current cost of equity as directly as the DCF is without foundation. However, in my direct testimony, I have clearly illustrated how the two measures are different. The main reason is that the RP method determines the rate of return on common equity indirectly by observing the cost of debt and adding to it an equity risk premium. The DCF measures equity more directly through the stock information (using equity information), whereas the RP method measures equity indirectly using debt information.

<u>**COMPARABLE EARNINGS**</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE CE METHOD.

A. Mr. Moul claims that using the CE method satisfies the comparability standard established in the *Hope* case. Additionally, he states, "the financial community has expressed the view that the regulatory process must consider the returns that are being achieved in the non-regulated sector to ensure that regulated companies can compete effectively in the capital markets" (UGI Electric Statement No. 9-R, p. 43, lines 18-22).

Q. DO YOU BELIEVE THAT THE COMPANIES USED BY MR. MOUL IN HIS CE METHOD ANALYSIS ARE COMPARABLE TO UGI ELECTRIC?

A. No. As explained in my direct testimony, the companies in Mr. Moul's analysis are not utilities, and therefore, are too disparate to be used in a CE analysis (I&E Statement No. 3, p. 36). For example, the criteria Mr. Moul uses to choose the non-utility companies in his CE group results in the selection of companies such as Abbot Laboratories (Medical Supplies), Bank of New York (Banking), CISCO Systems (Telecom Equipment), Comcast Corp. (Cable TV), Dolby Laboratories, Inc. (Entertainment Tech), Eli Lily and Co. (Drug), Gentex Corp. (Auto Parts), Hanover Insurance Group (Property Insurance), Microsoft Corp. (Software), Moody's Corp.

(Information Services), Raytheon Tech. (Aerospace/Defense), Starbucks Corporation (Restaurant), Vermont Industry (Diversified), Watts Water Technologies, Inc. (Machinery), and Xylem, Inc. (Machinery) (UGI Electric Exhibit B, p. 27, Schedule 14). All these companies operate in industries very different from a utility company and operate under varying degrees of regulation. Also, a large majority, if not all the companies Mr. Moul uses in his analysis, are not monopolies as utilities largely are. This means that they have significantly more competition and would require a higher return for the added risk. Further, the CE method should be excluded because it is entirely subjective as to which companies are comparable and it is debatable whether historical accounting returns are representative of the future.

MANAGEMENT PERFORMANCE POINTS

Q. SUMMARIZE THE COMPANY'S REBUTTAL TESTIMONY REGARDING MANAGEMENT PERFORMANCE POINTS.

A. Mr. Moul continues to advocate for 20 additional basis points to the cost of equity as he opines UGI Electric has performed in an exemplary manner. As in his direct testimony, he points to Mr. Brown's testimony for support (UGI Electric Statement No. 9-R, p. 44, lines 7-16).

Mr. Brown argues that additional basis points for exemplary management performance is in accordance with 66 Pa. C.S.A. § 523. He also discusses the 2017 UGI Electric case (at Docket No. R-2017-2640058) concerning the award of additional equity points for management performance (UGI Electric Statement No. 1-R, p. 16-17). He reiterates that UGI Electric maintains its high standards for electric reliability, as well as its voluntary Long Term Infrastructure Improvement Plan (LTIIP), voluntary Energy Efficiency and Conservation Program, improved customer service, and safety commitments (UGI Electric Statement No. 1-R, p. 17, lines 9-12). He rejects discussion of the management performance adder awarded to Aqua Pennsylvania in the 2021 case (at Docket Nos. R-2021-3027385 and R-2021-3027386) specifically for Aqua rescuing troubled water and wastewater systems at the Commission's request, which was in fact the criteria or measurement of management performance recognized by the Commission (UGI Electric Statement No. 1-R, p. 18, lines 17-22).

Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S REBUTTAL TESTIMONY REGARDING THE CONSIDERATION OF ADDITIONAL BASIS POINTS FOR MANAGEMENT PERFORMANCE?

A. As discussed in greater detail in my direct testimony (I&E Statement No. 3, pp. 62-65), I maintain that UGI Electric, or any utility company for that matter, should not reap additional rewards for programs funded by ratepayers or for meeting their obligations to provide "adequate, efficient, safe, and reasonable service and facilities and shall make all such repairs, changes, alterations, substitutions, extensions, and improvements in or to such service and facilities as shall be necessary or proper for the accommodation, convenience, and safety of its patrons, employees, and the public" under 66 Pa C.S.A. §1501. Also, while I am aware that under 66 Pa C.S.A. §523 the Commission shall consider a utility's effectiveness, it is not mandatory that the Commission grant additional points.

Further, the issuance of additional equity points to recognize management performance must always be done on a case-by-case basis. Again, as discussed in my direct testimony, the situation in the 2021 Aqua case was very specific to that company rescuing troubled water and wastewater systems and preventing health and safety concerns regarding drinking water. This scenario does not apply to UGI Electric. Notably, in the 2017 UGI Electric case, which was decided in a pre-pandemic climate when ratepayers were not faced with the current level of inflation, the Commission awarded UGI Electric a nominal five additional basis points for management effectiveness. This award does not set a precedent specifically for UGI Electric or other utilities for the Commission to award management effectiveness equity points.

Finally, while I don't dispute the Company's specific accomplishments identified by Mr. Brown, I must emphasize my primary argument, that for any company, true strong management performance is earning a higher return through its efficient use of resources and cost cutting measures. The greater net income resulting from cost savings and true efficiency in management and operations is available to be passed on to shareholders. It is nonsensical to support the idea of exemplary management performance because UGI Electric maintains various programs and achieved other accomplishments that are normal and routine business enhancement and efficiency related initiatives expected to be performed by all regulated utilities consistent with utility obligations under 66 Pa C.S.A. §1501. Mr. Brown's listing of management initiatives and accomplishments is not extraordinary or unusual such that it qualifies for a higher equity return in the context of a management performance adder.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS CONCERNING THE COMPANY'S CLAIM REGARDING MANAGEMENT PERFORMANCE?

A. Yes. While I am aware of the rising costs of capital due to the after-effects of the pandemic and the current levels of inflation impacting ratepayers, I believe it is important not to overburden ratepayers.

Additionally, and perhaps most importantly, I must reiterate that most of the programs the Company discusses are ultimately *funded by ratepayers* and any savings resulting from cost cutting measures would likely be offset by the addition of basis points for management performance as ratepayers would have to fund those additional costs as well. This defeats the purpose of efforts to reduce costs to benefit ratepayers. Furthermore, between rate cases, only the Company and its shareholders benefit from cost cutting measures as the reduced costs are not reflected in the rates that customers are being charged.

Q. HAS YOUR RECOMMENDATION REGARDING THE COMPANY'S REQUEST FOR ADDITIONAL BASIS POINTS FOR MANAGEMENT PERFORMANCE CHANGED?

A. No. I continue to recommend that any additional basis points in equity return for management performance be rejected.

OVERALL RATE OF RETURN

Q. HAS YOUR OVERALL RATE OF RETURN RECOMMENDATION CHANGED FROM YOUR DIRECT TESTIMONY?

A. Yes. I accept the Company's revised cost of long-term debt of 4.44%, but I continue to recommend a cost of equity of 8.76%.

Q. WHAT IS YOUR UPDATED OVERALL RATE OF RETURN RECOMMENDATION?

A. I recommend the following updated rate of return for UGI Electric:

Type of Capital	Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	45.41%	4.44%	2.02%
Common Equity	54.59%	8.76%	4.78%
Total	**100.00%**		**6.80%**

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Statement No. 4
Witness: Ethan H. Cline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – ELECTRIC DIVISION

Docket No. R-2022-3037368

Direct Testimony

of

Ethan H. Cline

Bureau of Investigation and Enforcement

Concerning:

Forfeited Discounts
Customer Charge
Scale Back of Rates

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<u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ethan H. Cline, and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission in the Bureau of Investigation and Enforcement ("I&E") as a Fixed Utility Valuation Engineer.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. My education and professional background are set forth in Appendix A, which is attached.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for representing the public interest in rate and other proceedings before the Commission. I&E's analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires balancing the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to evaluate the UGI Utilities, Inc. – Electric Division ("UGI Electric" or "Company") request for an annual increase in operating revenue of approximately $11,425,000. My testimony will address issues related to forfeited discounts, customer cost analysis, customer charge, and scale back.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. No.

Q. PLEASE DESCRIBE THE FILING.

A. On January 28, 2023, UGI Electric filed a base rate increase request of $11,425,000 using the Fully Projected Future Test Year ("FPFTY") ending September 30, 2024.

<u>TEST YEAR</u>

Q. WHAT IS A TEST YEAR AND HOW IS IT USED?

A. A test year is the twelve-month period over which a utility's costs and revenues are measured as the basis for setting prospective base rates. In order to meet its burden of proof, a utility has the option of selecting to use a historic test year ("HTY"), a future test year ("FTY"), or an FPFTY. An HTY is a twelve-month period selected by a company that represents a recent full year of actual data. An

FTY begins the day after the HTY ends and is determined using a combination of actual data and a projection of annualized and normalized estimates of future revenues and expenses and a corresponding rate base at the end of that period. The FPFTY is defined as the twelve-month period that begins with the first month that the new rates will be placed into effect, after the application of the full suspension period permitted under Section 1308(d).

Q. WHAT TEST YEARS HAS THE COMPANY USED IN THIS PROCEEDING?

A. UGI Electric has selected the year ended September 30, 2022 as the HTY, the year ending September 30, 2023 as the FTY, and the year ending September 30, 2024 as the FPFTY (UGI Electric, Book II, St. No. 2, p. 2).

Q. WHAT TEST YEAR HAS THE COMPANY BASED ITS REVENUE REQUIREMENT UPON IN THIS PROCEEDING?

A. UGI Electric based its requested revenue requirement on the FPFTY ending September 30, 2024 (UGI Electric, Book II, St. No. 2, p. 2).

<u>FORFEITED DISCOUNTS</u>

Q. WHAT ARE FORFEITED DISCOUNTS?

A. A public utility can assess a separate charge to customers who do not pay their bill on time. The term forfeited discounts revenue, also referred to as late payment charges, refers to the revenue received by the utility as a result of this charge.

Q. HOW MUCH REVENUE FROM FORFEITED DISCOUNTS DID THE COMPANY BUDGET?

A. UGI Electric budgeted $520,000 in forfeited discount under present rates in the FPFTY ending September 30, 2024 (UGI Electric, Book IV, Ex. A – Fully Projected, Sch. D-5, line 14, col. 6).

Q. WHAT LEVEL OF FORFEITED DISCOUNTS IS THE COMPANY CLAIMING AT PROPOSED RATES FOR THE FPFTY ENDING SEPTEMBER 30, 2024?

A. UGI Electric is projecting the same $520,000 of forfeited discounts under proposed rates for the FPFTY ending September 30, 2024 (UGI Electric, Book IV, Ex. A – Fully Projected Future, Sch. D-2, line 6, col. 6).

Q. WHAT DO YOU RECOMMEND REGARDING THE AMOUNT OF REVENUE FROM FORFEITED DISCOUNTS THE COMPANY WILL RECEIVE UNDER PROPOSED RATES FOR THE FPFTY?

A. I believe it is reasonable to expect that forfeited discounts revenues will increase when a utility's base rates are increased. Since forfeited discounts are generally a percentage of a customer's bill, increasing revenue through a rate increase will cause revenues from forfeited discounts to increase over time. Therefore, I recommend that UGI Electric's forfeited discount claim in the FPFTY be increased by the same percentage as the overall base rate increase granted by the Commission.

<u>CUSTOMER COST ANALYSIS</u>

Q. WHAT IS A CUSTOMER COST ANALYSIS AND HOW IS IT USED?

A. A customer cost analysis is part of a cost of service study that includes only customer costs. It is used to determine the appropriate customer charges for the various classes.

Q. DID THE COMPANY PREPARE AN ANALYSIS TO SUPPORT ITS PROPOSAL TO INCREASE THE CUSTOMER CHARGES?

A. Yes. The Company completed a customer cost analysis presented in UGI Electric, Book VIII, Exhibit D.

Q. WHAT RESULT DID THE COMPANY PRESENT FROM ITS DIRECT RESIDENTIAL CUSTOMER COST ANALYSIS?

A. The results of the direct residential customer cost analysis, shown on page 26 of UGI Electric Statement No. 6, indicate a $22.47 per customer cost.

Q. ARE YOU RECOMMENDING ANY CHANGES TO THE COMPANY'S RESIDENTIAL CUSTOMER COST ANALYSIS?

A. No.

<u>CUSTOMER CHARGES</u>

Q. WHAT IS THE PRESENT RESIDENTIAL MONTHLY CUSTOMER CHARGE?

A. The present residential customer charge is $9.50 per month (UGI Electric, Book III, Statement No. 6, p. 24).

Q. WHAT RESIDENTIAL MONTHLY CUSTOMER CHARGE IS THE COMPANY RECOMMENDING?

A. The Company is recommending that the current residential customer charge of $9.50 per month be increased by $4.00 per month to $13.50 per month which is an increase of 42.1% (UGI Electric, Book III, Statement No. 6, p. 24, and Book IV, Ex. E, p. 5).

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO THE COMPANY'S PROPOSED RESIDENTIAL CUSTOMER CHARGE OF $13.50?

A. Yes. I recommend that the proposed residential customer charge be $12.00 per month. While the Company's proposed $13.50 customer charge is supported by the customer cost analysis, the $4.00 increase from $9.50 to $13.50, or 42.1%, is a significant increase, compared to the base rate residential increase of 27.5% without purchased power costs, and only 9.1% with purchased power and surcharges.

Q. WHAT CUSTOMER CHARGE IS THE COMPANY PROPOSING FOR THE GS-1 RATE CLASS?

A. The Company is proposing to increase the GS-1 class customer charge by $1.00 from $13.00 to $14.00 (UGI Electric, Book IV, Ex. E, p. 3).

Q. ARE YOU RECOMMENDING A SCALE BACK OF THE COMPANY'S PROPOSED $14.00 GS-1 CUSTOMER CHARGE?

A. No. A $1.00, or approximately 8% increase, is not large enough to include in a scale back unless revenues are reduced beyond a level at which the usage rates would be set equal to present rates.

Q. WHAT CUSTOMER CHARGE IS THE COMPANY RECOMMENDING FOR THE GS-5 CLASS?

A. As shown on page 5 of UGI Electric, Book IV, Exhibit E, the present and proposed customer charge for the GS-5 class are the same as those for the residential class.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE GS-5 CLASS CUSTOMER CHARGE?

A. Yes. I recommend that the GS-5 class customer charge continue to be set equal to the residential customer charge.

<u>SCALE BACK OF RATES</u>

Q. WHAT SCALE BACK METHODOLOGY DO YOU RECOMMEND IF THE COMMISSION GRANTS LESS THAN THE FULL INCREASE?

A. If the Commission grants less than the Company's requested increase, I recommend the reductions should be applied proportionally to the percent increase shown on UGI Electric, Book III, Statement No. 6, p. 22, Table 3.

Q. SHOULD THE PROPOSED RESIDENTIAL CUSTOMER CHARGE ALSO BE SCALED BACK?

A. Yes. I recommend that the residential customer charge be included in the scale back of rates if the Commission grants less than the full requested increase. The Commission granted a lower customer charge despite approving the Company's customer cost analysis in the UGI Electric base rate case at Docket No. R-2017-2640058, p. 182, order entered October 25, 2018. This recommendation would also apply to the residential customer charge of $12.00 per month that I recommend, since that the $12.00 per month customer charge equates to an increase of 26.3% which is approximately 3 times the 9.1% overall requested increase in the average residential bill described above. As I stated above, the GS-5 class rates should remain equal to the residential class rates.

Q. WHAT IS THE RATE OF RETURN AND THE RELATIVE RATE OF RETURN, AND WHY ARE THEY IMPORTANT?

A. One of the determinations in a cost of service study is the rate of return earned by each class. It is often described as relative to the overall rate of return where a relative rate of return less than 1.0 indicates that the revenue received from that class is less than the cost of providing service to that class. A relative rate of return greater than 1.0 indicates that the revenue received from that class is more than the cost of providing service to that class.

Q. WHY IS A PROPORTIONAL SCALE BACK REASONABLE?

A. A proportional scale back is fair to all classes for two reasons. First, the proposed percentage increase for each class is the same at approximately 27%, thus reducing each increase proportionally is reasonable (UGI Electric, Book III, Statement No. 6, p. 22, Table 3). Second, this recommendation will move the relative rate of return for all classes towards 1.0, without any undue burden on any class.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

ETHAN H. CLINE

PROFESSIONAL EXPERIENCE AND EDUCATION

EXPERIENCE:

03/2009 - Present

Bureau of Investigation and Enforcement, Pennsylvania Public Utility Commission - Harrisburg, Pennsylvania

Fixed Utility Valuation Engineer – Assists in the performance of studies and analyses of the engineering-related areas including valuation, depreciation, cost of service, quality and reliability of service as they apply to fixed utilities. Assists in reviewing, comparing and performing analyses in specific areas of valuation engineering and rate structure including valuation concepts, original cost, rate base, fixed capital costs, inventory processing, excess capacity, cost of service, and rate design.

06/2008 – 09/2008

Akens Engineering, Inc. - Shiremanstown, Pennsylvania

Civil Engineer – Responsible, primarily, for assisting engineers and surveyors in the planning and design of residential development projects

10/2007 – 05/2008

J. Michael Brill and Associates - Mechanicsburg, Pennsylvania

Design Technician – Responsible, primarily, for assisting engineers in the permit application process for commercial development projects.

01/2006 – 10/2007

CABE Associates, Inc. - Dover, Delaware

Civil Engineer – Responsible, primarily, for assisting engineers in performing technical reviews of the sewer and sanitary sewer systems of Sussex County, Delaware residential development projects.

EDUCATION:

Pennsylvania State University, State College, Pennsylvania
Bachelor of Science; Major in Civil Engineering, 2005

- Attended NARUC Rate School, Clearwater, FL
- Attended Society of Depreciation Professionals Annual Conference and Training

TESTIMONY SUBMITTED:

I have testified and/or submitted testimony in the following proceedings:

1. Clean Treatment Sewage Company, Docket No. R-2009-2121928
2. Pennsylvania Utility Company – Water Division, Docket No. R-2009-2103937
3. Pennsylvania Utility Company – Sewer Division, Docket No. R-2009-2103980
4. UGI Central Penn Gas, Inc., 1307(f) proceeding, Docket No. R-2010-2172922
5. PAWC Clarion Wastewater Operations, Docket No. R-2010-2166208
6. PAWC Claysville Wastewater Operations, Docket No. R-2010-2166210
7. Citizens' Electric Company of Lewisburg, Pa, Docket No. R-2010-2172665
8. City of Lancaster – Bureau of Water, Docket No. R-2010-2179103
9. Peoples Natural Gas Company LLC, Docket No. R-2010-2201702
10. UGI Central Penn Gas, Inc., Docket No. R-2010-2214415
11. Pennsylvania-American Water Company, Docket No. R-2011-2232243
12. Pentex Pipeline Company, Docket No. A-2011-2230314
13. Peregrine Keystone Gas Pipeline, LLC, Docket No. A-2010-2200201
14. Philadelphia Gas Works 1307(f), Docket No. R-2012-2286447
15. Peoples Natural Gas Company LLC, Docket No. R-2012-2285985
16. Equitable Gas Company, Docket Nos. R-2012-2312577, G-2012-2312597
17. City of Lancaster – Sewer Fund, Docket No. R-2012-2310366
18. Peoples TWP, LLC 1307(f), Docket No. R-2013-2341604
19. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2013-2361763
20. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2013-2361764
21. Joint Application, Docket Nos. A-2013-2353647, A-2013-2353649, A-2013-2353651
22. City of Dubois – Bureau of Water, Docket No. R-2013-2350509
23. The Columbia Water Company, Docket No. R-2013-2360798
24. Pennsylvania American Water Company, Docket No. R-2013-2355276
25. Generic Investigation Regarding Gas-on-Gas Competition,
    Docket Nos. P-2011-227868, I-2012-2320323
26. Philadelphia Gas Works 1307(f), Docket No. R-2014-2404355
27. Pike County Light and Power Company (Gas), Docket No. R-2013-2397353
28. Pike County Light and Power Company (Electric), Docket No. R-2013-2397237
29. Peoples Natural Gas Company LLC 1307(f), Docket No. R-2014-2403939
30. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2014-2420273
31. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2014-2420276
32. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2014-2420279
33. Emporium Water Company, Docket No. R-2014-2402324
34. Borough of Hanover – Hanover Municipal Water, Docket No. R-2014-2428304
35. Philadelphia Gas Works 1307(f), Docket No. R-2015-2465656
36. Peoples Natural Gas Company LLC 1307(f), Docket No. R-2015-2465172
37. Peoples Natural Gas Company – Equitable Division 1307(f), Docket No. R-2015-2465181
38. PPL Electric Utilities Corporation, Docket No. R-2015-2469275
39. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2015-2480934
40. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2015-2480937
41. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2015-2480950
42. UGI Utilities, Inc. – Gas Division, Docket No. R-2015-2518438
43. Joint Application of Pennsylvania American Water, et al., Docket No. A-2016-2537209

44. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2016-2543309
45. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2016-2543311
46. City of Dubois – Company, Docket No. R-2016-2554150
47. UGI Penn Natural Gas, Inc., Docket No. R-2016-2580030
48. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2017-2602627
49. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2017-2602633
50. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2017-2602638
51. Application of Pennsylvania American Water Company Acquisition of the Municipal Authority of the City of McKeesport, Docket No. A-2017-2606103
52. Pennsylvania American Water Company, Docket No. R-2017-2595853
53. Pennsylvania American Water Company Lead Line Petition, Docket No. P-2017-2606100
54. UGI Utilities, Inc. – Electric Division, Docket No. R-2017-2640058
55. Peoples Natural Gas Company, LLC – Peoples and Equitable Division 1307(f), Docket Nos. R-2018-2645278 & R-2018-3000236
56. Peoples Gas Company, LLC 1307(f), Docket No. R-2018-2645296
57. Columbia Gas of Pennsylvania, Inc., Docket No. R-2018-2647577
58. Duquesne Light Company, Docket No. R-2018-3000124
59. Suez Water Pennsylvania, Inc., Docket No. R-2018-3000834
60. Application of Pennsylvania American Water Company Acquisition of the Municipal Authority of the Township of Sadsbury, Docket No. A-2018-3002437
61. The York Water Company, Docket No. R-2018-3000006
62. Application of SUEZ Water Pennsylvania, Inc. Acquisition of the Water and Wastewater Assets of Mahoning Township, Docket Nos. A-2018-3003517 and A-2018-3003519
63. Pittsburgh Water and Sewer Authority, Docket Nos. R-2018-3002645 and R-2018-3002647
64. Joint Application of Aqua America, Inc. et al., Acquisition of Peoples Natural Gas Company LLC, et al., Docket Nos. A-2018-3006061, A-2018-3006062, and A-2018-3006063
65. Implementation of Chapter 32 of the Public Utility Code Regarding Pittsburgh Water and Sewer Authority, Docket Nos. M-2018-2640802 and M-2018-2640803
66. Philadelphia Gas Works 1307(f), Docket No. R-2019-3007636
67. People Natural Gas Company, LLC, Docket No. R-2018-3006818
68. Application of Pennsylvania American Water Company Acquisition of the Steelton Borough Authority, Docket No. A-2019-3006880
69. Application of Aqua America, Inc. et al., Acquisition of the Wastewater System Assets of the Township of Cheltenham, Docket No. A-2019-3006880
70. Philadelphia Gas Works, Docket No. R-2019-3009016
71. Wellsboro Electric Company, Docket No. R-2019-3008208
72. Valley Energy, Inc., Docket No. R-2019-3008209
73. Citizens' Electric Company of Lewisburg, Pa, Docket Non. R-2019-3008212
74. Application of Aqua America, Inc. et al., Acquisition of the Wastewater System Assets of the East Norriton Township, Docket No. A-2019-3009052
75. Peoples Natural Gas Company, LLC 1307(f), Docket No. R-2020-3017850
76. Peoples Gas Company, LLC 1307(f), Docket No. R-2020-3017846
77. Philadelphia Gas Works, Docket No. R-2020-3017206
78. Pittsburgh Water and Sewer Authority, Docket Nos. R-2020-3017951 et al.
79. Columbia Gas of Pennsylvania, Docket No. R-2020-3018835
80. Pennsylvania America Water Company, Docket Nos. R-2020-3019369 and R-2020-3019371
81. PECO Energy Company – Gas Division, Docket No. R-2020-3019829

82. PGW 1307(f), Docket No. R-2021-3023970
83. Peoples Natural Gas Company, LLC 1307(f), Docket No. R-2021-3023965
84. Peoples Gas Company, LLC 1307(f), Docket No. R-2021-3023967
85. UGI Utilities, Inc. – Electric Division, Docket No. R-2021-3023618
86. Columbia Gas of Pennsylvania, Inc., Docket No. R-2021-3024926
87. Duquesne Light Company, Docket No. R-2021-3024750
88. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2021-3025652
89. Pittsburgh Water and Sewer Authority, Docket Nos. R-2021-3024773 et al.
90. Application of Aqua America Wastewater, Inc. et al., Acquisition of the Wastewater System Assets of Lower Makefield Township, Docket No. A-2021-3024267
91. Aqua Pennsylvania Water, Inc. and Aqua Pennsylvania Wastewater, Inc., Docket Nos. R-2021-3027385 and R-2021-3027386
92. Application of Pennsylvania-American Water Company for Acquisition of the Wastewater Collection and Treatment System Assets of the York City Sewer Authority, Docket No. A-2021-3024681
93. City of Lancaster – Bureau of Water, Docket No. R-2021-3026682
94. Application of Aqua America Wastewater, Inc. et al., Acquisition of the Wastewater System Assets of East Whiteland Township, Docket No. A-2021-30246132
95. UGI Utilities, Inc. – Gas Division, Docket No. R-2021-3030218
96. Peoples Natural Gas Company, LLC 1307(f), Docket No. R-2022-3030661
97. Columbia Gas of Pennsylvania, Inc., Docket No. R-2022-3031211
98. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2022-3032242
99. Pennsylvania American Water Company, Docket Nos. R-2022-3031672 and R-2022-3031673
100. The York Water Company, Docket Nos. R-2022-3031340 and R-2022-3032806
101. Columbia Gas of Pennsylvania, Inc., Docket No. R-2022-3032167

I&E Statement No. 4-SR
Witness: Ethan H. Cline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – ELECTRIC DIVISION

Docket No. R-2022-3037368

Surrebuttal Testimony

of

Ethan H. Cline

Bureau of Investigation and Enforcement

Concerning:

Forfeited Discounts
Customer Charge
Scale Back of Rates

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<u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ethan H. Cline, and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. ARE YOU THE SAME ETHAN H. CLINE THAT SUBMITTED DIRECT TESTIMONY ON APRIL 25, 2023?

A. Yes. I submitted I&E Statement No. 4 on April 25, 2023.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony submitted by witnesses on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" or "Company") by Tracy A. Hazenstab (UGI Electric St. No. 2-R) and John D. Taylor (UGI Electric St. No. 6-R) regarding issues related to forfeited discounts, customer cost analysis, customer charge, and scale back.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. No. However, I will refer to my direct testimony (I&E Statement No. 4) in this surrebuttal testimony.

Q. PLEASE DESCRIBE THE FILING.

A. On January 28, 2023, UGI Electric filed a base rate increase request of $11,425,000 using the Fully Projected Future Test Year ("FPFTY") ending September 30, 2024.

<u>FORFEITED DISCOUNTS</u>

Q. WHAT DID YOU RECOMMEND REGARDING FORFEITED DISCOUNTS?

A. I recommended that UGI Electric's forfeited discount claim in the FPFTY be increased by the same percentage as the overall base rate increase granted by the Commission (I&E St. No. 4, pp. 4-5).

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION REGARDING FORFEITED DISCOUNTS?

A. Yes. The Company accepted my recommendation and revised its filing to reflect an increase of $39,000 to its forfeited discount claim increasing its claim to $559,000 based on the revenue increase. The Company further indicated that a similar adjustment to forfeited discounts should be made related to any final revenue determination made by the Commission that would change the overall revenue increase. (UGI Electric St. No. 2-R, p. 6).

Q. DO YOU AGREE THAT THE COMPANY'S CLAIM FOR FORFEITED DISCOUNTS SHOULD BE ADJUSTED BASED ON ANY FINAL REVENUE DETERMINATION MADE BY THE COMMISSION THAT WOULD CHANGE THE OVERALL REVENUE INCREASE?

A. Yes. This is consistent with the recommendation set forth in my direct testimony.

<u>CUSTOMER CHARGES</u>

Q. WHAT IS THE PRESENT AND PROPOSED RESIDENTIAL MONTHLY CUSTOMER CHARGE?

A. The present residential customer charge is $9.50 per month. The Company proposed to increase the customer charge to $13.50 in this proceeding. (UGI Electric, Book III, Statement No. 6, p. 24).

Q. DID YOU RECOMMEND ANY ADJUSTMENTS TO THE COMPANY'S PROPOSED RESIDENTIAL CUSTOMER CHARGE OF $13.50?

A. Yes. I recommended that the proposed residential customer charge be $12.00 per month (I&E St. No. 4, p. 6).

Q. WHY DID YOU RECOMMEND THE COMPANY'S PROPOSED RESIDENTIAL CUSTOMER CHARGE BE SET AT $12.00?

A. As I stated on pages 6-7 of I&E Statement No. 4, while the Company's proposed $13.50 customer charge is supported by the customer cost analysis, the $4.00

increase from $9.50 to $13.50, or 42.1%, is a significant increase, compared to the base rate residential increase of 27.5% without purchased power costs, and 9.1% with purchased power and surcharges.

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION?

A. No. UGI Witness Taylor did not directly respond to my recommendation to limit the residential customer charge to $12.00 per month.

Q. DID THE COMPANY ADDRESS YOUR CONCERN THAT A 42% INCREASE IN THE RESIDENTIAL CUSTOMER CHARGE IS EXCESSIVE GIVEN THE SMALLER PERCENTAGE INCREASE IN THE USAGE RATE?

A. Not directly. However, the Company did address the OCA's recommendation that the residential customer charge not be increased stating that the Commission should only focus on the total bill a customer pays, and not the individual bill components. (UGI St. No. 6-R, p. 24).

Q. DO YOU AGREE WITH THE COMPANY THAT THE COMMISSION SHOULD ONLY FOCUS ON THE TOTAL BILL A CUSTOMER PAYS?

A. No. The Company admits that some residential customers have zero usage each month, and therefore under the Company's proposal will experience and 42% increase in their total bill. The rebuttal testimony concerning the total bill failed to consider my residential customer charge recommendation. Therefore, the Company's position concerning total bill comparison should be rejected.

Q. DO YOU WISH TO CHANGE YOUR RECOMMENDATION OF A $12.00 RESIDENTIAL CUSTOMER CHARGE?

A. No. I continue to recommend a $12.00 residential customer charge.

Q. DID YOU RECOMMEND ANY REDUCTION TO THE COMPANY'S PROPOSED $14.00 GS-1 CUSTOMER CHARGE?

A. No. As I stated on page 7 of I&E Statement No. 4, a $1.00, or approximately 8% increase, is not large enough to include in a scale back unless revenues are reduced beyond a level at which the usage rates would be set equal to present rates.

Q. DID THE COMPANY CHANGE ITS RECOMMENDATION REGARDING THE GS-1 CUSTOMER CHARGE?

A. Yes. On page 23 of UGI Electric Statement No. 6-R, the Company stated that it agreed with the Office of Small Business Advocate's proposal to increase the GS-1 customer charge to $17.00.

Q. DO YOU WISH TO CHANGE YOUR RECOMMENDATION REGARDING THE GS-1 CUSTOMER CHARGE?

A. I do not oppose the moderate $4.00 per month increase in the GS-1 customer charge. However, since the $4.00 per month increase equates to an increase of 30.1%, I recommend that that proposed $17.00 per month GS-1 customer charge be included in the scale back to reduce the 30.1% increase.

Q. DID YOU HAVE ANY RECOMMENDATIONS REGARDING THE GS-5 CLASS CUSTOMER CHARGE?

A. Yes. I recommended that the GS-5 class customer charge continue to be set equal to the residential customer charge (I&E St. No. 4, p. 8).

Q. DID ANY PARTIES RESPOND TO YOUR RECOMMENDATION REGARDING THE GS-5 RATE CLASS?

A. No. Therefore, I continue to recommend the GS-5 class customer charge continue to be set equal to the residential customer charge.

<u>SCALE BACK OF RATES</u>

Q. WHAT SCALE BACK METHODOLOGY DID YOU RECOMMEND IF THE COMMISSION GRANTS LESS THAN THE FULL INCREASE?

A. If the Commission grants less than the Company's requested increase, I recommended the reductions should be applied proportionally to the percent increase shown on UGI Electric, Book III, Statement No. 6, p. 22, Table 3. I also recommended that the residential customer charge be included in the scale back of rates if the Commission grants less than the full requested increase. As I stated above, the GS-5 class rates should remain equal to the residential class rates. (I&E St. No. 4, p. 8).

Q. DID ANY PARTIES RESPOND TO YOUR SCALE BACK RECOMMENDATION?

A. Yes. The Company stated that it agreed with the approach of proportionately adjusting the revenue if the Commission grants less than the requested increase but disagreed with the recommendation to include the customer charge in the scale back because the Company's proposed customer charge is lower than what is required to recover customer-related costs (UGI St. No. 6-R, pp. 5-6).

Q. DO YOU WISH TO CHANGE YOUR RECOMMENDATION REGARDING THE SCALE BACK OF THE CUSTOMER CHARGE?

A. No. For the reasons stated in my direct testimony, it is reasonable to include the $12.00 residential customer charge in any scale back of rates. Furthermore, a lower customer charge allows customers to have greater control of their monthly bill through usage rates than a higher customer charge.

Q. DO YOU WISH TO ADD A RECOMMENDATION CONCERNING THE GS-1 CUSTOMER CHARGE?

A. Yes. The agreed upon GS-1 customer charge of $17.00 per month equates to an increase of $4.00 per month or 30.8% ($4.00 / $13.00). This 30.8% increase is more than twice the overall GS-1 increase of 13.7%. Therefore, to reduce the 30.8% increase in the GS-1 customer charge, I recommend that that proposed $17.00 per month GS-1 customer charge be included in the scale back.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2022-3037368**
	:	
UGI Electric Division – Base Rate	:	
	:	

VERIFICATION OF ETHAN H. CLINE

I, **Ethan H. Cline**, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the **I&E Statement No. 4** and **I&E Statement No. 4-SR** were prepared by me or under my direct supervision and control.

Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same if called to the stand at any evidentiary hearing held in this matter.

This Verification is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsification to authorities.

Signed in New Bloomfield, Pennsylvania, this 12th day of June 2023.

/s/ Ethan H. Cline

Ethan H. Cline

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2022-3037368**
	:	
UGI Electric Division – Base Rate	:	
	:	

VERIFICATION OF CHRISTOPHER KELLER

I, **Christopher Keller**, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the **I&E Statement No. 2 (PROPRIETARY), I&E Exhibit No. 2 (PROPRIETARY), I&E Statement No. 2-R, I&E Exhibit No. 2-R, I&E Statement No. 2-SR (PROPRIETARY),** and **I&E Exhibit No. 2-SR** were prepared by me or under my direct supervision and control.

Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same if called to the stand at any evidentiary hearing held in this matter.

This Verification is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsification to authorities.

Signed in New Cumberland, Pennsylvania, this 8th day of June 2023.

/s/ Christopher Keller
Christopher Keller

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	**Docket No. R-2022-3037368**
	:	
UGI Electric Division – Base Rate	**:**	
	:	

VERIFICATION OF VANESSA OKUM

I, **Vanessa Okum**, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the **I&E Statement No. 1, I&E Exhibit No. 1,** and **I&E Statement No. 1-SR** were prepared by me or under my direct supervision and control.

Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same if called to the stand at any evidentiary hearing held in this matter.

This Verification is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsification to authorities.

Signed in Millersburg, Pennsylvania, this 8th day of June 2023.

_/s/ Vanessa Okum____________________

Vanessa Okum

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2022-3037368**
	:	
UGI Utilities, Inc. - Electric Division	:	

VERIFICATION OF D. C. PATEL

I, **D. C. Patel**, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the **I&E Statement No. 3, I&E Exhibit No. 3,** and **I&E Statement No. 3-SR** were prepared by me or under my direct supervision and control.

Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same if called to the stand at any evidentiary hearing held in this matter.

This Verification is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsification to authorities.

Signed in Harrisburg, Pennsylvania, this 8th day of June 2023.

/s/ DCPatel

D. C. Patel

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2022-3037368**
	:	
UGI Electric Division – Base Rate	:	
	:	

VERIFICATION OF ESYAN A. SAKAYA

I, **Esyan A. Sakaya**, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the **I&E Statement No. 5** was prepared by me or under my direct supervision and control.

Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same if called to the stand at any evidentiary hearing held in this matter.

This Verification is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsification to authorities.

Signed in Harrisburg, Pennsylvania, this 8th day of June 2023.

_/s/Esyan A. Sakaya___________________

Esyan A. Sakaya

I&E Statement No. 5
Witness: Esyan A. Sakaya

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – ELECTRIC DIVISION

Docket No. R-2022-3037368

Direct Testimony

of

Esyan A. Sakaya

Bureau of Investigation and Enforcement

Concerning:

Test Year
Utility Plant-in-Service
Rate Base
Future Test Year and Fully Projected Future Test Year Reports

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<u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Esyan A. Sakaya. My business address is 400 North Street, Harrisburg, Pennsylvania 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission ("Commission") in the Bureau of Investigation and Enforcement ("I&E") as a Fixed Utility Valuation Engineer.

Q. WHAT IS YOUR EDUCATIONAL AND EMPLOYMENT EXPERIENCE?

A. Appendix A, which is attached to my testimony, describes my educational background and professional experience.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN THIS PROCEEDING.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. The I&E analysis in the proceeding is based on its responsibility to represent the public interest. This responsibility requires balancing the interests of the ratepayers, the company, and the regulated community.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to evaluate UGI Utilities, Inc. – Electric Division

("UGI Electric" or "Company") request for an annual increase in operating revenue of approximately $11,425,000. My testimony will address issues related to the proposed test year, utility plant in service, rate base, and reporting requirements.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. No.

Q. PLEASE DESCRIBE THE FILING.

A. On January 27, 2023, UGI Electric filed a base rate increase request of $11,425,000 using the Fully Projected Future Test Year ("FPFTY") ending September 30, 2024 (UGI Electric Book IV, FPFTY, Sch. A-1, Col. 4, line 9).

<u>TEST YEAR</u>

Q. WHAT IS A TEST YEAR AND HOW IS IT USED?

A. A test year is the twelve-month period over which a utility's costs and revenues are measured as the basis for setting prospective base rates. In order to meet its burden of proof, a utility has the option of selecting to use a historic test year ("HTY"), a future test year ("FTY"), or an FPFTY. An HTY is a twelve-month period selected by a company that represents a recent full year of actual data. An FTY begins the day after the HTY ends and is determined using a combination of actual data and a projection of annualized and normalized estimates of future revenues and expenses and a corresponding rate base at the end of that period.

The FPFTY is defined as the twelve-month period that begins with the first month that the new rates will be placed into effect, after the application of the full suspension period permitted under Section 1308(d).

Q. WHAT TEST YEARS HAS THE COMPANY USED IN THIS PROCEEDING?

A. UGI Electric has selected the year ended September 30, 2022 as the HTY, the year ending September 30, 2023 as the FTY, and the year ending September 30, 2024 as the FPFTY (UGI Electric St. No. 2, p. 2).

Q. WHAT TEST YEAR HAS THE COMPANY BASED ITS REVENUE REQUIREMENT UPON IN THIS PROCEEDING?

A. UGI Electric based its requested revenue requirement on the FPFTY ending September 30, 2024 (UGI Electric St. No. 2, p. 2).

RATE BASE

Q. WHAT IS RATE BASE?

A. Rate base, also known as measure of value, is the depreciated original cost of a utility's investment in plant that is in place to serve customers plus other additions and deductions that the Commission deems necessary in order to keep the utility operating and providing safe and reliable service to its customers.

Q. HOW IS RATE BASE USED IN THE RATEMAKING FORMULA?

A. Rate base is one part of the financial equation used by the Commission to determine the appropriate revenue that a utility is granted in a rate proceeding. The revenue determination allows the utility to meet its expense obligations and gives it the opportunity to earn the rate of return established by the Commission in a rate proceeding. The equation used to determine the proper revenue requirement is:

Revenue Requirement = (Rate Base x Rate of Return) + Operating Expenses + Depreciation Expense + Taxes

Q. HOW IS THE DEPRECIATED ORIGINAL COST OF PLANT-IN-SERVICE AT THE END OF THE TEST YEAR DETERMINED?

A. The depreciated original cost is determined by subtracting the book reserve, which is the accumulation of all prior annual depreciation expense, and other items such as salvage value, from the original cost of the plant in service that is projected to be used and useful in the public service. The depreciated original cost of the plant in service is determined by taking a "snapshot" look at the depreciated original cost value of used and useful utility plant expected to be in service at the end of the FPFTY.

Q. WHAT ADDITIONS AND DEDUCTIONS ARE INCLUDED IN THE COMPANY'S RATE BASE CALCULATION?

A. The Company's calculation includes additions of Materials and Supplies and Cash Working Capital as well as deductions of accumulated deferred income taxes ("ADIT") and customer deposits as shown on UGI Electric, Book IV, Exhibit A – Fully Projected, Schedule C-1.

Q. WHAT IS UGI ELECTRIC'S CLAIM FOR RATE BASE IN THE FPFTY?

A. UGI Electric is claiming $172,242,000 of rate base (UGI Electric, Book IV, FPFTY, Ex. A, Sch. C-1, line 8).

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO THE COMPANY'S ADDITIONS AND DEDUCTIONS LISTED ABOVE?

A. No. Although other I&E witnesses have adjustments described in their testimony, I do not.

UTILITY PLANT-IN-SERVICE

Q. WHAT IS UTILITY PLANT-IN-SERVICE?

A. Utility plant-in-service comprises all the utility's intangible assets (i.e., organization costs, franchise and consents costs, and land right costs) and tangible assets (i.e., land, facilities, and equipment). Moreover, for plant to be included in rates, the plant must be used and useful in the provision of utility service to the customers. Therefore, by definition, only plant currently providing or capable of providing utility service to customers is eligible to be reflected in rates.

Q. WHAT IS UGI ELECTRIC'S UTILITY PLANT-IN-SERVICE CLAIM FOR ITS FTY AND FPFTY?

A. UGI Electric's utility plant-in-service claim for the FTY ending September 30, 2023 is $252,941,000 (UGI Electric, Book IV, FTY Ex. A, Sch. C-1, line 1). The Company's utility plant-in-service claim for the FPFTY ending September 30, 2024 is $275,001,000 (UGI Electric Book IV, FPFTY, Ex. A, Sch. C-1, line 1).

Q. WHAT ADDITIONS AND RETIREMENTS ARE BEING CLAIMED BY UGI ELECTRIC IN THE FUTURE TEST YEAR?

A. The Company provided schedules showing $23,221,000 of plant additions and $3,874,000 of retirements in the FTY ending September 30, 2023 (UGI Electric Book IV, FTY, Ex. A, Sch. C-2, pp. 4-5, Col. 3, line 48).

Q. WHAT ADDITIONS AND RETIREMENTS ARE BEING CLAIMED BY UGI ELECTRIC IN THE FULLY PROJECTED FUTURE TEST YEAR?

A. The Company provided schedules showing $24,665,000 of plant additions and $2,605,000 of retirements in the FPFTY ending September 30, 2024 (UGI Electric Book IV, FPFTY, Ex. A, Sch. C-2, pp. 4-5, Col. 3, line 48).

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE ADDITIONS AND RETIREMENTS LISTED ABOVE?

A. No.

<u>FTY AND FPFTY REPORTING</u>

Q. WHAT AMOUNT OF ADDITIONAL RATE BASE WILL BE ASSOCIATED WITH THE INCLUSION OF THE FPFTY ENDING SEPTEMBER 30, 2024?

A. As mentioned above, the Company's claimed rate base for the FPFTY ending September 30, 2024 is $172,242,000 (UGI Electric Book IV, FPFTY, Ex. A, Sch. C-1, Col. 5, line 8). UGI Electric's rate base for the FTY ending September 30, 2023 is $155,636,000 (UGI Electric Book IV, FTY, Ex. A, Sch. C-1, Col. 5, line 8). Therefore, $16,606,000 ($172,242,000 – $155,636,000) of rate base additions are associated with the FPFTY.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING PLANT ADDITIONS THAT UGI ELECTRIC PROJECTS TO BE IN SERVICE DURING THE FTY ENDING SEPTEMBER 30, 2023 AND THE FPFTY ENDING SEPTEMBER 30, 2024?

A. Yes. I recommend that the Company provide the Commission's Bureau of Investigation and Enforcement and the Office of Consumer Advocate with an update to UGI Electric Book IV, FTY, Ex. C-2, pp. 4-5 no later than January 2, 2024, which should include actual capital expenditures, plant additions, and retirements by month from October 1, 2022 through September 30, 2023 and an additional update to UGI Electric Book IV, FPFTY, Ex. C-2, pp. 4-5, no later than January 2, 2025, which should include actual capital expenditures, plant additions and retirements from October 1, 2023 through September 30, 2024.

Q. WHY DO YOU RECOMMEND THAT UGI ELECTRIC PROVIDE THESE UPDATES?

A. I&E continues to believe that there is value in determining how closely UGI projected investments in future facility comport with the actual investments that are made by the end of the FTY and FPFTY. Determining the correlation between UGI Electric's projected and actual results will help inform the Commission and the parties in UGI Electric's future rate cases as to the validity of UGI' s projections.

Using a FPFTY, UGI Electric is requesting ratepayers pre-pay a return on its projected investment in future facilities that are not in place and providing service at the time the new rates take effect, but also are not subject to any guarantee of being completed and placed into service. While the FPFTY provides for such projections, there should be verification of the projections. Therefore, requiring the Company to provide updates demonstrating that actual investments comport with projections used in setting rates using the FPFTY provides the

Commission with actual data to gauge the accuracy of UGI Electric’s projected investments in future proceedings.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes. However, I reserve the right to supplement or revise my recommendations if additional information is received that would alter my position in this direct testimony.

Esyan A. Sakaya

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION
400 North Street
HARRISBURG, PA 17120

Education:

National Association of Regulatory Utility Commissioners, Clearwater, FL
Utility Rate School; Utility Rate Making Basics, October 2019

Society of Depreciation Professionals, Philadelphia, PA
Introduction to Depreciation; Depreciation Fundamentals, September 2019

Temple University, Philadelphia, PA
Bachelor of Science; Major in Engineering Technology, 2015

Community College of Philadelphia, Philadelphia, PA
Associate of Applied Science; Major in Construction Management Technology, 2011

Island School of Building Arts, Gabriola Island, BC-Canada
Certificate Graduate: Heavy Timber Construction Aug 2002-Nov 2002

Solar Energy International, Carbondale, CO
Certificate Graduate: Basic and Advanced Photovoltaic Design, April 2002-May 2002

Experience:

12/2018-Present
Pennsylvania Public Utility Commission-Harrisburg, PA

<u>Fixed Utility Valuation Engineer-</u> Assist in engineering related studies related to valuation, depreciation, cost of service, quality of service as they apply to regulated utilities. Contribute in evaluating, contrasting and conducting performance analyses in distinctive sections of valuation engineering and rate structure involving valuation concepts, original cost, rate base, fixed capital costs, inventory processing, excess capacity, cost of service, and rate design. Provide expert testimony in rate related utility cases.

4/2018-12/2018
Pennsylvania Department of Transportation-Harrisburg, PA

Photogrammetry Technician I- Created three-dimensional mapping layouts of natural and man-made features from stereoscopic images on a computer workstation. Assisted in the field placement of ground based surveyed control-points prior to aerial photography acquisition. Provided field support in the use of laser scans for comprehensive digital surveying data. Operated global positioning satellite surveying equipment to obtain accurate geodetic coordinates of pre-established benchmarks.

8/2017-4/2018
Pennoni and Associates. Consulting Engineers-King of Prussia, PA

Construction Inspector-Provided quality assurance in the onsite material testing of concrete, soils, and asphalt. Read and interpreted construction drawings and specifications of materials and components. Completed daily reports regarding project progress to engineers, project managers/superintendents, contractors and clients.

TESTIMONY SUBMITTED:

I have assisted and/or submitted testimony in the following proceedings:

NO.	Case
1.	UGI Gas Utilities - Gas Division, Docket Number: R-2018-3006814
2.	Newtown Artesian Water Company, Docket Number: R-2018-3006904
3.	Pittsburgh Wastewater, Docket Number: M-2018-2640803
4.	PAWC Purchase of Steelton, Docket Number: A-2019-3006814
5.	Philadelphia Gas Works, Docket Number: R-2019-3009016 - 3007636
6.	Community Utilities Water, Docket Number: R-2019-3008947
7.	Aqua Purchase of Cheltenham, Docket Number: A-2019-3008491
8.	UGI NORTH, Docket Number: R-2019-3009647
9.	UGI CENTRAL, Docket Number: R-2019-3009647
10.	UGI SOUTH, Docket Number: R-2019-3009647
11.	Twin Lakes Utilities, Docket Number: R-2019-3010958
12.	Penn Power Company, Docket: P-2019-3012628
13.	UGI Gas Utilities, Docket Number: R-2019-3015162
14.	National Fuel and Gas Distribution, Docket Number: R-2020-3015251
15.	Columbia Gas of Pennsylvania, Docket: R-2020-3018993 -3018835
16.	Duquesne Light Company, Docket Number: P-2020-3019522

17. PA American Water Company, Docket R-2020-3019369 – 310937
18. Bethlehem Water Company, Docket R-2020-3020256
19. Audubon Water Company, Docket: R-2020-3020919
20. Twin Lakes Utilities, Docket: P-2020-3020914
21. Pike County Light and Power-Gas, Docket: R-2020-3022134
22. Pike County Light and Power-Electric, Docket: R-2020-3022135
23. Duquesne Light Company, Docket Number: R-2021-3024750
24. Community Utilities Water, Docket Number: R-2021-3025206
25. Community Utilities Wastewater, Docket Number: R-2021-3025206
26. Hanover Municipal Water Works, Docket Number: R-2021-3026116
27. Aqua Pennsylvania, Inc, Docket R-2021-3027385 – 3027386
28. Aqua Purchase of Willistown, Docket Number: A-2021-3027268
29. National Fuel and Gas Distribution, Docket Number: R-2022-3030235
30. UGI Gas Utilities, Docket Number: R-2021-3030218
31. PECO Energy Company – Gas, Docket Number: R-2022-3031113
32. Valley Energy, Inc, Gas, Docket: R-2022-3032300
33. Citizens Electric Company, Docket: R-2022-3032369
34. Leatherstocking Gas Company, LLC Docket: R-2022-303276
35. National Fuel and Gas Distribution, Docket Number: R-2022-3035730
36. Aqua Purchase of Shenandoah, Docket Number: A-2022-3034143

OCA Statement No. 1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**Docket No. R-2022-3037368**
UGI Utilities, Inc. – Electric Division	)	

DIRECT TESTIMONY OF

DANTE MUGRACE

ON BEHALF OF THE

COMMONWEALTH OF PENNSYLVANIA

OFFICE OF CONSUMER ADVOCATE

<u>PUBLIC VERSION</u>

April 25, 2023

TABLE OF CONTENTS

I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dante Mugrace. My business address is 22 Brooks Avenue, Gaithersburg, MD 20877.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am a Senior Consultant with the Economic and Management Consulting Firm of PCMG and Associates, LLC. (PCMG). In my capacity as a Senior Consultant, I am responsible for evaluating and examining rate and rate related proceedings before various governmental entities, preparing expert testimony, recommending revenue requirements, as well as offering opinions on economic policy, policy issues and methodologies used to set a value on a utility's rate base and cost of service components of revenue requirement.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. PCMG is an association of experts in utility regulation and policy, economics, accounting and finance. PCMG's members have over 75 years of collective experience providing assistance to counsel and expert testimony regarding the regulation of electric, gas, water and wastewater utilities that operate under local, state and federal jurisdictions. PCMG focuses on areas regarding revenue requirement, cost of service, rate design, cost of capital and rate of return. Prior to my association with PCMG, I was employed as a Senior Consultant with the consulting firm of Snavely King Majoros and Associates (SKM) from 2013 to 2015, in the same capacity as PCMG. Prior to SKM, I was employed by the New Jersey Board of Public Utilities (NJBPU) from 1983 to my retirement in 2011. During my tenure at the NJBPU, I held various Accounting, Rate Analyst, Supervisory and Management Positions. My last position was Bureau Chief of Rates in the Agency's Water Division (Bureau Chief of Rates). I held this position for nearly 10 years. My resume is attached as Appendix A.

Q. WHAT EXPERIENCE DO YOU HAVE IN THE AREA OF UTILITY RATE SETTING PROCEEDINGS AND OTHER UTILITY MATTERS?

A. In my capacity as Bureau Chief of Rates at NJBPU, I was responsible for overseeing the rate process regarding administrative, financial, and managerial functions of the Rates

Bureau. My primary duties were to ensure that the jurisdictional utilities had sufficient revenues to cover their operating expenses, the ability to earn a reasonable rate of return on plant investments, and to ensure that the provision of safe, adequate and proper service at reasonable rates was met. During my time at the NJBPU, I was involved in hundreds of rate and rate related proceedings. In my capacity as a Senior Consultant previously with SKM and now with PCMG, I have been and am currently involved in rate and rate related proceedings before the Commissions in the Commonwealth of Massachusetts and Pennsylvania, and the States of Maine, Maryland, New Jersey, New York, North Dakota, and Ohio. I was involved in the Generic Proceedings to Establish Parameters for the Next Generation Performance Based Rate Plans before the Alberta Utilities Commission. I was involved in transmission formula rate plans before the Federal Energy Regulatory Commission (FERC) regarding the PECO Energy Company on behalf of the Pennsylvania OCA and the Rockland Electric Company on behalf of the NJ Division of Rate Counsel.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Master of Business Administration (MBA) degree with a concentration in Strategic Management from Pace University-Lubin School of Business in New York, New York. I hold a Master of Public Administration (MPA) degree from Kean University in Union, New Jersey. I hold a Bachelor of Science (BS) degree in Accounting from Saint Peter's University in Jersey City, New Jersey.

II. PURPOSE OF TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate (OCA) with respect to the UGI Utilities, Inc. – Electric Division's base rate case proceeding filed with the PA Public Utility Commission in Docket No. R-2022-3037368 dated January 27, 2023.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to calculate and to make a recommendation regarding the UGI Utilities, Inc. – Electric Division's (UGI or Company) base rate case proceeding in the area of revenue requirement.[1] My recommendation includes the setting of the Company's Rate Base Valuation, and Pro Forma Operating Income at Present Rates for the Fully Projected Future Test Year Period Ending September 30, 2024. The Company requested an overall increase in rates for its electric distribution service of approximately $11.425 million or 7.50% above current operating revenues of approximately $152.691 million. Under distribution – only operating revenues the overall impact is a 20.5% increase above current operating revenues. The Company provides Electric Distribution service to about 63,000 customers located in certain parts of the counties of Luzerne and Wyoming. The Company's last base rate case increase was approved by the Commission in 2021 in the amount of $6.15 million or 7.10%. Included in my recommended position on Rate Base Valuation and Operating Income, I am also incorporating the recommendations of OCA witness Mr. Aaron Rothschild with respect to the overall rate of return, OCA witness Dr. Karl Pavlovic on any rate design adjustments, and OCA witness Mr. Roger Colton on Universal Service adjustments.

III. REVENUE REQUIREMENT ISSUES

A. SUMMARY

Q. WHAT REVENUE DEFICIENCIES OR ADJUSTMENTS ARE YOU RECOMMENDING?

A. Based upon the use of the Company's proposed fully projected future test year ending September 30, 2024, I have the following recommendations:

- My recommended Rate Base balance is $171,589,479 which is $$652,521 lower than the Company's proposed Rate Base balance of $172,242,000.
- My overall Rate of Return based upon OCA witness Rothschild's recommendation is 6.18%, which includes a Common Equity component of 8.44% and a Common Equity Ratio of 44.75%.

[1] UGI Utilities, Inc. – Electric Division is a wholly owned subsidiary of UGI Corporation. UGI Corporation has two operating divisions, the Gas Division and the Electric Division, both which are regulated by the PAPUC.

- My recommended Operating Revenue at Present Rates is computed at $152,717,832, which is $26,832 higher than the Company's Present Rate Revenue of $152,691,000.[2]
- My recommended total Operating Expenses are $141,736,181, which is $4,567,811 lower than the Company's proposed Operating Expenses of $146,303,992.
- My recommended Federal Income Tax is $1,848,728, which is $809,399 lower than the Company's proposed Federal Income Taxes of $2,658,000.
- My recommended State Income Tax is $912,536, which is $243,341 lower than the Company's Proposed State Income Tax of $1,155,877.
- Overall, I recommend a revenue requirement increase of $3,540,663, which is $7,883,442 lower than the Company's proposed revenue requirement increase of $11,425,000.

Q. WHAT EFFECT DOES MR. ROTHSCHILD'S DISALLOWANCE OF MR. MOUL'S MANAGEMENT PERFORMANCE PREMIUM OF 0.20% HAVE ON THE COMPANY'S REVENUE REQUIREMENT?

A. The effect of removing the 0.20% Management Performance Premium (basis point adder) from the Company's Cost of Equity would be a reduction from the Company's filed 11.30% Equity Cost Rate less 0.20% equals 11.10%. Incorporating this into the overall rate of return would be an 8.04% instead of the Company's 8.15%. The revenue requirement impact would be a reduction of about $288,000. (Rate Base of $172,242,000 times the rate of return of 8.04% equals $13,848,000 or a reduction from the Company's proposed income requirement of $14,038,000 of $190,000 multiplied by the gross revenue factor of 1.513583 equals $288,000. This would reduce the proposed revenue requirement from $11,424,105 to $11,136,105.

Q. USING UGI'S PROPOSED COMMON EQUITY RETURN OF 11.30%, REVENUE INCREASE AND CAPITAL STRUCTURE AS A STARTING POINT, WHAT IS THE DIFFERENCE IN THE REVENUE INCREASE IF MR. ROTHSCHILD'S RECOMMENDED CAPITAL STRUCTURE WAS ADOPTED BUT ALL OTHER FACTORS WERE HELD EQUAL INCLUDING THE PERFORMANCE ADDER?

[2] Any differences between Company Operating Revenues at Present Rates in its filing and my Schedules are due to rounding.

A. The difference between the use of the Company's proposed common equity return of 11.30% with all other factors held equal, and the use of Mr. Rothschild's capital structure would be as follows:

Company Proposed	Capitalization Ratio	Embedded Cost	Weighted Average
Long-Term Debt	45.410%	4.350%	1.98%
Short-Term Debt	0.000%	0.000%	0.00%
Common Equity	54.590%	11.300%	6.17%
Total	**100.000%**		**8.15%**

OCA Recommended (Rothschild)			
Long-Term Debt	55.250%	4.350%	2.403%
Short-Term Debt	0.000%	0.000%	0.000%
Common Equity	44.750%	11.30%	5.056%
Total	**100.000%**		**7.459%**

The Operating Income difference between the Company's 8.15% rate of return and Mr. Rothschild's rate of return using the common equity cost of 11.30% is 7.459% or \$1,284,753. The Revenue Requirement difference is \$1,944,580 (which includes the gross revenue factor of 1.513583). The purpose of these calculations is to demonstrate that there are multiple inputs that contribute to the size of the requested increase and from the perspective of consumers, it matters tremendously whether the Commission accepts the Company's capital structure, or the analysis presented by Mr. Rothschild.

Q. WHAT RATE BASE COMPONENTS ARE YOU ACCEPTING IN THIS PROCEEDING?

A. I am accepting the Company's balances related to Customer Deposits, and Materials and Supplies, which are shown on my Schedule DM-3.

B. RATE BASE (Measures of Value)

1. Electric Plant in Service (EPIS)

Q. WHAT HAS THE COMPANY PROPOSED REGARDING ITS ELECTRIC PLANT IN SERVICE?

A. The Company has proposed an EPIS balance of $275,001,000[3] for the fully projected future test year for the twelve months ending September 30, 2024. (Company Schedule C-1 and C-2). Company witness Ms. Tracy Hazenstab developed this balance by starting with the Historical Test Year (HTY) period ending September 30, 2022, and included appropriate ratemaking adjustments through the Future Test Year (FTY) period September 30, 2023. To that balance, the Company included proforma adjustments derived from UGI Electric's operating and capital budgets for the 12 months ending September 30, 2024. (Statement No. 2 at 3-4).

Included in that balance are plant additions that the Company expects to place in service during the FTY period ending September 30, 2023, and for the FPFTY period ending September 30, 2024, of which the amounts are calculated at $23,221,000 and $24,665,000, respectively. (Company Schedule C-2).

Q. HOW DID THE COMPANY DEVELOP ITS CAPITAL INVESTMENT TO PRODUCE THE TOTAL PROPOSED PLANT ADDITIONS OF $24,665,000 AS OF SEPTEMBER 30, 2024?

A. Company witness Ms. Vicky Schappell stated that the categories of plant additions are related to (1) replacement and betterment infrastructure, which includes transmission, substation and distribution assets; (2) new business, including expansion of the transmission and distribution to support growth; (3) information technology (IT); (4) and other capital spending (Statement No. 5 at 3). Ms. Schappell stated that the determination of projects that are included in the capital budgets identifies four critical areas where the Company must make capital investments in order to maintain safe and reliable service to customers. (Statement No. 5 at 4). This process is more fully explained in Ms. Schappell's

[3] Differences between the Company's balance and my balance are due to rounding.

testimony Statement No. 5 at page 4.[4] Ms. Schappell stated that the Company has included costs related to its Data Center. The Data Center will provide adequate IT infrastructure to support the Company's business functions and will replace the existing Data Center located in Reading, Pennsylvania. (Statement No. 5 at 11).

Q. HOW HAVE THE COMPANY'S ACTUAL CAPITAL ADDITIONS COMPARED TO BUDGETED CAPITAL ADDITIONS IN THE PAST?

A. According to Ms. Schappell, over the past five years, the Company's total budgeted capital additions produced a variance of $34.081 million which equates to 98% of the Company's plant additions of its budget, or a 2% variance between budgeted and actual plant placed in service. (Statement No. 5 at 8).

Q. WHAT COSTS ARE INCLUDED IN THE COMPANY'S EPIS BALANCE RELATED TO THE COMMISSION APPROVED LONG-TERM INFRASTRUCTURE IMPROVEMENT PLAN (LTIIP)?

A. As noted in response to OCA Set II-13, the Company has included approximately $266.908 million of LTIIP expenditures through the FTY ending September 30, 2023, and an additional $275.002 million through the FPFTY ending September 30, 2024. Company witness Ms. Schappell stated that capital budgets are made up of replacements and betterments projects that improve or replace existing infrastructure and make up the majority of projects captured in UGI Electric's LTIIP. UGI Electric's LTIIP guides the formulation of the overall replacement and betterments capital budget. Replacements and betterments projects are selected and prioritized in the budget under two key designations: condition-based replacements and reliability enhancements. (Statement No. 5 at 7-8). The Company has anticipated and budgeted about $15.127 million of replacement and betterments in the FPFTY period and is included in the Company's distribution plant additions. (Statement No. 5 at 8). Company witness Mr. Eric Sorber stated that the total expenditure balance for the initial LTIIP was nearly $49 million over the initial five-year term. (Statement No. 4 at 7).

Q. IS THE COMPANY UNDERTAKING A SECOND LTIIP?

[4] The Company identifies Major Projects as projects greater than $15 million which require Board approval. OCA-Set III-2.

A. Yes. In April 2022, the Company filed its second LTIIP. (Statement No. 4 at 7). The Commission approved this Second LTIIP on August 25, 2022 (OCA Set II-35). The Company stated that the Second LTIIP continues the Company's focus on accelerated infrastructure improvement, repair and replacement, including several infrastructure and technology-based programs that will target significant long-term reliability factors. (Statement No. 4 at 8). Mr. Sorber stated that during the five-year term of the Second LTIIP a total of $50 million is anticipated that will be used to modernize and continue to increase the overall resiliency of the system to guard against significant weather-related events as well as "blue sky" day emergencies. (Statement No. 4 at 9).

Q. WHAT ADUSTMENTS DID THE COMPANY HAVE WITH RESPECT TO THE COMPANY'S PROPOSED EPIS BALANCE OF $275,001,000?

A. In response to OCA Set II-13, I asked the Company as to whether any costs have changed from the as filed petition with respect to capital additions in the FTY and in the FPFTY period. The Company responded that at this point there have been no changes in the forecasted FTY plant additions and FPFTY plant additions. The Company does not anticipate a material variance to the FTY and FPFTY capital additions. To the extent operating conditions and circumstances change, such as the need to reprioritize projects or adjust anticipated in-service dates and potential increase in contractor costs impact the Company's projects for the FTY and the FPFTY, it will update its projections as needed.

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING THE COMPANY'S PROJECTED TIMELINE OF THESE IN-SERVICE DATES?

A. No.

Q. WHAT CONCERNS DO YOU HAVE WITH THE COMPANY'S DATA CENTER PROJECT?

A. I am recommending removing the contingency costs of $3.24 million (15% of total Project costs as addressed in response to OCA Set IX-3, of which $218,806 is allocated to UGI's Electric Distribution operations). In response to OCA-Set II-38, the Company provided a breakdown of the costs related to its Data Center Project. The Project was approved by the Board for $24.83 million in September 2022. The Project's contingency costs were 15% or 3.24 million. The Project's estimates were derived from the actual design costs incurred by UGI. In response to OCA Set II-39 (CONFIDENTIAL) the Company provided an attachment that showed the allocation of costs related to the Company in the amount of **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL).**

Q. WHAT IS YOUR TOTAL RECOMMENDED ADJUSTMENT TO THE COMPANY'S EPIS BALANCE THAT IS RELATED TO THE DATA CENTER PROJECT?

A. I am recommending removing $218,806 of contingency costs. The Company included $3.24 million of total contingency. Allocating this contingency to the UGI Electric Company by 9.08% calculates to a dollar amount of $294,192 ($3.24 million x 9.08%). Allocating this balance to the UGI Electric distribution operations of 74.3753% results in a balance of $218,806. I recommend removing this contingency costs. Contingency costs are amounts of money set aside to cover any unexpected costs that can arise throughout the construction project. This money is on reserve and is not allocated to any specific area of work, but rather acts as insurance against other unforeseen costs. Therefore, contingency costs are not known and measurable in the ratemaking process and are not appropriate to be paid for by ratepayers. Contingency costs are included for any anticipated price adjustments for various risks that cannot be otherwise accounted for. The Company has not identified any additional costs beyond the November 2023 in-service date but instead merely stated that some additional costs are likely. Therefore, I believe that contingency costs should be removed from the Company's EPIS balance. My recommended EPIS is $274,782,194 a reduction of $281,806 from the Company's proposed balance of $275,001,000. This is shown on my Schedule DM-5.

2. <u>Accumulated Depreciation</u>

Q. WHAT HAS THE COMPANY CALCULATED WITH RESPECT TO ITS ACCUMULATED DEPRECIATION?

A. The Company computed an Accumulated Depreciation balance in the amount of $85,745,000 as shown on Company Schedule C-3. Company witness Ms. Vivian Ressler stated that the Company started with an Accumulated Depreciation balance as of September 30, 2022, and added budgeted levels of depreciation expense for the FTY to produce an Accumulated Depreciation balance of $80,496,000 (Company Schedule C-3). For the FPFTY period, the Company calculated the impact of the FTY and FPFTY associated plant retirements and a provision for net salvage to arrive at the Accumulated Depreciation balance of $85,745,000. The amount of the net salvage value was calculated using a five-year amortization schedule in accordance with Commission precedent. (Statement No. 3 at 9).

Q. WHAT IS YOUR RECOMMENDATION?

A. I am accepting the Company's calculation with respect to the development of the Accumulated Depreciation balance. My adjustment is related to my recommended removal of the Company's Data Center Project as I addressed in my Electric Plant in Service balance above. Since the Data Center Project is an allocated IT Project, using my recommended Distribution Plant disallowance of $218,806 and a composite Depreciation Rate of 7.58% as shown on Company Book V (calculated annual depreciation fully projected future 2024 depreciation study) page II-4, I calculate an adjustment of $16,590 ($218,806 x 7.58%). This is carried over to the Accumulated Depreciation Expense balance (Schedule DM-6).

3. <u>Working Capital</u>

Q. WHAT DID THE COMPANY PROPOSE RELATED TO ITS CASH WORKING CAPITAL (CWC)?

A. The Company has proposed a CWC balance of $11.447 million as shown on Company Schedule C-1 and C-4[5]. Ms. Ressler stated that the CWC is the capital requirement arising from the difference between the lag in the receipt of revenue for rendering service and the lag in payment of cash expenses incurred to provide that service (Statement No. 3 at 9).

[5] Any differences between the Company's Schedule C-4 and Schedule DM-7 are due to rounding.

Ms. Ressler provides the calculation of the various components that make up the Company's CWC on Statement 3 beginning on page 10. (Company Schedule C-4).

Q. DO YOU HAVE ANY ADJUSTMENTS OR CHANGES IN THE METHODOLOGY USED BY THE COMPANY TO CALCULATE ITS CWC?

A. No. I am accepting the Company's CWC methodology. My adjustments are related to the adjustments that I recommend for O&M Expenses, and other adjustments used to develop the CWC balance.

Q. WHAT ARE YOUR ADJUSTMENTS WITH RESPECT TO THE COMPANY'S CWC BALANCE?

A. I adjusted the Company's CWC to incorporate my adjustments to my recommended O&M Expenses which flow through to the CWC document. My recommended balance for CWC is $11,027,033, or an adjustment of $428,333 and is shown on my Schedule DM-7 and carried over to Schedule DM-3.

4. <u>Accumulated Deferred Income Taxes (ADIT)</u>

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO ITS ACCUMULATED DEFERRED INCOME TAXES (ADIT)?

A. The Company proposed a balance in its ADIT in the amount of $29.665 million as shown on Company Schedule C-6. Company witness Mr. Darin Espigh stated that this balance reflects the difference between the accelerated tax depreciation and straight-line depreciation on test year plant balances, net of offsets associated with Contributions in Aid of Construction. (Statement No. 8 at 6). This balance was further reduced by the state regulatory liability associated with UGI's Electric repairs tax method. As the state tax consequence of accelerated depreciation flows through, there is no associated ADIT balance. (Statement No. 8 at 6).

Q. HAS THE COMPANY REDUCED THE RATE BASE BALANCE BASED UPON THE UNAMORTIZED EXCESS DEFERRED FEDERAL INCOME TAXES (EDFIT)?

A. Yes. Mr. Espigh stated that the Company has reduced its Rate Base by the unamortized EDFIT, which is incorporated in the ADIT balance shown on Schedule C-6. (Statement No. 8 at 7. (Confidential OCA Set II- 46 and 48). In response to Confidential OCA-II-46, Mr. Espigh provided the calculation related to the Excess Deferred Federal Income Tax balance which was flowed back to ratepayers. The excess activity balance is **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL).**

Q. PLEASE EXPLAIN THE COMPANY'S REPAIRS TAX METHOD?

A. Mr. Espigh stated that the Company adopted a tax accounting method to expense as repairs certain items capitalized for book purposes in accordance with federal tax regulations. (Statement No. 8 at 7). The Company normalized its federal income tax expense claim, inclusive of the repairs tax deduction. The difference between the accelerated tax depreciation and book depreciation in the calculation of federal tax expense created an ADIT. The Company chose to flow through the repairs tax benefits over the tax useful lives of the assets generating the tax deduction. The state ADIT balance associated with the repairs tax deduction is classified as a regulatory liability, representing the repairs tax benefit that ratepayers have not yet received. (Statement No. 8 at 8). The Company reduced its rate base by the sum of the federal ADIT balance and the state repair regulatory liability. (Statement No. 7 at 8).

Q. WHAT ADJUSTMENTS DO YOU HAVE RELATED TO THE COMPANY'S ADIT BALANCE, THE EDFIT BALANCE AND THE STATE REPAIRS BALANCE?

A. I do not have any adjustments with respect to the Company's ADIT, EDFIT and State Repairs balances or the methodologies utilized to calculate these balances. My adjustments reflect my recommended removal of the Company's Data Center project contingency costs of $218,806 that I addressed in my EPIS testimony section.

Q. WHAT IS YOUR TOTAL ADJUSTMENT RELATED TO THE COMPANY'S OVERALL ADIT BALANCE?

A. I utilized my recommended balance of the Accumulated Depreciation adjustment which includes my adjustment to the Company's contingency balance and multiplied the difference by 28.102% [6]to arrive at my balance shown on my Schedule DM-8.

C. OPERATING INCOME

1. <u>Operating Revenues</u>

Q. WHAT HAS THE COMPANY PROPOSED AS ITS OPERATING REVENUE AT PRESENT RATES AND PROPOSED RATES?

A. As shown on Company Schedule D-1, the Company calculated Operating Revenues at Present Rates of $152,691,000 and Revenues at Proposed Rates of $164,116,000. The difference represents the revenue increase of $11,425,000, or an increase of 7.48%.

Q. WHAT ADJUSTMENTS DID THE COMPANY MAKE TO DERIVE ITS PRESENT OPERATING REVENUES UNDER THE FPFTY PERIOD?

A. Company witness Ms. Tracy Hazenstab stated that the Revenues at Present Rates were determined by adjusting the budgeted revenues to reflect the anticipated change in the number of customers, the projected change in existing customer usage, the roll-in of revenues from the Distribution System Improvement Charge (DSIC) and other pro-forma annualizing and normalizing ratemaking adjustments. (Statement No. 2 at 12). The net effect of these adjustments is detailed on Schedule D-5. Company witness Ms. Sherry Epler stated that a 15-year normal heating degree day period (2005-2019) was used to develop the sales and revenue forecasts. (Statement No. 8 at 3). Ms. Epler stated that the Company's 15-year normal heating degree day period is updated every 5 years with the most recent being the 15-year period of 2005-2019. (Statement No. 8 at 3).

Q. DID THE COMPANY UPDATE ITS OPERATING REVENUE SUBSEQUENT TO THE INITIAL FILING?

A. No.

[6] Company Schedule D-35.

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S PRESENT RATE REVENUE?

A. With respect to the Company's Forfeited Discounts, Miscellaneous Revenues, and Rent from Gas Properties, I am recommending normalizing these revenues using a three-year period using the Company's Historic, Future and Fully Projected periods 2022, 2023 and 2024, respectively. I utilized the balance of these revenues as shown in response to OCA-II-49. These three-year balances average out to an increase of $26,832. (Schedule DM-4). As these types of revenues do fluctuate and change from year to year, depending on customer actions or inactions, customer arrangements, agreements between and among various entities, it is appropriate to normalize these various miscellaneous revenues, prospectively. My total recommended Operating Revenues at Present Rates are $152,717,832 and my adjustments are shown on my Schedule DM-4.

2. OPERATION AND MAINTENANCE EXPENSES

Q. HOW DID THE COMPANY DEVELOP ITS OPERATING EXPENSES PRESENTED FOR RECOVERY IN THIS RATE PROCEEDING?

A. According to Ms. Hazenstab, the expense portion of the Operating Budget is developed based upon the review of trends, monthly expenditure patterns, and new or changed programs. (Statement No. 2 at 7). Employee levels are reviewed, and appropriate staffing levels are set for the upcoming fiscal year. The direct expense portion or the Operating Budget is submitted for review and approval by senior management and the Company's direct expenses are then consolidated with allocated expenses from shared administrative and general functions within UGI and from other affiliated companies providing shared services to UGI Electric to develop the budgeted Statement of Operations. (Statement No. 2 at 7). Allocated expenses in the Statement of Operations included functions such as accounting, rates, gas supply, human resources, information systems, payroll, and remittance processing, which are performed in accordance with PUC-approved methods of allocation and affiliated interest arrangements or agreements. (Statement No. 2 at 7). Ms. Hazenstab stated that the Operating Budget as well as the Capital budget is in accordance with Act 11 of 2012 (Statement No. 2 at 8). UGI incurs costs for services provided by the

Company's parent UGI Corp. and other affiliated companies in accordance with affiliated interest arrangements authorized by the Commission. (Statement No. 2 at 8). Allocations of costs are done by a methodology applicable to the cost or if no one methodology is specific to the costs, by a formula referred to as the Modified Wisconsin Formula (MWF), or another reasonable allocation methodology. (Statement No. 2 at 8-9). The budget information is the starting point for the Company's claims and is adjusted as appropriate to reflect new information gained since the completion of the budgeted process and through application of other appropriate principles. (Statement No. 2 at 9).

Q. WHAT LEVEL OF OPERATING EXPENSES HAS THE COMPANY PROPOSED TO RECOVER IN THIS PROCEEDING UNDER ITS FPFTY TEST PERIOD?

A. As shown on Company Schedule D-1, the Company has proposed to recover $146,304,000 of Operating Expenses for the FPFTY period.[7] Ms. Hazenstab stated that these Operating Expenses reflect a normal, ongoing level of operations and are based upon the budgeted level of expenses. The budgeted data by FERC account was adjusted in accordance with Commission precedent and generally accepted ratemaking principles. (Statement No. 2 at 14). Ms. Hazenstab stated that the Company's Electric budget uses historical data as a basis for the distribution of expenses to each FERC account and that Company Schedule B-4 is the starting point to determine the FPFTY adjusted operating expenses that are shown on Company Schedule D-3 (Statement No. 2 at 14).

a. <u>Other Power Supply Expense</u>

Q. WHAT DID THE COMPANY PROPOSE REGARDING ITS OTHER POWER SUPPLY EXPENSES?

A. The Company proposed an Other Power Supply Expense balance of $91,176,000 as shown on Company Schedules D-2 and D-3. The Company began with a balance of $85,951,000 (budget year for end of 9/30/2024) and added $5,225,000 to adjust the Power Supply Expense for the normalized and annualized use per customer. (Statement No. 2 at 20). Ms. Hazenstab stated that this adjustment is designed to increase power supply expenses to match power supply revenue at current December 1, 2022, Generation Supply Revenue (GSR) levels and remove any potential distribution base rate impacts related to 1307 (e)

[7] Includes Depreciation Expense, and Taxes other than Income.

power cost recovery. (Statement No. 2 at 20). The total proposed Other Power Supply Expense balance under the FPFTY period is $91,176,000. ($85,951,000 + $5,225,000).

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S OTHER POWER SUPPLY EXPENSE?

A. No. I am accepting the Company's Power Supply Expense of $91,176,000 shown on my Schedule DM-4.

b. <u>Company Overall Salary & Wages (S&W) Increase</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS SALARY AND WAGES INCREASE?

A. The Company proposed a budgeted year balance of $6,196,000 related to Salary and Wages for the FPFTY period as shown on Company Schedule D-7. The Company began with a budgeted test year balance of $6,163,000 and added $33,000 to reflect the end of the FPFTY operating conditions to arrive at a balance of $6,196,000 (Statement No. 2 at 15).

Q. HOW DID THE COMPANY DEVELOP ITS PROPOSED PRO-FORMA S&W INCREASE OF $33,000?

A. The Company adjusted its Salary and Wages balance to include annualized payroll expenses that are distributed among the various cost accounts. The Company incorporated a Union increase of 3.00% effective 1/1/2024, a Non-Exempt increase of 4.00% effective 4/1/2024, and an Exempt increase of 4.00% effective 10/1/2023 as shown on Company Schedule D-7. The Company utilized an annualization factor of 25% for its Union employees, 50% for its Non-Exempt employees and 0% for its Exempt employees. Ms. Hazenstab stated that there are no annualization adjustments for the Exempt employees because these adjustments began at the start of the fiscal year and no adjustment is required for this employee classification. (Statement No. 2 at 15). Ms. Hazenstab stated that the split of the budgeted salaries was determined using the allocations of labor and headcount for Operating and Maintenance expenses in the budget which are the same groupings utilized in developing the labor budget. (Statement No. 2 at 16).

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S $33,000 OF SALARY AND WAGE INCREASE WITH RESPECT TO ITS ANNUALIZED PAYROLL?

A. No. I am accepting the Company's merit increases for its Union payroll of 3.00% and its Non-Exempt payroll of 4.00% effective on 1/1/2024 and 4/1/2024, respectively, along with the Exempt increase of 4.00% effective on 10/1/2023. I am also accepting the annualized factor of 25% for its Union employees, 50% for its Non-Exempt employees and 0% for its Exempt employees. These acceptances are shown on my Schedule DM-9.

Q. DID THE COMPANY INCLUDE ANY INCENTIVE COMPENSATION IN ITS FPFTY PERIOD?

A. Yes, in response to OCA-II-24 which referred to Confidential response I&E RE-14-D, the Company provided information related to its Incentive Compensation and Bonus Plan. I&E RE -14-D shows each plan and **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL).** [redacted] **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL),** which is broken down in detail in response to I&E RE-14 C.

Q. DID THE COMPANY PROVIDE A SET OF GOALS AND PERFORMANCE METRICS SUPPORTING ITS INCENTIVE COMPENSATION BALANCE?

A. Yes. In response to Confidential response to I&E RE-14-D the Company provided a set of Incentive Plans related to the following:

(BEGIN CONFIDENTIAL)

[redacted]

- [redacted]

(END CONFIDENTIAL)

In Confidential response to OCA-II-25, the Company provided a set of Incentive Plans related to its Management Incentive Plans and Utilities Executive Incentive Plans.

Q. WHAT ARE YOUR ADJUSTMENTS TO THE COMPANY'S INCENTIVE COMPENSATION COSTS?

A. I am recommending removing **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)** A breakdown of these disallowances are shown on my Schedule DM-9. These types of incentive costs do not benefit ratepayers in the areas of customer service, reliability, service issues, etc. With respect to the Company's proposed Stock Award payouts in the amount of **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)** these types of incentive payments benefits shareholders and Executives of the Company and rewards these Executive employees for areas other than the provision of safe and reliable utility service. These types of incentive payments relate to financial goals and the achievement of earnings per share increases and align with the growth profitability of the Company. (i.e. business growth and performance). These types of incentive costs should not be recovered from ratepayers as they are not responsible for the operations of the Company of which they have no control over. These types of incentives relate to business risks which should be solely the responsibility and ultimately be recovered by the shareholders of the Company.

Q. WHAT ARE YOUR NEXT ADJUSTMENTS TO THE COMPANY'S INCENTIVE COMPENSATION?

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[8] Any differences are due to rounding.

A. My next adjustments to the Company's Incentive Compensation are related to **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL).** With respect to **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)** I believe these costs do not benefit ratepayers in the areas of customer service, customer satisfaction, safety or reliability. These costs clearly benefit the Executives of the Company mainly in the form of retention payments such as stock awards, as well as succession planning which should be the sole responsibility of the Company. I believe these types of incentives are related to transactions for stock dividends, stock splits or cash dividends affecting the shares or securities of the Company and the share price of stock. With respect to the remaining Allocated Costs of **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)** I believe a portion of these costs should be recovered from ratepayers in the areas of **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)** among other things. In response to I&E RE-14-D, the Company provided a breakdown of incentive compensation by financial results, safety, and qualitative results. The Company provided a description of the payout percentages for the plan components. In reviewing this documents, I believe that costs related to **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL).**

Q. WHAT ARE YOUR REASONS FOR THIS DISALLOWANCES?

A. **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL).** I believe these costs reflect business risks and business decisions that lie with the Company.

I do not see a nexus between these types of incentive payments and ratepayer benefits. These types of incentive compensation do not center on areas related to service levels, safety, service reliability customer satisfaction, or outage response but rather relate to financial performance, meeting business goals, increasing net income and achieving a level of spending to budgeted projections and forecasts. Ratepayers should not be burdened with these types of costs that they do not see a benefit from. UGI Electric should be responsible in bearing these costs because they are considered business decisions along with risks associated with these decisions. Business decisions and the associated risks should remain within the Company's operational sphere.

Q. WHAT IS YOUR ADDITIONAL ADJUSTMENT RELATED TO THE COMPANY'S INCENTIVE COMPENSATION?

A. My next adjustment relates to the Company's **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL).** The breakdown is shown in response to OCA II - 25. With respect to the **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL).**

Q. WHY DO YOU BELIEVE CERTAIN OF THESE INCENTIVE COSTS SHOULD BE DISALLOWED?

A. I believe certain of these types of incentive costs should be disallowed because they relate to capital placement and deployment of capital that I believe are business-related decisions that accrue to the Company in the areas of increased earnings. Ratepayers should not be responsible for incentive compensation that is geared towards increasing earnings. The Company also included **(BEGIN CONFIDENTIAL)** [redacted] **(END**

CONFIDENTIAL). These types of incentive compensation are geared toward Company initiatives, and new technologies that may or may not benefit ratepayers.

Q. WHAT ARE YOUR TOTAL DISALLOWANCES?

A. My total Management Incentive Compensation that I am recommending disallowance are: **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL).** These types of costs should be borne by the Company because ratepayers do not have a say over which employees should be employed by the Company. The Company has control over the level of vacancies, turnover, retirees and reductions. I do not see any nexus between these types of incentive and ratepayer benefits in the areas of safe and reliable utility service.

Q. WHAT IS YOUR ADDITIONAL ADJUSTMENT TO THE COMPANY'S INCENTIVE COMPENSATION PLAN?

A. My last adjustment to the Company's Incentive Compensation Plan is related to the Company's **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL).** In response to OCA-II-25, the Company provided a breakdown of this plan: **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)** These types of incentives benefit the Company in the areas of increased income and earnings per share and are not related to ratepayer benefits in the areas of customer satisfaction, safety, and reliability. Furthermore, as the incentive compensation plan also rewards executives/management based on UGI's parent company performance, Pennsylvania ratepayers may be subsidizing executive/management action in other states as UGI Corporation operates as a multi-state utility operator.

Q. PLEASE SUMMARIZE THE IMPACT OF YOUR ADJUSTMENTS TO THE COMPANY'S PROPOSED INCENTIVE COMPENSATION?

A. My overall adjustment to the Company's Incentive Compensation Plan is a reduction of **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)**. This is shown on my Schedule DM-9.

Q. HOW MANY ADDITIONAL EMPLOYEES HAS THE COMPANY PROPOSED TO INCLUDE IN ITS FILING?

A. In response to OCA-II-20, the Company proposed **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)**.

Q. WHAT ARE YOUR ADJUSTMENTS TO THE COMPANY'S EMPLOYEE PROJECTIONS?

A. **(BEGIN CONFINDENTIAL)** [redacted] **(END CONFIDENTIAL)** If the Company has further information on this matter, I will revisit and make any necessary adjustments. My recommendation is shown on my Schedule DM-9.

Q. WHAT ARE YOUR FINAL ADJUSTMENTS TO THE COMPANY'S SALARY AND WAGES?

A. I have two remaining adjustments to the Company's Salary and Wages. My first adjustment is related to the Company's Overtime costs. My second adjustment is related to the Company's Supplemental Executive Retirement Plan (SERP).

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE COMPANY'S OVERTIME COSTS?

A. In response to I&E RE-12 -D, the Company provided a schedule of Overtime Expenses for the periods ending 2020 through 2022 and for the years ending September 2023 and 2024. I am recommending averaging out Overtime costs for the FPFTY period. These types of payroll costs fluctuate takes into consideration the level of employees, capital project work, and O&M spending for operations related to electric utility distribution system. Averaging out these costs for the HTY, the FTY and the FPFTY periods results in an increase adjustment of $23,333 or $590,333 from the Company's proposed Overtime costs of $567,000. My adjustment is shown on my Schedule DM-9.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE COMPANY'S SERP?

A. In response to OCA-Set II-26, the Company provided a level of SERP costs included in the FPFTY period of $25,000. I am recommending removing these costs from the Company revenue requirement because these costs benefit executives rather than benefit ratepayers. Typically these costs reward executives for staying with the Company and are based upon certain agreements to obtain a level of retirement income and other eligibility conditions that seek to incentivize executives to be retained by the Company. My adjustment is shown on my Schedule DM-9.

c. <u>Distribution Operations and Maintenance Expense</u>

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO ITS DISTRIBUTION EXPENSES – OPERATIONS AND MAINTENANCE?

A. The Company has proposed a Distribution Expense of $13,259,000 for the budget year ending 9/30/2024. $2,912,000 was attributable to Operation Expenses and $10,347,000 was attributable to Maintenance Expenses (Company Schedule B-4). To that balance, the Company made two adjustments; (1) Salaries and Wages for its Operation Expenses of 10,000; and (2) Salaries and Wages for its Maintenance Expenses of 5,000. The total proposed Distribution Expenses are calculated at $13,274,000 which is shown on Company Schedule D-2 and D-3.

Q. ARE THERE ANY OTHER SPECIFIC ADJUSTMENTS YOU MADE TO THE COMPANY'S DISTRIBUTION OPERATION AND MAINTENANCE EXPENSE?

A. Yes. I made adjustments related to the Company's Tree Trimming expense, (OCA-Set II-3), Major Storms (OCA Set II-4), Pipeline expenses (OCA-II-34), and Other Maintenance costs (OCA-II-34 and OCA-II-5 and II-6). My adjustments begin with the Company's Salary and Wages adjustments as indicated below:

1. <u>Salary and Wages (Schedule D-9 and D-10) - $15,000</u>

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS SALARY AND WAGES (S&W) FOR ITS DISTRIBUTION EXPENSE?

A. The Company has proposed $15,000 of additional S&W expense related to its Distribution Expenses. $10,000 is related to the Company's Distribution Operations and $5,000 is related to the Company's Distribution Maintenance. The development of these costs is discussed above under my Salary and Wages section b.

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S S&W EXPENSE RELATED TO DISTRIBUTION EXPENSES?

A. I am accepting the Company's proposed increases of $15,000. My recommendation is shown on my Schedule DM-9 and DM-10.

2. <u>Tree Trimming Expenses/Vegetation Management</u>

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS TREE TRIMMING EXPENSES AND VEGETATION MANAGEMENT?

A. In response to OCA Set II 3 and OCA Set II 5, the Company provided a schedule of its Tree Trimming Expenses and its Vegetation Management Expenses for the periods FY 2018 through the FPFTY 2024. (Account No. 593.00). These costs represent and include Salaries and Benefits, Transportation, and Contractor Costs. The Company has indicated that $3,931,777 is included in the FPFTY period.

Q. WHAT ARE YOUR ADJUSTMENTS?

A. I am recommending averaging out these costs over a five-year historic period (2018-2022). I am recommending a five-year historic period because it better reflects the recovery of costs based upon the most recent actual Tree Trimming costs. A five-year period provides for a normalization of costs that the Company incurred for line clearance and other storm-related events. The response to OCA-II-3 shows variability and fluctuations for these costs over the years beginning with FY 2018 and through the FPFTY period 2024. Account No. 593.00 include such costs as maintenance of line facilities such as poles, towers and fixtures, overhead conductors and devices as well as other expenses incurred in the maintenance of overhead distribution lines. These types of costs vary from year to year depending on the severity of storms. My five-year historic average of Tree Trimming and Vegetation Management costs results in a steady recovery of $2,500,626, or a decrease of $1,431,151. This adjustment is shown on my Schedule DM-10.

3. Major Storms Expenses

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS MAJOR STORMS EXPENSES?

A. In response to OCA Set II 4, the Company has included $300,000 of Storm Costs in the FTY and $300,000 in the FPFTY periods. The Company calculated a five-year average of Maintenance Expense and Mutual Assistance Expense of $561,000 and $241,000, respectively. The Company has not included any Mutual Assistance Expenses in either the FTY or the FPFTY periods. In OCA-II-4 Supplemental Response, the Company updated its costs related to Major Storms. The Company has included Maintenance Expenses of $460,000 for the FTY and the FPFTY periods, and $300,000 for Mutual Assistance Expense for the same FTY and FPFTY periods. The Company has included a total cost of $760,000 for both Maintenance Expenses and Mutual Assistance Expenses in the FPFTY period.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. Since I have averaged out Tree Trimming Expenses and Vegetation Management Expenses over a five-year period, and to be consistent, I am recommending using a five- year historic average for Major Storm Expenses. My reasons for the five-year historic average are the same as discussed above under the Major Storm Expenses section. I am accepting the Company's five-year average for its Maintenance Expenses of $561,000 and $241,000 for its Mutual Assistance Expenses for a total of $802,000. This increases the Company's

Major Storm Costs by $42,000. ($802,000 - $760,000). This is shown on my Schedule DM-10.

4. <u>Outside Contractors Expenses</u> (Contract Labor)

Q. WHAT HAS THE COMPANY INCLUDED IN ITS OPERATING AND MAINTENANCE EXPENSES RELATED TO OUTSIDE CONTRACTORS?

A. In response to OCA-Set-III-34, I asked the Company to provide information related to its outside contractor expenses and the services provided. These are accounted for in Administrative and General Expenses, Customer Account Operations Expenses and Distribution Expenses. After reviewing the response to OCA-II-34, and recorded in Account 595.00 and in Account 583.00, I have determined that certain Contract Labor costs have fluctuated over the two years of actual (2021-2022) and the partial forecasted year of 2023, and I am recommending normalizing these costs over a three-year period (2021 through 2023) based upon actually incurred and partially forecasted expenses.[9] As shown in OCA-Set-III -34, the Company provided a breakdown of its outside contractors expenses for the periods 2021 through FPFTY 2024. I have identified several expenses that show fluctuations and variability over the 2021 – 2022 actual period, and the forecasted period 2023, and what the Company has proposed under the FPFTY period. These costs are mainly related to contractor labor categorized as station expenses, pipeline and traffic, Miscellaneous, and Maintenance. I believe that these types of costs do fluctuate over time because they are outside the control of the Company, they are volatile in nature and are unpredictable. There are no discernable trends that show gradual or incremental increases in these expenses over time.

Q. WHICH EXPENSES ARE YOU RECOMMENDING APPLYING A THREE-YEAR AVERAGE TO?

A. I am recommending that the following Distribution Expenses be set using a three-year average (2021-2023):

[9] Account 583.00 – Contract Labor: 2021 - $68,000; 2022 – $59,000; 2023 - $149,000, 2024; 2024 – $163,000. Account 595.00 – Maintenance of Line Transformers-Pipeline: 2021- $39,000; 2022- $25,000; 2023 - $61,000; 2024 - $66,000.

Acct. No.	Description	Expense	OCA recommend.
583.00	Contract Labor-Pipeline	$163,000	$ 92,000
588.00	Miscellaneous	$ 7,000	$ 3,000
595.00	Maintenance of Line Transformers	$ 66,000	$ 41,667
596.00	Maintenance of Street Light	$ 7,000	$ 4,333
598.00	Maintenance of Misc. Distr. Plant	$ 5,000	$ 3,667

I believe it is appropriate to normalize these costs to provide for a steady and consistent recovery of costs going forward. As stated previously these types of costs tend to vary from year to year depending on the activities incurred and what is needed to maintain the distribution system.

Q. WHAT ARE YOUR TOTAL DISTRIBUTION EXPENSE ADJUSTMENTS?

A. As shown on my Schedule DM-10, my overall adjustment to the Company's Distribution Expenses is a reduction of $1,492,485 ($75,000 for the Distribution Operations and $1,417,485 for the Distribution Maintenance). My recommended balance is $11,781,515 or $1,492,485 lower from the Company's proposed forecasted expense balance of $13,274,000.

d. <u>Customer Accounts Expense</u>

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS CUSTOMER ACCOUNTS EXPENSE?

A. As shown on Company Schedule D-2, the Company proposed a Budgeted balance for the year ending 9/30/2024 in the amount of $9,463,000. To that amount the Company included the following: (1) Salaries and Wages of $9,000; (2) Interest on Customer Deposits of $66,000 and (3) Universal Service Expenses of $96,000. These adjustments bring the total Customer Accounts Expense to $9,634,000 for the Proforma period ending 9/30/2024. I will discuss each of these 3 adjustments below:

1. <u>Salary and Wages (Schedules D-6 and 7) - $9,000</u>

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS SALARY AND WAGES?

A. The Company proposed total adjustments to its Salary and Wages of $9,000. The development of these costs is discussed above under my Salary and Wages section b.

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S SALARY AND WAGE EXPENSE ADJUSTMENT?

A. As indicated previously under my Salary and Wage section b, I am accepting the Company's wage increase of $9,000.

2. <u>Customer Deposit Interest Adjustment – (Schedule D-15) $66,000</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS ADJUSTMENTS TO ITS CUSTOMER DEPOSIT INTEREST ADJUSTMENTS?

A. Company witness Ms. Hazenstab included $66,000 related to Interest on Customer Deposits (Statement No. 2 at 18). Ms. Hazenstab stated that the Company is required to pay interest on Customer Deposits it holds in accordance with other requirements of its tariff. The Company has added this $66,000 to its expense claim that is otherwise not reflected in the Company's operations budgets. Ms. Hazenstab used a 13-month average level of customer deposits anticipated for the FPFTY ($949,000) using a 7 percent interest rate as published by the PA Department of Revenue and required under the tariff.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I am accepting the Company's adjustments related to its Interest on Customer Deposits of $66,000. This is shown on my Schedule DM-11.

3. <u>Universal Service Program (USP) Expenses (Schedule D-16) $96,000</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS UNIVERSAL SERVICE EXPENSES?

A. The Company has calculated a Universal Service Expense of $96,000 as shown on Company Schedule D-16. Ms. Hazenstab stated that this adjustment normalizes the amount of USP expense recovered through the Company's USP Rider based upon the level of Universal Service Rider charge effective at the time of the Company's filing. (Statement

No. 2 at 19). This expense recovered costs of the Company's Customer Assistance Program (CAP) Credits, Pre-Program Arrearages, third party administrator expenses, LIURP expense and administrative costs associated with its Project Share program. As the USP Rider is a fully reconcilable rider, the USP adjustment assured that expenses related to the existing rider are aligned with revenues and that no impact related to USP flows through the revenue requirement calculation. (Statement No. 2 at 19).

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S UNIVERSAL SERVICE EXPENSES?

A. After a review of the documents and discovery responses I am accepting the Company's balance of $96,000.

Q. WHAT OTHER ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S CUSTOMER ACCOUNTS EXPENSE?

A. As I normalized certain of the Company's Distribution Expenses, I am normalizing the certain of the Company's Customer Accounts Expense to be consistent in my adjustments across all operating expense accounts. In response to OCA-Set II-6, which refers to I&E RE-8 D, the Company provided a breakdown of its Customer Accounts Expenses for the periods 2022 through the FPFTY 2024. These costs are related to Meter Reading Expenses, Miscellaneous Customer Accounts Expenses and Customer Records and Collections Expenses. I normalized these costs by averaging out the expenses over a three-year period (2022-2024). There is no discernable trend that shows a gradual or incremental increase in these expenses over time. These costs are as follows:

Acct. No.	Description	Expense	OCA recommended
902.00	Meter Reading Expense	$218,000	$157,000
905.00	Miscellaneous CA Expense	$ 139,000	$ 95,333
903.00	Customer Records/Collection	$9,185,000	$8,781,667

Q. PLEASE EXPLAIN EACH OF YOUR ADJUSTMENTS ABOVE.

A. Meter Expenses (Account 902.00) should be normalized over a three-year period (2022 – 2024) because these types of expenses fluctuate year by year depending on the number of employees engaged in meter reading, and other incidental expenses such as checking meter seals and minor incidental routine meter activity. My adjustment reduces the Company's expenses by $61,000 to a normalized level of recovery of $157,000. In response to OCA-Set IX-4, the Company stated that the variations in the Meter Expense account were due to FERC account mapping adjustments of the budget as compared to the Company's actual expenses for wages of meter service reps. The Company's meter service reps were allocated between account 903.0 and 902.0 with more expense historically being accounted for in account 903.0. This allocation led to more expenses in the Meter Expense account than in account 903.00 (Customer Records and Collections). Regardless of the FERC mapping adjustments, the Company still projected costs in this account as compared to prior time periods (2021 and 2022), which had projected increases. The Company's claim that wages in total are in line with historical amounts and not to specific accounts in the Meter Reading expenses supports this reasoning and provides a basis for why I am making my adjustment.

With respect to Miscellaneous CA Expenses (Account 905.00) these types of expenses vary from year to year depending on the level of materials and expenses used. My adjustment reduces the Company's expense by $43,667 to a normalized level of $95,333. These variations appear to be related to FERC mapping adjustments, however, the overall adjustments to wages are respect to total wages and not specific to the wages recorded in Miscellaneous CA Expenses, which is the account to which I am making my adjustment.

Finally with respect to Customer Records & Collection (Account 903.00), these costs relate to materials used and expenses incurred on customer applications, contracts, work orders, credit investigations, billing and accounting issues and complaints. The response to OCA-II-6 shows expenses as high as $9,185,000 in the FPFTY 2024, to a level of $8,979,000 in the FTY to a low of $3,055,000 in the HTY 2022. In response to OCA Set IX-4 the Company stated that the HTY 2022 balance should have been $8,181,999 instead of $3,055,000. The Company stated that the increased expense is driven by an increase in revenue, stemming from an increase in purchase power costs, and higher spending in the Company's USP program. My adjustment reduces the Company's expense by $403,333 to a normalized level of $8,781,667.

Q. WHAT ARE YOUR TOTAL ADJUSTMENTS TO THE COMPANY'S CUSTOMER ACCOUNTS EXPENSE?

A. My total recommended balance to the Company's Customer Accounts Expense is $9,126,000, which is $508,000 than the Company's Proforma balance of $9,634,000. This is shown on my Schedule DM-11.

e. <u>Uncollectible Accounts Expense (Schedule D-11) $662,000</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. The Company has proposed a total adjustment to its Uncollectible Accounts Expense of $662,000. (Company Schedule D-11). The Company began with a balance of $2,577,000 (Company Schedule B-4) and added $557,000 of additional uncollectible expense based upon its 2024 budgeted uncollectible balance of $2,239,000 million[10] and its Proforma Present Rate Revenue uncollectible balance of $2,796,000 million (Present Rate Revenue of $152,108,000 times a three-year average uncollectible balance of 1.838%). The Company then made an adjustment of $105,000 related to the amortization of the regulatory asset balance of $315,000 for COVID-19 Pandemic costs that was recorded after the filing of the 2021 UGI Electric Rate Case. (Statement No. 2 at 17-18 and Company Schedule D-11). The Company is proposing to amortize the $315,000 balance over three-years or $105,000 annually to its budgeted bad debt expenses. The total adjustment to the Company's Uncollectible Accounts expenses is $557,000 plus $105,000 or $662,000. Included in the Uncollectible Accounts Expense, the Company calculated additional Uncollectible Accounts based upon the Company's proposed revenue requirement increase of $11.425 million by the three-year average ratio of 1.8375% to arrive at an incremental expense of $210,000.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I am accepting the Company's three-year average ratio or uncollectible of 1.838%, and the regulatory asset balance of $315,000 amortized over 3-years. My adjustment is related to

[10] The Company calculated the $2,239,000 based upon a 1.838% estimated uncollectible rate. See response to OCA Set II-29.

my recommended revenue requirement increase of $3,540,663 million, which is shown on my Operating Income Schedule DM-4 and DM-12.

Q. WHAT IS YOUR TOTAL RECOMMENDED BALANCE RELATED TO THE COMPANY'S UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. My total adjustment is a reduction of $168,047 and a balance of $3,279,897 and is shown on my Schedule DM-12.

f. <u>Customer Information & Services Expense – (Schedule D-19 – EE&C Program)</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS CUSTOMER INFORMATION & SERVICE EXPENSE?

A. The Company proposed a balance of Customer Information & Services Expenses of $1,275,000 as shown on Company Schedule D-2. To that balance the Company added ($89,000) related to its Energy Efficiency & Conservation Program costs to arrive at a FPFTY balance of $1,186,000.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED ENERGY EFFICIENCY & CONSERVATION PROGRAM (EE&C)?

A. Ms. Hazenstab stated that the EE&C aligns the amount of EE&C expense with the EE&C Rider charges based upon the level of the EE&C Rider charges effective at the time of the Company's filing in this matter. (Statement No. 2 at 20). The EE&C Rider recovers the Labor and Administrative, Prescriptive Program, Retrofit Program, New Construction Program, Custom Program, Legal and Consulting, Combined Heat and Power, and other costs associated with the Company's EE&C program (Statement No. 2 at 20-21). The decrease of $89,000 aligns with the Company's current EE&C charge, and as it is fully reconcilable, the EE&C adjustment assures that the expenses related to the existing rider are aligned with revenues and that no impact related to EE&C flows through to the revenue requirement calculation. (Statement No. 2 at 21).

Q. WHAT IS YOUR ADJUSTMENT?

A. Based upon the information I accept the Company's adjustment of ($89,000) related to the EE&C program.

Q. WHAT IS YOUR TOTAL ADJUSTMENT TO THE COMPANY'S CUSTOMER INFORMATION AND SERVICE ACCOUNT?

A. As shown on my Schedule DM-13, I am accepting the Company's Customer Information balance of ($89,000).

Q. WHAT OTHER ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S CUSTOMER INFORMATION & SERVICE EXPENSES?

A. The Company proposed a balance to its Miscellaneous Customer Service & Information Expense in the amount of $1,157,000 (Account 910.00). In response to OCA Set IX – 4 Account 910.00, the Company stated that the balance for the Miscellaneous Customer Service & Information expenses was presented incorrectly for 2022. The balance should have been $992,000 instead of $6,123,000. The Company stated that it consolidated EE&C expenses into FERC account 910 in 2021 and prior adjustments would have been allocated across multiple accounts, which reflects the $0 balance in 2020. The Company stated that the increase in this expense is reflective of the expected increase within the Company's filed PUC Electric Division Energy Efficiency and Conservation Program. Given that the increase is expected, but not known and measurable at this time, I am recommending normalizing this expenses over three-years (2022-2024) which takes into consideration actual costs in 2022, and partially forecasted and forecasted costs in 2023 and 2024, respectively. This reduced the balance by $69,333 for a recommended balance of $1,087,667 shown on my Schedule DM-13.

With respect to Account 908.00 (Customer Assistance Expenses), the Company stated that the variations are related to an electric sales employee hired in 2021 causing an increase in wages for 2022 (OCA-Set IX-4). The Company's claim does not fully include this employee's salary for the FTY and the FPFTY period. I am recommending normalizing this expense over a three-year period which consists of the actual 2022 period and the partially projected and fully projected period 2023 and 2024, respectively. This results in an adjustment of $9,000 and a recommended balance of $21,000, which is shown on my Schedule DM-13.

g. Sales Expense

Q. WHAT DID THE COMPANY PROPOSE RELATED TO ITS SALES EXPENSE?

A. The Company did not propose any adjustments to its Sales Expense as shown on Company Schedule D-1 and Schedule D-2. Therefore, there are no adjustments to this expense category. (See Schedule DM-14).

h. Administrative & General (A&G) Operations and Maintenance Expense

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS ADMINISTRATIVE & GENERAL EXPENSES?

A. The Company proposed a beginning balance of its A&G Expenses of $8.151 million and added $447,000 of adjustments to arrive at a FPFTY balance of $8.598 million. The Company proposed three specific adjustments. These adjustments are broken down as follows: (1) Salary and Wages $9,000; (2) Rate Case Expenses ($59,000); and (3) Benefits Adjustments $427,500. I will discuss each of these adjustments below:

1. Salary and Wages (Schedule D-6 & D-7) $9,000

Q. HOW DID THE COMPANY DEVELOP ITS ADJUSTMENT TO ITS SALARY & WAGES OF $9,000?

A. As previously discussed above, under my Salary and Wage adjustments, the Company adjusted its Salary and Wages balance to include annualized payroll expenses that are distributed among the various cost accounts. The Company incorporated a Union increase of 3.00% effective 1/1/2024, a Non-Exempt increase of 4.00% effective 4/1/2024, and an Exempt increase of 4.00% effective 10/1/2023 as shown on Company Schedule D-7. The Company utilized an annualization factor of 25% for its Union employees, 50% for its Non-Exempt employees and 0% for its Exempt employees. The Company allocated $9,000 of the wage increase to the Administrative and General Expense category.

Q. WHAT ARE YOUR ADJUSTMENTS?

A. I am accepting the Company's proposed increase of $9,000 for its Administrative & General Expenses. This acceptance is shown on my Schedule DM-15.

2. Rate Case Expenses (Schedule D-10) ($59,000)

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO RATE CASE EXPENSES?

A. The Company has proposed a total rate case expense of $769,000. The Company then proposed to amortize this balance over a two-year period or an annual recovery of $385,000. The Company then adjusted this $385,000 balance by offsetting rate case expenses included in this proceeding of $444,000 to arrive at an adjustment of ($59,000).

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S $769,000 RATE CASE EXPENSE PROPOSAL?

A. The first adjustment that I am recommending is to the amortization period the Company is proposing. These costs should not be amortized over a two-year period, but instead they should be normalized, and they should be based upon the Company's actual prior rate case expense filings. As shown in response to OCA Set II-28 the Company has filed the following base rate case proceedings, including this instant proceeding, along with the associated actual rate case expenses incurred in those proceedings:

R-2022-3037368	$769,000	Year 2023
R-2021-3023618	$719,330	Year 2021
R-2017-2640058	$868,967	Year 2018
R-00953534	$ N/A	Year 1996
R-00932862	$ 372,000	Year 1993
R-00922195	$261,000	Year 1992
Total Years		30 Years
Number of filings		6
Normalized periods		5 years

Q. HOW DOES THE COMMISSION ACCOUNT FOR RATE CASE EXPENSES?

A. First, the Commission routinely normalizes, not amortizes rate case expense. It then looks to the historical filing frequency to determine the proper normalization period. Based upon the Company's historical rate case filings listed above, the Company filed 6 rate case filings over a 30-year period. This results in a normalized period of 5 years. The earliest rate case was filed in 1992 and the most recent rate case was filed in 2023, a thirty-year period. A

5-year normalization period would result in an annual recovery balance of $(769,000/5 or $153,800 per year. This results in an adjustment of $290,200 from the Company proposed balance of ($59,000), or a reduction of $231,200. My adjustment is shown on my Schedule DM-15.

3. <u>Benefits Adjustments (Schedule D-14) $427,000</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS BENEFITS ADJUSTMENTS?

A. The Company has proposed a Benefits adjustment of $427,000 as shown on Company Schedule D-14. Company witness Ms. Hazenstab stated that the adjustment related to Pension Expense reflects an updated pension expense prepared after the budget was finalized. (Statement No. 2 at 18) The updated adjustment is based upon more recent calculations and reflects the cash to be contributed to the plan in the FPFTY. The amounts reflected in the calculation for the pension adjustment include those directly attributable to the UGI Electric pension in addition to the portion of the UGI Corp. and UGI pension expense that is included in the expenses allocated to UGI Electric. (Statement No. 2 at 18). The Company allocated 80.05% of the balance to the UGI Electric distribution operations (Statement No. 3 at 18).

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I reviewed the response to OCA-II-30, which shows the Pension Expense and Cash Contributions for the periods September 30, 2018, through September 30, 2022. The Company's pension expense shows variability related to the pension expense from a high expense of $726,000 in September 30, 2018, to a low pension expense of $167,000 in September 30, 2019, to a budgeted expense balance of $293,000 in the FPFTY period. The non-capitalized portion of the cash contributions attributable to UGI Electric have been fairly stable and consistent during the same years (from a low of $665,000 as of September 30, 2020, to a high of $827,000 in the FPFTY period. Given this variability and the fact that pension plans can vary considerably over time depending on changes in the estimated costs, I am recommending normalizing the actual pension expense over a three-year period

2020-2022. This adjustment reduces the contribution and the proposed adjustment from $427,000 to $179,000, (after the allocation factors shown on Attachment OCA-II-30 (B)) a difference of $248,500. My adjustment is shown on my Schedule DM-15.

Q. WHAT OTHER ADJUSTMENTS DO YOU HAVE THAT THE COMPANY HAS NOT PROPOSED TO ADJUST IN THIS PROCEEDING?

A. I have several adjustments within the Administrative and General Expenses that the Company has not proposed in this proceeding. I will discuss each adjustment below:

4. <u>Injury & Damages (I&D) (Schedule D-15) $251,000 (Account 925.00)</u>

Q. WHAT HAS THE COMPANY BOOKED WITH RESPECT TO ITS INJURY AND DAMAGES?

A. The Company has booked $251,000 in its FPFTY period related to its I&D as shown in response to OCA-Set-II-6 which refers to I&E RE-8-D.

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S I&D ADJUSTMENT?

A. Yes. I am recommending averaging out the costs related to the Company's I&D expenses over a three-year period (2022-2024). These costs include workers compensation, safety and health claims, and the cost of various liability insurance coverages. These costs should be normalized to account for fluctuations of claims incurred related to damages and litigation and the changes in various liability insurance coverages. Using a three-year period of expenses, my adjustment increases the I&D expenses by $3,333 or a normalized level of $254,333. This is shown on my Schedule DM-15.

5. <u>Association Dues – (Account 930.20)</u>

Q. WHAT HAS THE COMPANY BOOKED WITH RESPECT TO ITS ASSOCIATION DUES?

A. As shown in response to OCA Set II-7, the Company provided a schedule of Association Dues for the periods 2022, 2023 and 2024.

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S ASSOCIATION DUES?

A. I recommend removing $9,000 (less 19.95% allocable to Transmission) or a net balance of $7,000 related to the Energy Association of PA (EAP). According to the EAP, this association promotes the interests of regulated electric and natural gas distribution companies operating in Pennsylvania. The Company has not provided a further breakdown of what is included in the $7,000. Therefore, I am recommending removing the $7,000 from the Company's revenue requirement proposal. My adjustment is shown on my Schedule DM-15.

6. <u>Advertising Expenses – (Account 930.10)</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS ADVERTISING EXPENSES?

A. As shown in response to OCA-Set-II-9, the Company proposed Advertising Expenses in the amount of $113,000 in its FPFTY period. In response to Company Attachment II-D-7 (d), the Company provided a breakdown of these costs by purpose and media.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I am recommending adjustments related to Other Advertising Expenses of $30,000, and Other Media Expenses of $74,000 less 19.95% allocable to Transmission, an adjustment of $83,252. In response to I&E RE-27-D, the Company provided a breakdown of its Other Advertising Expenses and other Media Expenses.

Q. WHY ARE YOU RECOMMENDING DISALLOWANCES OF THESE COSTS?

A. According to the response provided by the Company, the majority of these expenditures involve community-based sponsorship opportunities, wherein UGI advertises through community service and economic development organizations (special events activities, event program advertisements, website displays, signage, etc.). The response also stated that these costs represented recognition and promotion achieved through local community sponsorships, relationships and related events promoting energy conservation and sustainability, awareness of customer assistance programs and offerings. Sponsorships also provide the opportunity to develop relationships with local businesses and community leaders to promote local growth and the responsible and safe use of electricity. Portions of these advertising costs relate to organizations, chambers of commerce, alliances, economic development, and other consortiums that do not benefit Company ratepayers or relate to the provision of safe and reliable gas utility service.

Certain of these advertising costs mainly benefit the Company by contributing to its ability to provide advocacy on policy issues before State and Governmental agencies, be a good corporate citizen, and aiding in civic related initiatives. These types of costs do not comport to costs associated with Company memberships that provide benefits to the ratepayers of UGI-Electric that relate to safety, reliability and adequacy of service. These types of expenditures are not the sort of costs that ratepayers should be paying for through rates, and they are not related to the core business of providing utility services to ratepayers.

7. <u>Outside Services Employed – Account 923.00</u>

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS OUTSIDE SERVICES EMPLOYED?

A. As shown in response to OCA-Set-II-8, the Company proposed a balance of $1,887,000 for the FPFTY period.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. In response to OCA Set IX-2, I asked the Company to provide a detailed breakdown related to certain of its Outside Expenses balances. The Company included costs of $11,000 related to Environmental, Social and Governance Expenses (ESG) in the FPFTY period. I am recommending removing this balance from the Company's revenue requirement.

Q. WHY ARE YOU RECOMMENDING REMOVAL OF THIS EXPENSE?

A. These ESG costs mainly relate to corporate social goals of maximizing profits on behalf of the Company's shareholders and advocating for certain environmental goals. These types of costs also relate to support of certain social movements along with diversity, equity and inclusion movements. ESG is mainly a framework that helps stakeholders understand how an organization is managing risks and opportunities to environmental, social and governance criteria. It is a holistic view that sustainability extends beyond just environmental issues. These types of costs should not be recovered from ratepayers as they do not support the safe and reliable utility service requirements but rather the costs are akin to sponsorships and civic related activities. Ratepayers should not be responsible for how a company operates in its utility environment or be charged for costs related to how an organization manages its risk or corporate philanthropy. The Company's shareholders should bear these costs if they believe in contributing to these types of activities and social movements. My adjustment is shown on my Schedule DM-15.

8. A&G Salaries – Account 920.00

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS A&G SALARIES?

A. As shown in response to OCA-Set II-6, which refers to I&E RE-9-D, the Company proposed total A&G Salaries of $2,757,000 (Account 920.00) for the FPFTY period.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. In response to OCA Set II -10, the Company provided a breakdown of Charges Imposed by Affiliates which are recorded in Account 920.00. In response to OCA-Set-IX-6, the Company provided a breakdown of Compensation Costs that are included in Account 920.00. The total amount of Compensation (Bonus) that has been included in Account 920.00 is $178,000. I am recommending removing this balance from the Company's revenue requirement.

Q. WHAT ARE YOUR REASONS FOR REMOVAL?

A. These costs related to personnel of UGI Corp., Shared Executives and Shared Service Center, however, the Company did not provide any reasons for inclusion that relate to ratepayer benefits or customer service initiatives. There is no information as to whether these bonus payments related to business goals, financial goals, or operational goals in the areas of safety, reliability, customer satisfaction or the provision of safe and reliable utility service. Given the absence of goals benefiting ratepayers, I recommend removing these costs from rates.

Q. WHAT ARE YOUR OVERALL ADJUSTMENTS TO THE COMPANY'S A&G EXPENSES?

A. My overall adjustments to the Company's A&G Expenses are a reduction of $811,285 which is shown on my Schedule DM-15. [11]

i. DEPRECIATION EXPENSE

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO ITS DEPRECIATION EXPENSE?

A. The Company proposed a Depreciation Expense of $8.553 million as shown on Company Schedule D-2 and Schedule D-21. The Company began with the annual depreciation for electric distribution plant and general and common plant as budgeted during the 9/30/2024 period and allocated a portion of the common plant to the electric division minus depreciation expense related to transmission. The Company adjusted charges to Clearing Accounts of $479,000 and $42,000 related to business units – IT related. The Company made an adjustment to Net Salvage Amortization of $857,000 to arrive at a balance of $8.553 million. (Company Schedule D-21). The Company's claim for depreciation expense is based on a straight-line remaining life method of depreciation. (Statement No. 7 at 10). The Company's claim for depreciation is in connection with the Company's submission of its annual depreciation study report which was submitted to the PAPUC in May 2022 based upon electric plant in service as of September 30, 2021. (Statement No. 7 at 7).

Q. WHAT ARE YOUR RECOMMENDATIONS RELATED TO THE COMPANY'S DEPRECIATION EXPENSE?

A. I am accepting the Company's proposed depreciation expense for the FPFTY period in the amount of $8.553 million. My only adjustment is related to my removal of the Company's contingency costs related to the Data Service Center Project. My adjustment is a reduction of ($16,590) My recommendation is shown on my Schedule DM-16.

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[11] Any differences are due to rounding.

j. TAXES OTHER THAN INCOME

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO TAXES OTHER THAN INCOME TAXES?

A. The Company proposed total Taxes Other than Income in the amount of $9.719 million as shown on Company Schedule D-2 and Schedule D-31. The Company included taxes associated with payroll taxes, PURTA taxes, PA & Local Use taxes, and the PUC assessment. The Company added $716,000 of additional Gross Receipt taxes at 6.27%, related to the additional proposed revenue requirement increase of $11,425,000.

Q. WHAT ARE YOUR ADJUSTMENTS AND YOUR RECOMMENDED LEVEL OF TAXES OTHER THAN INCOME TAXES?

A. I am accepting the Company's methodology in the calculation of its Taxes Other Than Income. I am making adjustments to the Company's Payroll Taxes that reflect my recommended S&W balance, which includes my adjustments to the Company's proposed employee additions, and my adjustments to the Company's Incentive Compensation. I removed costs associated with certain Incentive Compensation adjustments, which are reflected in the Company's payroll rates accordingly. My remaining adjustment reflects the flow through of all other Taxes other than Income and includes my recommended revenue requirement of $3,540,663 million to calculate the additional Gross Receipts Tax expenses.

Q. WHAT IS YOUR TOTAL ADJUSTMENT TO THE COMPANY'S TAXES OTHER THAN INCOME?

A. My total recommended Taxes Other Than Income is $9,792,088 or a reduction of $642,912 as shown on my Schedule DM-17.

k. INCOME TAXES

Q. WHAT DID THE COMPANY CALCULATE WITH RESPECT TO ITS INCOME TAXES?

A. The Company proposed total Income Taxes of $3.774 million, of which $1.117 million is related to the State Income Taxes and $2.657 million is related to the Federal Income Taxes as shown on Company Schedule D-33.

Q. WHAT OTHER ADJUSTMENTS DID THE COMPANY MAKE TO COMPUTE ITS INCOME TAX EXPENSE?

A. According to Mr. Espigh, the Company included the use of debt interest synchronization, the normalization method for accelerated depreciation and the flow-through of accelerated depreciation benefits for federal and state tax purposes. (Statement No. 8 at 4). The Company continued to flow through the repairs tax benefit over the tax useful lives of the asset that generate the tax benefit which is generally 20 years. (Statement No. 8 at 4).

Q. DID THE COMPANY INCLUDE ADJUSTMENTS RELATED TO THE EXCESS DEFERRED FEDERAL INCOME TAXES AS A RESULT OF THE 2017 TAX CUTS AND JOBS ACT (TCJA)?

A. Yes. Company witness Mr. Espigh stated that the Excess Deferred Federal Income Taxes (EDFIT) have been calculated, amortized and flowed-back to ratepayers in the FPFTY period. The amount of the EDFIT has been calculated (Company Schedule D-33) and the total amortization is approximately $283,000 using the average rate assumption method (ARAM) as required by tax normalization rules. (Statement No. 8 at 6).

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S METHODOLOGY WITH RESPECT TO THE CALCULATION OF THE COMPANY'S INCOME TAXES?

A. No I am accepting the Company's methodology. My adjustments reflect the recommended changes of Rate Base and Operating Income.

Q. WHAT ARE YOUR RECOMMENDED FEDERAL INCOME TAXES AND RECOMMENDED STATE INCOME TAXES?

A. My recommended Federal Income Taxes are $1,848,728. My recommended State Income Taxes is $912,536.

Q. WHAT IS YOUR ADJUSTMENT RELATED TO THE COMPANY'S INTEREST EXPENSE CALCULATION?

A. Using my recommended Rate Base Balance of $171,589,479 and the recommended weighted cost of debt as recommended by Mr. Rothschild of 2.40%, my recommended Interest Expense is $4,123,939.

Q. WHAT IS YOUR TOTAL INCOME TAX EXPENSE?

A. My total Income Tax Expense is $2,761,263, $1,848,728 related to Federal Income Taxes and $912,536 related to State Income Taxes. This is shown on my Schedule DM-18.

D. Act 40 Requirements (Act 40 of 2016)

Q. WHAT IS THE ACT 40 REQUIREMENTS?

A. Act 40 took effect on August 11, 2016, and among other things, it eliminated the consolidated tax savings adjustment. Prior to Act 40, the Company would have been required to adjust its revenue increase request downward to reflect tax savings associated with filing taxes as part of a parent or holding company. This practice recognized that the Company's ratepayers only paid through rates those taxes that the Company actually paid. Act 40 requires the Company to continue its performance of the consolidated tax savings calculation and provide that consolidated tax savings differential as part of its rate case filing. In part, Act 40 states:

> If an expense or investment is allowed to be included in a public utility's rates for ratemaking purposes, the related income tax deductions and credits shall also be included in the computation of current or deferred income tax expense to reduce rates. If an expense or investment is not allowed to be included in a public utility's rates, the related income tax deductions and credits, including tax losses of the public utility's parent or affiliated companies, shall not be included in the computation of income tax expense to reduce rates. The deferred income taxes used to determine the rate base of a public utility for ratemaking purposes shall be based solely on the tax deductions and credits received by the public utility and shall not include any deductions or credits generated by the expenses or investments of a public utility's parent or any affiliated entity. The income tax expense shall be computed using the statutory income tax rates.

Act 40 further states:

> REVENUE USE- If a differential accrues to a public utility resulting from applying the ratemaking methods employed by the commission prior to the effective date of subsection (a) for ratemaking purposes, the differential shall be used as follows:
>
> (1) Fifty percent to support reliability or infrastructure related to the rate-base eligible capital investment as determined by the commission; and
>
> (2) Fifty percent for general corporate purposes.

As a result, ratepayers now pay taxes more than those taxes that the Company actually pays, and the revenue use requirement specifies how those additional revenues are to be applied. Section 1301.1 (b) requires the Company to use 50% of that differential for reliability or infrastructure related capital investment and the remaining 50% for general corporate purposes.

Q. HAS THE COMPANY CALCULATED A CONSOLIDATED TAX EXPENSE ADJUSTMENT (CTA)?

A. According to Ms. Hazenstab, the Company calculated what would have been the ratemaking level of a consolidated tax savings adjustment prior to the enactment of Section 1301.1 of the Public Utility Code. (Statement No. 2 at 23-24). The Company has calculated a CTA of $70,000 which would have been the amount of CTA savings applicable to UGI Electric. (Statement No. 2 at 24).

Q. HAS THE COMPANY SATISFIED THE FIRST REQUIREMENT UNDER ACT 40 – 50% OF THE DIFFERENTIAL SPENT ON INFRASTRUCTURE REPLACEMENT?

A. Yes. As explained by Ms. Hazenstab, and as further discussed by Company witness Ms. Schappell, the Company's pro-forma capital additions for reliability or infrastructure projects for the FTY is $13.762 million and for the FPFTY is $15.127 million, which are greater than the 50% the Company calculated with respect to its consolidated tax savings of $2.553 million (Statement No. 2 at 24). (OCA-Set II-32).

Q. WHAT IS UGI'S PROPOSAL FOR THE OTHER 50% OF THE DIFFERENTIAL, WHICH SECTION 1301.1(b)(2) STATES MUST BE USED FOR "GENERAL CORPORATE PURPOSES"?

A. According to Ms. Hazenstab, the Company claimed that its general corporate purpose expenses exceeded 50% of the tax benefit that resulted from the elimination of the consolidated tax adjustment (Statement No. 2 at 24). Ms. Hazenstab stated that the Company's operating budget of more than $121 million in operating expenditures would be used to render electric distribution service; 50% of the consolidated tax adjustment would equate to $35,000. (Statement No. 2 at 25).

Q. WHAT DO YOU CONCLUDE REGARDING THE 50% OF THE DIFFERENTIAL THAT ACT 40 REQUIRES TO BE USED FOR "GENERAL CORPORATE PURPOSES"?

A. UGI does not appear to propose a specific treatment for the other 50% of the differential, which Section 1301.1(b)(2) states must be used for "general corporate purposes." In response to OCA-II-32, I asked the Company to show how 50% of the consolidated tax savings has been used for general corporate purposes. The Company responded that its operating expenses of more than $121 million exceed the Company's calculation of the 50% level of the adjustment related to general corporate purposes. UGI stated that the expenses will be used to benefit ratepayers, including but not limited to $217,000 in meter reading expenses, $9,712,000 for maintenance of overhead lines and $1,275,000 for various customer service expenses. UGI has identified no specific way in which 50% of the differential would be used to benefit Pennsylvania ratepayers. One might conclude from this that UGI intends to use that money for the benefit of its stockholders, and not apply it in any manner to provide a quantifiable ratepayer benefit or in a manner that directly benefits service to Pennsylvania customers.

Q. WHAT DOES "GENERAL CORPORATE PURPOSES" AS USED IN ACT 40 MEAN?

A. Because UGI is a regulated utility in Pennsylvania, its "general corporate purpose" is to provide regulated utility service in the Commonwealth of Pennsylvania. While the term "general corporate purposes" is rather vague, general corporate purposes would typically include uses for such “differential” revenues as supporting capital expenditures necessary to execute utility business plans, paying off debt, funding construction projects, paying dividends, paying for maintenance and operating expenses, investing in utility plant in Pennsylvania, and providing a source of working capital. Many of these uses for “general corporate purposes” would have a quantifiable benefit to Pennsylvania ratepayers. As I read the entirety of Act 40, the "revenue use differential" addressed in the Act for “general corporate purposes” should mean public utility purposes and uses that result in having some identifiable and quantifiable benefit to Pennsylvania and UGI ratepayers, rather than just resulting in a windfall of $70,000 annually to UGI’s shareholders or affiliates.

Q. WHAT SPECIFIC RECOMMENDATION DO YOU HAVE IN THE CURRENT PECO RATE CASE FOR APPLYING THE 50% OF THE “REVENUE USE” DIFFERENTIAL THAT ACT 40 REQUIRES TO BE FOR “GENERAL CORPORATE PURPOSES”?

A. I have reflected the 50% differential for general corporate purposes as a source of non-investor-supplied funding for utility working capital. I have reduced the Company’s Rate Base balance by $35,000 as shown on my Schedule DM-3.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Public

SUMMARY REVENUE REQUIREMENTS

			(1) Company Proposed	Adjustments	OCA Recommended	References
1		**Rate Base Valuation**	**$ 172,242,000**	**$ (652,521)**	**$ 171,589,479**	DM-3
2		Rate of Return	8.150%		6.180%	DM-2
3		**Operating Income Requirement**	**$ 14,037,723**	**$ (3,433,021)**	**$ 10,604,702**	
4		Present Operating Income	$ 6,490,000	$ 1,775,442	$ 8,265,442	
5						DM-4
		Operating Income Deficiency	**$ 7,547,723**	$ (5,208,464)	**$ 2,339,259**	
6	(2)	Gross Revenue Conversion Factor	1.513583		1.513583	
		Revenue Requirement Increase	**$ 11,424,105**	**$ (7,883,442)**	**$ 3,540,663**	
7						
8		Present Rate Revenue	$ 152,691,000	$ 26,832	$ 152,717,832	DM-4
9		% Increase	7.48%		2.32%	

(1) Company Schedule A-1
(2) Company Schedule D-35

Gross Revenue Factor	1.000000
Uncollectible Expenses	(0.018380)
Net Revenues	0.981620
Gross Receipts Tax - 6.27%	(0.062700)
Factor after Gross Receipts Tax Rate	0.918920
State Income Tax - 8.99%	(0.082611)
Factor after State Income Tax	0.836309
Federal Income Tax - 21%	(0.175625)
Net Operating Income Factor	0.660684
Gross Revenue Factor	**1.513582**

Differences due to rounding

RATE OF RETURN

			Capitalization Ratio	Embedded Cost	Weighted Average
	(1)	**Company Proposed**			
1		Long-Term Debt	45.410%	4.350%	1.98%
2		Short-Term Debt	0.000%	0.000%	0.00%
3		Common Equity	54.590%	11.300%	6.17%
4		**Total**	**100.000%**		**8.14%**

(1) Company Schedule B-7

	(2)	**OCA Recommended**			
5		Long-Term Debt	55.250%	4.350%	2.403%
6		Short-Term Debt	0.000%	0.000%	0.000%
7		Common Equity	44.750%	8.440%	3.777%
8		**Total**	**100.000%**		**6.180%**

(2) OCA Witness Rothschild
OCA- Set II -18

OCA Set II-18

	RATE BASE VALUATION	(1) Company Proposed	Adjustments	OCA Recommended	References
1	Electric Utility Plant In Service	$ 275,001,000	$ (218,806)	$ 274,782,194	DM-5
2	Accumulated Depreciation	$ (85,745,000)	$ 16,590	$ (85,728,410)	DM-6
3	**Net Electric Utility Plant In Service**	**$ 189,256,000**	**$ (202,216)**	**$ 189,053,784**	
4	Working Capital Allowance	$ 11,447,000	$ (419,967)	$ 11,027,033	DM-7
5	Accumulated Deferred Income Taxes	$ (29,665,000)	$ 5,662	$ (29,659,338)	DM-8
6	Customer Deposits	$ (949,000)	$ -	$ (949,000)	
7	Materials & Supplies	$ 2,152,000	$ -	$ 2,152,000	
8	Consolidated Tax Adjustment	$ -	$ (35,000)	$ (35,000)	Exh DTE-3
9	**Total Rate Base Valuation**	**$ 172,241,000**	**$ (651,521)**	**$ 171,589,479**	OCA Set II-32

(1) Company Schedule C-1

					Company Proposed				OCA		
		OPERATING INCOME STATEMENT	Budget Year 9/30/2024	Adjustments	Proforma Present Rates	Adjustments	Proforma Proposed Rates	Adjustments	Recommended Present Rates	References	
	Acct No.		(1)								
		Operating Revenues									
1	440.00	Residential	$ 111,376,000	$ 5,890,000	$ 117,266,000	$ -	$ 117,266,000				
2	442.00	Commercial & Industrial	$ 32,040,000	$ 1,489,000	$ 33,529,000	$ -	$ 33,529,000				
3	444.00	Public Street & Highway	$ 749,000	$ 9,000	$ 758,000	$ -	$ 758,000				
4	445.00	Other Sales to Public Authorities	$ 19,000	$ -	$ 19,000	$ -	$ 19,000				
5	447.00	Sales for Resale	$ 16,000	$ -	$ 16,000	$ -	$ 16,000				
6	450.00	Forfeited Discounts	$ 520,000	$ -	$ 520,000	$ -	$ 520,000	$ 10,333		OCA Set II-49	
7	451.00	Misc. Service Revenue	$ 16,000	$ -	$ 16,000	$ -	$ 16,000	$ 5,092			
8	454.00	Rent from Electric Properties	$ 567,000	$ -	$ 567,000	$ -	$ 567,000	$ 11,407			
9		Rate Increase	$ -	$ -	$ -	$ 11,425,000	$ 11,425,000				
10		**Total Operating Revenues**	**$ 145,303,000**	**$ 7,388,000**	**$ 152,691,000**	**$ 11,425,000**	**$ 164,116,000**	**$ 26,832**	**$ 152,717,832**	OCA Set II-37	
		Operating Expenses									
11	555.00	Other Power Supply Expenses	$ 85,951,000	$ 5,225,000	$ 91,176,000	$ -	$ 91,176,000	$ -	$ 91,176,000		
12	560.00	Transmission Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
13	580-590	Distribution Expenses	$ 13,259,000	$ 15,000	$ 13,274,000	$ -	$ 13,274,000	$ (1,492,485)	$ 11,781,515		DM-10
14	901-05	Customer Accounts	$ 9,463,000	$ 171,000	$ 9,634,000	$ -	$ 9,634,000	$ (508,000)	$ 9,126,000		
15	904.00	Uncollectible Expense 1.838%	$ 2,577,000	$ 662,000	$ 3,239,000	$ 209,992	$ 3,448,992	$ (169,094)	$ 3,279,897		
16	907-10	Customer Information & Services	$ 1,275,000	$ (89,000)	$ 1,186,000	$ -	$ 1,186,000	$ (60,333)	$ 1,125,667		
17	911-17	Sales Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
18	920-35	Administrative & General Expenses	$ 8,220,000	$ 377,000	$ 8,597,000	$ -	$ 8,597,000	$ (810,785)	$ 7,786,215		
19	C C	[redacted]								OCA Set II-20	DM-9
20		Overtime/Other Wages						$ (1,667)	$ (1,667)		
21		**Sub-Total**	**$ 120,745,000**	**$ 6,361,000**	**$ 127,106,000**	**$ 209,992**	**$ 127,315,992**	**$ (3,908,814)**	**$ 123,407,177**		
22		Depreciation & Amortization	$ 9,075,000	$ (522,000)	$ 8,553,000	$ -	$ 8,553,000	$ (16,085)	$ 8,536,915		
23		Taxes Other Than Income	$ 9,375,000	$ 344,000	$ 9,719,000	$ 716,000	$ 10,435,000	$ (642,912)	$ 9,792,088		
24		**Total Operating Expenses**	**$ 139,195,000**	**$ 6,183,000**	**$ 145,378,000**	**$ 925,992**	**$ 146,303,992**	**$ (4,567,811)**	**$ 141,736,181**		
25		Net Operating Income Before Taxes	$ 6,108,000	$ 1,205,000	$ 7,313,000	$ 10,499,009	$ 17,812,009	$ (6,830,357)	$ 10,981,651		
26		Income Taxes - Present Rates - est.	$ (485,000)		$ 823,000						
27		Income Taxes - Proposed Rates				$ 2,951,000	$ 3,774,000	$ (1,057,791)	$ 2,716,209		
28		**Net Income**	**$ 5,623,000**		**$ 6,490,000**	**$ 7,548,009**	**$ 14,038,009**	**$ (5,772,566)**	**$ 8,265,442**		
		Rate Base	$ 172,242,000		$ 172,242,000		$ 172,242,000		$ 171,589,479		
		Rate of Return	3.265%		3.768%		8.1502%		6.18%		
		check	$ 5,623,000		$ 6,490,000	$ 7,548,009	$ 14,038,009	$ (3,433,779)	$ 10,604,230		

Await excel spreadsheets and confirm

(1) Company Schedules D-1, D-2 and D-5

	Acct. No.	ELECTRIC UTILITY PLANT IN SERVICE	(1) Company Proposed	Adjustments	OCA Recommended	References
1	301-02	Intangible Plant	$ 16,000	$ -	$ 16,000	OCA Set II-13 OCA Set II-15
2	350-59	Transmission Plant	$ -	$ -	$ -	
3	360-73	Distribution Plant	$ 239,335,000	$ -	$ 239,335,000	OCA Set II-38 OCA Set II-39
4	389-99	General & Common Plant	$ 35,650,000	$ (218,806)	$ 35,431,194	OCA Set IX-3 OCA Set II-40
5		**Total Electric Utility Plant in Service**	**$ 275,001,000**	**$ (218,806)**	**$ 274,782,194**	
6		Plant Additions 9/30/2023-9/30/2024	$ 24,665,000			
7		Less Retirements	$ (2,605,000)			
8		Total	$ 22,060,000			

(1) Company Schedule C-2

	Acct. No.	ACCUMULATED DEPRECIATION	(1) Company Proposed	Adjustments	OCA Recommended	References
1	301-03	Intangible Plant	$ -			
2	350-59	Transmission Plant	$ -			
3	360-73	Distribution Plant	$ 74,384,000	$ (16,590)	$ 74,367,410	OCA-IX-3
4	389-99	General & Common Plant	$ 11,361,000	$ -	$ 11,361,000	
5		**Total Accumulated Depreciation**	**$ 85,745,000**	**$ (16,590)**	**$ 85,728,410**	

(1) Company Schedule C-1 and C-3

WORKING CAPITAL REQUIREMENT

		TY Expenses (1)	Lag Days	Weighted $	Total	Adjustments		OCA Recommended
1	Revenue Lag Days				59.56			
	Expense Lag Days							
2	Payroll	$ 6,196,000	12.00	$ 74,352,000		$ (1,520,000)		$ 72,832,000
3	Purchased Power Costs	$ 91,176,000	33.29	$ 3,035,249,040		$ -		$ 3,035,249,040
4	Other Expenses	$ 26,495,000	30.76	$ 814,986,200		$ (88,330,521)		$ 726,655,679
5	**Total**	**$ 123,867,000**		**$ 3,925,499,000**				**$ 3,834,736,719**
6	O&M Expense Lag Days				31.69		31.92	
7	Net Lead/Lag Days				27.87		27.64	
8	Operating Expenses Per Day				339.36		329.12	
9	**Working Capital for O&M Expenses**				**$ 9,457,588**			**$ 9,096,011**
10	**Interest Payments**		(31.70)		**$ (295,492)**			**$ (295,223)**
11	Tax Payments Lag - Federal				$ 164,224			$ 114,222
12	Tax Payments Lag - State				$ 92,757			$ 75,733
13	PA Property Tax				$ (1,864.88)			$ (1,865)
14	PURTA				$ 6,155			$ 6,155
15	**Total Tax Payments**				**$ 261,271**			**$ 194,245**
16	**Total Prepaid Expenses**				**$ 2,032,000**	**$ -**		**$ 2,032,000**
17	**Total Working Capital Allowance**				**$ 11,455,367**		**$ (428,333)**	**$ 11,027,033**

(1) Company Schedule C-4

OCA Set II-33

	Acct. No.	ACCUMULATED DEFERRED INCOME TAXES	(1) Company Proposed	Adjustments	OCA Recommended	References
1	282.00	Electric Utility Plant	$ (30,062,000)	$ 4,662	$ (30,057,338)	OCA-IX-3
2		ADIT on CIAC	$ 2,177,000		$ 2,177,000	
3		Federal ADIT Balance	$ (27,885,000)	$ 4,662	$ (27,880,338)	
4		State Repair Regulatory Liability	$ (3,367,000)		$ (3,367,000)	
5		Pro-Rata Adjustment (EDIT 2017)	$ 1,588,000		$ 1,588,000	OCA Set II-46 OCA Set II-48
6		Balance at 9/30/2024	**$ (29,664,000)**	**$ 4,662**	**$ (29,659,338)**	

(1) Company Schedule C-6

	SALARY AND WAGE WORKSHEET	(1) **Company Proposed**	**Annualized**	**Adjusted Total**	**OCA Recommended**	**References**
	Distribution Operations					OCA Set II-11
1	Union			$ 885,000		OCA Set II-19
2	Non-Exempt			$ 236,000		OCA Set II-23
3	Exempt			$ 740,000		OCA Set II-21
4	**Total**	**$ 1,850,000**	**$ 10,000**	**$ 1,860,000**	**$ 1,860,000**	
	Customer Accounts Expense					
5	Union			$ -		
6	Non-Exempt			$ 407,000		
7	Exempt			$ 1,279,000		
8	**Total**	**$ 1,677,000**	**$ 9,000**	**$ 1,686,000**	**$ 1,686,000**	
	Customer Service & Information					
9	Union			$ -		
10	Non-Exempt			$ 7,000		
11	Exempt			$ 21,000		
12	**Total**	**$ 28,000**	**$ -**	**$ 28,000**	**$ 28,000**	
	Sales Expense					
13	Union			$ -		
14	Non-Exempt			$ 1,000		
15	Exempt			$ 4,000		
16	**Total**	**$ 5,000**	**$ -**	**$ 5,000**	**$ 5,000**	
	A&G Expense					
17	Union			$ -		
18	Non-Exempt			$ 403,000		
19	Exempt			$ 1,262,000		
20	**Total**	**$ 1,656,000**	**$ 9,000**	**$ 1,665,000**	**$ 1,665,000**	
	Distribution Maintenance					
21	Union			$ 437,000		
22	Non-Exempt			$ 117,000		
23	Exempt			$ 365,000		
24	**Total**	**$ 914,000**	**$ 5,000**	**$ 919,000**	**$ 919,000**	
	A&G Maintenance					
25	Union			$ -		
26	Non-Exempt			$ 8,000		
27	Exempt			$ 25,000		
28	**Total**	**$ 33,000**	**$ -**	**$ 33,000**	**$ 33,000**	
29	**Total Proposed Salary and Wages Adjustments**	**$ 6,163,000**	**$ 33,000**	**$ 6,196,000**	**$ 6,196,000**	
						OCA Set II-27
CONFID	[redacted]					OCA Set II-24
						OCA Set II-26
CONFID						OCA Set II-25
CONFID						OCA Set II-20
	Overtime	2022	2023	2024		I&E RE-12
	Union	$ 553,000	$ 492,000	$ 492,000		
	Non-Union	$ 5,000	$ 5,000	$ 5,000		
	Utility Shared Services	$ 79,000	$ 70,000	$ 70,000		
		$ 637,000	$ 567,000	$ 567,000	$ 590,333	
	Adjustment				**$ 23,333**	
	SERP Expenses			$ 25,000	**$ (25,000)**	OCA-Set-II-26
				$ (868,117)		

(1) Company Schedule D-7
Review OCA discovery

	Acct. No.	DISTRIBUTION EXPENSES	(1) Company Proposed	Adjustments	OCA Recommended	References
1		Distribution - Operations - Budget	$ 2,912,000	$ (75,000)	$ 2,837,000	
2		Salary Adjustment - D-7	$ 10,000	$ -	$ 10,000	
3		**Total**	**$ 2,922,000**	**$ (75,000)**	**$ 2,847,000**	
4		Distribution - Maintenance - Budget	$ 10,347,000	$ (1,417,485)	$ 8,929,515	
5		Salary Adjustment - D-7	$ 5,000	$ -	$ 5,000	
6		**Total**	**$ 10,352,000**	**$ (1,417,485)**	**$ 8,934,515**	
7		**Total Distribution Expenses**	**$ 13,274,000**	**$ (1,492,485)**	**$ 11,781,515**	
		OCA Adjustments				
	583.00	Contract Labor - Pipeline	$ 163,000	$ (71,000)	$ 92,000	
	588.00	Miscellaneous	$ 7,000	$ (4,000)	$ 3,000	OCA Set II-34
				$ (75,000)		
	593.00	Maintenance of OH Lines - Tree Trim	$ 3,931,777	$ (1,431,151)	$ 2,500,626	OCA Set II-3
	593.00	Maintenance of OH Lines - Major Storms	$ 760,000	$ 42,000	$ 802,000	OCA Set II-4
	595.00	Maintenance of Line Transformers-Pipeline	$ 66,000	$ (24,333)	$ 41,667	OCA Set II-34
	596.00	Maintenance of Street Light- Other	$ 7,000	$ (2,667)	$ 4,333	OCA Set II-34
	598.00	Maintenance of Misc. Dist. Plant -Pipeline	$ 5,000	$ (1,333)	$ 3,667	OCA Set II-5
						OCA Set II-6
		Total Adjustments		**$ (1,417,485)**		

(1) Company Schedule B-4, D-3
review three year averages and non-recurring expenses
Major Storms, Tree Trimming, and Veg Mgmt.

Acct. No.	CUSTOMER ACCOUNTS EXPENSE	(1) Company Proposed	Adjustments	OCA Recommended	References
1	Customer Accounts - Budget	$ 9,463,000	$ (508,000)	$ 8,955,000	
2	Salary Adjustment - D-7	$ 9,000	$ -	$ 9,000	
3	Interest on Customer Deposits - D-15	$ 66,000	$ -	$ 66,000	
4	Universal Service - D-16	$ 96,000	$ -	$ 96,000	
5	**Total**	**$ 9,634,000**	**$ (508,000)**	**$ 9,126,000**	
	OCA Adjustments				
					OCA Set II-14
902.00	Meter Reading Expenses	$ 218,000	$ (61,000)	$ 157,000	OCA Set II-6/IX-4
905.00	Miscellaneous CA Expenses	$ 139,000	$ (43,667)	$ 95,333	OCA-Set IX-4
903.00	Customer Records & Collection	$ 9,185,000	$ (403,333)	$ 8,781,667	OCA-IX-4
	Total		**$ (508,000)**		

(1) Company Schedule D-3, B-4

UNCOLLECTIBLE ACCOUNTS EXPENSE

Acct. No.		(1) Company Proposed	Adjustments	OCA Recommended	References
1	2024 Budget - D-11	$ 2,239,000		$ 2,239,292	OCA-II-29
2	Uncollectible Accounts - Budget - B-4	$ 2,577,000		$ 2,577,000	
3	Three-Year Average - Ratio	1.8375%		1.8375%	
4	Adjusted Revenues	$ 152,108,000		$ 152,108,000	OCA-II-29
5	**Proforma Uncollectible - Present Rates**	**$ 2,795,008**		**$ 2,794,985**	
6	**Difference** (Line 11 - Line 6)	**$ 556,008**		**$ 555,692**	
7	**Deferred Uncollectible Accounts**	$ 315,000		$ 315,000	
8	3-year amortization	**$ 105,000**		**$ 105,000**	
9	Total Uncollectible Account Adjustment (Line 6 + Line 8)	**$ 661,008**		**$ 660,692**	
10	**Total Uncollectible at Present Rates** (Line 5 + Line 9)	**$ 3,238,008**	**$ (316)**	**$ 3,237,692**	
11	Additional Uncollectible - Proforma Rates	$ 209,936		$ 42,205	
12	**Total Uncollectible Accounts Expense** Line 10 + Line 11)	**$ 3,447,944**	**$ (168,047)**	**$ 3,279,897**	

(1) Company Schedule D-11, B-4, D-1

	Acct. No.	CUSTOMER INFORMATION & SERVICE	(1) Company Proposed	Adjustments	OCA Recommended	References
1		Customer Information & Service - Budget	$ 1,275,000	$ (60,333)	$ 1,214,667	
2		EE&C Program - D-19	$ (89,000)		$ (89,000)	
3		**Total Proforma Balance**	**$ 1,186,000**	**$ (60,333)**	**$ 1,125,667**	
		OCA Adjustments				
	910	Misc, Customer Service & Info. Exp.	$ 1,157,000	$ (69,333)	$ 1,087,667	OCA Set II-6
	908	Customer Assistance Expenses	$ 12,000	$ 9,000	$ 21,000	OCA-IX-4
						OCA Set II-12
						OCA Set II-14

(1) Company Schedule B-4, D-3 and D-1

SALES EXPENSE

Acct. No.		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Sales - Budget (B-4)	$ -			
2	Adjustments (D-3)	$ -			
3	**Total Proforma Balance**	**$ -**	**$ -**	**$ -**	

(1) Company Schedule D-1 and D-3

	Acct. No.	ADMINISTRATIVE & GENERAL EXPENSES	(1) Company Proposed	Adjustments	OCA Recommended	References
1		A & G - Operations Budgeted (B-4)	$ 8,151,000	$ (275,919)	$ 7,875,081	
2		Salary Adjustment - (D-7)	$ 9,000	$ -	$ 9,000	
3		Rate Case Expenses (D-10)	$ (59,000)	$ (231,200)	$ (290,200)	OCA Set II-28
4		Benefits Adjustments (D-14)	$ 427,500	$ (248,500)	$ 179,000	OCA Set II-30
5	935.00	A&G - Maintenance - Budgeted (B-4)	$ 69,000	$ (55,667)	$ 13,333	OCA Set-II-6
6		**Total Proforma Balance**	**$ 8,597,500**	**$ (811,285)**	**$ 7,786,215**	

OCA Adjustments

930.20	Association Dues - EA of PA (80% to UGI-E)	$ 7,000	$ (7,000)	$ -	OCA Set II-7/Set IX-1
923.00	Outside Services Employed - ESG	$ 11,000	$ (11,000)	$ -	OCA Set II-8/Set IX-2
930.10	Advertising Expense	$ 113,000	$ (83,252)	$ 29,748	OCA Set II-9/II-D-7(d)
925.00	Injury and Damages	$ 251,000	$ 3,333	$ 254,333	OCA Set II-6
920.00	A&G Salaries	$ 178,000	$ (178,000)	$ -	OCA-Set IX-6
			$ (275,919)		OCA Set II-12
					OCA Set II-14
					OCA Set II-16
					OCA Set II-22

(1) Company Schedule B-4, D-1, D-3

Acct. No.	DEPRECIATION EXPENSE	Original Cost (1)	Company Proposed Depr. Rate	Company Proposed Depr. Expense	Adjustments	OCA Recommended	References
1	Intangible Plant	$ -	0.000%	$ -			OCA Set II-42
2	Transmission Plant	$ -	0.000%	$ -			
3	Distribution Plant	$ 239,022,741	2.207%	$ 5,274,490			
4	General Plant	$ 13,513,335	11.792%	$ 1,593,465			
5	Special Depreciable Plant	$ 4,718,755	9.912%	$ 467,714			
6	Non-Depreciable Plant	$ 524,120	0.000%	$ -			
7	**Sub-Total**	**$ 257,778,951**		**$ 7,335,669**		**$ 7,335,669**	
8	Allocated to Transmission	$ (4,725,890)	11.176%	$ (528,171)			
9	**Total Allocated to Distribution**	**$ 253,053,061**		**$ 6,807,498**		**$ 6,807,498**	
10	Total Allocated Common Plant	$ 4,860,027	2.988%	$ 145,198			
11	Total Allocated IT Services	$ 22,199,147	7.582%	$ 1,683,163	$ (16,590)	$ 1,666,573	OCA-II-38
12	Total Office Furniture & Equipment	$ 246,470	6.896%	$ 16,997			
13	Total Empire Building Allocated	$ 2,204,954	2.288%	$ 50,442			
14	Allocated to Transmission	$ (7,562,002)	6.424%	$ (485,793)			
15	**Total Depreciation Expense before adj.**	**$ 275,001,657**		**$ 8,217,505**	**$ (16,590)**	**$ 8,200,915**	
16	Charged to Other Business Units	$ -		$ (42,000)			
17	Charged to Clearing Accounts	$ -		$ (479,000)			
18	Net Salvage Amortization	$ -		$ 857,000			
19	**Total Proposed Depreciation Expense**	**$ 275,001,657**		**$ 8,553,505**	**$ (16,590)**	**$ 8,536,915**	

(1) Company Schedule D-21
Book V UGI Electric Exhibit C page II 3-5

	TAXES OTHER THAN INCOME	(1) Company Proposed	Adjustments	OCA Recommended	References
1	PURTA Taxes	$ 76,000	$ -	$ 76,000	OCA Set II-31
2	Gross Receipts Tax - 5.90%	$ 8,818,000	$ -	$ 8,818,000	
3	PA & Local Use Taxes (real estate)	$ 22,000	$ -	$ 22,000	I&E RE-4-D
4	Social Security Taxes (FICA) - 7.61%	$ 472,000	$ (66,064)	$ 405,936	
5	FUTA - 0.51%	$ 31,000	$ (4,427)	$ 26,573	
6	SUTA - 0.05%	$ 3,000	$ (434)	$ 2,566	
7	PUC Assessment	$ 297,000	$ -	$ 297,000	I&E RE-4-D
8	**Total Taxes Other Than Income**	**$ 9,719,000**	**$ (70,925)**	**$ 9,648,075**	
9	Additional Taxes Other Than Income	$ 716,000	$ (571,986)	$ 144,014	
10	**Total**	**$ 10,435,000**	**$ (642,912)**	**$ 9,792,088**	

(1) Company Schedule D-31 and D-32

		INCOME TAX CALCULATION	(1) Company	Proposed Proposed Rates	Adjustments	OCA Recommended Present Rates	References
1		Proposed Revenues		$ 164,116,000		$ 152,717,832	
2		Proposed Operating Expenses		$ (146,303,992)		$ (141,736,181)	
3		Operating Income Before Taxes		$ 17,812,009		$ 10,981,651	
		Interest Expense					
4		Proposed Rate Base	$ 172,241,000			$ 171,589,479	
5		Weighted Cost of Debt	1.98%			2.40%	
6		Synchronized Interest		$ (3,402,337)		$ (4,123,939)	
7		Base Taxable Interest		$ 14,409,672		$ 6,857,713	
8		Total Taxable Depreciation	$ 18,229,000			$ 18,229,000	OCA Set II-43
9		Total Proforma Book Depreciation	$ 8,957,000		$ (16,590)	$ 8,940,410	OCA Set II-43
10		State Taxable Depreciation (over)/under		$ (9,272,000)	$ (16,590)	$ (9,288,590)	
11		State Taxable Income		$ 5,137,672		$ (2,430,877)	
12		**State Income Tax (Expense) Refund**	**8.99%**	**$ (461,877)**		**$ (218,536)**	
		Total Taxable Depreciation	$ 17,308,000			$ 17,308,000	OCA Set II-43
		Total Proforma Book Depreciation	$ 8,957,000			$ 8,940,410	OCA Set II-43
		Federal Tax Deducts (over) under		$ (8,351,000)	$ (16,590)	$ (8,367,590)	
		Federal Taxable Income		$ 5,596,795		$ (1,728,413)	
		Federal Income Tax (Expense) Refund	**21.00%**	**$ (1,175,327)**		**$ (362,967)**	
		Total Tax Expense Before DIT		**$ (1,637,204)**		**$ (581,503)**	
		Deferred Federal Income Taxes					
		Total Straight Line Tax Depreciation	$ 8,218,000		$ (16,590)	$ 8,201,410	
		Total Tax Depreciation	$ 16,525,000			$ 16,525,000	
		Federal Tax Deducts (over) under		$ 8,307,000	$ 16,590	$ 8,323,590	
	(2)	**Deferred Federal Income Tax Rate**	**17.85%**	**$ (1,482,800)**		**$ (1,485,761)**	OCA Set II-45
		Deferred State Income Taxes					
		Repairs		$ (694,000)		$ (694,000)	
		CIAC		$ 38,000		$ 38,000	
		State Deferred Income Tax (Expense) Refund		$ (656,000)		$ (656,000)	
		Net Income Taxes - Combined		**$ (3,776,003)**		**$ (2,723,263)**	OCA Set II-44
		Federal Income Taxes		$ (2,658,126)	$ 809,399	$ (1,848,728)	
		State Income Taxes		$ (1,155,877)	$ 243,341	$ (912,536)	
		Total - check		$ (3,814,003)		$ (2,761,263)	
		difference - rounding		$ 38,000			
							OCA Set II-46
	(2)	Includes $283,000 of EDFIT flow back to ratepayers					OCA Set II-47

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2022-3037368
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Dante Mugrace, hereby state that the facts set forth in my Direct Testimony, OCA Statement 1, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 25, 2023
*344779

Signature: Dante Mugrace
Dante Mugrace

Consultant Address: PCMG and Associates
90 Moonlight Court
Toms River, NJ 08753

OCA St. 1SR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**Docket No. R-2022-3037368**
UGI Utilities, Inc. Electric Division	)	

SURREBUTTAL TESTIMONY OF

DANTE MUGRACE

ON BEHALF OF THE

PENNSYLVANIA

OFFICE OF CONSUMER ADVOCATE

<u>PUBLIC VERSION</u>

June 7, 2023

TABLE OF CONTENTS

I. PURPOSE OF SURREBUTTAL TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dante Mugrace. My business address is 22 Brooks Avenue, Gaithersburg, MD 20877.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS DOCKET?

A. Yes. I submitted Direct Testimony on April 20, 2022, which was marked as OCA Statement 1. My qualifications and experience are attached to my Direct Testimony.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my Surrebuttal Testimony is to address the Rebuttal Testimonies of Company witnesses Hazenstab (Statement No. 2-R), Ressler (Statement No. 3-R), Schappell (Statement No. 5-R) and Sorber (Statement No. 4-R). I am also making certain adjustments to proposals in my testimony and a revised calculation of the Company's revenue requirement that incorporates the effects of my adjustments. I've also updated the Company's adjustments to certain of its revenue requirement schedules, as noted in the Company's UGI Gas Exhibit A FPFTY Rebuttal. To the extent that I do not respond to or address a particular issue or argument, I defer to my Direct Testimony on those issues.

Q. HAS THE COMPANY MADE ADJUSTMENTS TO ITS AS FILED PETITION WITH RESPECT TO ITS PROPOSED REVENUE REQUIREMENT?

A. Yes. As stated by Ms. Hazenstab (Statement No. 2-R) the Company updated certain components of its rate filing related to Operating Revenue, Customer Deposits, Materials and Supplies, Weighted Average Cost of Debt, Salary and Wage Expense and the flow through of the adjusted expenses to develop the Taxes other than Income, Working Capital Allowance and Income Taxes. The overall effect of the updates and corrections to the Company's claim is that the Company has allegedly supported a revenue increase of $11,453,000 as compared to the as-filed claim of $11,425,000 using the Company's proposed capital structure, revised weighted average cost of debt and proposed return on equity of 11.30%. (Statement No. 2-R at 4-5).

Q. WITH YOUR ADJUSTMENTS TO YOUR DIRECT TESTIMONY, WHAT IS YOUR REVISED COMPANY REVENUE REQUIREMENT?

A. With my revised adjustments, I have calculated a revenue requirement increase of $5,591,225. This includes OCA Witness Mr. Rothschild's overall rate of return of 6.18% which includes a common equity cost rate component of 8.44%.

II. REVENUE REQUIREMENT ISSUES

A. Rate Base Issues

1. Utility Plant In Service (UPIS)

Q. WHAT IS THE COMPANY'S POSITION REGARDING YOUR ADJUSTMENTS TO ITS UTILITY PLANT IN SERVICE?

A. Company witness Ms. Ressler did not agree with my adjustments related to the Company's Plant in Service related to the Company's Data Center project. (Statement No. 3-R at 3). Ms. Ressler stated that the Company manages its capital budget for each year, including the FPFTY in total. The Company will reprioritize projects and update associated projections as needed in order to achieve a result which has the greatest likelihood of being on budget for the year in total. (Statement No. 3-R at 3). According to Ms. Ressler, the known and measurable is appropriately viewed in total and a selective disallowance of certain cost elements, as I have suggested with the Data Center contingency costs, is inappropriate. (Statement No. 3-R at 3). Company witness Ms. Schappell stated that a project contingency for construction is a specific amount of money that is identified at the outset of the project as part of the budget to address unforeseen additional costs arising during the construction process. (Statement No. 5-R at 3). She stated that construction contingencies arise for a variety of reasons including issues with materials, equipment, labor or supplies, price increases or limited supply availability, weather impacts and subcontractor changes. Ms. Schappell also stated that unforeseen change order impacts and general cost changes are other reasons for including contingencies. (Statement No. 5-R at 3). Ms. Shappell stated that these types of costs are a means to cover expenditures that have not been specifically foreseen by parties within the scope of the project but are likely to occur based on past experiences with similar types of projects. Contingency costs are commonly added to large or complex projects as an element of project management that allows the Company to balance the project's schedule, quality commitments and cost in a manner which accurately reflects real-world conditions. (Statement No. 5-R at 3).

Q. WHAT IS YOUR RESPONSE?

A. I am continuing to recommend disallowance of the contingency costs. In my opinion, contingency costs are amounts of money set aside to cover any unexpected costs that can arise throughout the construction project. This money is on reserve and is not allocated to any specific area of work, but as stated by Ms. Schappell, is identified at the outset of the project as part of its budget to address unforeseen costs. Therefore, contingency costs are not known and measurable in the ratemaking process and are not appropriate to be paid for by ratepayers. Basic ratemaking principles require that costs should be known and measurable, prudent in nature and provide service to ratepayers. The Company has not provided any convincing or reliable data related to these contingency costs but for a list of reasons why contingency costs are included for various risks that cannot be otherwise accounted for. These unknown risks are not the sort that ratepayers should bear. The Company has also not provided any other additional information nor identified any additional costs beyond the November 2023 in-service date but instead merely stated that some additional costs are likely. Therefore, I believe that contingency costs should be removed from the Company's EPIS balance. This is shown on my Schedule DM-SR-5.

2. Accumulated Depreciation

Q. WHAT DID MS. RESSLER STATE WITH RESPECT TO YOUR ADJUSTMENTS TO ACCUMULATED DEPRECIATION?

A. Ms. Ressler did not agree with my adjustments to the Company's Accumulated Depreciation Balance as she disagreed with my adjustments to the Company's Electric Plant in Service Balance. (Statement No. 3-R at 4).

Q. WHAT IS YOUR RESPONSE?

A. Given that I am continuing to recommend disallowance of the Company's contingency costs, my Accumulated Depreciation expense balance remains the same, and is shown on my Schedule DM-SR-6.

3. Accumulated Deferred Income Taxes

Q. WHAT DID MS. RESSLER STATE WITH RESPECT TO YOUR ADJUSTMENTS TO THE ACCUMULATED DEFERRED INCOME TAXES?

A. Ms. Ressler did not agree with my adjustments to the Company's Accumulated Deferred Income Taxes which are derived from my adjustments to the Company's claim for my plant in service balance. (Statement No. 3-R at 4).

Q. WHAT IS YOUR RESPONSE?

A. Given that I am continuing to recommend disallowance of the Company's contingency costs, my Accumulated Deferred Income Taxes remain the same, and is shown on my Schedule DM-SR-8.

4. Cash Working Capital

Q. WHAT DID MS. HAZENSTAB STATE REGARDING YOUR ADJUSTMENT TO THE COMPANY'S CASH WORKING CAPITAL?

A. Ms. Hazenstab stated that she did not agree with my adjustments to the extent that these adjustments relate to underlying expenses or tax adjustments. (Statement No. 2-R at 20). Ms. Hazenstab stated that my Cash Working Capital adjustments are based solely on my recommended expense adjustment. (Statement No. 2-R at 18-19).

Q. WHAT IS YOUR RESPONSE?

A. My Cash Working Capital balance reflects all my adjustments to the Company's revenue requirement proposal, and those flow-through adjustments reflect the balance that I am recommending. I do not believe we are in disagreement with the methodology used to compute the Cash Working Capital, just the adjustments to the calculation of the overall balance. My surrebuttal recommendation for the Company's Cash Working Capital is shown on my Schedule DM-SR-7.

B. OPERATING INCOME

1. Operating Revenues – Forfeited Discounts, Miscellaneous Revenues and Rent from Gas Properties

Q. WHAT HAS THE COMPANY STATED REGARDING YOUR ADJUSTMENT TO OPERATING REVENUE – FORFEITED DISCOUNTS, MISCELLANEOUS REVENUES AND RENT FROM PROPERTIES?

A. Ms. Hazenstab did not agree with my normalized three-year period adjustment for these Operating Revenues categories which total $26,832. (Statement No. 2-R at 6). Ms. Hazenstab stated that the Company is proposing to normalize forfeited discounts, miscellaneous revenues and rent from electric properties based in fiscal years of 2019, 2021 and 2022. This normalized adjustment uses actual data for all three years of the normalization calculation as opposed to my calculation, which uses one year of actual and two years of projected revenue. This adjustment will decrease revenue by $20,000 (Statement No. 2-R at 7).

Q. WHAT IS YOUR RESPONSE?

A. I am accepting Ms. Hazenstab's rebuttal adjustment that is based upon actual data for the years shown. Therefore, I am accepting the Company's balances for these Operating Revenues categories. My adjustment is shown on my Schedule DM-SR-4.

2. OPERATION AND MAINTENANCE EXPENSES

a. Salary and Wages – Additional Employees / Overtime Costs

Q. WHAT DID MS. HAZENSTAB STATE REGARDING YOUR ADJUSTMENTS TO PAYROLL EXPENSE?

A. Ms. Hazenstab agreed in part with my adjustment related to the anticipated hires to be filled. She agreed with my disallowance of one position in the amount of **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)**. (Statement No. 2-R at 8). Ms. Hazenstab stated that one of the two positions was authorized and posted on May 10, 2023, and anticipates filling this position by the end of June. (Statement No. 2-R at 8). Ms. Hazenstab stated that she did not agree with my adjustment to payroll expenses related to overtime costs. She stated that the Company's claim was based upon projected workload for the FTY and the FPFTY, and there has been no change in these assumptions and the Company's claim remained supported. (Statement No. 2-R at 9).

Q. WHAT IS YOUR RESPONSE TO THE ANTICIPATED HIRES AND THE ADJUSTMENTS TO OVERTIME COSTS?

A. Given this updated information on employee hires, I am accepting Ms. Hazenstab's on the Company's authorization of hiring one employee, and the disallowance of the second position that remains unauthorized. Given the Company's updated projected workload that is the basis for the Company's calculation of overtime costs, of which the assumptions have not changed, I am removing the overtime payrolls costs of $23,333. My adjustments are shown on my Schedule DM-SR-4.

b. Incentive Compensation / SERP Expenses

Q. WHAT DID THE COMPANY WITNESS MS. RESSLER STATE REGARDING YOUR ADJUSTMENTS TO INCENTIVE COMPENSATION EXPENSE?

A. Ms. Ressler stated that she did not agree with my disallowance to recover the Company's incentive compensation costs of $716,450. (Statement No. 3-R at 5). Specifically Ms. Ressler stated that she did not agree with my disallowance of **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL).** Ms. Ressler provided information related to each of the Company's five plans for incentive compensation. (Statement No. 3-R at 7-8). Ms. Ressler stated that my disallowance attempted to evaluate individual aspects of the Company's incentive compensation program in isolation and to single out and remove specific aspects of the Company's compensation plan. (Statement No. 3-R at 9). Ms. Ressler stated that my disallowance of the Company's incentive compensation should be rejected because they disregard the fact that UGI Electric is entitled to recover in rates all expenses reasonably necessary to provide electric service. Ms. Ressler stated that in order to provide electric service to customers, UGI Electric must be able to attract and retain qualified employees, managers, executives and directors and the Company's compensation package is directly related with providing these employees with reasonable and competitive compensation. (Statement No. 3-R at 9). Ms. Ressler stated that my adjustment to disallow certain aspects of the Company's total compensation package fundamentally undermines the Company's ability to attract qualified employees, managers, executive and directors and would fail to provide just and reasonable rates. (Statement No. 3-R at 9).

Q. WHAT IS YOUR RESPONSE?

A. The Company is not entitled to recover all of its reasonably projected expenses in rates but rather has the opportunity to recover those expenses that are deemed to be known and measurable, prudent in nature and provide for positive ratepayer benefits. The recovery of all of its projected expenses is not a guarantee. With respect to the retention and attraction of qualified employees, the Company should have the tools and mechanisms to keep such employees and incentive compensation is such a tool to be used. However, given that the decision to do so qualifies as a business risk, the Company should bear the costs of these expenses and should not pass these costs on to ratepayers. With respect to singling out and omitting certain aspects of the Company's total compensation package and the failure to do so would fail to produce just and reasonable rates, this viewpoint is unsupported. The Commission is not required to accept the Company's total compensation package (as an all or nothing approach), but rather the Commission should allow recover of costs that benefit ratepayers in the provision of utility service. Parties to the proceeding have every opportunity and a right to evaluate and analyze sections or pieces of a compensation package and select those costs that benefit ratepayers. As I discussed more thoroughly in my direct testimony, portions of the Company's incentive compensation plan do not directly benefit ratepayers but instead are dependent on the Company's financial performance on Wall Street. An all or nothing approach to incentive compensation is clearly unreasonable.

Q. WHAT DID MS. RESSLER STATE REGARDING PRIOR COMMISSION AFFIRMATION?

A. Ms. Ressler stated that despite my adjustments the Commission concluded that UGI's Electric incentive compensation as a whole was recoverable in the Company's last fully-litigated base rate case in Docket No. R-2017-2640058. She stated that the same type of incentive compensation that was accepted by the Commission in that case is at issue in this proceeding. (Statement No. 3-R at 10-11). Ms. Ressler stated that I made no attempt to distinguish between the programs at issue in the 2018 base rate case and this case, nor has offered any new reason why the same categories of expenses determined to be recoverable in the 2018 base rate case are not recoverable in this case. (Statement No. 3-R at 11).

Q, WHAT IS YOUR RESPONSE?

A. Incentive Compensation, as with all other expenses contained in a base rate case proceeding, should be reviewed and evaluated on a case by case basis, and not be reviewed as an overall blanket of acceptance. Different circumstances arise in each rate case filing and such, a review of the components of Incentive Compensation should be revisited as needed and as required. While segments of the Company's Incentive Compensation may appear to be reasonable at first glance, the underlying information may reveal that certain cost components are not beneficial to ratepayers. In my opinion, accepting the Company's Incentive Compensation as a total package is not a reasonable approach without reviewing the components that are contained in that incentive compensation package. The Company's all or nothing approach is not an appropriate way to evaluate compensation, as it is an unrealistic approach.

Simply put, UGI's proposed incentive compensation program is not aimed at enhancing the productivity and efficiency of the utility. As such, the program should be excluded from operating expenses. It is important to note that for the portion of the incentive compensation plan that is allocated to the Company's **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL).** This further indicates that a significant majority of employees receiving incentive compensation are not responsible for serving customers as the program appears entirely focused on awarding executives for financial, as opposed to operational, success. Ratepayers should not be required to pay Company executives additional forms of compensation in the form of stocks, as is the case here. The ratepayer provisioning of stocks for executive employees is excessive and unreasonable under the circumstances in this case. As discussed by OCA witness Rothschild, the Company is already requesting a management adder component for alleged superior management performance on top of asking ratepayers to pay for their incentive compensation plans, which should be paid for by shareholders.

Q. WHAT IS YOUR RESPONSE TO MS. RESSLER IN THAT A PUBLIC UTILITY MUST DEMONSTRATE THAT INCENTIVE COMPENSATION EXPENSES MUST BENEFIT CUSTOMERS IN ORDER TO BE RECOVERED?

A. Ms. Ressler's position that these incentive programs do not require customer benefits in order to be recovered is wrong and contrary to the prudence in nature concept of ratemaking. While the costs may or may not be reasonable in the abstract, they are not prudent in nature nor just and reasonable. Regulators have been granted broad discretion on whether a utility costs are reasonable. Utilities should not be granted unfettered access to ratepayer money but rather the money to be recovered from ratepayers should benefit ratepayers in providing utility service. Such costs as financial goals and achieving favorable credit ratings may not benefit ratepayers at all. Absent such recovery of incentive goals and costs, the Company would still be required in providing safe and reliable utility service. I do not believe that ratepayers should be burdened with costs related to the access of capital markets and to have the Company be attractive to investors to access capital markets. Moreover, there is no evidence in the record that UGI is having any difficulty retaining certain employees. There is also no indication that if shareholders were to pay for incentive compensation, it would make the Company less attractive to investors. These costs relate to strategic responsibilities that drive value for the Company's shareholders, including mergers and acquisitions, business transformation projects, capital project investment reviews, succession planning, regular discussion with management regarding the strategic direction and communication and direct engagement with the Company's investors. These are business decisions, and the business risks should lie with the Company. The customers do not have that decision-making ability nor has the Company asked the customers to do so. I believe this is the responsibility of the shareholders.

Q. WHAT DID MS. RESSLER STATE REGARDING YOUR ADJUSTMENT TO THE COMPANY'S EXECUTIVE BONUS PLAN?

A. Ms. Ressler stated that the Executive Bonus Plan of **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)** do reward executives and employees of UGI Corp. based on the performance of all business units under the ownership of UGI Corp. (Statement No. 3-R at 16). She stated that the costs of UGI Corp. including costs associated with incentive compensation paid to its executives and non-executive employees are assigned to its business units using an allocation methodology that reasonably apportions costs based upon the relative benefit of the service to each affected business unit. The costs allocated to UGI Electric are reflective of the benefits that UGI Electric receives, and the allocation does not result in Pennsylvanian customers subsidizing activities related to other states.

Q. WHAT IS YOUR RESPONSE?

A. As I stated previously, these types of incentive costs do not benefit ratepayers. The Company characterizes these costs as not subsidizing activities related to Pennsylvania ratepayers, as a reason for recovery. While these costs may not subsidize activities related to other states, these types of costs should not be recovered from ratepayers in Pennsylvania. As I stated above, these costs relate to strategic responsibilities that drive value for the Company's shareholders, including mergers and acquisitions, business transformation projects, capital project investment reviews, succession planning, regular discussion with management regarding the strategic direction and communication and direct engagement with the Company's investors. These are business decisions, and the business risks should lie with the Company. These employees are already being compensated by Pennsylvania ratepayers for the work that they provide. The customers do not have that decision-making ability nor has the Company asked the customers to do so. I believe this cost is the responsibility of the shareholders.

Q. WHAT DID MS. RESSLER STATE REGARDING THE RECOVERY OF SERP?

A. Ms. Ressler stated that she did not agree with my disallowance of $25,000 related to the SERP (Supplemental Executive Retirement Plan). The Company's SERP plan is designed to provide retirement benefits for executive-level employees who are not eligible to receive the full typical Company contribution within its pension or 401 (k) program. Current (not retired) executives who earn more than the cap for the regular pension or 401 (k) plan are eligible for SERP. (Statement No. 3-R at 17). Ms. Ressler stated that if the SERP were excluded, the Company would need to increase base salary or other compensation in order to remain competitive for talented executives. (Statement No. 3-R at 17). The SERP works together with other portions of the Company's pay and benefits program to provide a complete compensation package. (Statement No. 3-R at 17).

Q. WHAT IS YOUR RESPONSE?

A. As I stated previously regarding the disallowance of stock awards and stock options for the retainment and to be competitive in the industry for talent, I believe that the Company should be responsible for covering these types of costs, not ratepayers. SERP has no goals or criteria to be met, and therefore, is a business decision on the Company, and the responsibilities should lie with the Company to fund these costs.

c. Distribution Expenses

Q. WHAT HAS THE COMPANY STATED IN REGARD TO YOUR ADUSTMENT TO VEGETATION MANAGEMENT?

A. Company witness, Mr. Sorber (Statement 4-R), did not agree with my use of a five-year historical average to calculate the Company's Vegetation Management costs. He stated that this approach significantly understates the Company's actual vegetation management expenses for the FPFTY because it does not consider or reflect that the Company has significantly accelerated its vegetation management activities and expenses over the five-year period. He also stated that a five-year backward-looking analysis does not account for planned increases to vegetation management expense in the FTY or FPFTY. (Statement No. 4-R at 2). Mr. Sorber stated that my five-year average encompassed 2020 where COVID-19 materially impacted the Company's vegetation management spend. (Statement No. 4-R at 6). He stated that the 2020 data is an outlier. He stated that the use of 2018 and 2019 data is also clearly non-representative of the Company's existing program. (Statement No. 4-R at 6).

Q. WHAT IS YOUR RESPONSE?

A. The Company did not address the specific of its significant acceleration of its vegetation management activities through discovery. Mr. Sorber stated that the Company began its accelerated vegetation management activities in 2018. (Statement No. 4-R at 2). The Company booked the following expenses related to its vegetation management activities:

		Difference	Variance
FY 2021	$3,238,551		
FY 2022	$3,205,072	($33,479)	-1.03%
FY 2023	$3,807,997	$602,925	18.8%
FY 2024	$3,931,777	$123,780	3.25%

Q. WHAT DO THE ABOVE BALANCES SHOW?

A. In my opinion, the above balances do not reflect an accelerated activity related to vegetation management. In fact, the Company reduced its expenses from 2021 – 2022, increased the balance by 18.8% in the projected FY 2023 and increased the balance by 3.25% in FY 2024. (OCA-II-3). I do not consider this to be an accelerated program, at best it is a slight increase over historical periods. While I understand that COVID-19 affected the operations of the Company in 2020, the Company was still responsible to continue to provide safe and reliable service to its customers. In that instance, and for purposes of calculating a reasonable level of vegetation management costs going forward, the 2020 data should be considered an outlier. I note that the overall increase in vegetation management (in recent years) has gone from FY 2021 of $3,238,551 to a projected FPFTY 2024 of $3,931,777 or increase of $693,226 or 21.4%. The Company's vegetation management expenses are increasing over time, but not has much as Mr. Sorber has stated. The Company has not provided a detailed program that shows or reflects its accelerated activities to be instituted or implemented.

Q. WHAT ARE THE REASONS MR. SORBER PROVIDED REGARDING THE NEED TO ACCELERATE ITS VEGETATION MANAGEMENT COSTS?

A. Mr. Sorber stated that trees, especially off-right-of-way trees, are the leading cause of outages and customer minutes interrupted in Pennsylvania. To address critical safety and reliability, the Company has increased resource hours working on the entire scope of vegetation management activities across the system. (Statement No. 4-R at 3-4). Mr. Sorber stated that the Company's service territory has experienced the mass decline of certain prominent vegetation species, like ash and the hemlock woolly adelgid and the increased mortality of these large trees has created an elevated and ongoing danger tree risk that is expected to continue and potentially increase because of emerging issues from new invasive species such as the spotted lanternfly. (Statement No. 4-R at 4). These danger tree factors present an ongoing reliability challenge with respect to maintaining the current benchmark reliability performance metrics. Increased vegetation management activity translates to more tree removals, more trimming mileage and more off-cycle vegetation management work. (Statement No. 4-R at 4).

Q. WHAT IS YOUR RESPONSE?

A. While I understand the need to address deteriorating tree removal and the reasons for such in order to maintain reliability and safety metrics, the Company hasn't laid out any specific plan to address the accelerated removal. In my opinion, the Company has not fully explained the need for this acceleration. From my understanding the Company does not have the authority to trim off-right of way trees. Also, the costs that Mr. Sorber projected are merely forecasted costs that may or may not come to fruition. Moreover, the Company's vegetation management also includes the normal and routine tree trimming costs, that it does on a periodic basis. I am recommending that the Company prepare a report identifying and explaining its vegetation management program on an annual or semi-annual basis that shows what the specific plans are in its acceleration of certain tree removals. The Company should provide what it has projected to spend and what the actual costs are along with information on the progress related to its acceleration process.

Q. WHAT IS YOUR RECOMMENDED ADJUSTMENT RELATED TO TREE TRIMMING / VEGETATION MANAGEMENT COSTS?

A. I am still recommending the use of the five-year average of costs (2018-2022) that reflects a disallowance of $1,431,129. Given this new information on the Company's need to remove the deteriorating and rotting trees to maintain service reliability and safety issues, I am recommending a sharing of this disallowance or $715,565 from the Company's proposed level of $3,931,777. This will provide the Company with an ongoing level of tree trimming costs of $3,216,212. This is shown on my Schedule DM-SR-10.

Q. WHAT HAS MR. SORBER STATED WITH RESPECT TO YOUR ADJUSTMENT TO MAJOR STORM COSTS?

A. Mr. Sorber has accepted my additional dollars of $42,000 related to Major Storm expenses. (Statement No. 4-R at 9). Mr. Sorber stated that in this case, a multi-year average (normalization), is a reasonable approach for this expense considering the Company has little control over the causation of these expenses. He stated that these expenses are difference from vegetation management where the Company plans in advance for the use of its resources and has activity engaged in an accelerated approach to vegetation management planning over the last five-years. He stated that my use of the same methodology for both vegetation management and major storms should not be used as the surrounding cost build up are distinguishable. (Statement No. 4-R at 9-10).

Q. WHAT IS YOUR RESPONSE?

A. While Mr. Sorber accepted my adjustment to increase Major Storm costs by $42,000, his characteristics on when to normalize costs are misguided. Vegetation management and Major Storms, when taken together are uncontrolled in nature and unplanned in advance. There are some mutual characteristics. In a major storm event, vegetation management is part of the recovery of costs, and the occurrences vary over time given the severity of the storm event. Normalizing these types of costs better reflects the level of recovery based upon prior cost levels. Although the Company stated that its vegetation management activities are planned in advance, circumstances may prevent such activities to be completed.

Q. WHAT HAS MR. SORBER STATE REGARDING YOUR ADJUSTMENTS TO OUTSIDE CONTRACTOR EXPENSES?

A. Mr. Sorber did not agree with my adjustments related to Outside Contractor expenses of $103,000 (Statement No. 4-R at 10). He stated that a majority of these costs ($71,000) are related to FERC Account 583 and the use of a three-year average is entirely inappropriate. Mr. Sorber stated that these costs support the Company's ongoing-and long-term inspection and maintenance programs. (Statement No. 4-R at 11). He stated these programs are performed on a five-year cycle which includes an off-year at the end of the cycle and FY 2023 is the off-year. He stated that the expense amount for FY 2023 does not reflect a normalized costs for certain of these programs.

Q. DID MR. SORBER PROVIDE AN EXHIBIT TO SHOW A BREAKDOWN OF HISTORICAL SPENDING IN FERC ACCOUNT 583?

A. Yes. Mr. Sorber provided Exhibit EWS-3R to show the overall expense balances accounted for in FERC Account 583. Mr. Sorber stated that based upon this analysis my normalized level should be $169,038 higher. (Statement No. 4-R at 12).

Q. WHAT IS YOUR RESPONSE?

A. Mr. Sorber has included costs that were incurred in prior years and average out these costs in future years, when such costs were not recurring in FY 2023 and FY 2024. Cost recoveries should include recurring costs over time. When setting rates for utility services, the costs to be included should be costs that are expected to occur prospectively and continuing. Including costs in an average that are not recurring would have the effect of overstating the Company expenses and over recovering costs. While Mr. Sorber stated that the Company is not recommending an increase in those costs, he suggested that I use that approach when normalizing my adjustments. This is not an appropriate approach to use. I am still recommending normalizing the Company's expenses shown on Statement No. 4-R at 10 for the purpose of setting expense recoveries going forward. As I stated in my direct testimony, these types of costs do fluctuate and vary over time based upon the activities the Company has engaged in. My recommendation is shown on my Schedule DM-SR-10.

d. Customer Accounts Expenses

Q. WHAT HAS MS. HAZENSTAB STATED WITH REGARD TO YOUR ADJUSTMENT TO THE COMPANY'S CUSTOMER ACCOUNTS EXPENSES?

A. Ms. Hazenstab did not agree with my adjustments related to Meter Reading Expense, Miscellaneous Customer Accounts Expense and Customer Records/Collection Expense. (Statement No. 2-R at 14). Ms. Hazenstab stated that the Customer Records/Collection Expenses are related to the Universal Service Program and costs are recovered through a fully reconcilable Section 1307 Rider. In order to reflect the fully-reconcilable nature of Section 1307 rider, the Company budgets the expenses for the program at the same level as the revenue, thereby making the program margin neutral in the budget and the revenue requirement calculation. (Statement No. 2-R at 15). Mr. Hazenstab stated that with respect to the adjustments for Meter Reading Expenses, and Miscellaneous Customer Accounts Expense, taking a simple average of expenses does not consider inflation and supply chain impacts that were outlined in the direct testimony of Mr. Sorber (Statement No. 4 at 12-15). Based on current market conditions, the Company believes the costs presented in the FPFTY are justified.

Q. WHAT IS YOUR RESPONSE?

A. I am accepting the Company's argument related to the Customer Records / Collection Expenses. Given that these costs are reconcilable with revenues, (which I did not adjust) these costs result in revenue / expense neutrality. I've adjusted my recommendation by accepting the Company's Customer Records / Collection Expense of $9,185,000. With respect to the remaining costs related to Meter Reading and Miscellaneous Customer Accounts Expenses, these costs were increased based on the Consumer Pricing Index (CPI)[1] percentage which I believe are not known and measurable. The use of a CPI increase is not supportive of costs incurred by the Company but rather an overall blanket-type adjustments that are applied to all goods and services that may not be directly related to costs incurred by the Company. It is simply a prediction of cost adjustments. While inflation adjustments are used to develop economic data they should not be used for ratemaking purposes. Goods and services fluctuate, the costs increase and decrease over time. The Company has not provided any support or evidence that these costs will increase based upon inflation. Nor has the Company provided any information or evidence based upon supply chain impacts. My adjustment is shown on my Schedule DM-SR-11.

[1] The Consumer Price Index (CPI) measures the monthly changes in prices paid by U.S. consumers. The CPI is calculated as a weighted average of prices for a basket of goods and services representing the aggregate U.S. consumer spending. The CPI is widely used to measure inflation under economic conditions and cost of living adjustments, as well as, housing, clothing, food etc.

e. Uncollectible Accounts

Q. WHAT HAS MS. RESSLER STATED IN RESPONSE TO YOUR ADJUSTMENT REGARDING UNCOLLECTIBLE EXPENSE?

A. Mr. Ressler stated that she does not agree with my adjustment related to Uncollectible Accounts expense reduction of $168,047. (Statement No. 3-R at 23). She stated that my adjustment is based upon my recommended revenue requirement, and since the Company does not agree with my revenue requirement the Company does not agree with my recommended Uncollectible Accounts expense balance.

Q. WHAT IS YOUR RESPONSE?

A. Based upon my updated revenue requirement increase of $5,591,225, my recommended Uncollectible Accounts expense is $3,301,815 or a reduction of $146,644. This is shown on my Schedule DM-SR-12.

f. Customer Information & Service

Q. WHAT HAS MS. HAZENSTAB STATED WITH REGARDS TO YOUR ADJUSTMENTS TO THE COMPANY'S CUSTOMER INFORMATION & SERVICE EXPENSES?

A. Ms. Hazenstab stated that she does not agree with my adjustments related to Miscellaneous Customer Information Expenses and Customer Assistance Expenses. Ms. Hazenstab stated that the Miscellaneous Customer Information Expenses are related to the EE&C, and similar to the USP that is recoverable through Section 1307 rider, these costs are designed to be recoverable in the same manner. (Statement No. 2-R at 16). The Company budgets the expenses for the program at the same level as the revenue, thereby making the program margin neutral in the budget and the revenue requirement calculation. A reduction of the expense in this account without a corresponding reduction to revenue would affect the fully-reconcilable nature of the rider. (Statement No. 2-R at 16). With respect to Customer Assistance Expenses, Ms. Hazenstab did not agree with my three-year average to set this expense, increasing it by $9,000 to $21,000. (Statement No. 2-R at 17). She stated that by taking a simple average of expenses does not consider the inflation and supply chain impacts that were outlined by Mr. Sorber in Statement No. 4 at 12-15. Based upon current market conditions discussed by Mr. Sorber, the Company believes that the costs presented in the FPFTY are justified. (Statement No. 2-R at 17).

Q. WHAT IS YOUR RESPONSE?

A. I accept the Company's argument related to the Miscellaneous Customer Information Expenses. Given that these costs are reconcilable with revenues, (which I did not adjust) these costs result in revenue / expense neutrality. I've adjusted my recommendation by accepting the Company's Miscellaneous Customer Service & Information Expenses of $1,157,000. With respect to the costs related to Customer Assistance Expenses, these costs were adjusted based on the CPI percentage which, as I stated previously, are not known and measurable for setting rates for service. As discussed above, the use of a CPI increase is not supportive of costs incurred by the Company but rather an overall blanket-type adjustments that are applied to all goods and services that may not be directly related to costs incurred by the Company. It is simply a prediction of cost adjustments. While inflation adjustments are used to develop economic data they should not be used for ratemaking purposes. Goods and services fluctuate, the costs increase and decrease over time. The Company has not provided any support or evidence that these costs will be adjusted based upon inflation. Nor has the Company provided any information or evidence based upon supply chain impacts. Given that my adjustment increases the expense by $9,000, and to be consistent with all my other normalization expense adjustments, I am continually recommending this level of expense. My adjustment is shown on my Schedule DM-SR-13.

g. Administrative & General (A&G)

Q. WHAT HAS MS. RESSLER STATED REGARDING YOUR ADJUSTMENT TO A&G SALARIES?

A. Ms. Ressler stated that my disallowance in the amount of $178,000 related to bonus compensation is duplicative of the amounts which I already addressed and disallowed under my Incentive Compensation section of my testimony. (Statement No. 3-R at 18).

Q. WHAT IS YOUR RESPONSE?

A. After a review, I accept Ms. Ressler's position. My recommendation is shown on my Schedule DM-SR-15.

1. Pension Expense

Q. WHAT HAS MS. RESSLER STATED WITH REGARD TO YOUR ADJUSTMENT TO PENSION BENEFITS EXPENSE?

A. Ms. Ressler did not agree with my normalization of the pension expense over a three-year period. She stated that I have a misunderstanding of the basis for the Company's claim to recover pension costs, which is its cash contributions to the pension fund. (Statement No. 3-R at 20). She stated that my adjustment is inconsistent with established ratemaking practice in Pennsylvania, which allows utilities to claim expenses based on the cash contribution to their pension funds. (Statement No. 3-R at 20). Ms. Ressler stated that the Company made its claim based on the portion of total plan cash contributions that is related to the UGI Electric distribution. She stated that my adjustment appears to be predicated on a normalized amount of the difference between GAAP pension and pension cash contributions properly based on a recent actuarial report. (Statement No. 3-R at 21). Ms. Ressler stated that if my adjustment was accepted it would result in a claim that is based on neither GAAP expense nor cash contributions and not connected to the Company's cost for providing pension benefits. (Statement No. 3-R at 21). Ms. Ressler stated that it is generally inappropriate for cash contributions to be normalized. (Statement No. 3-R at 21). Ms. Ressler stated that if my adjustment were to normalize costs the amount should be based upon the Company's claim rather than my misguided calculation of the difference between expense and cash. (Statement No. 3-R at 23).

Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S ARGUMENT REGARDING YOUR NORMALIZATION ADJUSTMENT TO PENSION EXPENSES?

A. I believe it is appropriate to average out contributions made in prior years to contributions made during current years. As identified in response to OCA Set II-30, the Company provided five years of cash contribution attributable to UGI Electric – a non-capitalized portion of its pension expenses. While I understand that the Company based its cash contribution by relying on its actuarial firms recommendation, and the fact that the

Company made its adjustment based upon GAAP and established ratemaking practices in Pennsylvania, historical costs that were incurred should be taken into consideration, as solely relying on current actually-determined cash contributions to the pension fund can result in costs that may be too high *or* too low for the new regulatory period when new rates are set. Costs change over time, but not always proportionately. As such, normalization in this instance is appropriate.

2. Advertising / Association Dues / ESG costs

Q. WHAT HAS MS. RESSLER STATED REGARDING YOUR ADJUSTMENT TO ADVERTISING EXPENSES, ASSOCIATED DUES AND ITS ENVIRONMENTAL, SOCIAL AND GOVERNANCE COSTS (ESG)?

A. Ms. Ressler did not agree with my adjustment related to the Advertising Expense disallowance of $83,252, Association Dues of $7,000 and Environmental, Social and Governance costs of $11,000. (Statement No. 3-R at 25-27).

Q. PLEASE EXPLAIN MS. RESSLER'S OBJECTION TO YOUR ADVERTISING EXPENSE DISALLOWANCE OF $83,252?

A. Ms. Ressler stated that my adjustment proposes too narrow of a standard for determining whether these expenses can be recovered in rates. She stated that public utilities are not required to show that these types of advertisement expenses benefit customers but rather they must be reasonable, prudent and meet one of the criteria listed in 66 Pa. C.S. § 1316 (a). (Statement No. 3-R at 25). She stated that a public utility can show that its advertising expenses are recoverable if those advertisements provide information regarding safety, rate changes, means of reducing usage or bills, load management or energy conservation, or if the advertising is for the promotion of community service or economic development. (Statement No. 3-R at 25). Ms. Ressler further stated that the use of sponsorships is a means to connect with the communities in which it provides service, and the Company can develop a presence in the community in which customers can connect with the Company and receive information about billing, customer programs, safety or utility service. (Statement No. 3-R at 25). These costs also service as an attraction for potential customers and employees.

Q. WHAT IS YOUR RESPONSE?

A. None of the reasons that Ms. Ressler provided above are shown in response to Company Attachment II-7 (d). The Company only provided a single line item for certain of these cost. In response to I&E RE-27-D, the Company provided a description of these costs. The fact that the Company believes they are reasonable does not make these costs prudent in nature. I firmly believe that public utilities have a regulatory duty to require a showing of benefits to ratepayers. With respect to chambers of commerce and economic development, these costs should be borne by the Company or by state, local or municipal organizations, and promoting issues other than utility service issues should not be the responsibility of the ratepayer. Further, ratepayers do not have a say as to which organizations or entities these costs are paid to, nor do these entities provide any customer benefit related to utility services. I am still recommending the disallowance of $83,252 related to Advertising Expenses.

Q. WHAT HAS MS. RESSLER STATED RELATED TO YOUR DISALLOWANCE OF ASSOCIATION DUES?

A. Ms. Ressler stated that she did not agree with my $7,000 disallowance related to Association Dues. She stated that these Association Dues provides opportunities to connect with other public utilities in the state of Pennsylvania. (Statement No. 3-R at 27). These opportunities allow the Company professionals to discuss best practices related to operations, safety and other matters specific to the utility industry.

Q. WHAT IS YOUR RESPONSE?

A. The Company did not provide a breakdown of these costs as requested in response to OCA-II-7. Even though Ms. Ressler stated that the Company's claim excludes amounts related to the EAP (Energy Association of Pennsylvania), the Company did not identify this breakdown in its response to OCA-Set II-7. The Company provided a single line item with no other information provided. The argument that the costs were reasonable incurred is not a basis to determine whether the costs were prudently incurred or required for the provision of safe and reliable utility service. The Company has the burden of proof to support its expenses that related to utility service. I am still recommending disallowance of $7,000 related to Association Dues.

Q. WHAT HAS MS. RESSLER STATED REGARDING YOUR DISALLOWANCE OF ESG COSTS?

A. Ms. Ressler stated that my characterization of ESG goals is misguided. (Statement No. 3-R at 28). She stated that customers benefit from ESG initiatives in many ways, including but not limited to the efforts to reduce greenhouse gas emissions. According to Ms. Ressler, robust ESG programs such as the one being implemented at UGI Electric have the potential to increase transparency, improve corporate governance and nourish a corporate culture that will ultimately deliver a better quality of customer service experience to UGI Electric customers and the communities the Company serves. (Statement No. 3-R at 28). Ms. Ressler stated these costs are important to the investor community, which secures the future success of the Company and enables the continued provision of safe and reliable service to customers by funding capital investment. (Statement No. 3-R at 28). Ms. Ressler stated that ESG is a hot topic and investors are interested in a Company ESG strategy and often request this information prior to investing in a Company's stock. Ms. Ressler stated that the New York Stock Exchange has developed an ESG Resource Center website for its members and investors and the United States Securities and Exchange Commission (SEC) proposed enhanced and standardized climate-related disclosures from its registrants. (Statement No. 3-R at 29). Customers benefit from ESG goals and policies because of the resulting reduction in emissions and because such policies make the Company's stock more attractive to investors. (Statement No. 3-R at 29).

Q. WHAT IS YOUR RESPONSE?

A. I am continuing to recommend removal of these costs from rates. I believe these costs are geared to satisfy the investor community. The Company is free to fund these costs through shareholder monies but should not expect ratepayers to pay for costs that relate to supporting social movements, societal impacts and financial factors in the investor world to maintain a level of financial returns or growth. As I testified in my direct testimony, ESG costs are not related to the provision of safe and reliable utility services to ratepayers, but rather, are costs related to and are akin to national and societal issues, sponsorships and civic related activities. I am not convinced that these ESG costs actually benefits or lowers costs to ratepayers.

3. Rate Case Expense

Q. WHAT DID MS. HAZENSTAB STATE REGARDING YOUR ADJUSTMENT TO RATE CASE EXPENSES?

A. Ms. Hazenstab did not agree with my adjustment to amortize these costs over a five-year period. (Statement No. 2-R at 9). Ms. Hazenstab stated my five-year amortization period includes pre-2018 rate case filings and is too long. (Statement No. 2-R at 10 and at 13). Mr. Hazenstab stated that the Company proposed to normalize rate case expenses over a two-year period based upon its projected rate case filing frequency going forward. The Company did not propose an amortization schedule in its initial filing. (Statement No. 2-R at 10). Ms. Hazenstab stated that UGI Electric projected more frequent rate case filings due to its projected acceleration of capital expenditures and anticipated investments. Ms. Hazenstab stated that consistent with its prior projections in the 2021 base rate case, the Company continues to anticipate a two-year frequency for base rate cases. (Statement No. 2-R at 10).

Q. WHAT IS YOUR RESPONSE?

A. I am continuing to recommend normalizing rate case expenses based upon actual prior rate case expense filings. In response to OCA-II-28, the Company provided a schedule of prior rate case filing and the dates of each of the filing. There is a gap of 22 years between the 1996 filing and the 2018 filing. There is a 3-year gap between the 1996 and the 1993 filing and a 1-year gap between the 1992 and 1993 filing. Given this anomaly, I am recommending a 3-year normalization period. This takes into consideration the Company's proposed accelerated replacement program and provides a balance between the Company and ratepayers with respect to recovery of rate case expenses. My 3-year normalization period reduces the Company's rate case costs by $128,667. My recommendation is shown on my Schedule DM-SR-15.

h. Depreciation

Q. WHAT DID MS. RESSLER STATE REGARDING YOUR ADJUSTMENT TO THE COMPANY'S DEPRECIATION EXPENSE?

A. Ms. Ressler did not agree with my adjustments to the Company's plant in service balance, ($16,590), related to the Data Center Project. Ms. Ressler stated this adjustment is derivatives of my adjustments to the Company's plant in service (Statement No. 3-R at 29).

Q. WHAT IS YOUR RESPONSE?

A. As previously testified to earlier, I am continuing to disallow contingency costs related to the Company's Data Center Project. The depreciation expense is the adjustment related to the associated costs for the contingencies. My adjustment is shown on my Schedule DM-SR-16.

i. Taxes Other Than Income

Q. WHAT DID MS. HAZENSTAB STATE REGARDING YOUR ADJUSTMENTS TO THE COMPANY'S STATE AND LOCAL TAX EXPENSE?

A. Ms. Hazenstab stated that my adjustments to the Company's Taxes other than Income are derived from my other proposed adjustments to payroll expenses, employee headcount, incentive compensation and OCA's overall recommended revenue requirement adjustment. (Statement No. 2-R at 18). Ms. Hazenstab agreed to reduce the payroll expense related to the employee headcount and to adjust for forfeited discount revenues but disagrees with my remaining adjustments for Incentive Compensation. (Statement No. 2-R at 18).

Q. WHAT IS YOUR RESPONSE?

A. My adjustments related to the Company's Taxes other than Income are the flow through adjustments for certain of my expense adjustments related to employee headcount, incentive compensation and other related expenses. Ms. Hazenstab did not disagree with my methodology on how I calculated the Taxes other than Income, just the components that make up the balance. My surrebuttal balance for Taxes Other than Income is shown on my Schedule DM-SR-17 in the amount of $9,865,097.

j. Income Taxes

Q. WHAT DID MS. HAZENSTAB STATE REGARDING YOUR ADJUSTMENT TO THE COMPANY'S FEDERAL AND STATE INCOME TAXES?

A. Ms. Hazenstab stated that I accepted the Company's methodology for calculating these expenses but did not agree with the level of my recommended federal and state income taxes based upon my other proposed adjustments to rate base and operating income. (Statement No. 2-R at 18-19). Ms. Hazenstab stated that but for the adjustments to forfeited discounts and payroll expenses, she did not agree with my remaining adjustments because it does not allow for the full revenue requirement requested in this proceeding. (Statement No. 2-R at 19). Ms. Hazenstab stated that she did not agree with my adjustment to the Company's Interest Synchronization. As more fully identified by Company witness Mr. Moul in his rebuttal testimony, the Company's actual capital structure should be accepted and my adjustments to the Company's interest expense deduction should be rejected. (Statement No. 2-R at 22).

Q. WHAT IS YOUR RESPONSE?

A. My adjustments to the Company's federal and state income taxes are the flow through adjustments to certain of my recommended expenses related to rate base and operating income. In addition, my interest synchronization expense is based upon the recommendation of OCA witness Mr. Rothschild in which he recommended a cost of debt rate of 2.40%. My recommendations are shown on my Schedule DM-SR-18.

C. Act-40 Requirements (Act 40 of 2017)

Q. WHAT DID MS. HAZENSTAB STATE REGARDING YOUR ADJUSTMENTS TO THE COMPANY'S CONSOLIDATED TAX ADJUSTMENT (CTA) AND ACT 40 OF 2017?

A. Ms. Hazenstab stated that I argued that the Company has not demonstrated the remaining 50% of the CTA had been used related to general corporate purposes. (Statement No. 2-R at 23). Ms. Hazenstab stated that the Commission has previously rejected my proposal in prior rate proceedings. (Statement No. 2-R at 24). Ms. Hazenstab stated that my proposal in this proceeding offers nothing new to the arguments previously rejected by the Commission and the Commonwealth Court. (Statement No. 2-R at 24). Ms. Hazenstab stated that the Company is using 50% of the amount calculated pursuant to Act 40 for general corporate purposes and to support lawful expenditures. Ms. Hazenstab stated that I improperly attempted to limit the definition of general corporate purposes to only public utility purposes and uses, that resulted in having some identifiable and quantifiable benefit to Pennsylvania and UGI ratepayers. (Statement No. 2-R at 24-25). Ms. Hazenstab stated that while it is not practical to trace a hypothetical amount to specific projects, 50% of the Act 40 will be used to pay for the general operating expenses of the Company. Ms. Hazenstab stated that such expenses used to benefit ratepayers are meter reading expenses, maintenance of overhead line and various customer service expenses. (Statement No. 2-R at 25). Therefore, UGI Electric spent over 50% of the hypothetical CTA for general expenditures that are specifically for purposes of providing utility service. (Statement No. 2-R at 25). Ms. Hazenstab stated that my CTA adjustment to rate base would result in a tax normalization violation raising the risk of an adverse IRS ruling on the issues. Ms. Hazenstab stated that my adoption of my CTA adjustment has the potential of jeopardizing the loss of $29.665 million of ADIT to the detriment of the Company's customers and adversely impact the cash position of the Company, as those taxes may become due immediately, which the risk clearly overwhelms the minor benefit for customers that would result from my adjustment for tax benefits that are not the result of the Company's activities but rather the activities of the Company's non-regulated affiliates. (Statement No. 2-R at 25).

Q. WHAT IS YOUR RESPONSE?

A. The Company should not benefit from the use of the compliance with Act 40 without any specific use related to general corporate purposes. While Ms. Hazenstab stated that 50% of the CTA is related to "rate base eligible" infrastructure and has demonstrated that the Company has utilized these dollars for such, the Company simple omits how the other 50% of the differential is to be used for general corporate purposes. Ms. Hazenstab stated that 50% related to other costs such as meter reading expenses, maintenance of overhead line expenses and other customer service expenses, does not particularly go to the heart of the matter. Ratepayers are already supporting the Company's infrastructure and reliability investments through rates; more information is needed to show that the additional revenues now being provided by ratepayers is actually being used and not simply going to shareholders. The Company should provide evidence of actual applications of its differential related to general corporate purposes in a manner that reduces ratepayer obligations. With respect to any IRS violations, the Commission has the broad authoritative oversight to set rates based upon ratemaking principles and does not have to rely on whether any IRS violations exist. There will always be a difference of how the Company records costs on its books and records for corporate purposes, and how the Company records costs on its books and records for ratemaking purposes based upon Commission rulings.

Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

		SUMMARY REVENUE REQUIREMENTS	(1) Company Proposed	Adjustments	OCA Recommended	References
1		**Rate Base Valuation**	**$ 172,186,000**	**$ (512,943)**	**$ 171,673,057**	DM-3
2		Rate of Return	8.190%		6.180%	DM-2
3		**Operating Income Requirement**	**$ 14,102,033**	**$ (3,492,166)**	**$ 10,609,867**	
4		Present Operating Income	$ 6,535,000	$ 380,834	$ 6,915,834	
5						DM-4
		Operating Income Deficiency	**$ 7,567,033**	$ (3,873,001)	**$ 3,694,033**	
6	(2)	Gross Revenue Conversion Factor	1.513583		1.513583	
		Revenue Requirement Increase	**$ 11,453,333**	**$ (5,862,108)**	**$ 5,591,225**	
7						
8		Present Rate Revenue	$ 152,711,000	$ (20,000)	$ 152,691,000	DM-4
9		% Increase	7.50%		3.66%	

(1) Company Schedule A-1
(2) Company Schedule D-35

Gross Revenue Factor	1.000000
Uncollectible Expenses	(0.018380)
Net Revenues	0.981620
Gross Receipts Tax - 6.27%	(0.062700)
Factor after Gross Receipts Tax Rate	0.918920
State Income Tax - 8.99%	(0.082611)
Factor after State Income Tax	0.836309
Federal Income Tax - 21%	(0.175625)
Net Operating Income Factor	0.660684
Gross Revenue Factor	**1.513582**

Differences due to rounding

RATE OF RETURN

			Capitalization Ratio	Embedded Cost	Weighted Average
	(1)	**Company Proposed**			
1		Long-Term Debt	45.410%	4.440%	2.02%
2		Short-Term Debt	0.000%	0.000%	0.00%
3		Common Equity	54.590%	11.300%	6.17%
4		**Total**	**100.000%**		**8.19%**

(1) Company Schedule B-7

	(2)	**OCA Recommended**			
5		Long-Term Debt	55.250%	4.350%	2.403%
6		Short-Term Debt	0.000%	0.000%	0.000%
7		Common Equity	44.750%	8.440%	3.777%
8		**Total**	**100.000%**		**6.180%**

(2) OCA Witness Rothschild
OCA- Set II -18

OCA Set II-18

RATE BASE VALUATION

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Electric Utility Plant In Service	$ 275,001,000	$ (218,806)	$ 274,782,194	DM-5
2	Accumulated Depreciation	$ (85,745,000)	$ 16,590	$ (85,728,410)	DM-6
3	**Net Electric Utility Plant In Service**	**$ 189,256,000**	**$ (202,216)**	**$ 189,053,784**	
4	Working Capital Allowance	$ 11,437,000	$ (281,389)	$ 11,155,611	DM-7
5	Accumulated Deferred Income Taxes	$ (29,665,000)	$ 5,662	$ (29,659,338)	DM-8
6	Customer Deposits	$ (1,103,000)	$ -	$ (1,103,000)	
7	Materials & Supplies	$ 2,261,000	$ -	$ 2,261,000	
8	Consolidated Tax Adjustment	$ -	$ (35,000)	$ (35,000)	Exh DTE-3
9	**Total Rate Base Valuation**	**$ 172,186,000**	**$ (512,943)**	**$ 171,673,057**	OCA Set II-32

(1) Company Schedule C-1

	Acct No.	OPERATING INCOME STATEMENT	Budget Year 9/30/2024 (1)	Company Proposed Adjustments	Company Proposed Proforma Present Rates	Company Proposed Adjustments	Company Proposed Proforma Proposed Rates	Adjustments	OCA Recommended Present Rates	References	
		Operating Revenues									
1	440.00	Residential	$ 111,376,000	$ 5,890,000	$ 117,266,000	$ -	$ 117,266,000				
2	442.00	Commercial & Industrial	$ 32,040,000	$ 1,489,000	$ 33,529,000	$ -	$ 33,529,000				
3	444.00	Public Street & Highway	$ 749,000	$ 9,000	$ 758,000	$ -	$ 758,000				
4	445.00	Other Sales to Public Authorities	$ 19,000	$ -	$ 19,000	$ -	$ 19,000				
5	447.00	Sales for Resale	$ 16,000	$ -	$ 16,000	$ -	$ 16,000				
6	450.00	Forfeited Discounts	$ 520,000	$ 12,000	$ 532,000	$ -	$ 532,000	$ -		OCA Set II-49	
7	451.00	Misc. Service Revenue	$ 16,000	$ 5,000	$ 21,000	$ -	$ 21,000	$ -			
8	454.00	Rent from Electric Properties	$ 567,000	$ 3,000	$ 570,000	$ -	$ 570,000	$ -			
9		Rate Increase	$ -	$ -	$ -	$ 11,453,000	$ 11,425,000				
10		**Total Operating Revenues**	**$ 145,303,000**	**$ 7,408,000**	**$ 152,711,000**	**$ 11,453,000**	**$ 164,136,000**	**$ (20,000)**	**$ 152,691,000**	OCA Set II-37	
		Operating Expenses									
11	555.00	Other Power Supply Expenses	$ 85,951,000	$ 5,225,000	$ 91,176,000	$ -	$ 91,176,000	$ -	$ 91,176,000		
12	560.00	Transmission Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
13	580-590	Distribution Expenses	$ 13,259,000	$ 15,000	$ 13,274,000	$ -	$ 13,274,000	$ (776,898)	$ 12,497,102		DM-10
14	901-05	Customer Accounts	$ 9,463,000	$ 171,000	$ 9,634,000	$ -	$ 9,634,000	$ (104,667)	$ 9,529,333		
15	904.00	Uncollectible Expense 1.838%	$ 2,577,000	$ 662,000	$ 3,239,000	$ 210,506	$ 3,449,506	$ (147,692)	$ 3,301,815		
16	907-10	Customer Information & Services	$ 1,275,000	$ (89,000)	$ 1,186,000	$ -	$ 1,186,000	$ 9,000	$ 1,195,000		
17	911-17	Sales Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
18	920-35	Administrative & General Expenses	$ 8,208,000	$ 377,000	$ 8,585,000	$ -	$ 8,585,000	$ (461,252)	$ 8,123,748		
19	C C	[redacted]								OCA Set II-20	DM-9
20		Overtime/Other Wages						$ (25,000)	$ (25,000)		
21		**Sub-Total**	**$ 120,733,000**	**$ 6,361,000**	**$ 127,094,000**	**$ 210,506**	**$ 127,304,506**	**$ (2,297,959)**	**$ 125,006,548**		
22		Depreciation & Amortization	$ 9,075,000	$ (522,000)	$ 8,553,000	$ -	$ 8,553,000	$ (16,085)	$ 8,536,915		
23		Taxes Other Than Income	$ 9,369,000	$ 344,000	$ 9,713,000	$ 718,000	$ 10,431,000	$ (565,903)	$ 9,865,097		
24		**Total Operating Expenses**	**$ 139,177,000**	**$ 6,183,000**	**$ 145,360,000**	**$ 928,506**	**$ 146,288,506**	**$ (2,879,947)**	**$ 143,408,560**		
25		Net Operating Income Before Taxes	$ 6,126,000	$ 1,225,000	$ 7,351,000	$ 10,524,494	$ 17,847,494	$ (8,565,053)	$ 9,282,440		
26		Income Taxes - Present Rates - est.	$ 814,000		$ 814,000						
27		Income Taxes - Proposed Rates				$ 2,960,000	$ 3,774,000	$ (1,407,394)	$ 2,366,606		
28		**Net Income**	**$ 6,940,000**		**$ 6,537,000**	**$ 7,564,494**	**$ 14,073,494**	**$ (7,157,659)**	**$ 6,915,834**		
		Rate Base	$ 172,242,000		$ 172,242,000		$ 172,186,000		$ 171,673,057		
		Rate of Return	4.029%		3.795%		8.1734%		6.18%		
		check	$ 6,940,000		$ 6,537,000	$ 7,536,494	$ 14,073,494	$ (3,464,099)	$ 10,609,395		

Await excel spreadsheets and confirm

(1) Company Schedules D-1, D-2 and D-5

	Acct. No.	ELECTRIC UTILITY PLANT IN SERVICE	(1) Company Proposed	Adjustments	OCA Recommended	References
1	301-02	Intangible Plant	$ 16,000	$ -	$ 16,000	OCA Set II-13 OCA Set II-15
2	350-59	Transmission Plant	$ -	$ -	$ -	
3	360-73	Distribution Plant	$ 239,335,000	$ -	$ 239,335,000	OCA Set II-38 OCA Set II-39
4	389-99	General & Common Plant	$ 35,650,000	$ (218,806)	$ 35,431,194	OCA Set IX-3 OCA Set II-40
5		**Total Electric Utility Plant in Service**	**$ 275,001,000**	**$ (218,806)**	**$ 274,782,194**	
6		Plant Additions 9/30/2023-9/30/2024	$ 24,665,000			
7		Less Retirements	$ (2,605,000)			
8		Total	$ 22,060,000			

(1) Company Schedule C-2

	Acct. No.	ACCUMULATED DEPRECIATION	(1) Company Proposed	Adjustments	OCA Recommended	References
1	301-03	Intangible Plant	$ -			
2	350-59	Transmission Plant	$ -			
3	360-73	Distribution Plant	$ 74,384,000	$ (16,590)	$ 74,367,410	OCA-IX-3
4	389-99	General & Common Plant	$ 11,361,000	$ -	$ 11,361,000	
5		**Total Accumulated Depreciation**	**$ 85,745,000**	**$ (16,590)**	**$ 85,728,410**	

(1) Company Schedule C-1 and C-3

	WORKING CAPITAL REQUIREMENT	(1) TY Expenses	Lag Days	Weighted $	Total	Adjustments		OCA Recommended
1	Revenue Lag Days				59.56			
	Expense Lag Days							
2	Payroll	$ 6,121,000	12.00	$ 73,452,000		$ (900,000)		$ 72,552,000
3	Purchased Power Costs	$ 91,176,000	33.29	$ 3,035,249,040		$ -		$ 3,035,249,040
4	Other Expenses	$ 26,559,000	30.76	$ 816,954,840		$ (42,996,851)		$ 773,957,989
5	**Total**	**$ 123,856,000**		**$ 3,925,499,000**				**$ 3,881,759,029**
6	O&M Expense Lag Days				31.69		31.89	
7	Net Lead/Lag Days				27.87		27.67	
8	Operating Expenses Per Day				339.33		333.44	
9	**Working Capital for O&M Expenses**				**$ 9,445,000**			**$ 9,224,589**
10	**Interest Payments**		(31.70)		**$ (301,508)**			**$ (295,223)**
11	Tax Payments Lag - Federal				$ 164,224			$ 114,222
12	Tax Payments Lag - State				$ 92,757			$ 75,733
13	PA Property Tax				$ (1,864.88)			$ (1,865)
14	PURTA				$ 6,155			$ 6,155
15	**Total Tax Payments**				**$ 261,271**			**$ 194,245**
16	**Total Prepaid Expenses**				**$ 2,032,000**	**$ -**		**$ 2,032,000**
17	**Total Working Capital Allowance**				**$ 11,436,764**		**$ (281,153)**	**$ 11,155,611**

(1) Company Schedule C-4

OCA Set II-33

	Acct. No.	ACCUMULATED DEFERRED INCOME TAXES	(1) Company Proposed	Adjustments	OCA Recommended	References
1	282.00	Electric Utility Plant	$ (30,062,000)	$ 4,662	$ (30,057,338)	OCA-IX-3
2		ADIT on CIAC	$ 2,177,000		$ 2,177,000	
3		Federal ADIT Balance	$ (27,885,000)	$ 4,662	$ (27,880,338)	
4		State Repair Regulatory Liability	$ (3,367,000)		$ (3,367,000)	
5		Pro-Rata Adjustment (EDIT 2017)	$ 1,588,000		$ 1,588,000	OCA Set II-46 OCA Set II-48
6		Balance at 9/30/2024	**$ (29,664,000)**	**$ 4,662**	**$ (29,659,338)**	

(1) Company Schedule C-6

	SALARY AND WAGE WORKSHEET	(1) Company Proposed	Annualized	Adjusted Total	OCA Recommended	References
	Distribution Operations					OCA Set II-11
1	Union			$ 885,000		OCA Set II-19
2	Non-Exempt			$ 236,000		OCA Set II-23
3	Exempt			$ 740,000		OCA Set II-21
4	**Total**	**$ 1,850,000**	**$ 10,000**	**$ 1,860,000**	**$ 1,860,000**	
	Customer Accounts Expense					
5	Union			$ -		
6	Non-Exempt			$ 407,000		
7	Exempt			$ 1,279,000		
8	**Total**	**$ 1,677,000**	**$ 9,000**	**$ 1,686,000**	**$ 1,686,000**	
	Customer Service & Information					
9	Union			$ -		
10	Non-Exempt			$ 7,000		
11	Exempt			$ 21,000		
12	**Total**	**$ 28,000**	**$ -**	**$ 28,000**	**$ 28,000**	
	Sales Expense					
13	Union			$ -		
14	Non-Exempt			$ 1,000		
15	Exempt			$ 4,000		
16	**Total**	**$ 5,000**	**$ -**	**$ 5,000**	**$ 5,000**	
	A&G Expense					
17	Union			$ -		
18	Non-Exempt			$ 403,000		
19	Exempt			$ 1,262,000		
20	**Total**	**$ 1,656,000**	**$ 9,000**	**$ 1,665,000**	**$ 1,665,000**	
	Distribution Maintenance					
21	Union			$ 437,000		
22	Non-Exempt			$ 117,000		
23	Exempt			$ 365,000		
24	**Total**	**$ 914,000**	**$ 5,000**	**$ 919,000**	**$ 919,000**	
	A&G Maintenance					
25	Union			$ -		
26	Non-Exempt			$ 8,000		
27	Exempt			$ 25,000		
28	**Total**	**$ 33,000**	**$ -**	**$ 33,000**	**$ 33,000**	
29	**Total Proposed Salary and Wages Adjustments**	**$ 6,163,000**	**$ 33,000**	**$ 6,196,000**	**$ 6,196,000**	
	[redacted]					OCA Set II-27
CONFID						OCA Set II-24
						OCA Set II-26
CONFID						OCA Set II-25
CONFID					$ -	OCA Set II-20
					$ -	
	Overtime	2022	2023	2024		I&E RE-12
	Union	$ 553,000	$ 492,000	$ 492,000		
	Non-Union	$ 5,000	$ 5,000	$ 5,000		
	Utility Shared Services	$ 79,000	$ 70,000	$ 70,000		
		$ 637,000	$ 567,000	$ 567,000	$ 590,333	
	Adjustment				**$ -**	
	SERP Expenses			$ 25,000	**$ (25,000)**	OCA-Set-II-26
				$ (816,450)		

(1) Company Schedule D-7
Review OCA discovery

	Acct. No.	DISTRIBUTION EXPENSES	(1) Company Proposed	Adjustments	OCA Recommended	References
1		Distribution - Operations - Budget	$ 2,912,000	$ (75,000)	$ 2,837,000	
2		Salary Adjustment - D-7	$ 10,000	$ -	$ 10,000	
3		**Total**	**$ 2,922,000**	**$ (75,000)**	**$ 2,847,000**	
4		Distribution - Maintenance - Budget	$ 10,347,000	$ (701,898)	$ 9,645,102	
5		Salary Adjustment - D-7	$ 5,000	$ -	$ 5,000	
6		**Total**	**$ 10,352,000**	**$ (701,898)**	**$ 9,650,102**	
7		**Total Distribution Expenses**	**$ 13,274,000**	**$ (776,898)**	**$ 12,497,102**	
		OCA Adjustments				
	583.00	Contract Labor - Pipeline	$ 163,000	$ (71,000)	$ 92,000	
	588.00	Miscellaneous	$ 7,000	$ (4,000)	$ 3,000	OCA Set II-34
				$ (75,000)		
	593.00	Maintenance of OH Lines - Tree Trim	$ 3,931,777	$ (715,565)	$ 3,216,212	OCA Set II-3
	593.00	Maintenance of OH Lines - Major Storms	$ 760,000	$ 42,000	$ 802,000	OCA Set II-4
	595.00	Maintenance of Line Transformers-Pipeline	$ 66,000	$ (24,333)	$ 41,667	OCA Set II-34
	596.00	Maintenance of Street Light- Other	$ 7,000	$ (2,667)	$ 4,333	OCA Set II-34
	598.00	Maintenance of Misc. Dist. Plant -Pipeline	$ 5,000	$ (1,333)	$ 3,667	OCA Set II-5
						OCA Set II-6
		Total Adjustments		**$ (701,898)**		

(1) Company Schedule B-4, D-3
review three year averages and non-recurring expenses
Major Storms, Tree Trimming, and Veg Mgmt.

	Acct. No.	CUSTOMER ACCOUNTS EXPENSE	(1) Company Proposed	Adjustments	OCA Recommended	References
1		Customer Accounts - Budget	$ 9,463,000	$ (104,667)	$ 9,358,333	
2		Salary Adjustment - D-7	$ 9,000	$ -	$ 9,000	
3		Interest on Customer Deposits - D-15	$ 66,000	$ -	$ 66,000	
4		Universal Service - D-16	$ 96,000	$ -	$ 96,000	
5		**Total**	**$ 9,634,000**	**$ (104,667)**	**$ 9,529,333**	

	OCA Adjustments				
					OCA Set II-14
902.00	Meter Reading Expenses	$ 218,000	$ (61,000)	$ 157,000	OCA Set II-6/IX-4
905.00	Miscellaneous CA Expenses	$ 139,000	$ (43,667)	$ 95,333	OCA-Set IX-4
903.00	Customer Records & Collection	$ 9,185,000	$ -	$ 9,185,000	OCA-IX-4
	Total		**$ (104,667)**		

(1) Company Schedule D-3, B-4

Acct. No.	UNCOLLECTIBLE ACCOUNTS EXPENSE	(1) Company Proposed	Adjustments	OCA Recommended	References
1	2024 Budget - D-11	$ 2,239,000		$ 2,239,292	OCA-II-29
2	Uncollectible Accounts - Budget - B-4	$ 2,577,000		$ 2,577,000	
3	Three-Year Average - Ratio	1.8375%		1.8375%	
4	Adjusted Revenues	$ 152,108,000		$ 152,108,000	OCA-II-29
5	**Proforma Uncollectible - Present Rates**	**$ 2,795,008**		**$ 2,794,985**	
6	**Difference** (Line 11 - Line 6)	**$ 556,008**		**$ 555,692**	
7	**Deferred Uncollectible Accounts**	$ 315,000		$ 315,000	
8	3-year amortization	**$ 105,000**		**$ 105,000**	
9	Total Uncollectible Account Adjustment (Line 6 + Line 8)	**$ 661,008**		**$ 660,692**	
10	**Total Uncollectible at Present Rates** (Line 5 + Line 9)	**$ 3,238,008**	**$ (316)**	**$ 3,237,692**	
11	Additional Uncollectible - Proforma Rates	$ 210,451	$ (146,328)	$ 64,122	
12	**Total Uncollectible Accounts Expense** Line 10 + Line 11)	**$ 3,448,459**	**$ (146,644)**	**$ 3,301,815**	

(1) Company Schedule D-11, B-4, D-1

	Acct. No.	CUSTOMER INFORMATION & SERVICE	(1) Company Proposed	Adjustments	OCA Recommended	References
1		Customer Information & Service - Budget	$ 1,275,000	$ 9,000	$ 1,284,000	
2		EE&C Program - D-19	$ (89,000)		$ (89,000)	
3		**Total Proforma Balance**	**$ 1,186,000**	**$ 9,000**	**$ 1,195,000**	
		OCA Adjustments				
	910	Misc. Customer Service & Info. Exp.	$ 1,157,000	$ -	$ 1,157,000	OCA Set II-6
	908	Customer Assistance Expenses	$ 12,000	$ 9,000	$ 21,000	OCA-IX-4
						OCA Set II-12
						OCA Set II-14

(1) Company Schedule B-4, D-3 and D-1

Acct. No.	SALES EXPENSE	(1) Company Proposed	Adjustments	OCA Recommended	References
1	Sales - Budget (B-4)	$ -			
2	Adjustments (D-3)	$ -			
3	**Total Proforma Balance**	**$ -**	**$ -**	**$ -**	

(1) Company Schedule D-1 and D-3

	Acct. No.	ADMINISTRATIVE & GENERAL EXPENSES	(1) Company Proposed	Adjustments	OCA Recommended	References
1		A & G - Operations Budgeted (B-4)	$ 8,208,000	$ (97,919)	$ 8,110,081	
2		Salary Adjustment - (D-7)	$ 9,000	$ -	$ 9,000	
3		Rate Case Expenses (D-10)	$ (59,000)	$ (128,667)	$ (187,667)	OCA Set II-28
4		Benefits Adjustments (D-14)	$ 427,500	$ (248,500)	$ 179,000	OCA Set II-30
5	935.00	A&G - Maintenance - Budgeted (B-4)	$ 69,000	$ (55,667)	$ 13,333	OCA Set-II-6
6		**Total Proforma Balance**	**$ 8,654,500**	**$ (530,752)**	**$ 8,123,748**	

OCA Adjustments

930.20	Association Dues - EA of PA (80% to UGI-E)	$ 7,000	$ (7,000)	$ -	OCA Set II-7/Set IX-1
923.00	Outside Services Employed - **ESG**	$ 11,000	$ (11,000)	$ -	OCA Set II-8/Set IX-2
930.10	Advertising Expense	$ 113,000	$ (83,252)	$ 29,748	OCA Set II-9/II-D-7(d)
925.00	Injury and Damages	$ 251,000	$ 3,333	$ 254,333	OCA Set II-6
920.00	A&G Salaries	$ 178,000	$ -	$ 178,000	OCA-Set IX-6
			$ (97,919)		OCA Set II-12
					OCA Set II-14
					OCA Set II-16
					OCA Set II-22

(1) Company Schedule B-4, D-1, D-3

DEPRECIATION EXPENSE

Acct. No.		(1) Company Proposed Original Cost	Company Proposed Depr. Rate	Company Proposed Depr. Expense	Adjustments	OCA Recommended	References
1	Intangible Plant	$ -	0.000%	$ -			OCA Set II-42
2	Transmission Plant	$ -	0.000%	$ -			
3	Distribution Plant	$ 239,022,741	2.207%	$ 5,274,490			
4	General Plant	$ 13,513,335	11.792%	$ 1,593,465			
5	Special Depreciable Plant	$ 4,718,755	9.912%	$ 467,714			
6	Non-Depreciable Plant	$ 524,120	0.000%	$ -			
7	**Sub-Total**	**$ 257,778,951**		**$ 7,335,669**		**$ 7,335,669**	
8	Allocated to Transmission	$ (4,725,890)	11.176%	$ (528,171)			
9	**Total Allocated to Distribution**	**$ 253,053,061**		**$ 6,807,498**		**$ 6,807,498**	
10	Total Allocated Common Plant	$ 4,860,027	2.988%	$ 145,198			
11	Total Allocated IT Services	$ 22,199,147	7.582%	$ 1,683,163	$ (16,590)	$ 1,666,573	OCA-II-38
12	Total Office Furniture & Equipment	$ 246,470	6.896%	$ 16,997			
13	Total Empire Building Allocated	$ 2,204,954	2.288%	$ 50,442			
14	Allocated to Transmission	$ (7,562,002)	6.424%	$ (485,793)			
15	**Total Depreciation Expense before adj.**	**$ 275,001,657**		**$ 8,217,505**	**$ (16,590)**	**$ 8,200,915**	
16	Charged to Other Business Units	$ -		$ (42,000)			
17	Charged to Clearing Accounts	$ -		$ (479,000)			
18	Net Salvage Amortization	$ -		$ 857,000			
19	**Total Proposed Depreciation Expense**	**$ 275,001,657**		**$ 8,553,505**	**$ (16,590)**	**$ 8,536,915**	

(1) Company Schedule D-21
Book V UGI Electric Exhibit C page II 3-5

	TAXES OTHER THAN INCOME	(1) Company Proposed	Adjustments	OCA Recommended	References
1	PURTA Taxes	$ 76,000	$ -	$ 76,000	OCA Set II-31
2	Gross Receipts Tax - 5.90%	$ 8,819,000	$ -	$ 8,818,000	
3	PA & Local Use Taxes (real estate)	$ 22,000	$ -	$ 22,000	I&E RE-4-D
4	Social Security Taxes (FICA) - 7.61%	$ 466,000	$ (62,132)	$ 403,868	
5	FUTA - 0.51%	$ 31,000	$ (4,164)	$ 26,836	
6	SUTA - 0.05%	$ 3,000	$ (408)	$ 2,592	
7	PUC Assessment	$ 297,000	$ -	$ 297,000	I&E RE-4-D
8	**Total Taxes Other Than Income**	**$ 9,714,000**	**$ (67,704)**	**$ 9,646,296**	
9	Additional Taxes Other Than Income	$ 718,000	$ (499,199)	$ 218,801	
10	**Total**	**$ 10,432,000**	**$ (566,903)**	**$ 9,865,097**	

(1) Company Schedule D-31 and D-32

		INCOME TAX CALCULATION	(1) Company	Proposed Proposed Rates	Adjustments	OCA Recommended Present Rates	References
1		Proposed Revenues		$ 164,164,000		$ 152,691,000	
2		Proposed Operating Expenses		$ (146,288,506)		$ (143,408,560)	
3		Operating Income Before Taxes		$ 17,875,494		$ 9,282,440	
		Interest Expense					
4		Proposed Rate Base	$ 172,186,000			$ 171,673,057	
5		Weighted Cost of Debt	2.02%			2.40%	
6		Synchronized Interest		$ (3,478,157)		$ (4,125,947)	
7		Base Taxable Interest		$ 14,397,337		$ 5,156,493	
8		Total Taxable Depreciation	$ 18,229,000			$ 18,229,000	OCA Set II-43
9		Total Proforma Book Depreciation	$ 8,957,000		$ (16,590)	$ 8,940,410	OCA Set II-43
10		State Taxable Depreciation (over)/under		$ (9,272,000)	$ (16,590)	$ (9,288,590)	
11		State Taxable Income		$ 5,125,337		$ (4,132,097)	
12		**State Income Tax (Expense) Refund**	**8.99%**	**$ (460,768)**		**$ 371,476**	
		Total Taxable Depreciation	$ 17,308,000			$ 17,308,000	OCA Set II-43
		Total Proforma Book Depreciation	$ 8,957,000			$ 8,940,410	OCA Set II-43
		Federal Tax Deducts (over) under		$ (8,351,000)	$ (16,590)	$ (8,367,590)	
		Federal Taxable Income		$ 5,585,569		$ (2,839,621)	
		Federal Income Tax (Expense) Refund	**21.00%**	**$ (1,172,969)**		**$ (596,321)**	
		Total Tax Expense Before DIT		**$ (1,633,737)**		**$ (224,845)**	
		Deferred Federal Income Taxes					
		Total Straight Line Tax Depreciation	$ 8,218,000		$ (16,590)	$ 8,201,410	
		Total Tax Depreciation	$ 16,525,000			$ 16,525,000	
		Federal Tax Deducts (over) under		$ 8,307,000	$ 16,590	$ 8,323,590	
	(2)	**Deferred Federal Income Tax Rate**	**17.85%**	**$ (1,482,800)**		**$ (1,485,761)**	OCA Set II-45
		Deferred State Income Taxes					
		Repairs		$ (694,000)		$ (694,000)	
		CIAC		$ 38,000		$ 38,000	
		State Deferred Income Tax (Expense) Refund		$ (656,000)		$ (656,000)	
		Net Income Taxes - Combined		**$ (3,772,537)**		**$ (2,366,606)**	OCA Set II-44
		Federal Income Taxes		$ (2,655,769)	$ 573,688	$ (2,082,081)	
		State Income Taxes		$ (1,154,768)	$ 832,243	$ (322,524)	
		Total - check		$ (3,810,537)		$ (2,404,606)	
		difference - rounding		$ 38,000			
							OCA Set II-46
	(2)	Includes $283,000 of EDFIT flow back to ratepayers					OCA Set II-47

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2022-3037368
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Dante Mugrace, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 1SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: June 7, 2023
*347167

Signature: Dante Mugrace
Dante Mugrace

Consultant Address: PCMG and Associates
90 Moonlight Court
Toms River, NJ 08753

OCA Statement 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF
UGI UTILITIES, INC. - ELECTRIC DIVISION
FOR ADJUSTMENT OF RATES AND CHARGES

DOCKET NO. R-2022-3037368

DIRECT TESTIMONY
OF
AARON L. ROTHSCHILD

COST OF CAPITAL

ON BEHALF OF
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

April 25, 2023

Contents

I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Aaron L. Rothschild. My title is President, and my business address is 15 Lake Road, Ridgefield, CT.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am President of Rothschild Financial Consulting ("RFC").

Q. PLEASE STATE YOUR EDUCATIONAL ACHIEVEMENTS AND PROFESSIONAL DESIGNATIONS.

A. I have a B.A. degree in mathematics from Clark University (1994) and an M.B.A. from Vanderbilt University (1996).

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE.

A. I performed financial analysis in the telecom industry in the United States and Asia Pacific from 1996 to 2001, investment banking consulting in New York, complex systems science research regarding the power sector at an independent research institute, and I have prepared rate of return testimonies since 2002. See Appendix F for my resume.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION, OR OTHER STATE COMMISSIONS? IF SO, WHICH COMMISSIONS?

A. Yes, I have testified before Pennsylvania Public Utility Commission. My expert witness experience also includes testifying in over 50 cost of capital proceedings before the following state commissions: California, Colorado, Connecticut, Delaware, Florida, New Jersey, Maryland, North Dakota, Pennsylvania, Tennessee, and Vermont. See Appendix G for the list of dockets for each of my testimonies.

Q. ON WHOSE BEHALF ARE YOU PROVIDING THIS TESTIMONY?

A. The Pennsylvania Office of Consumer Advocate ("OCA").

II. PURPOSE

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to address the cost of capital for UGI Utilities, Inc. - Electric Division ("UGI" or the "Company") which includes the following three components:

1. Cost of Equity ("COE")
2. Cost of Debt
3. Capital Structure

Based on my analysis of these cost of capital components, I recommend an allowed rate of return for ratemaking purposes (6.18% in this case for UGI) including an appropriate authorized return on equity ("ROE"), authorized cost of debt, and authorized capital structure.

Q. PLEASE DEFINE THE COE, COST OF DEBT, AND CAPITAL STRUCTURE.

A.

1. **COE:** My COE recommendation is my opinion of the return investors require to provide equity capital to UGI based on current capital markets. Since investors must pay the market price of a stock to make an investment, investors' required returns are based on the return they expect to receive on the market price of stocks. In other words, UGI's COE is forward-looking and "market-based." My recommendation is consistent with the following legal standards set by the United States Supreme Court for a fair rate of return:

   > The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[1]

   And

   > [S]ufficient to . . . support its credit and . . . raise the money necessary for the proper discharge of its public duties.[2]

2. **Cost of Debt:** My cost of debt recommendation is based on the actual cost of debt paid by the utility to its sources of debt. For example, if a utility has issued a bond with a 3% interest rate three years ago, its authorized cost of debt should be 3% even if interest rates are currently higher or lower than 3%.

3. **Capital Structure:** Capital structure is the percentage of equity and debt that makes up the finances of a utility. For example, if a utility raises $1 million of equity capital and $1 million of debt capital, we say it has a capital structure containing 50% equity and 50% debt. My capital structure recommendation is based on my review of UGI's

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[1] *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944).
[2] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of the State of W. Va.* 262 U.S. 679, 692-693 (1923).

justification for its requested regulatory capital structure, the capital structure ratios of other electric utility companies, and the capital structure of UGI's parent, UGI Corp.. As discussed below, it may not be fair to charge consumers based on the actual capital structure of a utility that is a wholly owned subsidiary if has equity that is disproportionally high.[3]

Q. WHAT IS THE DIFFERENCE BETWEEN UGI'S COST OF EQUITY AND ITS AUTHORIZED ROE?

A. The COE is the market-based return investors expect to earn on the market value of any given stock. In other words, the COE is the return investors expect to earn on the market price of equity. As it applies to this proceeding, it is the return investors require to provide equity capital to UGI, or another investment of comparable risk. The appropriate authorized ROE is based on the Commission's determination of the COE at the time of the proceeding, after reviewing the evidentiary record, which incorporates investor expectations. Once the Commission issues an authorized ROE, the market-based cost of equity will continue to fluctuate as capital markets inevitably continue to change. The authorized ROE is based on a snapshot of the COE, which is constantly changing.

Q. PLEASE DEFINE THE APPROPRIATE RATE OF RETURN.

A. The appropriate Rate of Return (ROR) is based upon the weighted overall cost of capital (WACC) of the current cost of debt and equity at the time of this proceeding. The weighted cost rate is calculated by multiplying the capital structure ratios of the sources of capital (debt, preferred equity, and equity) times respective cost rates.

[3] A higher common equity ratio, all else equal, results in higher rates for consumers because equity is more expensive than debt.

WACC = Cost of Debt X Debt Ratio + COE X Common Equity Ratio.

Q. CALCULATING THE COST OF EQUITY IS A HIGHLY TECHNICAL TOPIC. HOW CAN A DECISION MAKER WHO IS NOT SPECIALIZED IN FINANCE BEST USE THE CONTENT OF THIS TESTIMONY?

A. My testimony includes a thorough technical analysis, including the use of specialized mathematical models. Models are required to determine the cost of equity like a map is required to plan a road trip. Maps and models are useful because they simplify the complexity and vastness of reality into a form that is understandable and useful. A map of Pennsylvania that left out no details would be the same size as the state and thus unusable. A model that included every detail of financial markets (e.g., the trading activity of every single stock investor on earth) would be unusable as well. It is critical to remember that models are simplifications of reality and there are arguably as many "models" as there are investors. My ROE recommendation is based on the best tools I am aware of to calculate UGI's COE, however, I urge the Commission to test the reasonableness of my model results by comparing them to model results from sources that have nothing to do with this proceeding. For example, I recommend that the Commission consider the long-term equity return expectations of pension funds and leading financial institutions like the ones shown in Table 4 on page 14.

Q. HAVE YOU REVIEWED UGI'S APPLICATION AND DIRECT TESTIMONY?

A. Yes.

III. INTRODUCTION AND SUMMARY OF CONCLUSIONS

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I provide a summary of my recommendations, an overview of cost of equity concepts, and explanation of how current capital markets relate to my cost of equity calculations. Second, I provide a more detailed discussion of current capital markets and how key parameters are impacting equity costs. Third, I provide a detailed explanation of the various models I use in my cost of equity calculations. Lastly, I provide an evaluation of UGI's rate of return testimony.

Q. PLEASE PROVIDE A SUMMARY OF YOUR RECOMMENDATIONS.

A. I recommend the following cost of capital for UGI's electric distribution operations:

- An overall cost of capital of 6.18% (6.06% - 6.30%)
- An ROE of 8.44% (8.16% - 8.71%)
- A capital structure containing 44.75% common equity, 55.25% long-term debt and 0.00% short-term debt
- A debt cost rate of 4.35%[4]

A summary of my cost of capital recommendations for UGI's electric distribution operations is presented in Table 1 on page 9.

[4] Mr. Moul's Direct Testimony, page 2, lines 6-7.

TABLE 1: ALR RECOMMENDED RANGE MIDPOINT - UGI UTILITIES, INC. - ELECTRIC DIVISION Docket No. R-2022-3037368			
	Capital Structure Ratios	**Cost Rate**	**Weighted Cost Rate**
Long-Term Debt	55.25%	4.35%	2.40%
Short-Term Debt	0.00%	0.00%	0.00%
Preferred Equity	0.00%	0.00%	0.00%
Common Equity	44.75%	8.44%	3.78%
Rate of Return			6.18%

Exhibit ALR-1

Q. PLEASE SUMMARIZE HOW YOU DETERMINED YOUR 8.44% COST OF EQUITY RECOMMENDATION FOR UGI'S ELECTRIC DISTRIBUTION OPERATIONS.

A. To arrive at my recommendations, I applied the Constant Growth form of the Discounted Cash Flow ("DCF") Model to a proxy group of 24 publicly traded electric utility companies ("RFC Electric Proxy Group") using data available through March 31, 2023. I also used a Capital Asset Pricing Model ("CAPM") analysis as a check on the DCF results, and to ensure that the Commission is able to consider how inflation and interest rates are impacting UGI's cost of equity.

As shown in Table 2 below, Cost of Equity Model Results, the high-end results of my three cost of equity models, including eight variations of the CAPM, range between 8.25% and 9.34%, with an upper quartile of 8.71%. The low-end results of my three cost of equity models, including eight variations of the CAPM, range between 7.78% and 9.05%, with a lower quartile of 8.16%.

TABLE 2: COST OF EQUITY MODEL RESULTS		
DCF	**Low**	**High**
Constant Growth - Sustainable Growth	8.12%	8.26%
Constant Growth - Option-Implied Growth	8.47%	9.34%
Non-Constant Growth	9.05%	9.06%
CAPM		
Spot (Mar. 31, 2023)		
Risk Free Rate - 3-Month T Bill	8.48%	8.54%
Risk Free Rate - 30-Yr T Bond	8.17%	8.25%
3-Mo. Weighted Average (Jan. to Mar. 2023)		
Risk Free Rate - 3-Month T Bill	8.13%	8.60%
Risk Free Rate - 30-Yr T Bond	7.78%	8.35%
Outer Quartile Range	**8.16%**	**8.71%**
Midpoint of Range	**8.44%**	

Exhibit ALR-2

Q. ARE YOU RECOMMENDING A SPECIFIC ROE OF 8.44% OR AN ROE RANGE OF 8.16% TO 8.71%?

A. I recommend both a range of appropriate ROEs and a specific point within that range that I consider to be the most appropriate. It is not possible to measure UGI's COE with the precision of measuring temperature with a thermometer. However, my recommended ROE range of 8.16% to 8.71% already eliminates the extreme ends of the results of my models and provides the Commission with a range of ROEs that will allow UGI to raise the capital it needs to provide safe and reliable service. However, I also recommend a specific point of 8.44% within that range that I feel best reflects UGI's COE.

Q. DO YOUR DCF MODEL RESULTS ALONE SUPPORT YOUR 8.44% ROE RECOMMENDATION?

A. Yes. My sustainable growth DCF model ranges between 8.12% and 8.26% which indicates that my 8.44% ROE recommendation is more than sufficient for UGI to be able to raise the equity capital it needs to provide safe and reliable service. My constant growth DCF method based on option-implied growth ranges between 8.47% and 9.34%. However, the 9.34% results is based on only one day of stock option prices and a broader analysis indicates that the 9.34% results is being impacted by daily fluctuations and not representative of investors' longer-term equity return expectations. As discussed below, my COE Term-Structure Analysis indicates that investors expect the cost of equity to remain relatively stable over the next five years despite recent increases in interest rates.

The following additional evidence indicates that my 8.44% is appropriate for UGI, as 1) electric utility stocks have been outperforming the overall market over the past year[5] indicating they are attractive investments, 2) stock option data indicates that investors consider the chance of a large drop in electric utility stocks to remain relatively low compared to the overall market, and 3) the term-structure of the COE remains stable over the next 5-years.

Q. ARE YOUR COE MODELS BASED ON ESTABLISHED METHODOLOGIES?

A. Yes. My constant growth DCF model is used by major financial institutions. J.P. Morgan Chase uses the sustainable growth form of the DCF method, as I do, in its 2019 Long-Term Capital Market Assumptions publication.[6] *Principles of Corporate Finance*, a leading

[5] Electric utility stocks have underperformed the overall market in the first three months of 2023.
[6] 23rd Annual Edition, Long-Term Capital Market Assumptions - Time-tested projections to build stronger portfolios, pp. 62-63.

financial textbook used in business schools and investment banks around the world, recommends using the very same method I use to calculate the cost of equity for regulated energy utility companies.[7] As discussed in Section V.Q - F. Capital Asset Pricing Model on page 58, my CAPM is based on methodologies used by Value Line, the Chicago Board of Options Exchange (CBOE), and published in peer-reviewed academic journals (e.g., The Review of Financial Studies). My CAPM method has also been recognized by state utility commissions. On April 9, 2020, the South Carolina Public Service Commission stated the following:

> Amongst the three witnesses, Consumer Affairs Rothschild's approach was unique in that he included the use of both historical and forward-looking, market-based data in his analysis. Based on the testimony and facts presented, the Commission therefore adopts the recommended ROE of 7.46% proposed by witness Rothschild.[8]

In California's 2017 Water Cost of Capital proceedings, a company witness acknowledged the validity of RFC's method. California Administrative Law Judge Bemesderfer stated the following:

> [O]n cross-examination Vilbert [California Water Service Company witness] admitted that Rothschild's use of the method [b x r method] was "reasonable" and that Rothschild had "implemented the methodology correctly" in arriving at his Water Proxy Group ROE of 8.25%.[9]

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[7] Brealey, Myers, and Allen (2017), Principles of Corporate Finance, 12th Edition, McGraw-Hill Irwin, New York, page 86-87.
[8] Order Ruling on Application for Adjustment in Rates, Docket No. 2019-290-WS, Order No. 2020-306, April 9, 2020, page 43.
[9] Proposed Decision of ALJ Bemesderfer, p.19, Public Utility Commission of California, Application No. 17-04-001 (February 6, 2018).

Q. HOW DO YOUR RECOMMENDATIONS COMPARE TO THE RECOMMENDATIONS OF UGI'S RATE OF RETURN WITNESS, MR. MOUL?

A. As shown in Table 3 below, my 8.44% cost of equity and capital structure recommendations result in a 6.18% overall rate of return. Mr. Moul's 11.30% cost of equity and capital structure recommendations result in an overall rate of return of 8.14%.

TABLE 3: RECOMMENDATION COMPARISON - ROTHSCHILD AND MOUL

	Cost of Equity	Cost of Debt	Common Equity %	Debt %	Rate of Return
Rothschild [1]	8.44%	4.35%	44.75%	55.25%	6.18%
Moul [2]	11.30%	4.35%	54.59%	45.41%	8.14%

[1] Exhibit ALR-1
[2] Direct Testimony of Paul R. Moul, page 18, lines 22-23.

I recommend a different ROE[10] for UGI than its witness Mr. Moul for many reasons.

First, we have different analytical approaches. I focus primarily on using market data (e.g., stock prices, bond yields, stock option prices) to measure investors' expectations as much as possible, which is a better approach because of the reliance on current information. Current financial data is forward looking because it represents investors' expectations. On the other hand, Mr. Moul relies considerably on historical data (e.g., betas in his CAPM are based on data from the past 5 years) and non-market data, including accounting returns that have almost nothing to do with UGI's COE which can inflate his results.

[10] My ROE recommendation is based on UGI's current market-based COE. As stated previously, the authorized ROE is based on a snapshot of the COE which is constantly changing. In the context of this case my recommended COE and ROE are synonymous.

Q. PLEASE PROVIDE A SUMMARY OF HOW YOUR COST OF EQUITY RECOMMENDATION COMPARES TO RETURN EXPECTATIONS OF MAJOR FINANCIAL INSTITUTIONS.

A. My cost of equity recommendation of 8.44% (8.16% to 8.71%) for UGI is in the middle to upper part of the range of the expectations published by major banks and brokerage houses (6.6% to 9.5%) shown in Table 4 below. My recommendation is consistent with the cost of equity demanded by investors and enables UGI to raise the capital needed to provide safe and reliable service.

TABLE 4: U.S. EQUITY RETURN EXPECTATIONS AMONG MAJOR FINANCIAL INSTITUTIONS

Duff & Phelps/Kroll (Jan 2023) [1]	**9.5%**
Horizon Actuarial Services, LLC Survey - 20 Year Horizon (August 2022) [2]	
U.S. Equity - Large Cap (3.7-9.2%, 50% Percentile - 6.6%)	**6.6%**
U.S. Equity - Small / Mid Cap (2.9-9.9%, 50% Percentile - 7.1%)	**7.1%**
J.P. Morgan Asset Management - Equity Long-Term Returns (2022) [3]	**7.9%**
Charles Schwab - 10-year U.S. Large Cap Returns (March 2022) [4]	**6.6%**

Sources:
[1] Kroll Cost of Capital in the Current Environment, hhttps://www.kroll.com/-/media/kroll-images/pdfs/cost-of-capital-inf
Note: Duff & Phelps acquired Kroll in 2021 and rebranded itself as Kroll.
[2] Horizon Actuarial Services, LLC, Survey of Capital Market Assumptions Survey, August 2022, page 18.
Survey participants Include: Bank of New York Mellon, BlackRock, Goldman Sachs Asset Management, J.P. Morgan Asset Management, Merrill, Morgan Stanley Wealth Management, Royal Bank of Canada, UBS.
[3] J.P. Morgan Asset Management - 2023 Long-Term Capital Market Assumptions, 2022, page 14.
[4] Schwab's 2022 Long-Term Capital Market Expectations, March 1, 2022.

The data presented in Table 4 above shows that major financial institutions are informing their clients to expect returns on their investments similar to the cost of equity I propose in this testimony. These expectations are for the overall stock market (e.g., US Large Cap, S&P 500[11]), which should be higher than the return expectations for buying utility stocks because regulated monopoly utilities are lower risk than most, if not all, unregulated companies in the S&P 500, like Tesla and Amazon. Additionally, defensive

[11] The S&P 500 is a stock market index that includes 500 of the largest U.S. companies, including 11 sectors to show the health of the U.S. stock market and broader economy. The Dow Jones Industrial Average, 30 of the largest U.S. companies, is another commonly used measure of equity markets in general.

stocks like utilities have been outperforming the overall market in the current capital market environment which indicates, along with other financial data, that the relative COE for utility companies has been decreasing since the figures shown in Table 4 were published. Therefore, to the degree investors respect the advice of major financial institutions when setting their own investment return expectations, we should expect that UGI's COE should be lower than the return expectations presented in Table 4 on page 14.

Mr. Moul's 11.30% ROE recommendation is considerably higher than return expectations published by major consulting firms, brokerage houses, and market data publications for the overall market (6.6% to 9.5%). Indeed, the fact that his ROE recommendation for a regulated utility company like UGI is significantly higher than what financial institutions are telling their clients to expect for the riskier overall market indicates that his ROE recommendation is excessive.

Q. DO YOU HAVE ADDITIONAL EVIDENCE THAT MR. MOUL'S 11.30% ROE RECOMMENDATION IS HIGHER THAN UGI'S MARKET-BASED COE?

A. Yes. The market-to-book ratios of electric utility companies show that investors expect a market return significantly less than 11.30%. The average future expected return on book equity for the 24 companies in my RFC Electric Proxy Group is 10.30%.[12] If the market price of electric utility stocks was equal to book value then investors could expect to earn a market return equal to about 10.30%.[13] But the market price of electric utility stocks is about two times the book value, which means that investors likely expect to earn

[12] Exhibit ALR-3, page 1.
[13] As shown in Table 4 on page 14 major financial institutions expect equity investors will receive a return of less than 10% over the long-term even for the overall market which we should expect to have a higher COE/long-term equity return than for electric utility stocks.

significantly less than 10.00% or 11.30%. Appendix A explains why a market-to-book ratio significantly above one means that the market-based COE is significantly less than the expected return on book equity.

Q. PLEASE COMPARE UGI'S REVENUE REQUIREMENT IF YOUR RECOMMENDATIONS ARE ADOPTED INSTEAD OF MR. MOUL'S.

A. If my 8.44% cost of equity recommendation and capital structure recommendation are used to set rates for UGI, the operating income requirement will be about $10.60 million annually. On the other hand, if Mr. Moul's 11.30% cost of equity recommendation and capital structure recommendation are used to set rates, the annual operating income requirement will be about $14.04 million. As shown in Table 5 below, if Mr. Moul's rate of return recommendations are adopted instead of mine, consumers will pay approximately $5.20 million more each year without an improvement in the key attributes that consumers care about: reliability, sustainability, or affordability.

TABLE 5: ANNUAL REVENUE IMPACT VS. REQUESTED - UGI UTILITIES, INC. - ELECTRIC DIVISION
($ million)

	Opearing Income Requirement	Rate of Return Component Difference Moul Rothschild
Rothschild	$10.60	
Moul	$14.04	$5.20

Inputs:

Rate Base (UGI)	$	172.24
Rate Base (OCA)	$	171.59
Gross Revenue Factor		1.51358

Source: Mr. Dante Mugrace's Direct Testimony, Schedule DM-1.

Q. IS IT APPROPRIATE TO ALLOW UGI AN AUTHORIZED ROE BASED ON THOSE ALLOWED IN OTHER JURISDICTIONS OR THOSE ALLOWED FOR OTHER UTILITIES?

A. No. A common misconception promoted by utility companies is that an authorized ROE must be consistent with authorized ROEs in other proceedings. UGI's authorized ROE should be market-based. In other words, it should be based on investors' return expectations as indicated by current market data. Even if it were assumed that all historical authorized ROEs of electric utility companies in other jurisdictions are based on accurate market-based cost of equity calculations, they are from the past. The cost of equity should be based on current market conditions. Setting rates based on historical data is like driving a car by looking out the rear-view mirror. Unless authorized ROEs are set based on investors' current expectations as indicated by market data at the time of the proceeding, the resulting rates could be either too low to permit a utility to raise capital on reasonable terms or too high so that ratepayers would be overcharged. For these reasons, I strongly recommend using the results of my market-based methods, which are confirmed by the equity return expectations of leading financial institutions shown in Table 4 on page 14.

Q. YOU RECOMMEND THAT UGI SHOULD BE AUTHORIZED TO EARN AN ROE EQUAL TO ITS MARKET-BASED COST OF EQUITY OF 8.44% (8.16% TO 8.71%). PLEASE EXPLAIN MORE REGARDING THE IMPORTANCE OF DETERMINING THE MARKET-BASED COE AS ACCURATELY AS POSSIBLE.

A. As discussed above, UGI's authorized ROE should be in line with its market-based COE. In other words, the cost of equity is the return investors expect to earn when they purchase the equity (or stock) of a company. The return investors expect can come in the form of capital gains (stock price appreciation) or dividend payments. As investors buy and sell stock in the market, they convey information about their return expectations and therefore the underlying cost of equity (companies with different risk profiles will have different costs of equity). It is impossible to determine the cost of equity based on accounting information alone (e.g., revenue, net income, equity book value, or return on book equity) as it can only be established by capital market prices (e.g., stocks, stock options).

It is important that the cost of equity used to set rates for UGI in this proceeding be market-based. This makes sense because investor-owned utility companies ("IOUs") raise money from investors. It is thus critical that the authorized ROE be consistent with the market return expectations of investors.

Q. DO ANY ROE WITNESSES USE A DIFFERENT DEFINITION FOR THE COST OF EQUITY?

A. Yes. All ROE witnesses I have encountered over my more than 20 years in the industry, including Mr. Moul, define the cost of equity as market-based somewhere in their testimony. Mr. Moul correctly states that the DCF model produces a "market-determined cost of equity"[14] However, Mr. Moul's approach significantly relies on the personal opinions of equity analysts in both his CAPM and DCF analysis instead of the supply and demand of stocks and bonds as indicated by market data. Calculating the cost of equity should be an interpretive approach (i.e., using market data to measure investors' expectations as Mr. Moul did in some parts of his testimony) rather than a speculative one (e.g., using analyst forecasts instead of investors' expectations as revealed in stock option prices).

[14] Mr. Moul's Direct Testimony, page 30, lines 18-19.

Q. IS YOUR MARKET-BASED COST OF EQUITY RECOMMENDATION BASED ON YOUR OPINION OF FUTURE STOCK PRICE RETURNS?

A. No. I do not pretend to be able to predict the future. Capital markets are unpredictable and, as explained above, it is investors' expectations that matter since they are the ones providing the capital. Therefore, I provide an expert interpretation of investors' return expectations as indicated by the current market prices of stocks, bonds, and stock options, without attempting to predict future prices. This is an important topic that I will revisit throughout my testimony.

I do use Value Line and Zacks analyst forecasts to estimate the market-based cost of equity in my DCF analyses. However, I do not use them mechanically and I go to great lengths to distill the sustainable growth component to ensure it is in line with investors' long-term expectations, including using a DCF model that is based only on market data (stock option prices). My CAPM is based on a direct measurement of investors' expectations as indicated by market prices instead of analyst forecasts, which have proven to be unrealistic.

IV. COST OF EQUITY IN TODAY'S FINANCIAL MARKETS

Q. HOW DO RECENT FINANCIAL MARKET DEVELOPMENTS AFFECT THE COST OF EQUITY?

A. The COE for electric utility companies has been increasing as the Federal Reserve continues to fight historically high inflation (5.3%), having raised the Federal Funds rate from 0% in January 2022 to 4.83%[15] as of March 31, 2023. In a testimony I filed last year based on data as of March 31, 2021,[16] I determined that the COE for two electric utility companies operating in Connecticut was 7.17%, which corresponded to the midpoint of my COE model results at the time. Nineteen months later, the midpoint of my COE model results in this testimony (based on data as of March 31, 2023) is 8.44%, an increase of 127 basis points. However, as discussed above, despite recent increases in interest rates and market volatility, capital market data show that investors expect the COE to remain about the same for a stock they plan to sell in 5 years than for a stock they plan to sell in 1 year. In other words, stock option prices show a flat term structure for the COE.

Below I discuss investors' expectations regarding the following: 1) inflation and interest rates, 2) stock price volatility, 3) probability of a large drop in stock price, and 4) term structure of the COE.

Q. PLEASE DISCUSS MARKET DEVELOPMENTS THAT IMPACT THE COST OF EQUITY.

A. Market developments that have impacted the cost of equity include:

1. **Inflation and Interest rates.** As shown on Chart 2 on page 24, investors expect the Federal Reserve to start lowering the federal funds rate later this year. As shown on Chart 3 starting on page 26, investors expect inflation to decrease sharply over the next few years and long-term interest rates to remain near current levels in coming decades.

[15] YCharts - https://ycharts.com/indicators/effective_federal_funds_rate.
[16] Eversource and United Illuminating, Docket No. 17-12-03RE11, Rate of Return / Interim Rate Reduction, April 2021.

2. **Stock price performance.** Electric utility stocks have performed considerably better than the overall market over the past year, indicating that investors consider them attractive investments in today's markets. This makes sense because regulated utility companies' earnings are relatively protected from the economy and can provide investors steady dividends even when stock prices are volatile.

3. **Stock price volatility**. Investors expect stock prices to remain more volatile in 2023 than before COVID-19. However, as shown on Chart 10 on page 34, investors' volatility expectations are lower than highs reached in October, 2022.

4. **Probability of a larger stock price drop (Option Implied Skewness).** Investors' expectations regarding the chance of a large drop in utility stock prices remain significantly below that of the overall market which indicates that the relative cost of equity for electric utility companies remains low. As shown in Chart 12 on page 37, in recent months investors have increased their expectation that the S&P will experience a large drop while this same measure has remained stable for electric utility companies.

5. **Term Structure of COE.** Despite high inflation, increasing interest rates, and volatile equity markets, market data indicates that investors expect the COE to remain the same in the future. A stable term structure of COE is a good sign that electric utility companies, including UGI, will be able to raise the capital it needs to fund assets with long useful lives at a reasonably low cost of equity despite high inflation rates and recent increases in interest rates.

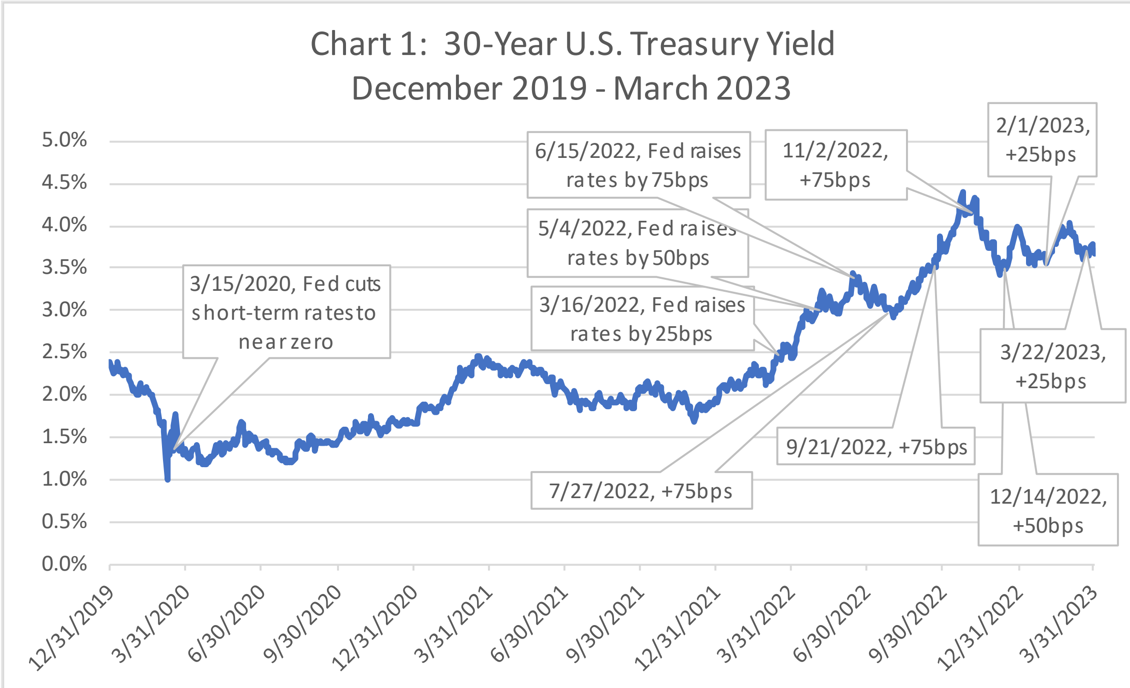
I elaborate on each of the points above in the following sections.

A. Inflation and Interest Rates

Q. PLEASE DISCUSS THE CURRENT INFLATION AND INTEREST RATE ENVIRONMENT AND WHAT IT INDICATES REGARDING THE COST OF EQUITY.

A. The stated reason the Federal Reserve increased Federal Funds Rate on March 16, 2022, was to fight potential increases in inflation. The minutes of the January 31-February 1, 2023, Federal Open Market Committee reported that the Committee anticipates ongoing increases in the federal funds rate will be required to return inflation to 2% over time.[17] As the Fed has increased the Federal Funds Rate from near zero to near 4.83% as of March 31, 2023, long-term interest rates (e.g., U.S. Government Bonds, Corporate Bonds, mortgage rates) have been increasing as well. As shown in Chart 1 on page 23, the yield on the 30-year U.S. Treasury bond has increased from about 2% at the start of 2022 to 3.67% as of March 31, 2023.

[17] Minutes of the Federal Open Market Committee January 31–February 1, 2023, February 22, 2023.



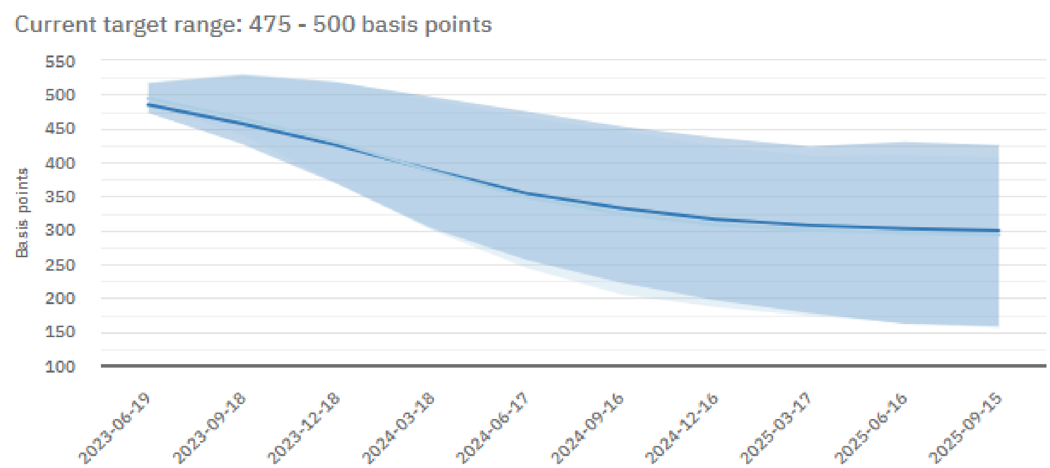
Higher inflation can impact the cost of equity because it can impact interest rates. Higher interest rates, all else equal, generally indicate a higher cost of equity for electric utility companies because fixed income investments become relatively more attractive when they start paying a higher rate (e.g., a bond with an interest rate of 3% is more attractive to investors, all else equal, than when they are paying a 2% rate). However, as discussed above the cost of equity for utility companies has likely been decreasing relative to the overall market because utility companies can provide investors stable dividends during capital market uncertainty. Additionally, the Commission can be confident that my 8.44% ROE recommendation reflects interest rate changes because it is based on market data, including the changing market yields on government bonds.

There is a lot in the news regarding the economic consequences of high inflation, including how it could impact capital markets and the cost of equity. As stated throughout this testimony, the cost of equity should not be based on the forecasts of economists, but on investors' return expectations because investors are the ones providing the capital.

Q. WHAT DOES MARKET DATA INDICATE REGARDING INVESTORS' CURRENT INFLATION AND INTEREST RATE EXPECTATIONS?

A. As shown in Chart 2 below, the Federal Reserve Bank of Atlanta estimated that as of November 21, 2022, investors expect the three-month average Federal Funds rate[18] will most likely decease from its current range of 4.75%-5.0% to an expected value of about 3% by September 2025. The Federal Reserve Bank of Atlanta calculates market-implied probabilities by using options, futures, and swap spreads.

Chart 2: Investors' Federal Funds Rate Expectations
Three-Month Average



Source: Federal Reserve Bank of Atlanta

Q. YOU STATED THAT THE FEDERAL RESERVE BANK OF ATLANTA USES MARKET DATA TO CALCULATE INVESTORS' EXPECTATIONS REGARDING

[18] The Federal Funds rate guides overnight lending among U.S. banks, but this short-term rate impacts the interest rates on debt with longer maturities.

THE FEDERAL FUNDS RATE. IS THERE A WAY TO MEASURE INVESTORS' INFLATION AND LONG-TERM INTEREST RATE EXPECTATIONS AS WELL?

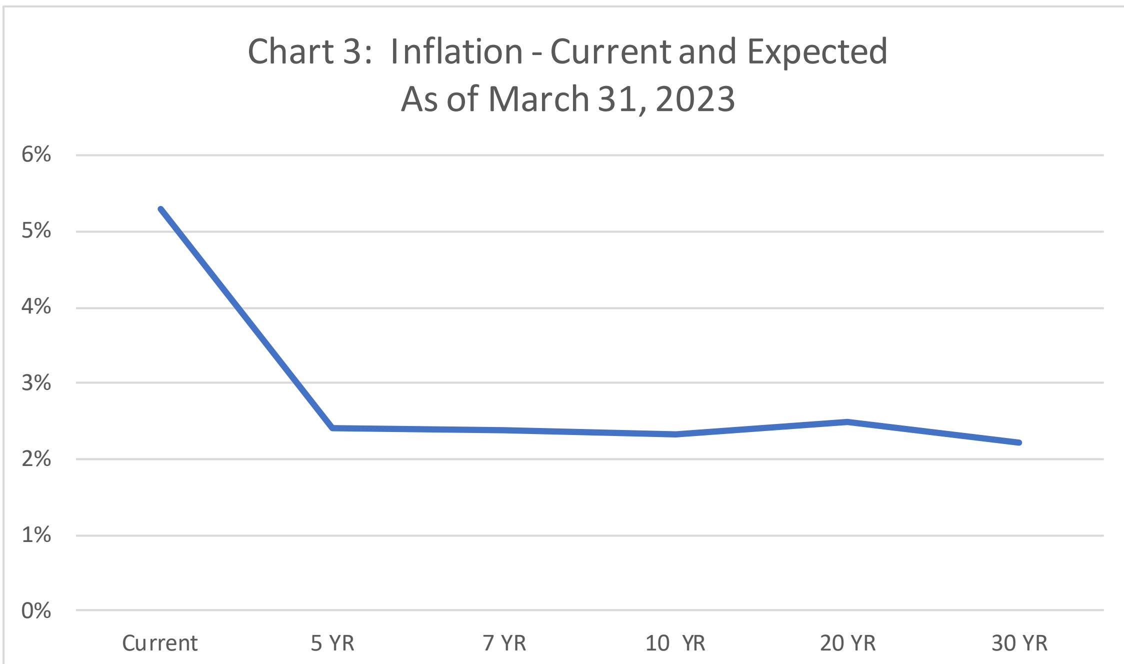
A. Yes. Regarding inflation, it is possible to measure investors' expectations directly simply by subtracting the interest rate of nominal Treasuries and TIPS (Treasury Inflation - Protected Securities) of comparable maturities. This difference is referred to as the "breakeven inflation rate" because it represents what inflation would have to be for an investor to "break even" or make the same return on both nominal Treasuries and TIPS. For example, if the yield on a nominal 10-year Treasury is 2.5% and TIPS of the same duration are 1.5%, an investor would make the same real return on both bonds if the inflation rate is 1% over the next 10 years.

Nominal yield – real yield = breakeven inflation rate

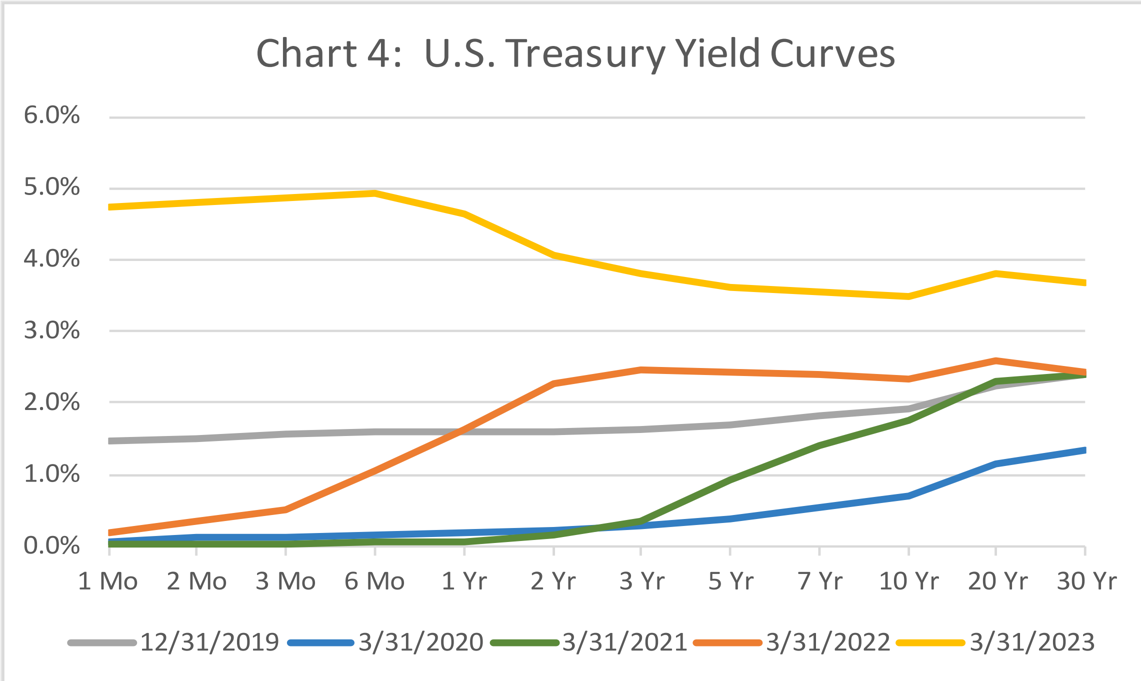
In this case, investors' breakeven inflation rate is 1% (2.5% - 1.5% = 1%).

It makes sense that investors' inflation expectation is equal to the breakeven inflation rate because if investors, on average, believed that inflation was going to be 10%, in the example above, they would buy TIPS and expect to make exceptional profits. The investor who purchases TIPS would earn 1.5% + 10% inflation = 11.5%. The investor who purchased the nominal Treasury would lose 7.5% (2.5% yield — 10% inflation rate). With such large relative returns to be made buying TIPS in this hypothetical example, investors would bid up the price of TIPS and drive down the yield until investors expect the same real return on nominal Treasuries and TIPS. And in this way, the relationship between the market yields on TIPS vs. nominal Treasury bonds is a self-balancing safe measurement of investors' expectation of inflation.

As indicated by the difference between nominal-treasuries and TIPS, Investors expect the FED's actions will reduce the inflation rate substantially in the coming years. As shown on Chart 3 below, the relative market price of inflation-protected bonds as compared to regular Treasury bonds as of March 31, 2023, indicates that investors expected the inflation rate to decline from the current 5.30% to only 2.40% over the next 5 years and 2.23% over the 30-year horizon.



Regarding interest rates, it is possible to use the yield curve to calculate investors' expectations regarding future interest rates. An upward sloping yield curve indicates investors expect higher interest rates and a downward sloping yield curve indicates investors expect lower interest rates in the future. In 2022, the yield curve went from upward slopping to mostly flat. As shown in Chart 4 on page 27, the yield curve went from being significantly upward sloping on March 31, 2021 to downward sloping as of March 31, 2023.



Consistent with a declining yield curve, Chart 5 below shows that investors expect long-term interest rates (10-year U.S. Treasury Bond) to remain relatively stable over the next 20 years, increasing from 3.48% as of March 31, 2023, to 4.14% over the next ten years and then to falling to 3.39% over the 20-year time frame.

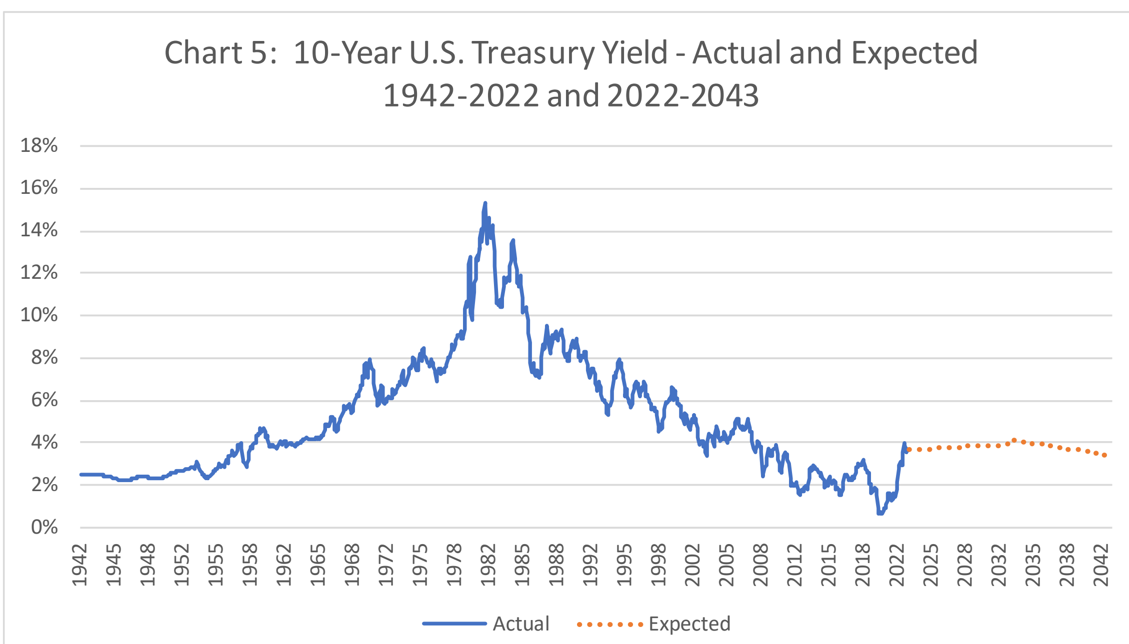


Chart 5 on page 27 also shows that although long-term interest rates have increased in recent months, they remain below interest rates from the 1970s and 1980s when the yield on the 10-year U.S. Treasury bond climbed over 14%.

Q. HOW DO YOU RESPOND TO PEOPLE WHO CLAIM THAT INTEREST RATES WILL CONTINUE TO INCREASE?

A. It is important to recognize that current long-term Treasury bond yields represent a direct observation of investor expectations and there is no need to use "experts" to determine market-based cost of equity.

Many economists and forecasters will continue to be quoted in the press prognosticating on possible developments that are truly unpredictable. The Nobel Laureate Economist Daniel Kahneman stated the following regarding forecasting:

> It is wise to take admissions of uncertainty seriously, but declarations of high confidence mainly tell you that an individual has constructed a coherent story in his mind, not necessarily that the story is true.[19]

B. Stock Price Performance

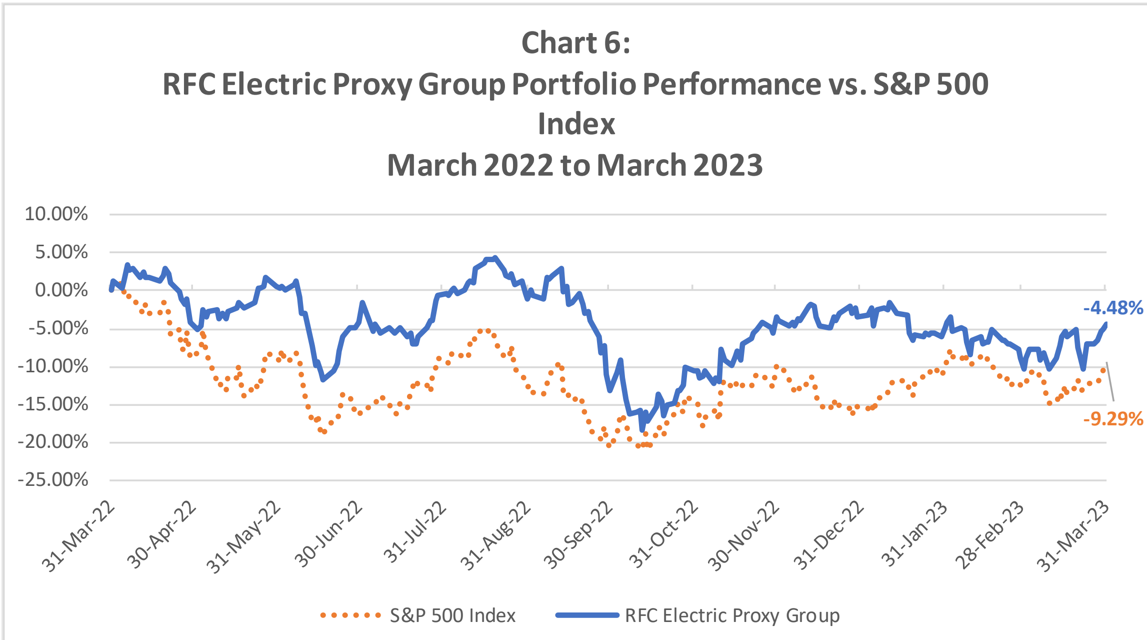
Q. HOW HAVE UTILITY STOCKS PERFORMED DURING THIS TIME OF HIGH INFLATION AND INCREASING INTEREST RATES?

A. After reaching 70 all-time highs in 2021,[20] U.S. equity markets performed poorly in 2022. As shown in Chart 6 on page 29, as of March 31, 2023, the S&P 500 is down 9.29% for the last twelve months. IT, communications services, and the consumer discretionary sectors declined by 28.9%, 40.4%, and 37.6% respectively in 2022. Electricity is not

[19] DANIEL KAHNEMAN, *Thinking Fast and Slow*, p. 212 (2011).

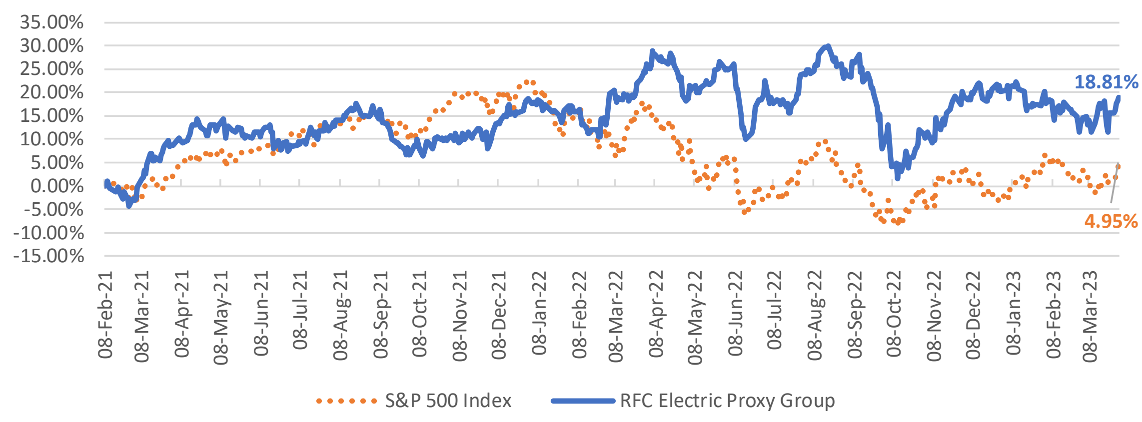
[20] 2022 SBBI Yearbook, Stock, Bonds, bills, and Inflation, page 35.

discretionary and electric utility stocks have performed considerably better than the overall market. As of March 31, 2023, the RFC Electric Proxy Group is only down 4.48% for the year. The relatively good performance of electric utility stocks shows that investors view them as attractive investments during current capital market conditions.



Electric utility stocks have outperformed the overall market by an even greater margin since UGI's last rate case in 2021. As shown in Chart 7 on page 30 as of March 31, 2023, the S&P 500 is up 4.95% while electric utility companies are up over 18% since February 2021.

**Chart 7:
RFC Electric Proxy Group Portfolio Performance vs. S&P 500 Index
February 2021 to March 2023**



Q. DO INCREASING ELECTRIC UTILITY STOCKS MEAN A LOWER COST OF EQUITY?

A. Not necessarily. But in this case market data indicates that the cost of equity for utility stocks is decreasing as their stock prices are increasing. The Wall Street Journal reported that common financial ratios (price-to-earnings ratios) indicate that utility stocks are relatively expensive. The utility companies in the S&P 500 have a price-to-future earnings ratio of 19 compared to 17 to the average of all the companies in the S&P 500.[21] In other words, investors are willing to receive a lower expected return on their equity investments when investing in utility stocks than for the average company in the S&P 500.

[21] Defensive Stocks Become Hideout for Investors in a Rocky Market, WSJ, December 29, 2022.

C. Volatility Expectations

Q. PLEASE DISCUSS CURRENT STOCK PRICE VOLATILITY EXPECTATIONS AND WHAT THEY INDICATE REGARDING THE COST OF EQUITY.

A. Volatility, uncertainty, and risk are synonymous. There are two primary types of volatility: "realized volatility" and "implied volatility." The former is based on historical returns, which may or may not represent future volatility. On the other hand, implied volatility is calculated from options data, which indicates investors' future expectations for volatility. As discussed below, the "term structure" of volatility indicates investors' volatility expectations over different forward-looking time periods (i.e., 1 month, 1 year, etc.).

Q. PLEASE EXPLAIN THE "TERM STRUCTURE OF VOLATILITY."

A. Investors can expect volatility to increase or decrease over time. In general (i.e., in "normal" financial markets), investors expect higher volatility for longer time horizons. For example, investors generally expect the chance stock prices will increase or decrease by 10% in 1 year to be greater than the chance of a 10% (annualized) move over the next 30 days. This makes sense because there is more uncertainty regarding economic and stock market changes the further in the future you look out.

However, during the height of a crisis, when volatility generally tends to rise in the short-term, investors often expect volatility to decrease in coming months or years. In other words, investors expect the current capital market hurricane to pass and the winds to die down. During the peak of implied volatility in mid-March 2020, shortly after the World Health Organization declared COVID-19 a pandemic, the data indicated that investors expected stock price volatility to decrease over time. This implies that investors expected the riskiness of equity investments to decrease over time. As shown in Chart 8 on page 32, before the COVID-19 outbreak, investors expected volatility to increase from less than 15% annually at the 1-month time frame to about 20% annually at the 24-month time frame. Investors' volatility expectations peaked in March 2020. At that time, investors expected stock price volatility would decrease from over 70% at the 1-month time frame to about 38% at the 24-month time frame. Chart 8 also shows that investors' volatility expectations were higher for all time frames when Russia invaded Ukraine as compared to 2021 and remain elevated as of March 31, 2023.

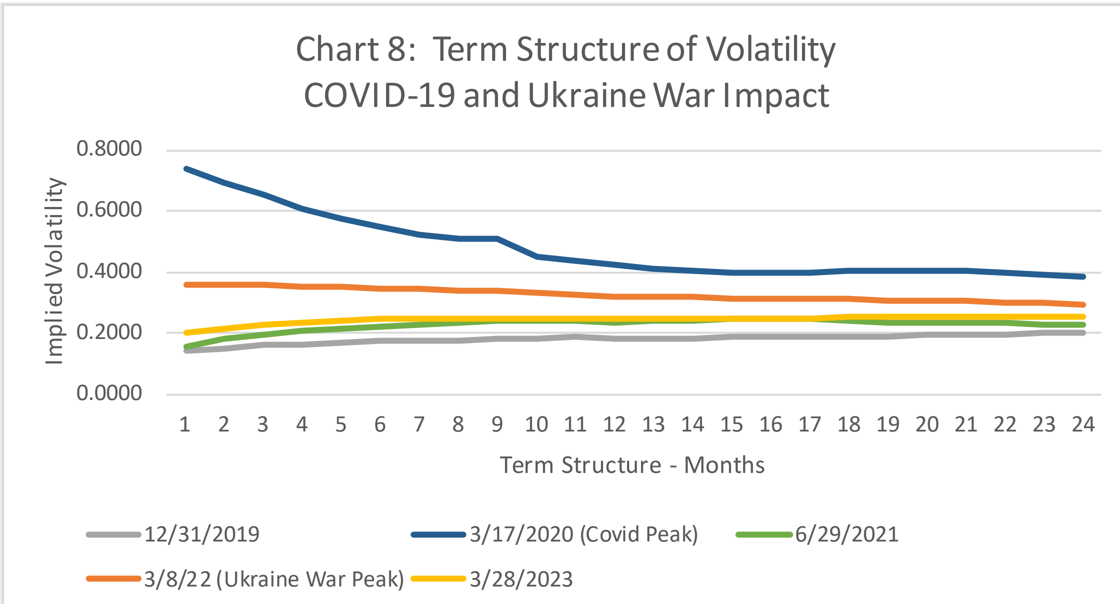


Chart 9 on page 33 provides a 3-dimensional surface[22] to show how the term structure of volatility has evolved since before the COVID-19 outbreak and how it has changed during and since the outbreak. Chart 8 above is simply five selected cross sections of the same data in the surface in Chart 9. In the surface chart, one can see that on December 31, 2019, the term structure of volatility is almost flat, increasing slightly from the 1-month to the 24-month time frame. In mid-March 2020, the implied volatility

[22] The X axis shows the implied volatility. The Y axis shows the data. The Z axis shows market expectation of future implied volatility of different time frames. Series1 = 1 month and Series24 = 24 months.

increased over every time period in comparison to December 31, 2019, but one can see that investors expected a declining term structure of volatility. By the end of July 2020, the implied volatility for all time periods had decreased, and the declining term structure moved to a more typical structure in which investors expected higher volatility over longer time periods. As of the end of March 2023, the term structure of volatility is now slightly increasing over the 24-month time frame.

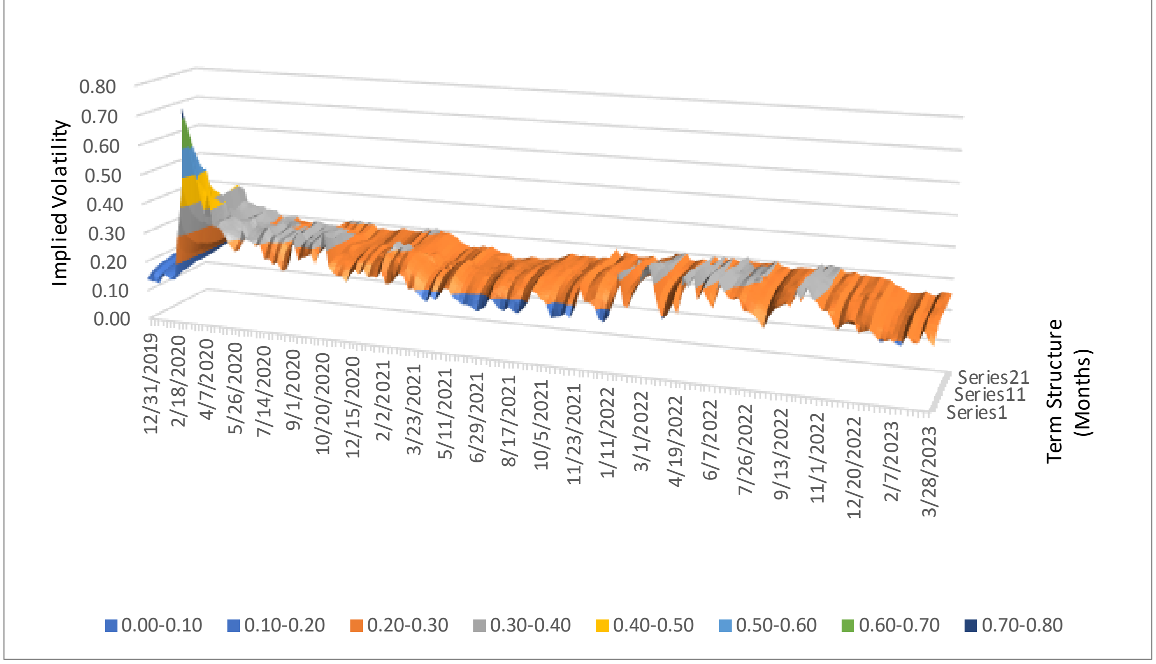
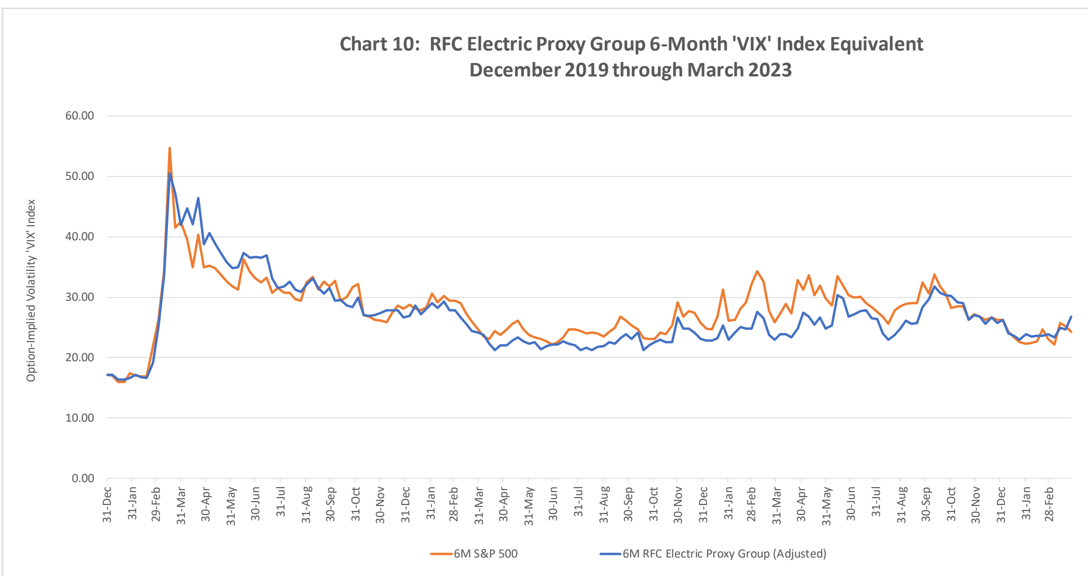


Chart 9: VIX Volatility Term Structure Surface

Q. HOW HAVE VOLATILITY EXPECTATIONS FOR ELECTRIC UTILITY COMPANIES COMPARED TO VOLATILITY EXPECTATIONS FOR THE S&P 500?

A. The solid orange line in Chart 10 on page 34 show investors' stock price volatility expectations for the overall market (S&P 500) increased significantly as COVID-19 infections spread to the U.S. and continued to grow exponentially around the world. The solid orange line shows volatility expectations over the next 6 months. In December 31, 2019, investors expected an annualized change of 13.78% over the next 30 days. In mid-March 2020, investors' volatility expectations peaked at over 80% (on March 16, 2020, a point not actually shown on the chart, which has weekly data on Tuesdays). As of the end of March 2023, investors expect an annualized change of 19.97%.

The blue line in Chart 10 shows that investors' adjusted[23] 6-month volatility expectations for my RFC Electric Proxy Group, as indicated by their stock option prices, increased along with the market in mid-March 2020, but to a significantly lesser degree. Investors' 6-month adjusted volatility expectations for electric utility companies were higher than for the S&P 500 for the most part from May through August 2020, remained very comparable through mid-July 2021, and have mostly remained about the same as expectations for the market since then through the end of March 2023.



[23] The implied volatility for individual stocks and small groups of stocks is almost always higher than the overall market because of the effects of diversification, even when the underlying stocks in the smaller portfolio are less risky, as is the case with electric utility companies. As a result, Chart 10 adjusts the 6-month expected volatility for the RFC Electric Proxy Group by the difference with the 6-month expected volatility for the S&P 500 Index on 12/31/2019 to facilitate the comparison throughout the chart.

As discussed above, changes in implied volatility do not paint the full cost of equity picture. We must consider implied covariance, or how much investors expect the volatility of returns for electric utility companies to correlate with the overall market (e.g., S&P 500 Index). In the CAPM section below, I explain how covariation relates to the cost of equity and how this shows that electric utility stocks continue to have a lower risk than the overall market.

D. Investor-Perceived Downside Risk (Option-Implied Skewness)

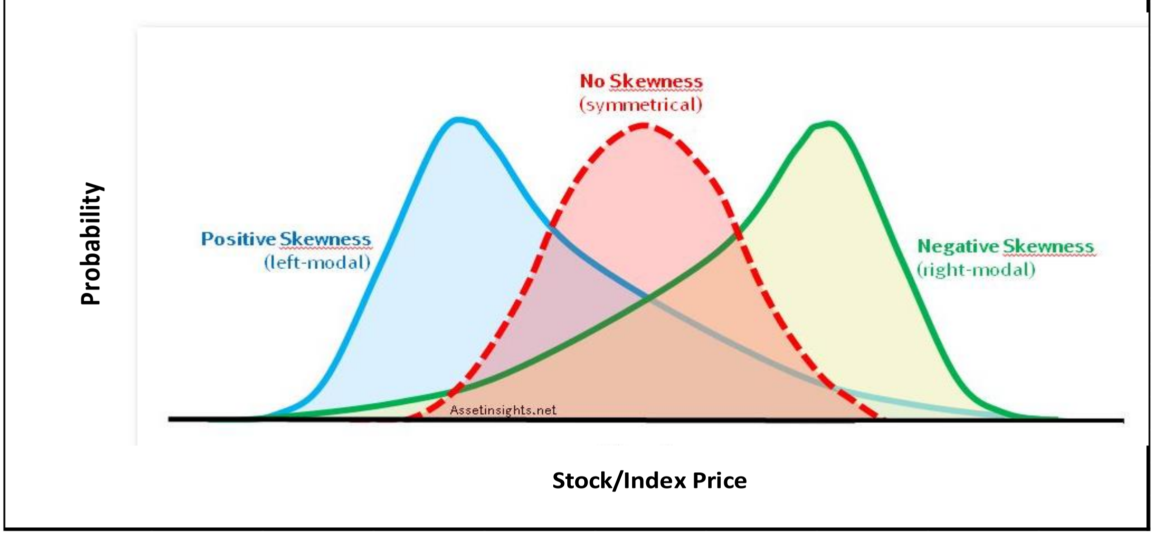
Q. YOU EXPLAINED EARLIER THAT ELECTRIC UTILITY STOCKS HAVE OUTPERFORMED THE OVERALL MARKET IN 2022. DOES STOCK OPTION DATA SHOW THAT INVESTORS MAY FIND ELECTRIC UTILITY STOCKS RELATIVELY ATTRACTIVE BECAUSE INVESTORS BELIEVE THERE IS A LOWER RISK OF A LARGE DROP IN THE SHARE PRICE OF ELECTRIC UTILITY STOCKS THAN THE OVERALL MARKET?

A. Yes. Stock option prices provide considerable information regarding investors' expectations. The most well-known measure of investors' expectations as measured by stock option prices is the VIX Index (or Volatility Index). The VIX Index is a measure of investors' volatility expectations and is referred to as the "fear index" because, all else equal, higher volatility expectations indicate higher uncertainty, risk, and scared investors. However, volatility expectations are only one piece of a multi-dimensional puzzle that reveals the market-based cost of equity. After volatility expectations, the next dimension to explore (referred to as the third moment in statistics) is skewness. Option-Implied skewness reflects investors' expectations regarding the asymmetry of the probability distribution.

Option-implied probability distributions are almost always negatively skewed for stock market indexes (e.g., S&P 500) and individual stocks, which means that investors almost always think there is a greater chance of a large decrease in stock prices than large increases. The CBOE also publishes an index based on option-implied skewness referred to as the SKEW Index.

As shown in Chart 11 below, the probability distribution that is negatively skewed has a tail that is longer on the left. A probability distribution with positive skewness has a longer tail on the right. The right and left tails of a probability distribution with no skewness are symmetrical. If the option-implied skewness looked like the red probability distribution in Chart 11 below it would mean that investors believed there was an equal chance that stock prices would move up or down by a certain amount.

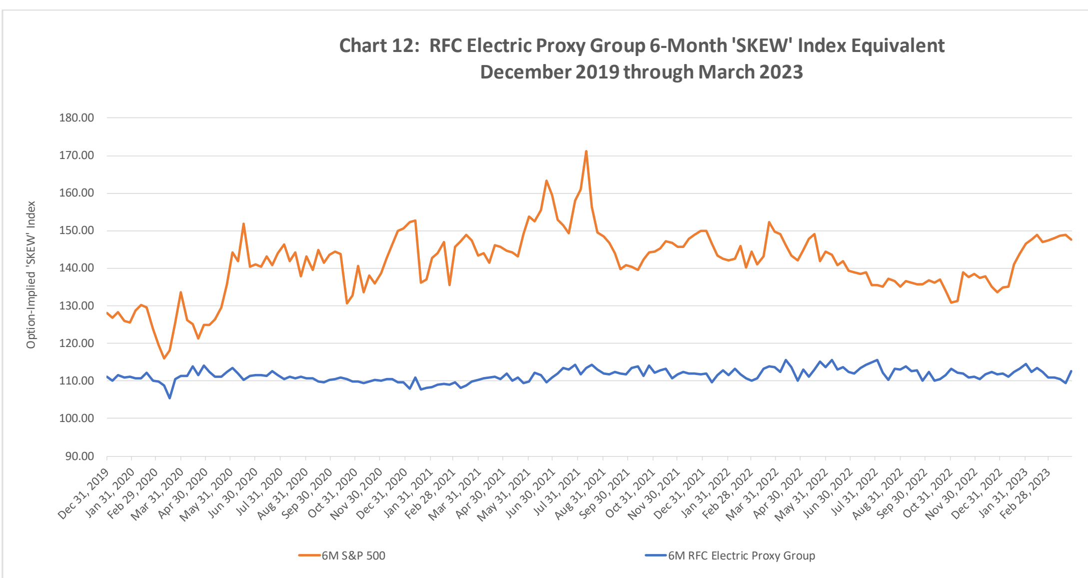
Chart 11: Probability Distributions with and without Skewness



The CBOE also publishes an index based on option-implied skewness referred to as the SKEW Index.

Q. WHAT DOES THE SKEW INDEX REVEAL REGARDING THE IMPACT OF THE COVID PANDEMIC AND THE WAR IN UKRAINE ON UGI'S COST OF EQUITY?

A. As shown in Chart 12 below, comparing the SKEW Index to an equivalent metric based on electric utility company stock options indicates that in the first quarter of 2023, investors have expected the chance of electric utility stocks suffering from a large drop in investment is much lower than their expectations the overall market will experience a large drop. This indicates the cost of equity for electric utility companies has likely decreased relative to the overall market as interest rates have increased and the banking sector has experienced extensive turmoil. Electric utility stocks might be outperforming the overall market in 2022 because investors believe there is a lower chance of a large drop in their share prices. After all, utility stocks are a defensive sector that can provide investors a stead stream of dividends even during capital market uncertainty.



E. Term Structure of Beta Coefficients and COE

Q. PLEASE EXPLAIN THE "TERM STRUCTURE OF COE" AND DISCUSS WHAT IT INDICATES REGARDING THE COST OF EQUITY.

A. Investors can expect the cost of capital (both, debt and equity) to increase or decrease over time. How the cost of capital changes based on different investment horizons is referred to as its term structure. This fundamental concept is easy to understand by thinking about mortgage interest rates. Any homeowner knows that the interest rate on a 30-year mortgage will be different than that of a 10-year mortgage. Along the same lines, rate of return witnesses sometimes make two cost of debt recommendations, one for short-term debt and one for long-term debt.

The same logic applies to the cost of equity. However, in regulatory proceedings, rate of return witnesses generally calculate a single COE to make a single ROE recommendation, rarely if ever addressing the term structure of the COE. Standard COE models used in utility proceedings do not have the capacity to measure the COE over different time periods. However, stock options allow us to measure the COE over different time periods because there are many stock option contracts that expire over different time periods. Option contracts for each expiration period allow us to calculate option-implied beta coefficients, market risk premia, and thus the resulting COE for each investment horizon. The resulting term structures for the beta coefficients and the COE of the proxy group used in this proceeding are presented in Chart 13 and Chart 14 starting on page 39. Chart 13 shows that option-implied betas are relatively stable for electric utility stocks when looking at longer investment horizons, which means that investors expect the risk of investing in electric utility stocks to be stable over longer investment horizons. Chart 14 shows that the COE for electric utility stocks reaches levels a little over 8% at the 1- to 11-month horizons and then decreases to about 7.3% at the 4.5-year horizon.

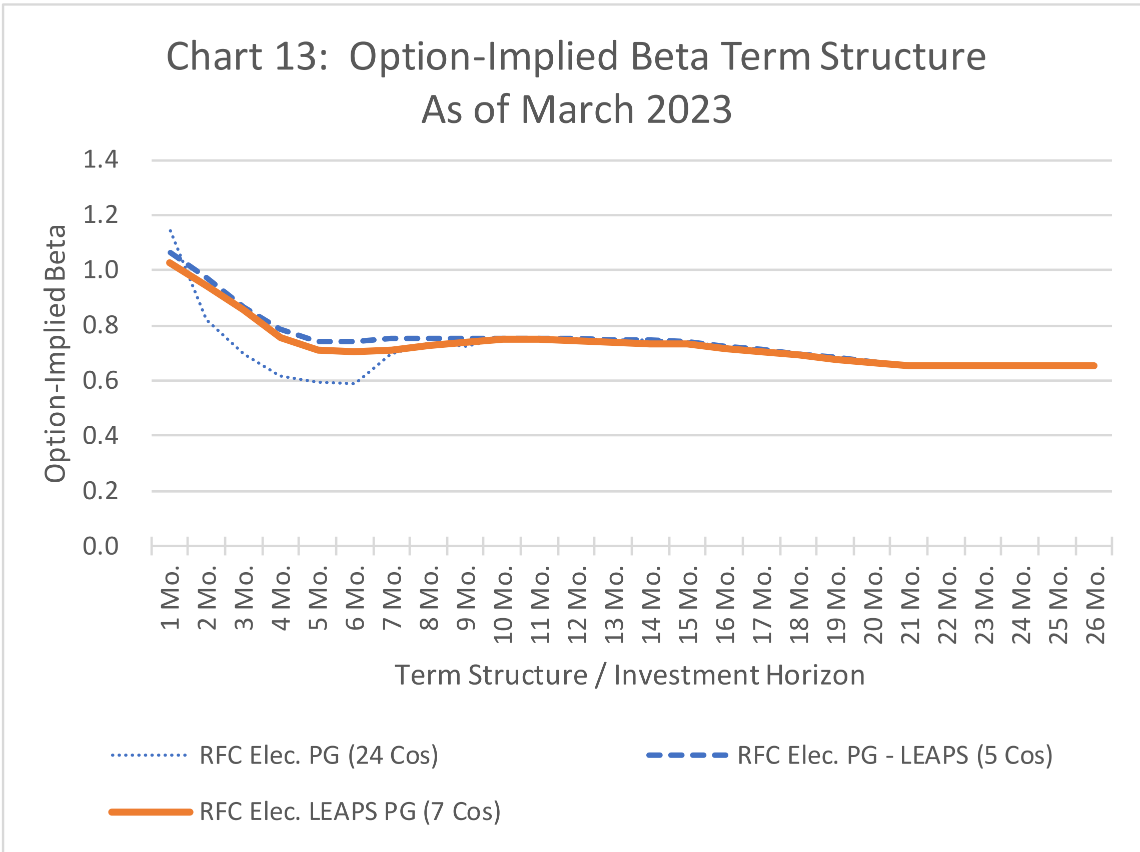
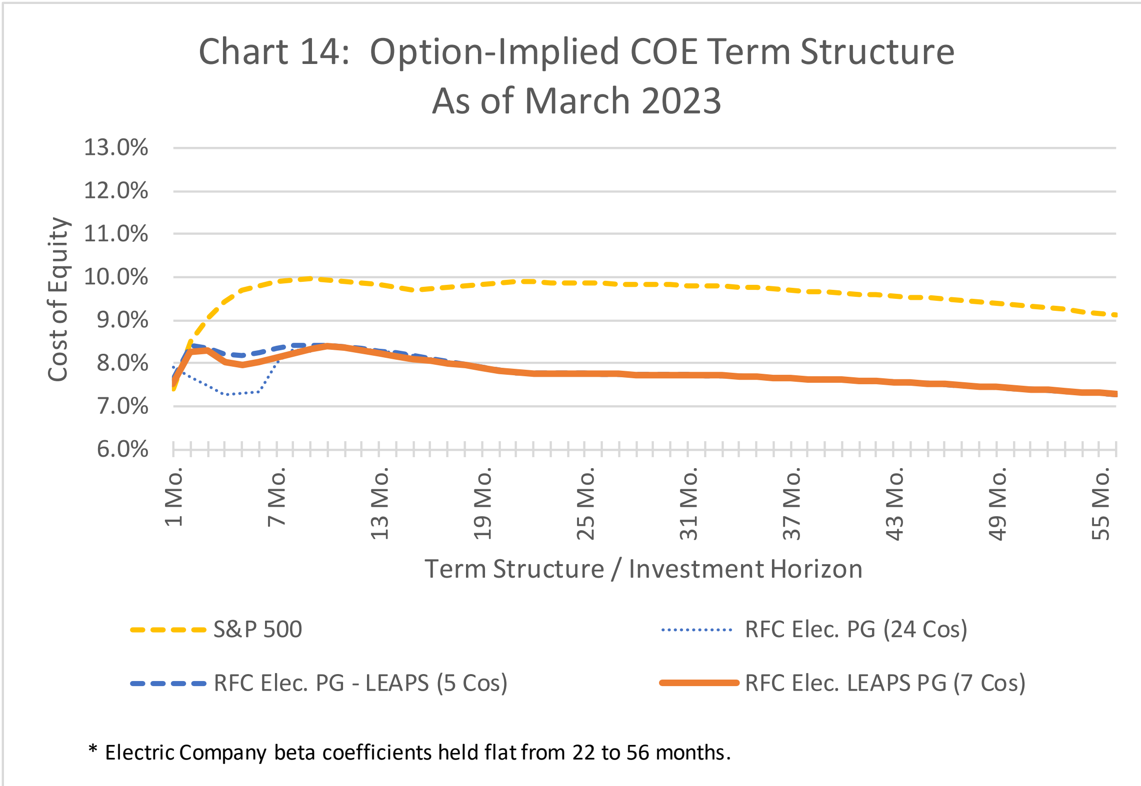


Chart 13: Option-Implied Beta Term Structure
As of March 2023



V. CAPITAL STRUCTURE AND COST OF DEBT

Q. UGI IS REQUESTING A CAPITAL STRUCTURE OF 54.59% COMMON EQUITY AND 45.41% DEBT. IS THIS REQUEST APPROPRIATE?

A. No. UGI's requested capital structure is not appropriate for setting rates in this proceeding for three reasons. First, UGI witness Mr. Moul did not provide any evidence to demonstrate that UGI's requested capital structure would minimize its weighted average cost of capital to customers. A utility company has the burden of proof to demonstrate that its requested capital structure will result in the lowest, reasonable overall rate of return. Second, it contains significantly more common equity than the average common equity ratio used by other electric utility companies in the country (44.7%).[24]

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND BE USED FOR UGI'S OVERALL COST OF CAPITAL?

A. For UGI, I recommend using a capital structure that comprises 44.75% common equity and 55.25% long-term debt based on the average common equity ratio of the electric utility companies in RFC Electric Proxy Group. The companies in this proxy group all have investment grade credit ratings and therefore are able to raise capital on reasonable terms with their capital structures. Absent evidence from the applicant in support of the need for a different capital structure, using the average capital structure of the proxy group is consistent with the Commission's duty to set reasonable rates because otherwise, using a common equity ratio higher than other companies creates unreasonably higher rates.

Q. IF UGI PROVIDES SUFFICIENT EVIDENCE THAT ITS REQUESTED CAPITAL STRUCTURE IS JUSTIFIED, WOULD YOU CHANGE YOUR RECOMMENDATION?

A. Yes. It is in the best interest of consumers for UGI to be able to access the capital markets. If UGI's ROE is lower than returns required by investors or if its capital structure does not allow it to raise the necessary capital, this would be harmful to consumers.

[24] Exhibit ALR-5, page 5.

VI. COST OF EQUITY CALCULATION

A. Overview

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR PERSPECTIVE REGARDING HOW CAPITAL MARKETS RELATE TO THE COE AND THE OVERALL COST OF CAPITAL.

A. The cost of capital is the return investors require to provide capital to UGI based on current capital markets. Capital markets are constantly changing. Turmoil in the banking sector is the latest development impacting capital markets as uncertainty regarding the war in Ukraine remains. To measure the cost of equity accurately during unavoidable unpredictable change, it is critical to use current market data because it increases the chance that the authorized ROE will match UGI's market-based COE when it needs to raise equity capital.

As discussed above, my COE recommendation is my opinion of the return investors require to provide equity capital to UGI based on current capital markets. My recommendation is consistent with the following legal standards set by the United States Supreme Court for a fair rate of return: "[t]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks"[25] and "sufficient to… support its credit and… raise the money necessary for the proper discharge of its public duties."[26]

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[25] *Fed. Power Comm'n v. Hope Nat. Gas Co.* v. Hope Nat. Gas Co., 320 U.S. 591, 603 (1944).
[26] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of the State of W. Va*, 262 U.S. 679, 692-693 (1923).

Because the cost of equity is not a published figure like a bond yield, some interpretation is required to determine the appropriate market price. My cost of equity recommendation is based on my computation of what the market indicates investors require (return on investment) to provide capital to companies with comparable risk to UGI.

As explained below, I use current market prices (e.g., stocks, bonds, options), which measure investors' expectations directly, instead of relying solely on historical data and analyst forecasts.

A COE based on market prices (market-based) is superior to a COE based on historical data (non-market-based) for two reasons:

1. The COE that UGI has to pay investors is based on capital markets. It is possible interest rates will continue to increase, but what really matters are investors' expectations because they are the ones that provide the capital. Investors' expectations, including interest rates, are revealed in the current prices of bonds.
2. Capital markets are unpredictable. Regarding capital markets' unpredictability, investment guru Warren Buffet recently gave the following advice to investors: "[t]hey should not listen to a lot of the jabbering about what the market is going to do tomorrow, or next week or next month because nobody knows."[27]

Current capital markets are our best source of investors' expectations regarding future capital markets. Current market prices of stocks and bonds reflect investors' forecasts for long-term interest rates and capital markets in general. If, indeed, investors

[27] PBS News Hour, June 26, 2017, Part 1 – America should stand for more than just wealth, says Warren Buffett available at www.pbs.org/newshour/show/pbs-newshour-full-episode-june-26-2017.

in the aggregate should be expecting interest rates to continue to increase, for example, adding a separate factor for this on top of what is already indicated in market prices would amount to a double count. As I will discuss below, UGI's witness, Mr. Moul's 11.30% recommendation should be disregarded because it is not market-based.

Q. HOW DID YOU ARRIVE AT YOUR COE RECOMMENDATION?

A. To arrive at my recommendation, I considered the results of COE models applied to two proxy groups as well as overall capital market conditions. My decision process can be broken into the following two categories: 1. Primary COE Calculation and 2. COE Term Structure Analysis.

1. Primary COE Calculation. I applied the Constant Growth and Non-Constant Growth versions of the DCF and eight variations of the CAPM to a proxy group of 24 publicly traded electric utility companies ("RFC Electric Proxy Group") using data available through March 31, 2023. My RFC Electric Proxy Group contains 24 companies. In all of my models, I use both historical averages and the most recently available spot data for the inputs wherever it is possible and applicable. As discussed above, the results of my DCF models alone support my 8.44% ROE recommendation.

2. COE Term Structure Analysis. I applied the CAPM to a proxy group of 24 publicly traded electric utility companies with active LEAPS markets ("RFC Electric Proxy Group")[28] using data available through March 31, 2023 to calculate the "term structure" of the COE for electric utility stocks and for the overall market (S&P 500) by using stock option prices with different maturity dates (1 month to about 5 years). The purpose of this

[28] LEAPS are Long-Term Equity Anticipation Securities. These are stock option contracts with expiration periods of 12 months or more.

analysis was to determine investors' equity return expectations (i.e., COE) over longer time horizons to make sure that UGI will be able to raise capital from investors with long-term horizons such as pension funds.

Q. CONSIDERING THAT STOCK AND OPTION PRICES AND BOND YIELDS CHANGE DAILY, WOULD IT NOT BE BETTER TO USE HISTORICAL AVERAGES EXCLUSIVELY FOR THE INPUTS IN YOUR MODELS?

A. Not necessarily. Most people would agree that the use of spot market data, the value of a particular input on a particular day, can lead to COE results that can vary over short periods of time. It may therefore be tempting to find a more stable value based on historical averages that are not overly influenced by short-term fluctuations in capital markets. When doing a forward-looking analysis, however, it is equally important to look at the most recent market data as an indication of trends and where a given value is more likely to be in the future. This is a broad and generally accepted principle, as made clear in the following example.

As a simple example using historical stock prices to make the point clear, if Company A's stock price were to go up linearly over the course of one year from \$50 to \$100, its average stock price over that year would be \$75. If Company B's stock price declined linearly from \$100 to \$50 over the same year, it would have the same exact average stock price of \$75. But most people would agree that predicting both stock prices at \$75 over the near future would be overly simplistic and leave readily accessible forecasting data unused. Without relying on any additional data, at the very least, it would stand to reason that in the near future, Company A's stock price is more likely to be between \$75 and \$100 than Company B's stock price, and that Company B's stock price is more likely to be between $50 and $75 than Company A's stock price. These observations cannot be made by looking at the yearly averages alone and must take the most recent data into consideration.

The point above does not eliminate concerns regarding the effect of daily fluctuations in market data, especially during periods of volatility. As a result, it is important to consider both averages and recent spot values when using market data for forward-looking analyses. That is precisely my approach when using market data that are expected to continue to fluctuate, such as stock prices, dividend yields, betas, and market risk premia.

Q. CAN A DIFFERENCE OF ONE DAY IN THE SELECTION OF SPOT DATA HAVE A SIGNIFICANT POSITIVE OR NEGATIVE EFFECT ON ROE RESULTS? IF SO, HOW DO YOU GO ABOUT CHOOSING WHICH DAY TO USE FOR MARKET-BASED SPOT DATA?

A. Daily fluctuations in stock prices, resulting dividend yields, betas, etc., all have an impact on resulting ROE calculations, especially when using recent spot values for market data. Such is the nature of market data, which changes from day to day. This is rightfully noted as a potential risk of using spot data but given the stated benefits of using recent spot data for forward-looking analyses, there are ways to address such potential pitfalls.

For this reason, it is very important to establish consistent methodologies that eliminate the possibility of personal bias, especially when using spot market data. I consistently use the last trading day of the last full calendar month before my schedule preparations for all market-based spot data and as the last day for all historical market-data averages.

It is important to keep in mind that even averages fluctuate over time, and all responsible data analysts must find a consistent and reproducible way to "freeze time" to work with such fluctuations while eliminating bias.

It is also important to point out once again that I use recent spot market-data to establish one benchmark for market-based inputs, which are balanced by using historical averages, as stated previously.

B. Proxy Group Selection

Q. WHAT PROXY GROUPS DID YOU USE TO CALCULATE UGI'S COE?

A. I applied COE models to the following two proxy groups:

RFC Electric Proxy Group: 24 publicly traded electric utility companies used by UGI witness Mr. Moul in his COE analysis. I used this proxy group in my Primary COE Calculation.

RFC Electric LEAPS Group: The 7 companies that trade LEAPS[29] out of the 36 publicly traded electric utility companies for which Value Line provides quarterly full company reports. Four of the 7 companies in the RFC Electric LEAPS Group are also in the RFC Electric Proxy Group. I used this proxy group in my COE Term Structure Analysis because the companies in this group have options that have investment horizons beyond 1 year.

[29] LEAPS are Long-Term Equity Anticipation Securities. These are stock option contracts with expiration periods of 12 months or more.

Q. MOST RATE OF RETURN WITNESSES USUALLY USE ONLY ONE PROXY GROUP TO CALCULATE THEIR COE RECOMMENDATION. WHY DID YOU CHOOSE TO CONSIDER TWO PROXY GROUPS IN THIS CASE?

A. I chose to consider two proxy groups in this proceeding to provide the Commission with a broader set of model results in support of my ROE recommendations and to specifically consider the COE term structure. My RFC Electric Proxy Group is comprised of regulated utility companies with similar investment risk characteristics to UGI, they have publicly traded stock and stock options, and they are covered by Value Line, all of which provides the data needed to apply my COE models. My RFC Electric Proxy Group includes 24 electric utility companies with significantly longer option expiration periods which allows me to determine the term structure for the COE out to 28 months. My RFC Electric LEAPS Group includes the 7 companies in my RFC Electric Proxy Group that trade LEAPS.

Q. PLEASE EXPLAIN HOW YOU SELECTED THE COMPANIES IN YOUR COMPARABLE PROXY GROUP?

A. I selected the following 24 publicly traded electric utility companies (see Table 6 below) to include in my comparable proxy group, referred to as the RFC Electric Proxy Group based on the following criteria:

Criteria 1: The company is categorized by Value Line as an electric utility;

Criteria 2: The company has at least 50% of its revenues from regulated electric operations;

Criteria 3: The company pays dividends and has not cut the size of its dividend in the past 6 months;

Criteria 4: The company is not involved in any significant merger and acquisition ("M&A") activity;

Criteria 5: The company holds an investment-grade credit rating.

Q. PLEASE LIST THE COMPANIES IN YOUR RFC ELECTRIC PROXY GROUP.

A. The RFC Electric Proxy Group is comprised of the following 24 companies:

TABLE 6: RFC ELECTRIC PROXY GROUP COMPOSITION

	Company Name	Ticker
1	AMEREN	AEE
2	AMERICAN ELEC. PWR.	AEP
3	ALLETE	ALE
4	AVISTA CORP.	AVA
5	CMS ENERGY CORP.	CMS
6	DOMINION ENERGY	D
7	DUKE ENERGY	DUK
8	CON. EDISON	ED
9	EDISON INTERNAT'L	EIX
10	EVERSOURCE ENERGY	ES
11	ENTERGY CORP.	ETR
12	EVERGY, INC.	EVRG
13	HAWAIIAN ELECTRIC	HE
14	IDACORP, INC.	IDA
15	ALLIANT ENERGY	LNT
16	MGE ENERGY INC.	MGEE
17	NEXTERA ENERGY	NEE
18	NORTHWESTERN	NWE
19	OGE ENERGY CORP.	OGE
20	PINNACLE WEST	PNW
21	PORTLAND GENERAL	POR
22	SOUTHERN COMPANY	SO
23	WEC ENERGY GROUP	WEC
24	XCEL ENERGY	XEL

C. Discounted Cash Flow

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR DCF MODELS.

A. I used both the constant growth form of the DCF method, which determines growth based on the sustainable retention growth procedure, and a non-constant growth DCF method. The results of my constant growth DCF model range between 8.12% and 8.26% when using a sustainable growth rate and between 8.47% and 9.34% when using an option-implied growth rate.[30] The results of my non-constant growth DCF method indicate a COE of between 9.05% and 9.06% for the RFC Electric Proxy Group.[31]

Q. WHAT IS THE DISCOUNTED CASH FLOW METHOD?

A. The DCF method, is an approach to determining the COE. The method recognizes that investors purchase common stock to receive future cash payments. These payments come from: (a) current and future dividends, and (b) proceeds from selling stock. A rational investor will buy stock to receive dividends and to ultimately sell the stock to another investor at a gain. The price the new owner is willing to pay for stock is related to that buyer's expectation of future flow of dividends and the future expected selling price. The value of the stock is the discounted value of all future dividends until the stock is sold plus the value of proceeds from the sale of the stock.

[30] Exhibit ALR-3, page 1.
[31] Exhibit ALR-3, page 3 and Exhibit ALR-3, page 4.

D. Constant Growth Form of the DCF Model

Q. YOU STATE YOU USED THE CONSTANT GROWTH FORM OF THE DCF MODEL. WHAT IS THE CONSTANT GROWTH FORM OF THE DCF MODEL?

A. The constant growth form of the DCF model is a form of the DCF method that can be used in determining the COE when investors can reasonably expect that the growth of retained earnings and dividends will be constant.

Retained earnings are funds that a company keeps in its treasury, so that they are available for future needs, such as operating expenses, capital expenditures, debt payments, and new investments. These retained earnings show investors whether the company is growing, which, in turn, is a measure of the future indicator of dividends and the value of a company's stock.

Q. DESCRIBE HOW THE CONSTANT GROWTH MODEL WORKS.

A. The constant growth model is described by this equation k= D/P + g, where: [32]

k= cost of equity (COE);
D=Dividend; and
P=Market price of stock at time of the analysis

and where:

g=the growth rate, where g= br + sv;
b=the earnings retention rate;
r=return on common equity investment (referred to below as "book equity");
v=the fraction of funds raised by the sale of stock that increases the book value of the existing shareholders' common equity; and
s=the rate of continuous new stock financing

The constant growth model is therefore correctly recognized to be:

[32] M. GORDON, *Cost of Capital to a Public Utility*, p. 32-33 (MSU Public Utility Studies 1974).

$$k = D/P + (br + sv)$$

The COE demanded by investors is the sum of two factors. The first factor is the dividend yield. The second factor is growth (dividends and stock price). The logical relationship among these factors is as follows: the dividend yield is calculated based on current dividend payments while growth indicates what dividends and stock price will be in the future.

Q. WHAT OTHER FACTORS IMPACT HOW ONE USES THE CONSTANT GROWTH FORM OF THE DCF MODEL?

A. Sufficient care must be taken to be sure that the growth rate "g" is representative of the constant sustainable growth. To obtain an accurate constant growth DCF result, the mathematical relationship between earnings, dividends, book value and stock price must be respected.

The basic difference between the use of an analysts' earnings per share growth rate in the constant growth DCF formula and using the "br" (b (the earnings retention rate) X r (rate of return on common equity investment)) approach is that the "br" form, if properly applied, eliminates the mathematical error caused by an inconsistency between the expectations for earnings per share growth and dividends per share growth. Because it eliminates that error, the results of a properly applied "br" approach will be superior to the answer obtained from other approaches to the constant growth form of the DCF model. This is not to say that even a properly applied "br" approach will be perfect. The self-correcting nature of a properly applied "br" to forecasted differences in earnings per share and dividends per share growth rates helps to mitigate the resultant error but should not be viewed as the perfect way to quantify the impact of expected non-constant growth rates.

Q. HOW HAVE YOU IMPLEMENTED THE CONSTANT GROWTH FORM OF THE DCF MODEL IN THIS CASE?

A. I have applied the constant growth form of the DCF model by staying true to the mathematically derived "k=D/P + (br + sv)" form of the DCF model. I have also taken care to fully allocate all future expected earnings to either future cash flow in the form of dividends ("D") or to retained earnings (the retention rate, "b"). This extra accuracy is obtained only when the retention rate "b" is derived from the values used for "D" and "r," rather than independently.

Q. PLEASE EXPLAIN HOW YOU OBTAINED THE VALUES YOU USED IN THE CONSTANT GROWTH FORM OF THE DCF METHOD.

A. The DCF model generally calls for the use of the dividend expected over the next year. A reasonable way to estimate next year's dividend rate is to increase the quarterly dividend rate by half of the current actual quarterly dividend rate. This is a good approximation of the rate that would be obtained if the full prior year's dividend were escalated by the entire growth rate.[33]

I obtained the stock price—"P"—used in my DCF analysis from the closing prices of the stocks on March 31, 2023. I also obtained an average stock price for the 12 months ending March 31, 2023 by averaging the high and low stock prices for the year.

[33] For example, assume a company paid a dividend of $0.50 in the first quarter a year ago, and has a dividend growth rate of 4 % per year. This dividend growth rate equals (1.04)^4-1=0.00985 % per quarter. Thus, the dividend is $0.5049 in the second quarter, $0.5099 in the third quarter, and $0.5149 in the fourth quarter. If that 4 % per annum growth continues into the following year, then the dividend would be $0.5199 in the 1st quarter, $0.5251 in the 2nd quarter, $0.5303 in the 3rd quarter, and $0.5355 in the 4th quarter. Thus, the total dividends for the following year equal $2.111 (0.5199 + 0.5251 + 0.5303 + 0.5355). I computed the dividend yield by taking the current quarter (the $0.5149 in the 4th quarter in this example) and multiplying it by 4 to get an annual rate of $2.06. I then escalated this $2.06 by half the 4 % growth rate, which means it is increased by 2 %. $2.06 x 1.02= $2.101, which is within one cent of the $2.111 obtained in the example.

I based the value of the future expected return on equity— "r" —on the average return on book equity expected by Value Line, adjusted in consideration of recent returns. I also made a computation that was based on a review of both the earned return on equity consistent with analysts' consensus earnings growth rate expectations and on the actual earned returns on equity. For a stable industry such as utility companies, investors will typically look at actual earned returns on equity as one meaningful input into what can be expected for future earned returns on book equity. See Exhibit ALR-3, page 1.

This return on book equity expectation used in the DCF method to compute growth must *not* be confused with the COE. Since the stock prices for the comparative companies are substantially higher than their book value, the return investors expect to receive on their market price investment is considerably less than the anticipated return on book value. If the market price is low relative to book value, the COE will be higher than the future expected return on book equity, and if the market price is high, then the return on book equity will be less than the COE.

In addition to growing through the retention of earnings, utility companies also grow by selling new common stock. Selling new common stock increases a company's growth. I quantified this growth caused by the sale of new common stock by multiplying the amount that the actual market-to-book ratio exceeds 1.0, by the compound annual growth rate of stock that Value Line forecasts. The results of that computation are shown on line 4 of Exhibit ALR-3, page 1.

Pure financial theory prefers concentrating on the results from the most current price because investors cannot purchase stock at historical prices. There is a legitimate concern, however, about the potential distortion of using just a single price. I present DCF results based on the most recent stock pricing data (March 31, 2023) as well as the average of the high and low stock price over the past 12 months to obtain a range of reasonable values. As shown in Exhibit ALR-3, page 1, the DCF result based on the average of the high and low stock price for the year ending March 31, 2023 is 8.12%. The DCF result based on the stock price as of March 31, 2023 is 8.26%. Exhibit ALR-3, page 1, shows more of the specifics of how I implemented the constant growth form of the DCF model for the RFC Electric Proxy Group.

Q. PLEASE EXPLAIN HOW YOU DETERMINED WHAT VALUE TO USE FOR "R" WHEN COMPUTING GROWTH IN YOUR CONSTANT GROWTH FORM OF THE DCF MODEL.

A. The inputs I considered are shown in Footnote [C] of Exhibit ALR-3, page 1. The value of "r" that is appropriate to use in the DCF formula is the value anticipated by investors to be maintained on average in the future. This Exhibit shows that the average future return on equity forecasted by Value Line for the RFC Electric Proxy Group between 2022 and 2025-27 is 10.76%. The same footnote also shows that the future expected return on equity derived from the Zacks consensus forecast is 10.80%, and that the actual returns on equity earned by the RFC Electric Proxy Group on average were 9.78% in 2020, 10.24% in 2021, and 10.07% in 2022. Based on the combination of the forecasted return on equity derived from the Zacks consensus, the recent historical actual earned returns, and Value Line's forecast, I made the DCF growth computation using a 10.30%[34] value of "r".

[34] I used 10.30% in consideration of historical returns, Zacks's projections, and Value Line projected returns for the RFC Electric Proxy Group.

Q. WHAT COE IS INDICATED BY THE CONSTANT GROWTH FORM OF THE DCF METHOD THAT YOU RELY ON FOR YOUR RECOMMENDATION?

A. The result of my DCF analysis using the Constant Growth form of the DCF indicates a COE range of between 8.12% and 8.26% for the RFC Electric Proxy Group.[35] Since these DCF findings use analysts' forecasts to derive sustainable growth (in part) and on analysts' forecasts of dividend growth and book value growth in the non-constant form of the DCF method, the results should be considered as conservatively high. This is because, as previously mentioned above, analysts' forecasts of such growth have been notoriously overstated.

My results are not as influenced by overly-optimistic analysts' forecasts as would have been the case had I merely used analysts' five-year earnings growth rate forecasts as a proxy for long-term growth. This is because the DCF methods I use compute sustainable growth rates, rather than growth rates that can exaggerate the growth rate due to assuming that a relatively short-term forecast (5 years) will remain indefinitely.

E. Non-Constant Growth Form of the DCF Model

Q. PLEASE EXPLAIN HOW YOU IMPLEMENTED THE NON-CONSTANT GROWTH FORM OF THE DCF MODEL.

A. The non-constant growth form of the DCF model determines the return on investment expected by investors based on an estimate of each separate annual cash flow the investor expects to receive. For the purpose of this computation, I have incorporated Value Line's detailed annual forecasts to arrive at the specific non-constant growth expectations that an

[35] Exhibit ALR-3, page 1.

investor who trusts Value Line would expect. This implementation is shown on Exhibit ALR-3, page 3 and Exhibit ALR-3, page 4. In the first stage, cash flow entry is the cash outflow an investor would experience when buying a share of stock at the market price. The subsequent years of cash flow are equal to the dividends per share that Value Line forecasts. For the intermediate years of the forecast period in which Value Line does not provide a specific dividend, the annual dividends were obtained by estimating that dividend growth would persist at a compound annual rate. The cash flow at the end of the forecast period consists of both the last year's dividend forecast by Value Line, and the proceeds from the sale of the stock. The stock price used to determine the proceeds from selling the stock was obtained by estimating that the stock price would grow at the same rate at which Value Line forecasts book value to grow.

Q. WHY DID YOU USE BOOK VALUE GROWTH TO PROVIDE THE ESTIMATE OF THE FUTURE STOCK PRICE?

A. For any given earned return on book equity, earnings are directly proportional to the book value. Furthermore, book value growth is the net result after the company produces earnings, pays a dividend and also, perhaps, either sells new common stock at market price or repurchases its own common stock at market price.

Once these cash flows are entered into an Excel spreadsheet, the compound annual return an investor would achieve as a result of making this investment was obtained by using the Internal Rate of Return (IRR) function built into the spreadsheet. As shown on Exhibit ALR-3, page 3 and Exhibit ALR-3, page 4, this multi-stage DCF model produced an average indicated COE of 9.06% based on the year-end stock price, and 9.05% based on average prices for the year ending March 31, 2023 for the RFC Electric Proxy Group.

Q. WHAT COST OF EQUITY DOES YOUR NON-CONSTANT GROWTH DCF METHOD INDICATE?

A. My non-constant growth DCF method indicates a cost of equity of between 9.05% and 9.06%.[36]

F. <u>Capital Asset Pricing Model</u>

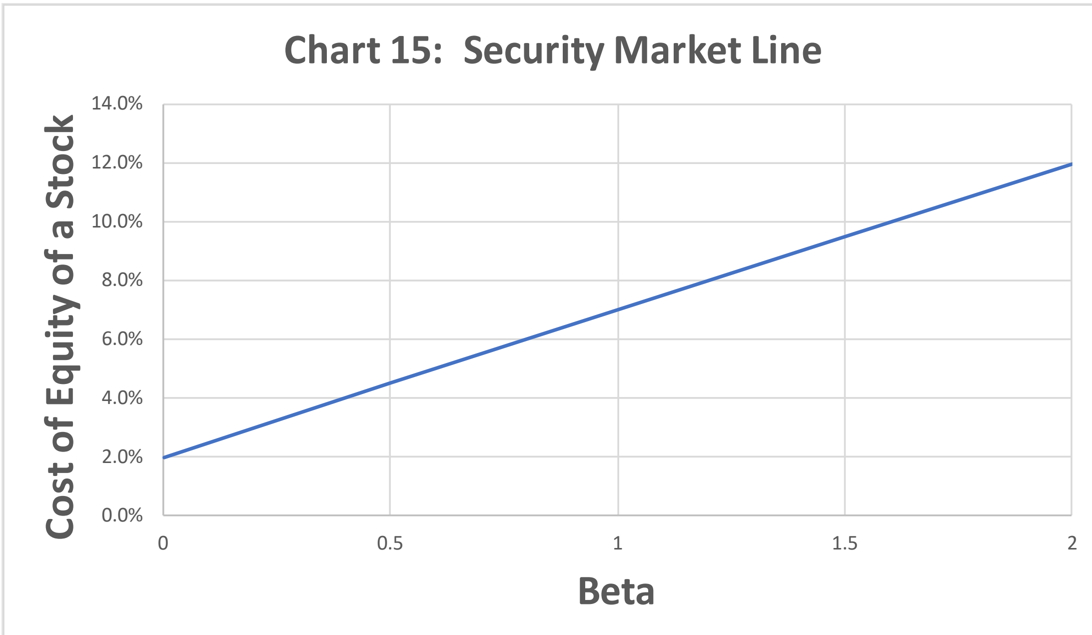
Q. PLEASE DESCRIBE THE CAPM.

A. CAPM stands for "Capital Asset Pricing Model." The CAPM relates return to risk; specifically, it relates the expected return on an investment in a security to the risk of investing in that security. The riskier the investment, the greater the expected return (i.e., the cost of equity) investors require to make that investment.

Investors in a firm's equity face two types of risks: (1) firm-specific risk and (2) market risk (financial analysts refer to this market risk as systematic risk). Firm-specific risk refers to risks unique to the firm, such as management performance and losing market share to a new competitor. Investors can reduce firm-specific risk by purchasing stocks as part of a diverse portfolio of companies if they construct the portfolio to cause the firm-specific risk of individual companies to balance out. Market-related risk refers to potential impacts from the overall market, such as a recession or interest rate changes. This risk cannot be removed by diversification, so the investor must bear it no matter what. Because the investor has no option but to bear market risk, the investor's cost of equity will reflect that risk. The CAPM predicts that for a given equity security, the cost of equity has a positive linear relationship to how sensitive the stock's returns are to movements in the

[36] Exhibit ALR-3, page 3 and Exhibit ALR-3, page 4.

overall market (e.g., S&P 500). A security's market sensitivity is measured by its beta.[37] As shown in Chart 15 below, the higher the beta of a stock, the higher the company's cost of equity—the return required by the investor to invest in the stock.



Here is the standard CAPM formula:

$$K = Rf + \beta í * (Rm - Rf)$$

Where:

K is the cost of equity;
Rf is the risk-free interest rate;
Rm is the expected return on the overall market (e.g., S&P 500);
[Rm – Rf] is the premium investors expect to earn above the risk-free rate for investing in the overall market ("equity risk premium" or "market risk premium"); and
βí (Beta) is a measure of non-diversifiable, or systematic, risk.

Q. PLEASE EXPLAIN HOW YOU IMPLEMENTED THE CAPM.

A. First, I determined appropriate values or ranges for each of the three model inputs: (a) Risk-Free Rate, (b) Beta, and (c) Equity Risk Premium. Second, I used the equation above to

[37] The covariation of the return on an individual security with the return on the market portfolio.

calculate the cost of equity implied by the model. Below I will explain how I calculated the three model inputs and summarize the CAPM cost of equity numbers resulting from those inputs. Table 7 and Table 8 on page 74 show the results of my CAPM.

Risk-Free Rate

Q. WHAT RISK-FREE RATE DID YOU USE IN YOUR CAPM?

A. It is generally preferable to use the market yield on short-term U.S. Treasury yields as the risk-free rate because these bonds have a beta close to zero. *Principles of Corporate Finance* states "The CAPM… calls for a short-term interest rate."[38] I chose to use a risk-free rate based on both long- and short-term Treasury yields, however, because investors with a longer investment horizon might use a higher risk-free rate as an opportunity cost for their investment decisions. My short-term risk-free rate is based on the yield of 3-month U.S. Treasury bills and my long-term risk-free rate is based on the yield of 30-year U.S. Treasury bonds. In line with my Spot and Weighted Average CAPM approaches, I use both spot values as of March 31, 2023 and weighted averages over the 3 months ending on that date for these two yields.

As outlined in Exhibit ALR-4, page 2, my spot and weighted average short-term risk-free rates are 4.85% and 4.82%, respectively. My spot and weighted average long-term risk-free rates are 3.67% and 3.75%, respectively.

U.S. government bonds are reasonable to use as a risk-free rate because they have a negligible risk of default. The value of short-term U.S. Treasury bills has a relatively low

[38] BREALEY, MYERS, AND ALLEN, *Principles of Corporate Finance*, p. 228, (McGraw-Hill Irwin, New York, 12th ed. 2017).

exposure to swings in the overall market. The value of long-term U.S. Treasury bonds is relatively more exposed to the market and therefore must be used with caution.

Regarding my weighted average risk-free rates, it is worth noting that any form of averaging or weighting approach applied to the last 12 months of historical yield data would not have any significant effect on my CAPM results.

Q. WHAT IS YOUR RESPONSE TO ANALYSTS WHO CLAIM THAT THE CAPM SHOULD BE IMPLEMENTED WITH A RISK-FREE RATE BASED ON A LONG-TERM INTEREST RATE (E.G., YIELD ON 30-YEAR TREASURY BOND) AND OR BASED ON INTEREST RATE FORECASTS INSTEAD OF MARKET YIELDS?

A. As discussed in Appendix D, a CAPM analysis that uses a risk-free rate based only on long-term interest rates may overstate the COE because these bonds do not have a zero beta. It is not appropriate to use a risk-free rate based on interest rate forecasts because it likely does not represent investors' expectations.

Beta

Q. WHAT BETA DID YOU USE IN YOUR CAPM?

A. Since the cost of equity should be based on investor expectations, I chose to use two betas. My "forward beta" is based on forward-looking investor expectations of non-diversifiable risk. My "hybrid beta" is based on both forward-looking investor expectations and historical return data.

Most published betas are based exclusively on historical return data. For example, Value Line publishes a 5-year historical beta for each of the companies it covers. However, it is also possible to calculate betas based on investors' expectations of the probability distribution of future returns. This probability distribution of future returns expected by investors can be calculated based on the market prices of stock options.

Q. WHAT IS A STOCK OPTION?

A. A stock option is the right to buy or sell a stock at a specific price for a specified amount of time. A call option is the right to buy a stock at a specified exercise or strike price on or before a maturity date. A put option is the right to sell a stock at a specified exercise or strike price on or before a maturity date. For example, a call option to purchase Apple Computer stock for $230 on January 17, 2020, allows the owner the option (not the obligation) to buy Apple stock for $230 on that date. At the end of July 2019, Apple stock was trading at about $215 per share. Why would anyone pay for the right to buy a stock higher than the current price? Investors who purchased those call options thought there was a chance Apple stock would be trading higher than $230 on January 17, 2020, and those options gave those investors the right to buy Apple stock for $230 and profit by selling it at the market price on that date, if it was higher. The price of Apple's stock was $317.98 at the close of trading on January 17, 2020. Therefore, the investor who purchased this call option for $635 on July 31, 2019, earned a profit of $8,163[39] at expiry on January 17, 2020. On the other hand, the investor who purchased an Apple put option with the same expiration date and strike price on July 31, 2019, would have lost the price of the option ($2,248) and gained nothing on the expiration date because the right to sell Apple stock for $230 when the price is over $300 is worthless.

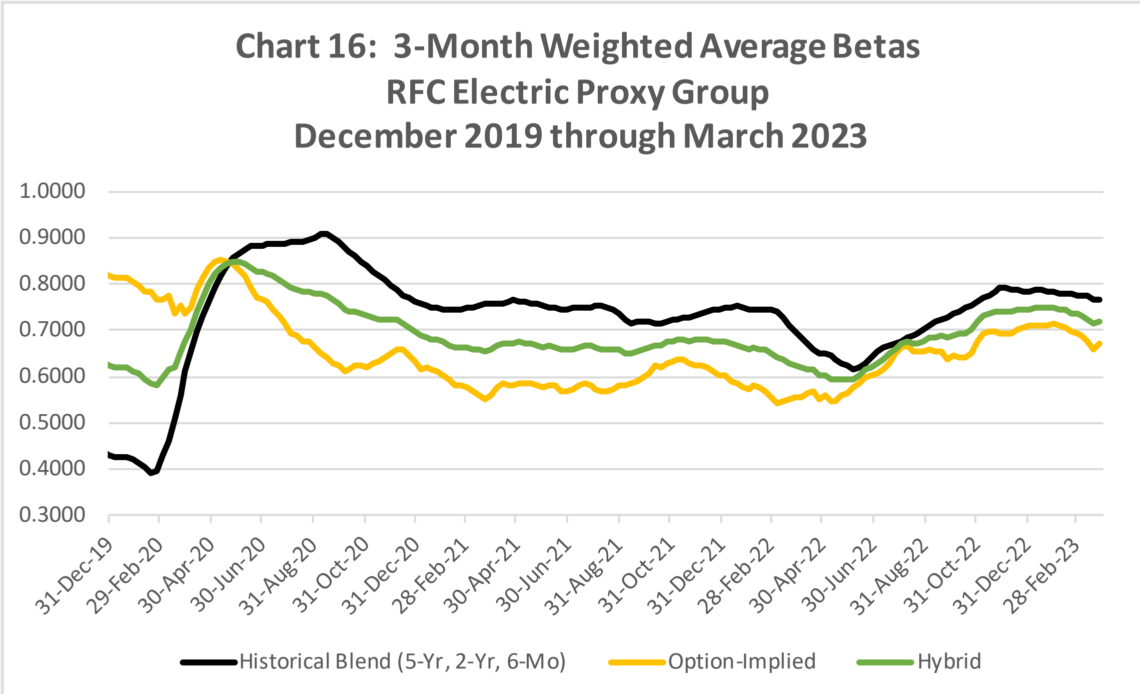
[39] $8,163 profit from exercising call option ($31,798 from selling at $317.98 market price - $23,000 cost to purchase at $230) - $635 ($6.35 X 100) option purchase price. Note: Each call option is the right to purchase 100 shares.

The market prices of put options and call options provide information regarding the probability distribution of future stock prices expected by investors. Using established techniques, I am able to use price data for stock options of my RFC Electric Proxy Group companies and the S&P 500 Index to determine investors' return expectations, including the relationship (covariance) between the return expectations for individual RFC Electric Proxy Group companies and those for the overall market (S&P 500). This covariance between the expected returns for my RFC Electric Proxy Group and for the S&P 500 indicates what investors expect betas will be in the future. I refer to betas based on option price calculations as "option-implied betas."

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE BETAS USED IN YOUR CAPM.

A. Traditionally, the betas used in CAPM calculations are calculated from historical returns. This approach has strengths and weaknesses. An alternative way to calculate betas is to incorporate investors' return expectations by calculating option-implied betas as explained in the previous paragraph. As discussed below, I have chosen to use both historical and option-implied betas in my CAPM analysis. I chose to use option-implied betas in my CAPM analysis because, among other reasons, studies have found that betas calculated based on investor expectations (option-implied) provide information regarding future perceived risks and expectations.[40]

[40] Bo-Young Chang & Peter Christoffersen & Kris Jacobs & Gregory Vainberg. Option-Implied Measures of Equity Risk, *Review of Finance*, Vol. 16, Issue 2, pp. 385-428 (April 2012) available at https://academic.oup.com/rof/article/16/2/385/1584560.



As shown in Chart 16 above, stock option prices indicate that investors likely expect lower betas for the RFC Electric Proxy Group in the future.

Exhibit ALR-4, page 3 contains the last three months of data used in creating Chart 16 above, which is what I use in my CAPM analysis. Specifically, I use the following two betas in my CAPM analysis:

1. **Hybrid Beta:** 50% Option-Implied Beta (6 months) + 25% Historical Beta (6 months) + 15% Historical Beta (2 years) + 10% Historical Beta (5 years).
2. **Forward Beta:** 100% Option-Implied Beta (6 months).

Q. WHY DO YOU USE PERIODS OF 6 MONTHS, 2 YEARS, AND 5 YEARS FOR YOUR HISTORICAL BETA CALCULATIONS, AS OPPOSED TO RELYING EXCLUSIVELY ON THE 5-YEAR PERIOD USED BY VALUE LINE?

A. Using shorter periods for the return regression analysis portion of the historical beta calculation allows me to see if the correlation between the returns of each of the companies in my RFC Electric Proxy Group and those of the S&P 500 Index has changed in the last 2 years or 6 months. Using a 5-year period exclusively tends to make recent changes in the correlation more difficult to identify because of the weight of 5 years of data.

Q. WOULD YOU AGREE THAT CHANGES IN MARKET DYNAMICS WILL HAVE A LARGER EFFECT ON 6-MONTH HISTORICAL BETAS THAN THEY WILL ON 2-YEAR OR 5-YEAR HISTORICAL BETAS?

A. Yes. As with other historical metrics based on a given time period, say, average stock prices, the longer the time horizon under consideration, the more data points are considered, and the smaller the effect of any one given change in the data set.

Q. IS THIS LARGER EFFECT ON 6-MONTH HISTORICAL BETAS FROM CHANGES IN MARKET DYNAMICS A GOOD OR A BAD THING?

A. The answer depends on what the beta will be used for. I would argue that in any attempt to forecast the beta coefficient of a company for any forward-looking analysis such as the cost of capital calculations in this proceeding, more recent historical data should be given more relevance than data from 5 or 10 years ago. The weight of 10 years of data makes a beta coefficient react extremely slowly to market developments. Even pronounced permanent market changes can take more than 6 months to have a detectable effect on a 10-year beta.

As with using spot values and averages of historical market data, I believe the right answer is not to use *either* 6-month historical betas or historical betas with longer horizons, but to consider *both*. For this reason, I have created my hybrid betas, which take into consideration 6-month, 2-year, and 5-year historical betas along with forward-looking, option-implied betas.

Q. DO YOU THINK IT IS A GOOD IDEA TO RELY ON 6-MONTH HISTORICAL BETAS DESPITE MARKET DEVELOPMENTS IN THE PAST YEAR THAT SOME WOULD CALL "MARKET DISLOCATIONS?"

A. Financial markets are constantly in flux due to the influence of countless factors. What some people may refer to as "market dislocations," though arguably more significant, I would say are just some of the numerous factors that are constantly affecting markets. To attempt to separate any one specific factor from "real" underlying market dynamics would be an exercise in futility.

Furthermore, it is very difficult if not impossible for anyone to predict how long any one influencing factor will be present or how long its effects will be felt by financial markets. When interest rates came down to historical lows in 2008, many analysts referred to it as an aberration that would be short-lived. Twelve years later, rates have not only remained low, but have come down even further due to yet another unexpected event. COVID-19 affected markets tumultuously, and though the initial wall of the tsunami has passed, no one can say for sure if its direct fallout and the effects of its reverberations or a resurgence will continue to affect financial markets for months or years to come.

So, in response, yes, I think it is a good idea to use 6-month historical betas to measure recent and current market dynamics regardless of recent developments. I use them as part of my hybrid betas in conjunction with longer-term historical betas and forward-looking, option-implied betas to achieve the most reasonable result.

Speaking specifically about the most significant initial impact caused of the onset of the COVID-19 pandemic in March 2020, it should be pointed out that 6-month betas calculated in the past 3 months no longer cover that period of time.

Q. GIVEN THE SHORTER PERIOD COVERED BY 6-MONTH HISTORICAL BETAS, CAN THEY STILL BE CONSIDERED STATISTICALLY SIGNIFICANT? HOW MANY DATA POINT PAIRS ARE USED IN THE CALCULATION OF YOUR 6-MONTH HISTORICAL BETA COEFFICIENTS?

A. A 6-month historical beta based on weekly returns calculated weekly is calculated using 26 closing price points for a company and for its corresponding market index, in this case the S&P 500 Index. This translates into 25 pairs of return data that are then used in the regression analysis. This is most certainly enough data to achieve statistical significance as addressed further below.

Furthermore, as stated above, the recent improvement in my calculation of historical betas of using weekly returns on every day of the week as opposed to using only one day of the week, as Value Line does, has the added benefit of providing significantly more data pairs to be used in the regression analysis used to calculate beta. For 6-month historical betas, instead of relying on 25 return pairs, the regression is performed on 117 return pairs.

Q. PLEASE EXPLAIN HOW YOU CALCULATED OPTION-IMPLIED BETAS.

A. Calculating option-implied betas of a company requires (1) obtaining stock option data for that company and a market index, (2) filtering the stock option data, (3) calculating the option-implied volatility for the company and for the index, (4) calculating the option-implied skewness for the company and for the index, and (5) calculating option-implied betas for the company based on implied volatility and skewness for the company and for the index. There are various ways one could choose to perform the steps above, but I chose to filter stock option data and calculate option-implied volatility[41] and skewness[42] following exactly the same methodology used by the Chicago Board of Options Exchange (CBOE) in the calculation of their widely-used VIX and SKEW Index, respectively.

I start my process with publicly available trading information for all the options for a given security (company or index) for a complete trading day. I then filter the option data as described by the CBOE using the following guidelines:

1. Use the mid-quote or mark (average of bid and ask) as the option price.
2. Use only out-of-the-money call and put options.
   - Determine the "moneyness" threshold where absolute difference between call and put prices is smallest (using CBOE "Forward Index Price" formula).
   - Include "at-the-money" call and put options and use average of call and put prices as price for "blended" option.
3. Exclude all zero bids.
4. Exclude remaining (more out-of-the-money) options when two sequential zero bids are found.

I then apply the series of formulas clearly described in both of the CBOE's white papers to the remaining options to calculate Option-Implied Volatility and Option-Implied Skewness. In the words of the CBOE, each of its two indices is "an amalgam of the information reflected in the prices of all of the selected options." To be clear, Implied

[41] CBOE Volatility Index White Paper (2018) available at https://cdn.cboe.com/resources/indices/srvix-white-paper.pdf. Please note that the cover page says, "proprietary information." However, this document has been in the public domain for over 3 years.

[42] The CBOE SKEW Index (2010) available at: https://cdn.cboe.com/resources/indices/documents/SKEWwhitepaperjan2011.pdf. Please note that the cover page says, "proprietary information." However, this document has been in the public domain for over 3 years.

Volatility is not exactly the same as the VIX Index, and Implied Skewness is not exactly the same as the SKEW Index, but both indices are directly based on their corresponding statistical value.

Option-Implied Volatility reflects investors' expectations regarding future stock price movements. Option-Implied Skewness reflects investors' expectations regarding how implied volatility changes for strike prices that are closer and further to the current value of the underlying stock price.

The CBOE calculates Times to Expiration by the minute—as do I. The Time to Expiration of traded options cannot be changed and varies from day to day. For the sake of consistency, the CBOE calculates the VIX and SKEW indices on a "30-day" basis by interpolating for two sets of options with Times to Expiration closest to the 30-day mark. I prefer to focus on as long of a time horizon as possible for forecasting purposes. Option Times to Expiration vary significantly for various stocks but can consistently be found to go out to 6 months (180 days) for utility companies. Therefore, for the sake of consistency, I have chosen to calculate 6-month volatility and skewness where possible. Occasionally, Times to Expiration for a given stock do not go out to 180 days. If the greatest Time to Expiration available is 171 days (95%) or greater, I use the volatility and skewness for that group of options as a proxy for the 180-day volatility and skewness, respectively.

Finally, once I have calculated the option-implied volatility and skewness for each company and index using the methodology described above, I calculate option-implied betas using the following formula developed by Christoffersen, Chang, Jacobs and Vainberg (2011):[43]

$$\beta_i = \left(\frac{SKEW_i}{SKEW_m}\right)^{1/3} \left(\frac{VAR_i}{VAR_m}\right)^{1/2}$$

Where:

β_i: $option - implied\ beta\ of\ security\ (e.g. stock, fund)$;
$SKEW_i$: $skewness\ of\ security$;
$SKEW_m$: $skewness\ of\ overall\ market\ (S\&P\ 500)$;
VAR_i: $variance\ of\ company$;
VAR_m: $variance\ of\ overall\ market\ (S\&P\ 500)$.

Q. YOU CALCULATE YOUR OPTION-IMPLIED BETAS BASED ON A 6-MONTH HORIZON. WOULD IT NOT BE BETTER TO USE A LONGER FORECASTING HORIZON?

A. The methodology I use to calculate my option-implied betas "allows for the computation of a complete term structure of beta for each company so long as the options data are available,"[44] so there is nothing inherent in the methodology that limits it to a certain time horizon.

For many applications, including cost of capital, one could argue that the longer the time horizon for the option-implied betas, the better. The limitation on the forecasting horizon is always set by the longest expiration period of the options currently traded in the market. Some companies trade options with expiration periods up to 2 or 3 years into the future. As evidenced by the exhaustive option data in my working papers, the maximum

[43] Bo-Young Chang & Peter Christoffersen & Kris Jacobs & Gregory Vainberg, Option-Implied Measures of Equity Risk, *Review of Finance* Volume 16, Issue 2, pp. 385-428 (April 2012) available at https://academic.oup.com/rof/article/16/2/385/1584560.
[44] Peter Christoffersen, Kris Jacobs, and Gregory Vainberg, *Forward-Looking Betas*, p. 24 (April 25, 2008) available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=891467.

expiration period for the options of the 24 companies in my RFC Electric Proxy Group is approximately 28 months. However, most of those companies never trade options with expiration periods of more than 8 months (13 of 24). New options are issued roughly every 3 months for these 13 companies, so the maximum expiration period on any given trading day is somewhere between 5 and 8 months. For consistency across companies in my proxy group and across dates within the 3-month period on which my analysis is focused (January through March 2023), I chose to use 6 months for the time horizon of my option-implied betas. If the maximum expiration period for the options of a given company on a given day is less than 6 months, I use the maximum expiration period as an approximation for the target 6-month horizon. Although my option-implied betas are focused on a 6-month investment horizon in my Primary COE Calculation, the risk premium portion of my CAPM is based on options contracts with expiration periods exceeding 1 year, and as far out as 59 Months. Additionally, as explained above, my COE Term Structure Analysis includes all electric utility companies covered in-depth by Value Line for which there is a LEAPS market (options contracts with expirations over 1 year). Therefore, my 8.44% is based on an analysis that incorporates investors' long-term equity return expectations, out to as far as 56 months.

Market Risk Premium

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE EQUITY RISK PREMIUM USED IN YOUR CAPM.

A. Traditionally, the risk premium used in CAPM calculations is derived from historical returns and/or equity analyst projections. The former approach is historically accurate but does not take into account investors' expectations for future market risks and returns. The latter approach is based on analyst projections, which are not market-based and do not reflect current investor expectations. A superior market-based way to calculate the equity risk premium is to use option-implied return expectations, which is the approach I have used.

My equity risk premium is the expected return on the S&P 500 minus the risk-free rate. I calculate an expected return on the S&P 500 by using stock options traded on this index. To begin with, I use exactly the same methodology used by the Chicago Board of Options Exchange to filter stock option data and calculate option-implied volatility and skewness,[45] as described in detail in the Beta section starting on page 67. The volatility and skewness calculated in this way describe a probability function representing the possible trajectories for the S&P 500 implied by the options market. The resulting skewed probability function can be closely approximated by a log-normal function using established statistical formulas, which then make it straightforward to calculate the expected growth for the S&P 500 for any given cumulative probability. A cumulative probability of 50% represents the median of the probability distribution, or the option-implied market consensus, which is how I arrive at my calculation of expected market growth.

Once the option-implied growth rate of the S&P 500 has been estimated as described above, I add the dividend yield and subtract the risk-free rate to arrive at the market risk premium, as laid out in Exhibit ALR-4, page 4 and Exhibit ALR-4, page 6. In line with my Spot and Weighted Average CAPM approaches, I use both spot values as of March 31, 2023 and weighted averages over the 3 months ending on that date for option-

[45] As used in the calculation of their widely-used VIX (or Volatility Index) and SKEW Index, respectively.

implied growth, dividend yields, and short- and long-term risk-free rates in these calculations to arrive at a total of 4 estimated values for the market risk premium. The market risk premia I use in my Weighted Average CAPM analysis with short- and long-term risk-free rates are 4.94% and 6.01%, respectively. The market risk premia I use in my Spot CAPM analysis with short- and long-term risk-free rates are 4.92% and 6.10%, respectively.[46]

Q. DID YOU TAKE INTO CONSIDERATION THE DIFFERENCE IN VOLATILITIES ACROSS EXPIRATION PERIODS IN THE OPTIONS TRADED ON THE S&P 500?

A. Yes. The volatility implied by the options market changes over time as investors' perception of risk changes. For example, during a crisis, implied volatility generally increases as investors expect that stock market prices have a greater chance of large swings compared to times when there is no crisis. As discussed earlier, investors also often have different volatility expectations over different time periods. For example, on any given day, investors might expect volatility to be relatively high over the next 30 days and to decrease over the next year or longer. The same holds true for skewness, even though it is less intuitive to understand changes in skewness than in volatility. Because of these changes across option expiration periods, I take a weighted average of the entire term structure of the option-implied volatility and skewness, which for the S&P 500 typically goes out to 54 to 61 months[47], interpolating where necessary, and giving the most weight to the option expiration period of 12 months.

[46] Both market risk premia happen to be the same because short- and long-term risk-free rates happen to be the same as of March 31, 2023.

[47] Prior to November 2021, the longest expiration period for stock options traded on the S&P 500 was 36 months.

CAPM Results

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR CAPM.

A. Table 7 and Table 8 below show the results of my Weighted Average CAPM and Spot CAPM Analyses, respectively. The market risk premia happen to be the same in my Spot CAPM Analysis because short- and long-term risk-free rates happen to be the same as of October 31, 2022.

Weighted Average CAPM

TABLE 7: CAPITAL ASSET PRICING MODEL (CAPM) - INDICATED COST OF EQUITY
WEIGHTED - All Inputs Weighted From January 2023 to March 2023

	3-Month Treasury Bill		30-Year Treasury Bond	
	Historical Blended Be	Forward Beta	Historical Blended Be	Forward Beta
Risk-Free Rate	4.82%	4.82%	3.75%	3.75%
Beta	0.77	0.67	0.77	0.67
Risk Premium	4.94%	4.94%	6.01%	6.01%
CAPM	8.60%	8.13%	8.35%	7.78%

Source: Exhibit ALR-4, page 1

Spot CAPM

TABLE 8: CAPITAL ASSET PRICING MODEL (CAPM) - INDICATED COST OF EQUITY (SPOT
SPOT - All Inputs Based on Last Available Data as of March 31, 2023

	3-Month Treasury Bill		30-Year Treasury Bond	
	Historical Blended Be	Forward Beta	Historical Blended Be	Forward Beta
Risk-Free Rate	4.85%	4.85%	3.67%	3.67%
Beta	0.75	0.74	0.75	0.74
Risk Premium	4.92%	4.92%	6.10%	6.10%
CAPM	8.54%	8.48%	8.25%	8.17%

Source: Exhibit ALR-4, page 5

As shown in Chart 14 on page 39 stock option data indicate that the COE generally remains relatively steady over longer investment horizons (e.g., the cost of equity is about the same over a 5-year investment horizon and a 1-year horizon). The market-based COE starts at a little over 8% at the 1-month horizon and decreases to about 7.5% for the 5-year horizon.

Please see Appendix E for a chart showing how the results of my CAPM analysis applied to the RFC Electric Proxy Group have changed over time since the onset of the Covid pandemic.

VII. ADDITIONAL COMMENTS ON MR. MOUL'S TESTIMONY

Q. PLEASE SUMMARIZE THE TESTIMONY OF MR. MOUL

A. Mr. Moul has recommended that the Company be allowed a return on equity of 11.30%, a cost of debt of 4.35% and an overall cost of capital of 8.14%.[48] He relies on his own versions of the Discounted Cash Flow ("DCF") model, Risk Premium analysis, Capital Asset Pricing Model ("CAPM") and the Comparable Earnings approach.[49] He determined that 11.10% represents a reasonable cost of equity. However, he claims that UGI is entitled to an additional 0.2% in recognition management performance and therefore an authorized ROE of 11.3% (11.1% + 0.2%).[50] Mr. Moul testified that, "At any point in time, a single method can provide an incomplete measure of the cost of equity depending upon extraneous factors that may influence market sentiment."[51] He claims that it in today's high

[48] Mr. Moul's Direct Testimony, page 2, lines 6-7.
[49] Mr. Moul's Direct Testimony, page 4, lines 12.
[50] Mr. Moul's Direct Testimony, page 4, lines 13-16.
[51] Mr. Moul's Direct Testimony, page 6, lines 4-6.

interest rate environment the DCF model is not as reliable as the Risk Premium and CAPM methods and presumably should not be used exclusively.[52] Mr. Moul adds a leverage adjustment to his DCF result and a size adjustment to his CAPM method. Additionally, he adds 0.32% to his Risk Premium Analysis to account for relatively low interest rate environment.[53]

Mr. Moul applied his four cost of equity methods to his "Electric Group" of 10 electric utility companies. The results of Mr. Moul's four cost of equity methods are shown on Table 9 below.

TABLE 9: MR. MOUL'S COST OF EQUITY RESULTS - MOUL ELECTRIC GROUP

METHOD	Model Results
Discounted Cash Flow (DCF)	10.45%
Risk Premium (RP)	11.75%
Capital Asset Pricing Model (CAPM)	15.95%
Comparable Earnings (CE)	13.10%

[1] Mr. Moul's Direct Testimony, UGI Electric Exhibit B, Page 2 of 29

Q. WHAT IS YOUR OVERALL REACTION TO MR. MOUL'S TESTIMONY?

A. Mr. Moul's DCF result is 9.48% before adding 0.97% for a "leverage adjustment."[54] Mr. Moul's DCF result is unreasonably above the market-based cost of equity before including his inappropriate adjustments. Below I will explain why Mr. Moul's adjustments are inappropriate and the flaws in Mr. Moul's DCF method.

A. DCF Method

52 Mr. Moul's Direct Testimony, page 6, lines 4-8.
53 Mr. Moul's Direct Testimony, page 34, lines 3-19.
54 Mr. Moul's Direct Testimony, Schedule 1 [2 of 2].

Q. DOES MR. MOUL CONSIDER THE DCF METHOD HIS PRIMARY METHOD FOR DETERMINING THE COST OF EQUITY?

A. No. He claims that in today's high interest rate environment "the use of multiple methods is particularly compelling because the Risk Premium method and CAPM capture changes in interest rates much more expeditiously than does the DCF method."[55]

Q. WHAT FORMULA DOES MR. MOUL USE IN HIS DCF ANALYSIS?

A. Dividend Yield (D/P) + Growth Rate (g) + leverage Adjustment (lev).[56]

Q. HOW DID MR. MOUL CALCULATE HIS GROWTH RATE FOR HIS DCF METHOD?

A. On page 26, lines 15-16 of Mr. Moul's testimony he says "…IBES/First Call, Zacks, and Value Line, provide the best indication of investor expectations." Mr. Moul states, "DCF growth rates should not be established by a mathematical formulation, and I have not done so. In my opinion, a growth rate of 6.00% is a reasonable estimate of investor-expected growth for the Electric Group."[57] Below are the five-year projected earnings per share rates by the four investment research firms he chose:

IBES/First Call: 6.25%

Zacks: 5.89%

Value Line: 4.83%

Mr. Moul's 6.00% growth rate is higher than the average of Zacks' and Value Line's growth forecasts. The average of IBES/First Call's earnings forecasts for the 10 companies

[55] Mr. Moul's Direct Testimony, page 6, lines 6-8.
[56] Mr. Moul's Direct Testimony, page 31, lines 5-6.
[57] Mr. Moul's Direct Testimony, page 26, lines 19-21.

in Mr. Moul's Electric Group is 6.25%, but this includes a 17.47% growth rate for PPL Corp. If investors consider PPL Corp's growth rates to be an outlier and not representative of Electric Group's growth prospects, Mr. Moul's DCF result of 9.48% overstates UGI Electric's cost of equity.

Q. DOES MR. MOUL PROPERLY APPLY THE SIMPLIFIED OR CONSTANT GROWTH DCF METHOD?

A. No. Mr. Moul correctly cautions against deriving the DCF growth component exclusively using mathematical formulas. As I explain starting on page 92, judgement is required to determine the appropriate growth rate component. However, Mr. Moul's DCF method produces an unreliable result of 9.48% because, as explained below, he relies exclusively on analysts' 5-year earnings per share growth rate forecasts as his growth component.[58] The correct application of the DCF method requires that the dividend yield be computed properly, and that the growth rate used be derived from a careful study of what future *sustainable* growth in cash flow is anticipated by investors. As discussed above, major financial institutions like J.P. Morgan Chase do not use a growth rate based on analyst 5-year EPS growth rates as Mr. Moul has done. Please see Appendix B for explanation of why a future-oriented "B X R" method is superior to Mr. Moul's DCF method.

Q. BESIDES GROWTH RATE, ARE THERE ANY OTHER DCF ANALYSIS INPUTS THAT MR. MOUL HAS ESTIMATED INCORRECTLY?

A. Yes. Mr. Moul made an unjustifiable "leverage adjustment."

[58] Mr. Moul's Direct Testimony, Schedule 9.

Q. PLEASE DESCRIBE THE LEVERAGE ADJUSTMENT PROPOSED BY MR. MOUL IN THIS PROCEEDING.

A. Mr. Moul has proposed a leverage adjustment addition to his DCF derived cost of equity, stating "In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes), the market-derived cost rate must be adjusted to account for the difference in financial risk."[59] He then goes on to say: "Because the ratemaking process uses ratios calculated from a firm's book value capitalization, further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the firm's equity."[60] Because of this alleged higher financial risk, Mr. Moul recommends adding 0.97%[61] to the DCF derived cost of equity.

Q. JUST BECAUSE THE MARKET VALUE CAPITAL STRUCTURE CONTAINS A HIGHER PERCENTAGE OF COMMON EQUITY THAN BOOK VALUE CAPITAL STRUCTURE, DOES THIS MEAN THE MARKET VALUE CAPITAL STRUCTURE HAS LOWER FINANCIAL RISK THAN THE BOOK VALUE CAPTIAL STRUCTURE?

A. No. Market value capital structure and book value capital structure are two completely different ways of measuring the same thing. Concluding that a market value capital structure is lower in risk because it contains more equity than the book value based capital structure for the same company is as inconsistent and illogical as claiming that a person who weighs 150 pounds could lose weight simply by stepping on a scale that measures weight in kilos instead of pounds. Financial risk is determined by a company's ability to

[59] Mr. Moul's Direct Testimony, page 27, lines 17-19.
[60] Mr. Moul's Direct Testimony, page 28, lines 4-7.
[61] Mr. Moul's Direct Testimony, page 31, lines 5-7.

meet its cash flow obligations. The most common and perhaps most important single measure of financial risk is the pretax interest coverage ratio. The interest coverage ratio is computed by dividing the sum of interest expense and pre-tax income by interest expense. This number is useful because it gives bondholders a sense of how far earnings would have to decline before a company would not be able to meet its interest payments. For example, if a company has an interest coverage ratio of 3.0, this means that at its current earnings rate, its earnings available for both payment of interest and pre-tax earnings, is three times as much as is needed to make its interest payments.

Q. DOES A DECLINE IN MARKET PRICE LOWER THE COVERAGE RATIO?

A. Lowering the market value does not directly cause a change in the coverage ratio computation. Therefore, changing from a market value orientation to a book value orientation does no more to change a company's financial risk than the weight of a person was influenced by switching to a scale calibrated in kilos instead of pounds.

Q. DO INVESTORS UNDERSTAND THAT AS PART OF THE REGULATORY PROCESS ALLOWED RETURNS ARE APPLIED TO BOOK VALUE?

A. Yes, they do. This is a process that has been going on for decades and it is hard to argue that investors are not aware of this. By recommending this leverage adjustment, Mr. Moul is implying that investors forget this after each rate case. Evaluating the cost of equity based on a comparative group is like taking a snapshot of their expectations. After this snapshot is taken, it is then applied to the individual company so even if the allowed return affected the expectation of the investors in the comparative group it would be after the snapshot was taken.

Q. DOES MR. MOUL'S LEVERAGE ADJUSTMENT GO AGAINST ORIGNAL COST RATEMAKING?

A. Yes. Mr. Moul claims, "The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different from the capital structure indicated by the market price (P)."[62] In other words, Mr. Moul is saying that as a consequence of original cost ratemaking an upward adjustment is needed. When a company has a market to book value above 1, and is thus over earning, applying the correct rate of return to the book value could have downward pressure on the stock price. No matter what logic is applied to the reason for adding a value to the rate of return, the leverage adjustment distorts the natural market dynamic between a regulated utility's stock price and its allowed rate of return.

B. <u>Risk Premium Method</u>

Q. PLEASE EXPLAIN MR. MOUL'S RISK PREMIUM CALCULATION METHODOLOGY, AS PRESENTED IN HIS DIRECT TESTIMONY.

A. Mr. Moul calculates an equity risk premium of large company stocks over long-term corporate bonds based on historical data between 1926-2021 and presents the results in three categories based on the relative level of interest rates.[63]

Common Equity Risk Premium:

Low Interest Rate 6.81%

Average Across All Interest Rates 5.93%

[62] Mr. Moul's Direct Testimony, page 27, lines 23-25.
[63] Mr. Moul's Direct Testimony, Schedule 12, [1 of 2].

High Interest Rates 5.05%[64]

Q. PLEASE COMMENT ON MR. MOUL'S RISK PREMIUM METHOD.

A. Mr. Moul's risk premium method is flawed for three reasons. First, it does not measure investors' current equity return expectations, which are fundamental to calculate the current COE. Instead, it measures historical returns (annual equity and bond returns) which are unlikely to reflect investors' current expectations. Second, the return period he uses in his analysis (annual) is over too short a time period to be an appropriate measure of the COE. UGI's COE should be based on investors' long-term return expectations because utility assets are long-lived (often over 20 years) and because many investors that purchase utility stocks (e.g., pension funds) have investment horizons considerably longer than 1 year. Third, Mr. Moul's has not demonstrated that the regression analysis, measuring the relationship between interest rates and the equity risk premium, is statistically significant.[65]

C. CAPM Method

Q. PLEASE SUMMARIZE MR. MOUL'S CAPM METHOD.

A. Mr. Moul explains that, "To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return."[66] He uses a risk free rate of 4.00% based

[64] Mr. Moul's Direct Testimony, page 34, lines 9-10.
[65] A regression analysis comparing the Mr. Moul's Equity Risk Premium to the yield on long-term government bonds has an extremely small R-squared of 0.0045. This means that less than 1% of the equity risk premium is explained by the yield on long-term government bonds.
[66] Mr. Moul's Direct Testimony, page 35, lines 13-16.

on interest rate forecasts and recent trends in long term Treasury yields.[67] The market premium portion of his CAPM analysis (10.12%) is based on the forecasted S&P 500 returns. He adds a "small size adjustment" of 1.02% to account for the relatively small size of UGI Electric relative to the companies in the Electric Group.[68]

Q. DO YOU AGREE WITH THE RESULTS OF MR. MOUL'S CAPM ANALYSIS?

A. No, I do not agree with results of Mr. Moul's CAPM analysis because I believe that they significantly and inaccurately overstate the Company's cost of equity.

The arithmetic average return that Mr. Moul uses overstates the historical risk premium by nearly 200 basis points. The 2022 SBBI Yearbook shows that investors earned a compounded annual return of 10.5%[69] between 1926 and 2021. The arithmetic mean return of 12.3%[70] is possibly valuable to stockbrokers and fund managers attempting to predict future bonuses, but not for calculating the cost of equity. A Dow Jones Newswire article stated, "Some financial advisers rely too heavily on a formula known as the arithmetic average, which can be misleading when investing for the long term. Financial advisors who use this formula may be overstating your potential profit and leading you to take risks you might otherwise avoid…"[71] His prospective risk premium of 11.89%[72] calculation is over 500 basis points higher than the supply-side equity risk premia (6.22%) published in a source used extensively by Mr. Moul, the Kroll SBBI 2022 Yearbook.[73] on a DCF analysis that is not based on sustainable growth. His DCF analysis for the S&P 500

[67] Mr. Moul's Direct Testimony, page 38, lines 11-12.
[68] Mr. Moul's Direct Testimony, page 39, lines 16-18.
[69] Kroll SBBI® 2022 Yearbook, page 58.
[70] Kroll SBBI® 2022 Yearbook, page 58.
[71] Kaja Whitehouse, To Financial Advisors and Fuzzy Math, Dow Jones Newswires October 8, 2003.
[72] Mr. Moul's Direct Testimony, Schedule 13 [2 of 3].
[73] The Kroll SBBI 2023 Yearbook published a supply-side equity risk premia of 6.35% on page 202.

has a growth component of an astounding 15.02% as published by Value Line.[74] A research report published by the Journal of Banking & Finance found that "Value Line's long-term stock return projections are extremely overoptimistic and have no predictive power…"[75]

Q. IS MR. MOUL'S ADDER FOR A SMALL SIZE EFFECT AN APPROPRIATE PART OF A CAPM ANALYSIS?

A. Mr. Moul claims that his CAPM result should be increased by 1.02% to reflect UGI's higher relative risk to the companies in his proxy group because it is smaller. Mr. Moul cites research from the 1990s that he claims supports the need to adjust the cost of equity for smaller firms. However, Mr. Moul does not provide any evidence that small electric companies have a higher cost of equity than larger utilities in the same industry.

I believe that it is appropriate to calculate UGI's cost of equity based on my proxy group of larger publicly traded electric companies because the evidence indicates that investors do not demand a higher expected return on equity to invest in small companies as compared to larger ones. The Kroll 2021 SBBI Yearbook states the following regarding the theory that investors require higher returns to invest in smaller firms:

> The size effect is not without controversy, nor is this controversy something new. Traditionally, small companies are believed to have greater required rates of return than large companies because smaller companies are inherently riskier. It is not clear, however, whether this is due to size itself, or to other factors closely related to or correlated with size…[76]

[74] Mr. Moul's Direct Testimony, Schedule 13, page 2 of 3.
[75] Szakmary, Et al., An examination of Value Line's long-term projections, Journal of Banking & Finance, page 832, 2007.
[76] Kroll SBBI® 2021 Yearbook, page 7-2.

Many scholars have expressed concerns with the results of older studies (1980s and 1990s) that found that smaller companies have higher required returns. Professor Aswath Damodaran said the following regarding the supposed "small cap premium:"

> Even if you believe that small cap companies are more exposed to market risk than large cap ones, this is an extremely sloppy and lazy way of dealing with that risk, since risk ultimately has to come from something fundamental (and size is not a fundamental factor).[77]

Q. HAVE RECENT STUDIES FOUND THAT THE RELATIONSHIP BETWEEN SIZE AND EXPECTED RETURN IS WEAK?

A. Yes. A 2018 study conducted by scholars at AQR Capital Management and Yale University found that "the size effect diminished shortly after its discovery and publication."[78] The authors of this research found that data errors plagued the early studies regarding the relationship between firm size and return. They found that the data in the earlier studies did not include delisted companies and since smaller firms are delisted more often than larger stocks, the biased data (referred as a "delisting bias") made the returns of smaller stocks look higher than reality.[79] In light of this recent data, Mr. Moul's use of an implied premium for the size of the Company is not appropriate and should be disregarded.

[77] Aswath Damodaran, Equity Risk Premiums (ERP): Determinates, Estimation and Implications – The 2014 Edition (paper updated, March 2015) page 42.
[78] Ron Alquist, Ronen Israel, and Tobias Moskowitz, Fact, Fiction, and the Size Effect, *The Journal of Portfolio Management*, Fall 2018, page 3.
[79] Ron Alquist, Ronen Israel, and Tobias Moskowitz, Fact, Fiction, and the Size Effect, *The Journal of Portfolio Management*, Fall 2018, page 5.

Q. HAVE OTHER UTILITY COMMISSIONS DETERMINED THAT IT IS NOT APPROPRIATE TO ALLOW HIGHER ROES TO UTILITY COMPANIES BECAUSE THEY ARE SMALL?

A. Yes. Based on my research and experience testifying in other states, New Hampshire, California, Pennsylvania and South Carolina Commissions have not allowed higher authorized ROEs for small companies simply based on their size.

D. Comparable Earnings Method

Q. PLEASE EXPLAIN THE COMPARABLE EARNINGS METHOD PRESENTED BY MR. MOUL.

A. Mr. Moul selected a group of non-regulated companies that he believes to be of comparable risk to the Electric Group. After selecting the companies, he presents the historic and Value Line expected return on book equity. See Schedule 14, page 2 of 3 of Mr. Moul's direct testimony. The final column of numbers on this table is the "Projected 2025-27." However, what he labels as the projected 2025-27 return is actually the return on book equity that Value Line forecasts, not the return that Value Line projects investors will receive on their investment as a result of purchasing the common stock at current prices. According to Mr. Moul's Schedule 14, the total return expected by Value Line on the book equity of these industrial companies is between a 7.50% and a high of 77%, for an average of 20.9% (13.4% excluding companies with values > 20%).

Q. IS THIS METHOD VALID?

A. No. Mr. Moul has attempted to determine the cost of equity that would be demanded by investors on the market price of a company comparable to UGI Electric by comparing it to the historic and projected returns on book equity of a selection of industrial companies. Leaving aside the problems with actually being able to select companies that are comparable, the overriding problem with Mr. Moul's comparable earnings analysis is that it did not address the cost of equity at all. It simply considered the returns on book equity that were achieved and are expected to be achieved by Value Line in the next 3 to 5 years. The earned return on book equity is an entirely different concept from the cost of equity.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF MR. MOUL'S TESTIMONY.

A. Mr. Moul recommends that the Company be allowed a return on equity of 11.30%. Mr. Moul's DCF result of 10.45% is high because he adds a leverage adjustment that misrepresents the basics of evaluating a company's cost of equity. Without his leverage adjustment, his DCF result is 9.48%. Mr. Moul's Risk Premium method was developed based upon an improper mathematical approach to quantifying historic actual returns. Mr. Moul's CAPM approach relies on invalid implementations of the DCF method to quantify the projected cost of equity, an improper inflation of the "beta" because of a high market-to-book ratio, and he adds the invalid "size premium." The incorrect claim that investors demand a higher cost of equity to invest in a small company (referred to as "size premium") is manufactured by an incorrect use of data. Mr. Moul's Comparable Earnings method is not really an equity costing method at all, as no consideration was given to investor's reactions to the earned returns on book equity.

VIII. PROPOSED EQUITY ADDER FOR MANAGEMENT PERFORMANCE

Q. ON PAGE 1, LINES 20-21 OF MR. MOUL'S DIRECT TESTIMONY, IT STATES THAT HIS 11.30% COE RECOMMENDATION INCLUDES A INCLUDES A "20 BASIS POINT ADDER "IN RECOGNITION OF THE STRONG PERFORMANCE OF THE COMPANY'S MANAGEMENT". PLEASE RESPOND.

A. This request by UGI should be rejected, for several reasons. First of all, ratepayers should not be obligated to compensate shareholders for the Company's management doing its job. Second, I recommend that the Commission consider the burden on consumers that would result if the Commission increased the ROE by an additional 20 basis points. Third, OCA witnesses Roger Colton (OCA Statement 4) presents evidence that the Company's claims of strong management performance are "over-stated".[80] Finally, Mr. Moul's 11.30% COE recommendation is already significantly above a market-based rate as explained throughout my testimony. Therefore, regardless of UGI's management performance, an allowed ROE of anything near 11.30% is excessive and would result in significantly over charging consumers.

IX. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.

A. Based on the evidence presented in my testimony, I conclude that the cost of equity allowed for UGI should be between 8.16% to 8.71% (recommended at 8.44%). Based on my

[80] Mr. Colton's Direct Testimony, page 53, line 9.

recommended common equity ratio of 44.75%, that results in an overall cost of capital of between 6.06% and 6.30% (recommended at 6.18%).

My recommendations satisfy the requirements of *Hope* and *Bluefield* that regulated utility companies should have the opportunity to earn a return commensurate with returns on investments in other enterprises having corresponding risks. My recommendations are consistent with legal standards set by the United States Supreme Court and market data and will allow UGI to raise capital on reasonable terms while fulfilling its obligation to provide safe and reliable service.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APPENDIX A. MARKET TO BOOK RATIOS AND THE MARKET-BASED COE

Q. PLEASE EXPLAIN WHY A MARKET TO BOOK RATIO OF SIGNIFICANTLY ABOVE ONEINDICATES THAT THE COST OF EQUITY FOR ELECTRIC UTILITY TY COMPANIES IS LOWER THAN THE EXPECTED RETURN ON BOOK EQUITY?

A. Calculating the cost of equity (investors' equity return expectations) is more complicated than calculating the return on a rental property, but the same concept applies regarding the relationship between market returns and book returns. If an investor purchases an apartment for $100,000 and expects to receive $500 per month ($500 X 12 = $6,000 per year) in rent, he or she will expect an annual return of 6% ($6,000/$100,000) on their investment. When the investor purchases the apartment, he would record the book value as $100,000 and the market value as $100,000 unless he determined that the purchase price was higher or lower than the market value. If the value of the apartment increases to $350,000, for example, the market to book ratio would increase to approximately 3.5, and therefore, his return on book value would remain at about 6% while his return on the market value of the apartment would decrease to about 1.7%.

In this rental property example, an increasing market value results in a lower expected return on market (1.7%) compared to expected return on book (6%) if the rent price remains constant. Rent prices do not increase to maintain an expected 6% return on book value; they are set by what the rental market reasonably can bear. The same is true of utility stocks. You do not establish an ROE based on a constant return on book (accounting) returns, it is set based on what investors in the market expect that market to return. In the case of a utility stock, an increasing market value results in a lower return on market for the same expected return on book. As this rental property example demonstrates, there is nothing inconsistent about investors expecting a lower return on the market price of an investment than on the book value of an investment. In fact, with market to book ratios of electric utility companies significantly above one it would be surprising if investors expected a return on market equal, or anywhere close, to return on book.

APPENDIX B. FUTURE-ORIENTED "B X R" METHOD

Q. ARE YOU AWARE OF CLAIMS ALLEGING THAT THE "BR" APPROACH TO THE CONSTANT GROWTH DCF MODEL IS FLAWED BECAUSE IT RELIES ON THE VALUE OF THE FUTURE EXPECTED RETURN ON BOOK EQUITY "R" TO ESTIMATE WHAT THE EARNED RETURN ON EQUITY SHOULD BE?

A. Yes. One common criticism is that it is not reasonable for the DCF to indicate a COE (market return) that is different (lower or higher) than the expected return on book equity (accounting). There are multiple reasons why this concern is unfounded:

1. The constant growth form of the equation using "br" is:

$$k = D/P + (br + sv)$$

   In this equation, "k" is the variable for the COE, and "r" is the future expected return on equity. The COE, "k," is not the same variable as the future expected earned return on equity, "r." In fact, there often is a large difference between the two.

2. The correct value to use for "r" is the return on book equity expected by investors as of the time the stock price and dividend data are used to quantify the D/P term in the equation. Therefore, even if future events occur that may change what investors expect for "r," the computation of the COE "k" remains correct as of the time the computation was made.

3. The ability of a commission's ROE decision to influence future cash flow expectations is not unique to the retention growth DCF approach. The five-year analysts' earnings per share growth rate is a computation that is directly influenced by what earnings per share will be in 5 years. Allowed ROEs

impact earning – higher allowed returns lead to higher earnings growth because the higher allowed returns the more earnings are available for reinvestment.

Q. CAN CHANGES IN THE ACTUAL EARNED RETURNS IMPACT GROWTH ABOVE AND BEYOND WHATEVER GROWTH RESULTS FROM EARNINGS RETENTION?

A. Yes, but large short-term changes in earnings per share caused by a perceived change in the future expected earned returns are unsustainable. The new perceived earned return on book equity should be part of the computation, but the one-time growth spurt to get there is no more indicative of the sustainable growth required in the constant growth DCF formula than the temporary negative growth that occurs when a company has a bad year.

Q. CAN YOU PLEASE SUMMARIZE WHY A FUTURE-ORIENTED "B X R" METHOD IS SUPERIOR TO A FIVE-YEAR EARNINGS PER SHARE GROWTH RATE FORECAST IN PROVIDING A LONG-TERM SUSTAINABLE GROWTH RATE?

A. The primary cause of sustainable earnings growth is the retention of earnings. A company is able to create higher future earnings by retaining a portion of the prior year's earnings in the business and purchasing new business assets with those retained earnings. There are many factors that can cause short-term swings in earnings growth rates, but the long-term sustainable growth is caused by retaining earnings and reinvesting those earnings. Factors that cause short-term swings include anything that causes a company to earn a return on book equity at a rate different from the long-term sustainable rate. Assume, for example, that a particular utility company is regulated so that it is provided with a reasonable opportunity to earn 9% on its equity. Should the company experience an event such as the loss of several key customers, or unfavorable weather conditions, which cause it to earn only 6% on equity in a given year, the drop from a 9% earned return on equity to a 6% earned return on equity would be concurrent with a very large drop in earnings per share. In fact, if a company did not issue any new shares of stock during the year, a drop from a 9% earned return on book equity to a 6% earned return on book equity would result in a 33.3% decline in earnings per share over the period.[81] However, such a drop in earnings would not be an indication of what is a long-term sustainable earnings per share growth rate. If the drop were caused by weather conditions, the drop in earnings would be immediately offset once normal weather conditions return. If the drop were from the loss of some key customers, the company would replace the lost earnings by filing for a rate increase to bring revenues up to the level required for the company to be given a reasonable opportunity to recover its cost of equity.

For the reasons above, changes in earnings per share growth rates that are caused by non-recurring changes in the earned return on book equity are inconsistent with long-term sustainable growth, but changes in earnings per share because of the reinvestment of additional assets is a cause of sustainable earnings growth. The “b x r” term in the DCF equation computes sustainable growth because it measures only the growth which a company can expect to achieve when its earned return on book equity “r” remains in equilibrium. If analysts have sufficient data to be able to forecast varying values of “r” in future years, then a complex, or multi-stage DCF method must be used to accurately

[81] By definition, earned return on equity is earnings divided by book value. Therefore, whatever level of earnings is required to produce earnings of 6% of book would have to be 33.3% lower than the level of earnings required to produce a return on book equity of 9%.

quantify the effect. Averaging growth rates over sub-periods, such as averaging growth over the first five years with a growth rate expected over the subsequent period, will not provide an appropriate representation of the cash flows expected by investors in the future and, therefore, will not provide an acceptable method of quantifying the cost of equity using the DCF method. The choices are either a constant growth DCF, in which one growth rate derived using "b x r" should be used, or a complex DCF method in which the cash flow anticipated in each future year is separately estimated. Mr. Moul has done neither. Instead, he mechanically adds analysts' five-year earnings per share growth rate to the dividend yield.

Q. WHY ARE ANALYSTS' FIVE-YEAR CONSENSUS GROWTH RATES NOT INDICATIVE OF LONG-TERM SUSTAINABLE GROWTH RATES?

A. Analysts' five-year earnings per share growth rates are earnings per share growth rates that measure earnings growth from the most currently completed fiscal year to projected earnings five years into the future. These growth rates are not indicative of future sustainable growth rates in part because the sources of cash flow to an investor are dividends and stock price appreciation. While both stock price and dividends are impacted in the long run by the level of earnings a company is capable of achieving, earnings growth over a period as short as five years is rarely in synchronization with the cash flow growth from increases in dividends and stock prices. For example, if a company experiences a year in which investors perceive that earnings temporarily dipped below normal trend levels, stock prices generally do not decline at the same percentage that earnings decline, and dividends are usually not cut just because of a temporary decline in a company's earnings. Unless both the stock price and dividends mirror every down swing in earnings, they cannot be expected to recover at the same growth rate that earnings recover. Therefore, growth rates such as five-year projected growth in earnings per share are not indicative of long-term sustainable growth rates in cash flow. As a result, they are not applicable for direct use in the simplified DCF method.

Q. IS THE USE OF FIVE-YEAR EARNINGS PER SHARE GROWTH RATES IN THE DCF MODEL ALSO IMPROPER?

A. Yes. A raw, unadjusted, five-year earnings per share growth rate is usually a poor proxy for either short-term or long-term cash flow growth that an investor expects to receive. When implementing the DCF method, the time value of money is considered by equating the current stock price of a company to the present value of the future cash flows that an investor expects to receive over the entire time that he or he owns the stock. The discount rate required to make the future cash flow stream, on a net present value basis, equal to the current stock price is the cost of equity. The only two sources of cash flow to an investor are dividends and the net proceeds from the sale of stock at whatever time in the future the investor finally sells. Therefore, the DCF method is discounting future cash flows that investors expect to receive from dividends and from the eventual sale of the stock. Five-year earnings growth rate forecasts are especially poor indicators of cash flow growth, even over the five years being measured by the five-year earnings per share growth rate number.

Q. WHY IS A FIVE-YEAR EARNINGS PER SHARE GROWTH RATE A POOR INDICATOR OF THE FIVE-YEAR CASH DIVIDEND GROWTH EXPECTATIONS?

A. The board of directors of a company changes dividend rates based upon long-term earnings expectations combined with the capital needs of a company. Most companies do not decrease dividends simply because a company has a year in which earnings were below sustainable trends, and similarly they do not increase dividends simply because earnings for one year happened to be above long-term sustainable trends. Therefore, over any given five-year period, earnings growth is frequently very different from dividend growth. In order for earnings growth to equal dividend growth, at a minimum, earnings per share in the first year of the five-year earnings growth rate period would have to be exactly on the long-term earnings trend line expected by investors. Since earnings in most years are above or below the trend line, the earnings per share growth rate over most five-year periods is different from what is expected for dividend growth.

Q. WHY IS THE FIVE-YEAR EARNINGS PER SHARE GROWTH RATE A POOR INDICATION OF FUTURE STOCK PRICE GROWTH?

A. If a company happens to experience a year in which earnings decline below what investors believe is consistent with the long-term trend, then the stock price does not drop anywhere near as much as earnings drop. Similarly, if a company happens to experience a year in which earnings are higher than the investor-perceived long-term sustainable trend, the stock price will not increase as much as the earnings. In other words, the P/E ratio of a company will increase after a year in which investors believe earnings are below sustainable levels, and the P/E ratio will decline in a year in which investors believe earnings are higher than expected. Since stock price is one of the important cash flow sources to an investor, a five-year earnings growth rate is a poor indicator of cash flow, both because it is a poor indicator of stock price growth over the five years being examined, and because it is equally a poor predictor of dividend growth over the period.

Q. ARE YOU SAYING THAT ANALYSTS' CONSENSUS EARNINGS PER SHARE GROWTH RATES ARE USELESS AS AN AID TO PROJECTING THE FUTURE?

A. No. Analysts' EPS growth rates are, however, very dangerous if used in a simplified DCF without proper interpretation. While they are not useful if used in their "raw" form, they can be very useful in computing estimates of what earned return on equity investors expect will be sustained in the future, and as such, are useful in developing long-term sustainable growth rates. This is exactly what I do in the application of my Constant Growth DCF Analysis.

APPENDIX C. NON-CONSTANT GROWTH FORM OF THE DCF MODEL

Q. YOUR NON-CONSTANT GROWTH DCF MODEL USES ANNUAL EXPECTED CASH FLOWS. SINCE DIVIDENDS ARE PAID QUARTERLY RATHER THAN ANNUALLY, HOW DOES THIS SIMPLIFICATION IMPACT YOUR RESULTS?

A. I used the annual model because it is easier for observers to visualize what is happening. Using cash flows on an annual basis rather than on a quarterly basis, causes a small overstatement of the COE.

Q. WHY IS IT A SMALL OVERSTATEMENT OF THE COE IF YOU HAVE MODELED DIVIDENDS TO BE RECEIVED SOME MONTHS AFTER INVESTORS ACTUALLY EXPECT TO RECEIVE THEM?

A. The process of changing from an annual model to a quarterly model would require two changes, not just one. A quarterly model would show dividends being paid sooner and would also show earnings being available sooner. A company that receives its earnings sooner, rather than at the end of the year, has the opportunity to compound them. Since revenues, and therefore earnings, are essentially received every day, a company that is supposed to earn an annual rate of 9.00% on equity would have to earn only 8.62% if the return were compounded daily.[82] This reduction from 9.00% to 8.62% would then be partially offset by the impact of the quarterly dividend payment to bring the result of switching from the simplifying annual model closer to, but still a bit below 9.00%.

[82] (1+.0862/365)^365=1.09=9.00%.

Q. BY USING CASH FLOW EXPECTATIONS AS THE VALUATION PARAMETER, DOES THE NON-CONSTANT DCF MODEL STILL RELY ON EARNINGS?

A. Yes. It relies on an expectation of future cash flows. Future cash flows come from dividends during the time the stock is owned and capital gains from the sale of the stock once it is sold. Since earnings impact both dividends and stock price, the non-constant DCF model still relies on earnings.

Every dollar of earnings is used for the benefit of stockholders, either in the form of a dividend payment, or earnings reinvested for future growth in earnings and/or dividends. Earnings paid out as a dividend have a different value to investors than earnings retained in the business. Recognizing this difference and properly considering it in the quantification process is a major strength of the DCF model and is why the non-constant DCF model as I have set forth is an improvement over either the price-to-earnings ratio (P/E ratio) or dividend/price (D/P) methods. Comparing the P/E ratios and the dividend yield (D/P) are helpful as a rule of thumb, but they must be used with caution because, among other reasons, two companies with the same dividend yield can have a different COE if they have different retention rates. A DCF model is more reliable than these rules of thumb because it can account for different retention rates, among other factors.

Q. WHY IS THERE A DIFFERENCE TO INVESTORS IN THE VALUE OF EARNINGS PAID OUT AS A DIVIDEND COMPARED TO THE VALUE OF EARNINGS RETAINED IN THE BUSINESS?

A. The return on earnings retained in the business depends upon the opportunities available to that company. If a regulated utility reinvests earnings in needed "used and useful" utility assets, then those reinvested earnings have the potential to earn at whatever return is consistent with ratemaking procedures allowed and the skill of management in prudently operating the system.

When an investor receives a dividend, he can either reinvest it in the same or another company or use it for other things, such as paying down debt or paying living expenses. Although an investor could theoretically use the proceeds from any dividend payments to simply buy more stock in the same company, when an investor increases his investment in a company by purchasing more stock, the transaction occurs at market price. However, when the same investor sees his investment in a company increase because earnings are retained rather than paid as a dividend, the reinvestment occurs at book value. Stated within the context of the DCF terminology: earnings retained in the business earn at the future expected return on book equity "r," and dividends used to purchase new stock earn at the rate "k." When the market price exceeds book value (that is, the market-to-book ratio exceeds 1.0), retained earnings are worth more than earnings paid out as a dividend because "r" will be higher than "k." Conversely, when the market price is below book value, "k" will be higher than "r," meaning that earnings paid out as a dividend earn a higher rate than retained earnings.

Q. IF RETAINED EARNINGS WERE MORE VALUABLE WHEN THE MARKET-TO-BOOK RATIO IS ABOVE 1.0, WHY WOULD A COMPANY WITH A MARKET-TO-BOOK RATIO ABOVE 1.0 PAY A DIVIDEND RATHER THAN RETAIN ALL OF THE EARNINGS?

A. Retained earnings are more valuable than dividends only if there are sufficient opportunities to profitably reinvest those earnings. Regulated utility companies are allowed to earn the cost of capital only on assets that are used and useful in providing utility service. Investing in assets that are not needed may not produce any return at all. For unregulated companies, opportunities to reinvest funds are limited by the demands of the business. For example, how many new computer chips can Intel profitably develop at the same time?

Q. UNDER THE NON-CONSTANT DCF MODEL, IS IT NECESSARY FOR EARNINGS AND DIVIDENDS TO GROW AT A CONSTANT RATE FOR THE MODEL TO BE ABLE TO ACCURATELY DETERMINE THE COST OF EQUITY?

A. No. Because the non-constant form of the DCF model separately discounts each and every future expected cash flow, it does *not* rely on any assumptions of constant growth. The dividend yield can be different from period to period, and growth can bounce around in any imaginable pattern without harming the accuracy of the answer obtained from quantifying those expectations. When the non-constant DCF model is correctly used, the answer obtained is as accurate as the estimates of future cash flow.

APPENDIX D. CAPITAL ASSET PRICING MODEL

Risk-Free Rate

Q. WHAT IS YOUR RESPONSE TO ANALYSTS WHO CLAIM THAT THE CAPM MUST BE IMPLEMENTED WITH A LONG-TERM INTEREST RATE (E.G., YIELD ON 30-YEAR TREASURY BOND) AS AN ESTIMATE OF THE RISK-FREE RATE COMPONENT OF THE CAPM?

A. When looking for a security to calculate an estimate of the risk-free rate, it could be argued that it is appropriate to find one with a term or maturity that best matches the life of the asset being financed. In that sense, the 30-year Treasury bond yield can be argued to be ideal for this specific application. However, it is equally important to find a security that has a beta coefficient with the overall market as close to zero as possible, because by the very definition of the risk-free rate in the CAPM model, its movements should have no correlation to the movements of the market. And this is where the problem with the 30-year Treasury bond yield arises, as it has an established non-zero beta. The 3-month Treasury bill yield has a considerably lower beta, and therefore is superior in that respect to the 30-year Treasury bond yield. Neither one is a perfect fit on both fronts, which is why I have chosen to consider both as proxies for the risk-free rate to establish a range for my CAPM results.

Q. HOW DO YOU RESPOND TO ANALYSTS WHO CLAIM THAT THE RISK-FREE RATE SHOULD BE BASED ON INTEREST RATE FORECASTS FROM FIRMS SUCH AS BLUE CHIP FINANCIAL?

A. It is important to recognize that current long-term Treasury bond yields represent a direct observation of investor expectations and there is no need to use "expert" forecasts such as

Blue Chip to determine the appropriate risk-free rate to use in a CAPM analysis or any other cost of equity calculations.

Many economists and forecasters will continue to be quoted in the press prognosticating on possible developments that are truly unpredictable. The Nobel Laureate Economist Daniel Kahneman stated the following regarding forecasting:

> It is wise to take admissions of uncertainty seriously, but declarations of high confidence mainly tell you that an individual has constructed a coherent story in his mind, not necessarily that the story is true.[83]

Historical Beta

Q. PLEASE EXPLAIN HOW YOU CALCULATE HISTORICAL BETAS.

A. I calculate historical betas following the methodology used by Value Line, with some modifications. Specifically, Value Line adheres to the following guidelines:

1. Returns for each security are regressed against returns for the overall market in the following form:

$$Ln\,(p^{I}_{t} / p^{I}_{t-1}) = a_{I} + B_{I} * Ln\,(p^{m}_{t} / p^{m}_{t-1})$$

   Where:

   - p^{I}_{t} is the price of the security I at time t
   - p^{I}_{t-1} is the price of the security I one week before time t
   - p^{m}_{t} and p^{m}_{t-1} are the corresponding values of the market index
   - B_{I} is the regression estimate of Beta for the security against the market index

2. The natural log of the price ratio is used as an approximation of each return and no adjustment is made for dividends paid during the week.

[83] DANIEL KAHNEMAN, *Thinking Fast and Slow*, p. 212(New York: Farrar, Straus, and Giroux, 2011).

3. Weekly returns are calculated on one day of the week, with a stated preference for Tuesdays to minimize the effect of holidays as much as possible.

4. Betas calculated using the regression method above are adjusted as per Blume (1971)[84] using the following formula:

$$\text{Adjusted } B_I = 0.35 + 0.67 * \text{Calculated } B_I$$

There are four differences between my historical beta calculations and Value Line's calculations:

1. The first significant difference is that whereas Value Line uses the New York Stock Exchange Composite Index as the market index, I use the S&P 500 Index.

2. Another important difference is that whereas Value Line calculates weekly returns on one day of the week, with a stated preference for Tuesdays, I calculate weekly returns on all days of the week.

3. Value Line only calculates betas every 3 months in their quarterly company reports, whereas I use the same consistent methodology to calculate betas every week during the most recent 3 complete months (January through March 2023).

4. Value Line always uses a 5-year period for the return regression,[85] whereas I calculate historical betas for periods of 6 months, 2 years, and 5 years, as shown in Chart 16 on page 64.

[84] M. Blume, On the Assessment of Risk, *The Journal of Finance*, Vol. XXVI (March 1971) available at www.stat.ucla.edu/~nchristo/Fiatlux/blume2.pdf..

[85] They offer betas calculated over different time periods on their website, including 3 years and 10 years.

In the following pages, I explain my rationale for making the four modifications above to Value Line's beta calculation methodology.

Q. WHY DO YOU CALCULATE YOUR HISTORICAL BETAS VS. THE S&P 500 INDEX INSTEAD OF THE NEW YORK STOCK EXCHANGE (NYSE) COMPOSITE INDEX, AS VALUE LINE DOES?

A. A critical factor in the calculation of a beta coefficient is the choice of index to represent the overall market. Using exactly the same beta calculation methodology with a different market index will result in different values of beta for a given company or portfolio – sometimes drastically different values. It is easy to jump to the conclusion that this points to a flaw in CAPM theory, as different values of beta would result in a different implied cost of equity. However, another key component of the CAPM, the market risk premium, also depends on the choice of the market index, which in theory would have an offsetting effect on the cost of equity calculation. This points to the most important aspect of selecting a market index for a CAPM analysis, which is to be consistent and use the same index for the calculation of beta as for the calculation of the market risk premium. This is a fundamental concept of the CAPM and using betas based on one index with a market risk premium based on a different index yields invalid results.

As stated above, Value Line calculates its published betas based on the NYSE Composite Index. Most methodologies used to calculate the market risk premium, including those I rely on, are based on the S&P 500 Index, so using them in the CAPM together with Value Line betas exactly as published would yield invalid results.

For this reason, I calculate my historical betas versus the S&P 500 Index, making my CAPM approach entirely consistent.

As an aside related to my option-implied betas, using the S&P 500 Index consistently throughout my CAPM has the added benefit that this index has a much larger number of options traded, which makes the calculation of option-implied betas more reliable.

Q. WHY DO YOU CALCULATE YOUR HISTORICAL BETAS USING WEEKLY RETURNS ON EVERY DAY OF THE WEEK AS OPPOSED TO USING ONLY ONE DAY OF THE WEEK, AS VALUE LINE DOES?

A. Using one day of the week to calculate weekly returns for use in the regression analysis used to calculate historical betas has the unintended effect of generating different values of betas depending on the day of the week that is used. To clarify, if one were to use Value Line's precise methodology for calculating a 5-year historical beta for a given company using weekly returns calculated on Tuesdays, the resulting beta value would be different than the resulting value if one were to use the same exact methodology, but using weekly returns calculated on Wednesdays, or any other day of the week. Even though 5-year historical betas should in theory be quite stable and should not change very much from one day to the next, calculating returns on only one day of the week results in differences that can be significant and make no sense conceptually.

I only became aware of this side-effect recently, but it is easy to understand why it happens. Even though there is some correlation due to some overlap, the set of weekly returns calculated on Mondays is a completely different set of numbers than the set of weekly returns calculated on Tuesdays. As a result, there are five 5-year betas that can result from Value Line's methodology, and even though the Monday beta for a given company will change slowly from week to week, the change between the Monday beta and the Tuesday beta, calculated just one trading day apart, can be quite significant.

Since I became aware of this undesirable effect, I began calculating my historical betas based on an all-encompassing set of weekly returns calculated on every trading day in the beta calculation period. This methodology has the effect of averaging out the five possible betas that could result from using only one day of the week for the return calculations,[86] as Value Line does. In this way, a 5-year beta calculated on any two consecutive trading days would only change minimally, as it should.

Using a daily calculation of weekly returns could be criticized for the resulting overlap in a weekly return from Monday to Monday with that from Tuesday to Tuesday. However, given that the overlap is consistent and equal for the net effect of every trading day, no trading day is given undue weight in the regression. Even though the effect of each trading day appears 5 times in the weekly return data, there are also 5 times the total number of weekly returns in the overall set used in the regression, so any individual trading day has the same relative weight than in Value Line's methodology. The fact that the resulting beta value of this aggregate approach turns out to be a sort of average of the five possible values that would result from Value Line's methodology on different days of the week is the final confirmation that this is the superior approach for calculating a historical beta based on weekly returns.

Using a daily calculation of weekly returns has the added marginal benefit of providing more data pairs to be used in historical beta calculations for shorter periods, such

[86] The resulting beta is not a direct arithmetic or geometric average of the other five betas, but rather a regression based on the union of all five possible sets of weekly returns.

as for 6-month historical betas, where instead of 25 return pairs, the regression is performed on 117 return pairs.

Q. ARE THERE ADDITIONAL BENEFITS TO DOING YOUR OWN HISTORICAL BETA CALCULATIONS?

A. Doing my own historical beta calculations using Value Line's established methodology allows me to see how beta values change from week to week and to use the most up-to-date beta calculations instead of relying on stale beta values that can be more than 3 months old.

Q. HOW MANY DATA POINT PAIRS ARE NECESSARY TO ESTABLISH A STATISTICALLY SIGNIFICANT CORRELATION BETWEEN TWO VARIABLES IN A REGRESSION ANALYSIS, SUCH AS THE ONE USED TO ESTABLISH BETA COEFFICIENTS?

A. Establishing a minimum number is somewhat subjective, though various authorities on statistics argue the number is between 3 and 8 data pairs. While one can broadly correctly generalize that the more data point pairs one uses, the more certain one can be about the significance of the results of any correlation analysis, this is very different from stating that one cannot achieve statistical significance with a relatively low number of data pairs. In fact, it is important to realize that one can achieve statistical significance with less than 10 data pairs, and that even hundreds of data pairs do not guarantee statistical significance. For precisely this reason, statisticians have developed a tool that helps determine statistical significance based on the number of data pairs in a regression analysis.

A "table of critical values" of Pearson's correlation, which can be readily found online[87] or in most statistics books, tells a statistician that for 25 data point pairs (implying N-2=23 "degrees of freedom"), a correlation, or beta, coefficient of 0.505 or higher will occur *by chance* with a probability of only 0.01.[88] As explained in more detail in the text regarding how to use the table of critical values,[89] any beta coefficient above this level, and certainly above the 0.795 3-month average for the recent 6-month betas for my RFC Electric Proxy Group, by definition are considered statistically significant. The threshold for statistical significance for 117 data point pairs (implying 115 "degrees of freedom"), is so low that it is not even included in the table of critical values. The maximum "degrees of freedom" listed is 100, with an already very low threshold of 0.254.

Hybrid beta

Q. HOW DID YOU DECIDE ON THE RELATIVE WEIGHTS YOU ALLOCATE TO EACH COMPONENT OF YOUR HYBRID BETAS? IS THERE ANY ACADEMIC SUPPORT FOR YOUR APPROACH?

A. I am not aware of any academic study specifically focused on the optimal relative weight of historical betas to predict future betas. However, the authors of the paper I relied upon for guidance on the calculation of my option-implied betas did attempt to quantify the predictive power of 6-month option-implied ("forward-looking") betas as well as that of 6-month ("180-day"), 1-year, and 5-year historical betas by back-testing historical predictions with actual *expost* results, or "realized" betas, for the 30 companies in the Dow

[87] University of Connecticut, *r Critical Value Table*, available at: https://researchbasics.education.uconn.edu/r_critical_value_table/#
[88] In fact, many researchers use a more lenient "alpha level" of 0.05 for determinations of statistical significance.
[89] University of Connecticut, *Statistical Significance: Is there a relationship (difference) or isn't there a relationship (difference)?* available at https://researchbasics.education.uconn.edu/statistical_significance

Jones Index. In addition to using each of the betas above independently, they also measured the predictive power of a "mixed" beta consisting of a simple average of the six-month option-implied beta and the 6-month historical beta.

Their conclusions for predicting 6-month future betas are as follows:

> The forward-looking beta outperforms the other methods ten times, and the same is true for the 180-day historical beta. The mixed beta is the best performer in seven cases, and the 1-year historical beta in three cases. The 5-year historical beta is always outperformed by at least one other method, and it often ranks last. The 180-day historical beta clearly dominates the two other historical methods.[90]

Their conclusions for predicting 1-year and 2-year future betas are as follows:

> Somewhat unexpectedly, the performance of the forward-looking beta compared to that of the 180-day historical beta is much better [for the one-year prediction] than [for the six-month prediction], and this conclusion carries over to [the two-year prediction]. The mixed beta also perform [sic] well. It is perhaps not surprising that the performance of the 180-day historical beta [for the one- and two-year predictions] is poorer than [for the six-month prediction], because the horizons used in the construction of realized betas are no longer equal to 180 days. What is harder to explain is why the correlation between realized beta and forward-looking beta is in many cases higher [for the one- and two-year predictions] than [for the six-month prediction]. Finally, it is also interesting that the 1-year and 5-year historical betas do not perform well [for the one-and two-year predictions]. In summary, [for the one-year prediction] either the forward-looking beta or the mixed beta is the best performer in nineteen out of thirty cases. [For the two-year prediction], this the case twenty-two times out of thirty.[91]

Their conclusions strongly support the use of 6-month historical betas, 6-month option-implied betas, and/or an average of the two as predictors of future betas 6 months, 1 year, or 2 years into the future. They also seem to indicate that historical betas lose predictive power the longer the period that is used.

[90] Peter Christoffersen, Kris Jacobs, and Gregory Vainberg, *Forward-Looking Betas*, p. 16 (April 25, 2008) available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=891467.
[91] *Id. at 17.*

I decided on the composition of my hybrid betas primarily based on the conclusions of the authors above. A mixed or hybrid beta made up of 50% historical betas and 50% forward-looking option-implied betas seemed to be the best way to go. Though the predictive power of longer-term historical betas seems to be quite reduced, it is not zero, so in an effort to preserve the effect of longer-term market trends in my hybrid betas, I chose to further subdivide the historical component into 50% (25% of the hybrid) for the stronger predicting 6-month historical betas, 30% (15% of the hybrid) for the 2-year historical betas, and 20% (10% of the hybrid) for the 5-year historical betas.

Market Risk Premium

Q. WHICH CUMULATIVE PROBABILITY DID YOU USE TO ESTIMATE THE OPTION-IMPLIED GROWTH OF THE S&P 500 IN THE CALCULATION OF YOUR MARKET RISK PREMIUM AND WHY?

A. I used a cumulative probability of 50.0% in the calculation of my option-implied growth for the S&P 500, which results in a value of 8.11% as of March 31, 2023 and a value of 8.08% for the weighted average of the 3 months ending on that date. As stated above, a cumulative probability of 50% represents the median of the probability distribution, or in this case the option-implied market consensus, which is why I have chosen to use this level.

As a matter of fact, using the same probability distribution derived from the options market described above, one can also calculate the cumulative probability implied by a given cost of capital. For instance, using the same risk-free rates and betas for the RFC Electric Proxy Group in my CAPM analysis, Mr. Moul's median CAPM COE result of

10.95%[92] implies an average market risk premium of 9.6%, an average overall market return of 13.9%, average growth for the S&P 500 of 12.2%, and a cumulative probability of 61.1%. In other words, to achieve the required market growth of 12.2%, reality would have to exceed 61.1% of the scenarios investors currently see as plausible for the market in aggregate, considerably more than the median market consensus at 50%. To put this into perspective, it is important to note that values on the tails of the probability function get increasingly separated, requiring an ever-increasing growth rate for every additional percentage in the cumulative probability, and making it impossible to ever arrive at 100%.

Using exactly the same methodology using the betas of the RFC Electric Proxy Group, my median CAPM COE result of 9.33% implies an average market risk premium of 5.7%, an average overall market return of 10.0%, average growth for the S&P 500 of 8.3%, and a cumulative probability of 50.5%.

Q. ARE THE CUMULATIVE PROBABILITIES YOU REFER TO IN THIS CASE DIRECTLY COMPARABLE TO THE CUMULATIVE PROBABILITIES YOU HAVE USED OR REFERRED TO IN PRIOR TESTIMONIES YOU HAVE FILED?

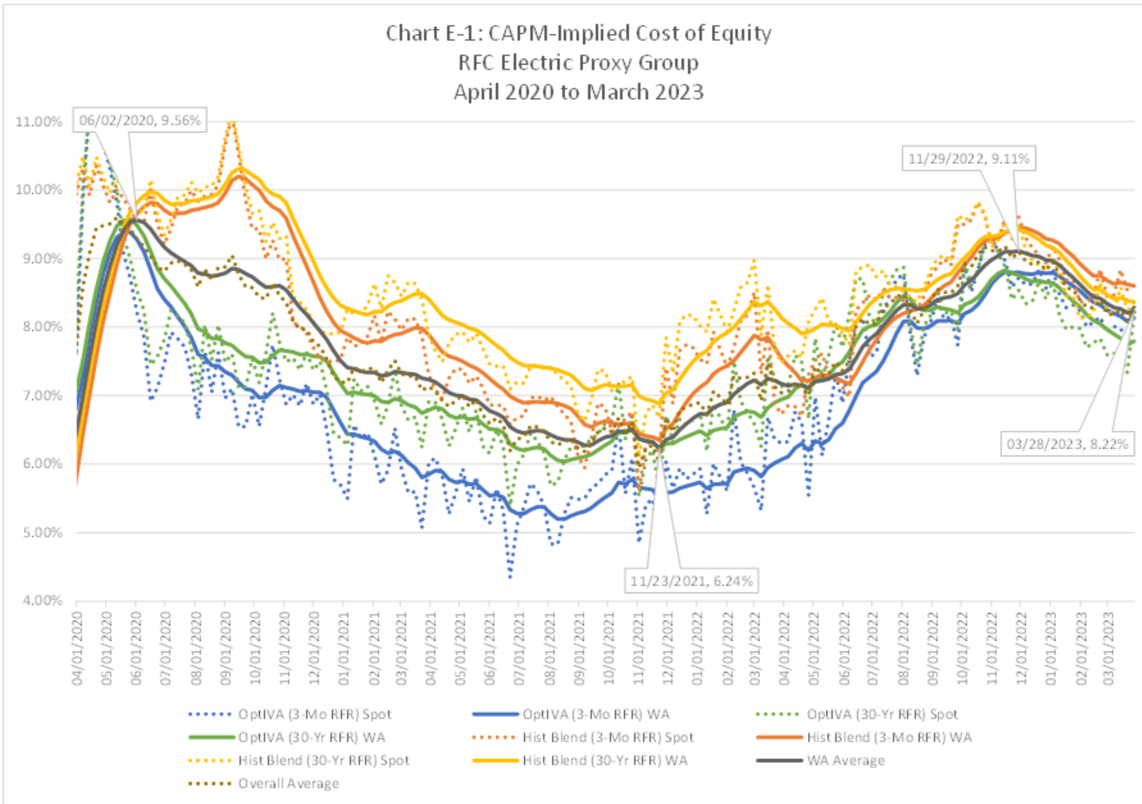
A. In late 2020, after significant efforts related to the complexities in processing extremely large volumes of option data, I was finally able to use option-implied volatility and option-implied skewness to come up with a log-normal function that approximates the probability distribution of the possible trajectories for the S&P 500 implied by the options market as of any given day, as explained above. All the testimonies I have filed since then, starting in 2021, have used this complete and superior approach along with a cumulative probability of 50%, representing the median of the probability distribution, or the option-implied

[92] Mr. Moul's Direct Testimony, page 5, line 10.

market consensus, to estimate expected market growth. Any references to cumulative probability in these testimonies are directly comparable.

Prior to incorporating skewness into the approximation, I used a normal function to estimate the same probability distribution referred to above. Using a normal distribution as an approximation is a simplification used commonly in economics, including in the Black-Scholes formula for a single option. However, unlike a skewed log-normal function, a normal function has the same median and mean, meaning that when applied in this case, the option-implied market consensus of this simplified approximation implies market growth of 0%. As a result, before using log-normal functions, I had to resort to finding an adequate level of cumulative probability above 50% to estimate market growth, which is admittedly somewhat subjective. To be conservative, I often used a cumulative probability of 68.3%, which is the probability found within one standard deviation of the mean of a normal distribution, which I understood would lead to a conservatively high estimate for market growth. It is important to point out that the cumulative probabilities of the simplified normal function approximation I used in cases before 2021 cannot be directly compared to the cumulative probabilities of the superior log-normal function approximation, which takes skewness into account. The considerably improved approximation based on a log-normal function eliminates all subjectivity in arriving at the implied market consensus and allows a much better measure of implied cumulative probabilities of deviations from that market consensus.

APPENDIX E. CAPM-IMPLIED COST OF EQUITY FOR RFC ELECTRIC PROXY GROUP OVER TIME SINCE ONSET OF COVID PANDEMIC



Notes regarding the content of this chart:

- *The information in this chart is the property of Rothschild Financial Consulting ("RFC") and may not be used for any purpose without the express written consent of RFC. Even when the underlying data is publicly available from another source, the results of analyses performed by RFC and the way of presenting the data are and remain the property of RFC.*

- *The data presented herein may not agree 100% with past recommendations by RFC for numerous reasons, including differences in the underlying proxy group and the fact that this chart represents only results based on the CAPM, whereas RFC usually bases recommendations on the CAPM and other models, such as various forms of the DCF.*

APPENDIX F. RESUME OF AARON L. ROTHSCHILD

SUMMARY

Financial professional providing U.S. public utility commissions financial tools and expert testimony to assist in rate setting for regulated utility companies (e.g., regulated electric distribution providers, natural gas pipelines). Relevant experience includes developing and applying methodologies that directly measure investors' equity return expectations based on stock option prices, applied mathematics research for utility industry as an affiliate of the New England Complex Systems Institute, and serving as Head of Business Analysis for a major U.S. telecom firm in Asia Pacific.

EXPERIENCE

Rothschild Financial Consulting, Ridgefield, CT **November 2001- present**
Independent consulting firm specializing in utility sector
President

- Provide financial expert testimony (e.g., rate of return and M&A) to regulators, policy makers, foundations, and consumer groups in utility rate case proceedings, including representing the California Public Advocates Office and the Wild Tree Foundation in the ongoing California water and energy cost of capital proceedings
- Developed cost of equity models that have been adopted by the Public Service Commission of South Carolina in 2020 (decision upheld by the South Carolina Supreme Court in September 2021) and the Connecticut Public Utilities Regulatory Authority in September 2021
- Developing market-based cost of equity methodology in ongoing regulated natural gas pipeline case before the Federal Energy Regulatory Commission (FERC), including proposing replacing equity analyst earnings per-share forecasts (IBES, Value Line) with options-implied growth expectations to determine authorized return on equity (ROE)
- Present at utility regulation conferences (NARUC/NASUCA and MARC) regarding rate of return, power purchase agreements, complex systems science, and subsidy auctions

360 Networks, Hong Kong **January 2001 - October 2001**
Pioneer of the fiber optic telecommunications industry
Senior Manager

- Business development and investment evaluation
- Negotiated landing rights and formed local partnerships in Korea, Japan, Singapore, and Hong Kong for $1 billion undersea cable project
- Structured fiber optic bandwidth swapping agreement with Enron and Global Crossing
- Established relationships with Hong Kong based Investment Bankers to communicate Asia Pacific objectives and accomplishments to Wall Street

Dantis, Chicago, IL **July 2000- December 2000**
Start-up managed data-hosting services provider
Director

- Built capital raise valuation models and negotiated with potential investors
- Team raised $100M from venture capital firm through valuation negotiations and internal strategic analysis

MFS, MCI-WorldCom, Chicago, Hong Kong, Tokyo September 1996- July 2000
American Telecommunications Company
Head of Business Analysis for Japan operations

- Managed staff of 5 business development analysts
- Raised $80M internally for Japanese national fiber network expansion plan by conducting an investment evaluation and presenting findings to CEO of international operations in London, UK
- Built financial model for local fiber optic investment evaluation that was used by business development offices in Oak Brook, IL and Sydney, Australia

EDUCATION

Vanderbilt University, Nashville, TN 1994-1996
MBA, Finance

- Completed business plan for Nextlink Communications in support of their national fiber optic network expansion, including identifying opportunities from passage of Telecom Act of 1996
- Developed analytical framework to evaluate predictability of rare events
- Provided financial and accounting analysis to Chicago's consumer advocate, the Citizens Utility Board (CUB) as a summer intern

Clark University, Worchester, MA 1990 - 1994
BA, Mathematics

APPENDIX G. TESTIFYING EXPERIENCE OF AARON L. ROTHSCHILD

Filed Rate of Return Testimonies:

California
- Pacific Gas and Electric Company, Application 22-04-008, Rate of Return, August 2022
- Southern California Edison, Application 22-04-009, Rate of Return, August 2022
- San Diego Gas & Electric Company, Application 22-04-012, Rate of Return, August 2022
- California American Water Company, Application 21-05-001, Rate of Return, January 2022
- California Water Service Company, Application 21-05-002, Rate of Return, January 2022
- Golden State Water Company, Application 21-05-003, Rate of Return, January 2022
- San Jose Water Company, Application 21-05-004, Rate of Return, January 2022
- Southern California Edison, Application 21-08-013, Rate of Return/Cost of Capital Mechanism, January 2022
- San Diego Gas & Electric Company, Application 21-08-014, Rate of Return/Cost of Capital Mechanism, January 2022
- Pacific Gas and Electric Company, Application 21-08-015, Rate of Return/Cost of Capital Mechanism, January 2022
- Pacific Gas and Electric Company, Application 21-01-004, Securitization, February 2021
- Pacific Gas and Electric Company, Application 20-04-023, Securitization, October 2020
- Southern California Edison, Application 20-07-008, Securitization, September 2020
- San Diego Gas & Electric Company, Application 19-04-017, Rate of Return, August 2019
- Southern California Gas Company, Application 19-04-016, Rate of Return, August 2019
- Pacific Gas and Electric Company, Application 19-04-015, Rate of Return, August 2019
- Southern California Edison, Application 19-04-014, Rate of Return, August 2019
- Liberty Utilities, Application A.18-05-006, Rate of Return, August 2018
- San Gabriel Water Company, Application 18-05-005, Rate of Return, August 2018
- Suburban Water Company, Application 18-05-004, Rate of Return, August 2018
- Great Oaks Water Company, Application 18-05-001, Rate of Return, August 2018
- California Water Service Company, Application 17-04-006, Rate of Return, August 2017
- California American Water Company, Application 17-04-003, Rate of Return, August 2017
- Golden State Water Company, Application 17-04-002, Rate of Return, August 2017
- San Jose Water Company, Application 17-04-001, Rate of Return, August 2017

Colorado
- Public Service Company of Colorado, Docket No. 11AL-947E, Rate of Return, March 2012

Connecticut
- United Illuminating Company, Docket No. 22-08-08, Rate of Return, December 13, 2022
- Aquarion Water Company of Connecticut, Docket No. 22-07-01, Rate of Return, October 2022
- Eversource and United Illuminating, Docket No. 17-12-03RE11, Rate of Return / Interim Rate Reduction, April 2021

- United Water Connecticut, Docket No. 07-05-44, Rate of Return, November 2008
- Valley Water Systems, Docket No. 06-10-07, Rate of Return, May 2007

Delaware
- Tidewater Utilities, Inc., PSC Docket No. 11-397, Rate of Return, April 2012

Florida
- Florida Power & Light (FPL), Docket No. 070001-EI, October 2007
- Florida Power Corp., Docket No. 060001 Fuel Clause, September 2007

New Jersey
- Aqua New Jersey, Inc., BPU Docket No. WR11120859, Rate of Return, April 2012

Maryland
- Delmarva Power & Light, Case No. 9317, Rate of Return, June 2013
- Columbia Gas of Maryland, Case No. 9316, Rate of Return, May 2013
- Potomac Electric Power Company, Case No. 9286, Rate of Return, March 2012
- Delmarva Power & Light, Case No. 9285, Rate of Return, March 2012

North Dakota
- Montana-Dakota Utilities Co., Case No. PU-20-379, Rate of Return, January 2021
- Otter Tail Power Company, Case No. PU-17-398, Rate of Return, May 2018
- Montana-Dakota Utilities Co., Case No. PU-15-90, Rate of Return, August 2015
- Northern States Power, Case No. PU-400-04-578, Rate of Return, March 2005

Pennsylvania
- Pennsylvania American Water Company, Docket No. R-2022-3031672 and R-2022-3031673, Rate of Return, July 2022
- UGI Utilities, Inc. – Electric Division, Docket No. R-2021-3023618, Rate of Return, May 2021
- Pennsylvania American Water Company, Docket No. P-2021-3022426, Rate of Return, February 2021
- Audubon Water Company, Docket No. R-2020-3020919, Rate of Return, November 2020
- Pennsylvania American Water Company, Docket No. R-2020-3019369 and R-2020-3019371, Rate of Return, September 2020
- Twin Lakes Utilities, Inc., Docket No. R-2019-3010958, Rate of Return, October 2019
- City of Lancaster Sewer Fund, Docket No. R-2019-3010955, Rate of Return, October 2019
- Community Utilities of Pennsylvania Inc. Wastewater Division, Docket No. R-2019-3008948, Rate of Return, July 2019
- Community Utilities of Pennsylvania Inc. Water Division, Docket No. R-2019-3008947, Rate of Return, July 2019
- Newtown Artesian Water Company, Docket No. R-20019-3006904, Rate of Return, May 2019
- Hidden Valley Utility Services, L.P. – Wastewater Division, Docket No. R-2018-3001307, Rate of Return, September 2018
- Hidden Valley Utility Services, L.P. – Water Division, Docket No. R-2018-3001306, Rate of Return, September 2018
- The York Water Company, Docket No. R-2018-3000019, Rate of Return, August 2018
- SUEZ PA Pennsylvania, Inc., Docket No. R-2018-000834, Rate of Return, July 2018

- UGI Utilities, Inc. – Electric Division, Docket No. R-2017-2640058, Rate of Return, April 2018
- Wellsboro Electric Company, Docket No. R-2016-2531551, Rate of Return, December 2016
- Citizens' Electric Company of Lewisburg, PA, Docket No. R-2016-2531550, Rate of Return, December 2016
- Columbia Gas of Pennsylvania, Inc., Docket No. R-2016-2529660, Rate of Return, June 2016
- Columbia Gas of Pennsylvania, Inc., Docket No. R-2015-2468056, Rate of Return, June 2015
- Pike County Light & Power Company, Docket No. R-2013-2397353 (gas), Rate of Return, April 2014
- Pike County Light & Power Company, Docket No. R-2013-2397237 (electric), Rate of Return, April 2014
- Columbia Water Company, Docket No. R-2013-2360798, Rate of Return, August 2013
- Peoples TWP LLC, Docket No. R-2013-2355886, Rate of Return, July 2013
- City of Dubois – Bureau of Water, Docket No. R-2013-2350509, Rate of Return, July 2013
- City of Lancaster – Sewer Fund, Docket No. R-2012-2310366, Rate of Return, December 2012
- Wellsboro Electric Company, Docket No. R-2010-2172665, Rate of Return, September 2010
- Citizens' Electric Company of Lewisburg, PA, Docket No. R-2010-2172662, Rate of Return, September 2010
- T.W. Phillips Gas and Oil Company, Docket No. R-2010-2167797, Rate of Return, August 2010
- York Water Company, Docket No. R-2010-2157140, Rate of Return, August 2010
- Joint Application of The Peoples Natural Gas Company, Dominion Resources, Inc. and Peoples Hope Gas Company LLC, Docket No. A-2008-2063737, Financial Analysis, December 2008
- York Water Company, Docket No. R-2008-2023067, Rate of Return, August 2008

South Carolina

- Duke Energy Progress, LLC., Docket No. 2022-254-E, Rate of Return, December 2022
- Daufuskie Island Utility Company, Inc., Docket No. 22-142-WS, Rate of Return, September 2022
- Piedmont Natural Gas Company, Inc., Docket No. 22-89-G, Rate of Return, July 2022
- Kiawah Island Utility, Inc., Docket No. 2021-324-WS, Rate of Return, February 2022
- Palmetto Wastewater Reclamation, Inc., Docket No. 2021-153-S, Rate of Return, September 2021
- Dominion Energy South Carolina, Inc., Docket No. 2020-125-E, Rate of Return, November 2020
- Palmetto Utilities, Inc., Docket No. 2019-281-S, Rate of Return, May 2020
- Palmetto Utilities, Inc., Docket No. 2019-281-S, Accounting, May 2020
- Blue Granite Water Company, Docket No. 2019-290-WS, Rate of Return, January 2020

Tennessee

- Kingsport Power Company D/B/A AEP Appalachian Power, Docket No. 21-00107, Rate of Return, March 2022

Vermont

- Central Vermont Public Service Corp., Docket No. 7321, Rate of Return, September 2007

Wisconsin

- American Transmission Company, LLC, ITC, Midwest, LLC, Case No. 19-CV-3418, financial and regulatory analysis regarding requested temporary injunction to halt the construction in Wisconsin of the proposed Cardinal-Hickory Creek transmission line, October 2021

OVERALL COST OF CAPITAL
UGI Utilities, Inc. - Electric Division

	Ratios		Cost Rate		Weighted Cost Rate
					[D]
Long-Term Debt	55.25%	[A]	4.35%	[B]	2.40%
Short-Term Debt	0.00%	[B]	0.00%	[B]	0.00%
Preferred Equity	0.00%	[B]	0.00%	[B]	0.00%
Common Equity	44.75%	[A]	8.44%	[C]	3.78%
	100.00%				**6.18%**

RECOMMENDED RANGES

		Low		High
Proxy Group Cost of Equity Range		8.16%		8.71%
Proxy Group Cost of Equity			8.44%	
Based on RFC Capital Structure Recommendation				
Capital Structure Risk Adjustment	[E]		0.00%	
Adjusted Recommended Cost of Equity Range		**8.16%**		**8.71%**
Company Specific Cost of Equity Recommendation			$\boxed{\textbf{8.44\%}}$	
Cost of Capital Range		6.06%		6.30%
Based on Mr. Moul's Capital Structure Recommendation				
Capital Structure Risk Adjustment	[F]		-0.39%	
Adjusted Recommended Cost of Equity Range		**7.77%**		**8.32%**
Company Specific Cost of Equity Recommendation			$\boxed{\textbf{8.04\%}}$	
Cost of Capital Range		6.22%		6.52%
Comprehensive Cost of Capital Range				
Cost of Debt Range		4.35%		0.00%
Common Equity Ratio Range		44.75%		42.27%
Comprehensive Cost of Capital Range		6.06%		3.68%

Sources:
[A] Recommendation based on Proxy Group capital structures
[B] Direct Testimony of Paul R. Moul, page 18, lines 22-23.
[C] Company Specific Cost of Equity Recommendation based on RFC Capital Structure Recommendation
[D] Ratios times Cost Rate
[E] Not applicable because of recommended Capital Structure within Proxy Group range.
[F] Based on estimate of 0.04% change in Cost of Equity for each 1% difference in Common Equity Ratio compared to the Proxy Group (Exhibit ALR-1 vs. Exhibit ALR-5, page 4).

COST OF EQUITY SUMMARY

RFC Electric Proxy Group (24 Companies)

		Low		High
DCF				
Constant Growth - Sustainable Growth	[A]	8.12%		8.26%
Constant Growth - Option-Implied Growth	[B]	8.47%		9.34%
Non-Constant Growth	[C]	9.05%		9.06%
CAPM				
3-Mo. Weighted Average (Jan. to Mar. 2023)				
3-Month Treasury Bill Risk-Free Rate	[D]	8.13%		8.60%
30-Year Treasury Bond Risk-Free Rate	[D]	7.78%		8.35%
Spot (Mar. 31, 2023)				
3-Month Treasury Bill Risk-Free Rate	[E]	8.48%		8.54%
30-Year Treasury Bond Risk-Free Rate	[E]	8.17%		8.25%
Average		**8.31%**		**8.63%**
Outer Quartile Range		**8.16%**		**8.71%**
Proxy Group Cost of Equity			$\boxed{\textbf{8.44\%}}$	

Sources:
[A] Exhibit ALR-3, page 1
[B] Exhibit ALR-3, page 2
[C] Exhibit ALR-3, page 3 and Exhibit ALR-3, page 4
[D] Exhibit ALR-4, page 1
[E] Exhibit ALR-4, page 5

CONSTANT GROWTH DISCOUNTED CASH FLOW (DCF) - INDICATED COST OF EQUITY
RFC Electric Proxy Group (24 Companies)

		Based on Average Market Price For Year Ending 3/31/2023	Based On Market Price As Of 3/31/2023
1 Dividend Yield On Market Price	[A]	3.69%	3.69%
2 Retention Rate:			
a) Market-to-Book Ratio	[A]	1.97	1.90
b) Dividend Yield on Book	[B]	7.25%	7.03%
c) Expected Return on Equity	[C]	10.30%	10.30%
d) Retention Rate	[D]	29.63%	31.72%
3 Reinvestment Growth	[E]	3.05%	3.27%
4 New Financing Growth	[F]	1.30%	1.22%
5 Total Estimate of Investor Anticipated Growth	[G]	4.35%	4.49%
6 Increment to Dividend Yield for Growth to Next Year	[H]	0.08%	0.08%
7 Indicated Cost of Equity	**[I]**	**8.12%**	**8.26%**

Sources:

[A] Exhibit ALR-5, page 1

[B] Line 1 x Line 2a

[C] Some of the considerations for determining Future Expected Return on Equity:

	Median	Mean	From
Value Line Expectation	**10.00%**	**10.76%**	Exhibit ALR-5, page 2
Return on Equity to Achieve Zacks Growth	9.94%	10.80%	Exhibit ALR-5, page 3
Average Historical Growth	10.12%	10.03%	
Earned Return on Equity in 2022	9.90%	10.07%	Exhibit ALR-5, page 2
Earned Return on Equity in 2021	10.53%	10.24%	Exhibit ALR-5, page 2
Earned Return on Equity in 2020	9.91%	9.78%	Exhibit ALR-5, page 2

[D] 1 - Line 2b / Line 2c

[E] Line 2c x Line 2d — From

[F] S x V = (Ext. Fin Rate) x (Line 2a - 1) — Ext. Fin. Rate = 1.35% — Exhibit ALR-3, page 5

S = rate of continuous new stock financing

V = fraction of funds raised by sale of stock that increases the book value of existing shareholders' common equity

[G] Line 3 + Line 4

[H] Line 1 x one-half of Line 5

[I] Line 1 + Line 5 + Line 6

CONSTANT GROWTH DISCOUNTED CASH FLOW (DCF) - INDICATED COST OF EQUITY
RFC Electric Proxy Group (24 Companies)

			Based On Weighted Averages As Of 3/31/2023	Based On Spot Market Values As Of 3/31/2023
1	Dividend Yield On Market Price	[A]	3.69%	3.69%
2	Total Estimate of Investor Anticipated Growth	[B]	4.69%	5.54%
3	Increment to Dividend Yield for Growth to Next Year	[C]	0.09%	0.10%
4	**Indicated Cost of Equity**	**[D]**	**8.47%**	**9.34%**

Sources:
[A] Exhibit ALR-5, page 1
[B] 6-Month Option-Implied Growth
[C] Line 1 x one-half of Line 2
[D] Line 1 + Line 2 + Line 3

NON-CONSTANT GROWTH DISCOUNTED CASH FLOW (DCF) - INDICATED COST OF EQUITY

(BASED ON VALUE LINE FORECASTS AND CLOSING STOCK PRICE)

RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
		Forecasted Dividends per Share					Growth	Book Value		Closing Stock Price		Cash Flow From Buying and Selling Stock (At Closing Price)					
		2023	**2024**	**2024**	**2025**	**2026**	**2023-26**	**3/31/23**	**3/31/26**	**3/31/2023**	**3/31/2026**		**2023**	**2024**	**2025**	**2026**	**IRR / DCF**
		[A]	[A]	[B]	[B]	[A]	[B]	[C]	[C]	[D]	[E]	[F]	[F]	[F]	[F]	[F]	[G]
AMEREN	AEE	$2.52	NA	$2.76	$3.02	$3.30	9.41%	$40.13	$54.91	$86.39	$118.20		($84.50)	$2.76	$3.02	$119.02	14.27%
AMERICAN ELEC. PWR.	AEP	$3.35	NA	$3.60	$3.87	$4.16	7.49%	$48.10	$57.20	$90.99	$108.20		($88.48)	$3.60	$3.87	$109.24	10.03%
ALLETE	ALE	$2.71	NA	$2.80	$2.90	$3.00	3.45%	$47.57	$52.32	$64.37	$70.79		($62.34)	$2.80	$2.90	$71.54	7.72%
AVISTA CORP.	AVA	$1.83	NA	$1.90	$1.97	$2.05	3.86%	$31.13	$34.21	$42.45	$46.65		($41.08)	$1.90	$1.97	$47.17	7.83%
CMS ENERGY CORP.	CMS	$1.95	NA	$2.06	$2.18	$2.30	5.66%	$24.38	$25.15	$61.38	$63.33		($59.92)	$2.06	$2.18	$63.90	4.53%
DOMINION ENERGY	D	$2.75	NA	$2.92	$3.11	$3.30	6.27%	$32.90	$41.69	$55.91	$70.85		($53.85)	$2.92	$3.11	$71.67	13.62%
DUKE ENERGY	DUK	$4.06	NA	$4.14	$4.22	$4.30	1.93%	$63.19	$68.58	$96.47	$104.70		($93.43)	$4.14	$4.22	$105.77	7.19%
CON. EDISON	ED	$3.24	NA	$3.39	$3.55	$3.72	4.71%	$58.80	$66.64	$95.67	$108.43		($93.24)	$3.39	$3.55	$109.36	7.90%
EDISON INTERNAT'L	EIX	$2.95	NA	$3.12	$3.31	$3.50	5.86%	$42.43	$45.75	$70.59	$76.12		($68.38)	$3.12	$3.31	$77.00	7.15%
EVERSOURCE ENERGY	ES	$2.71	NA	$2.95	$3.20	$3.48	8.69%	$44.78	$53.20	$78.26	$92.99		($76.23)	$2.95	$3.20	$93.86	9.81%
ENTERGY CORP.	ETR	$4.30	NA	$4.52	$4.75	$5.00	5.16%	$61.69	$71.99	$107.74	$125.74		($104.52)	$4.52	$4.75	$126.99	9.61%
EVERGY, INC.	EVRG	$2.53	NA	$2.69	$2.87	$3.05	6.43%	$42.07	$46.80	$61.12	$67.99		($59.22)	$2.69	$2.87	$68.75	8.19%
HAWAIIAN ELECTRIC	HE	$1.44	NA	$1.49	$1.54	$1.60	3.57%	$20.31	$24.38	$38.40	$46.08		($37.32)	$1.49	$1.54	$46.48	10.24%
IDACORP, INC.	IDA	$3.25	NA	$3.48	$3.73	$4.00	7.17%	$56.31	$64.51	$108.33	$124.10		($105.89)	$3.48	$3.73	$125.10	7.94%
ALLIANT ENERGY	LNT	$1.81	NA	$1.96	$2.12	$2.29	8.16%	$25.38	$30.49	$53.40	$64.16		($52.04)	$1.96	$2.12	$64.73	10.09%
MGE ENERGY INC.	MGEE	NA	NA	NA	NA	NA	NA	NA	NA	$77.67	NA		NA	NA	NA	NA	NA
NEXTERA ENERGY	NEE	$1.87	NA	$2.12	$2.41	$2.74	13.58%	$20.34	$27.55	$77.08	$104.40		($75.68)	$2.12	$2.41	$105.08	13.47%
NORTHWESTERN	NWE	$2.56	NA	$2.60	$2.64	$2.68	1.54%	$45.03	$48.62	$57.86	$62.48		($55.94)	$2.60	$2.64	$63.15	7.23%
OGE ENERGY CORP.	OGE	$1.70	NA	$1.75	$1.80	$1.85	2.86%	$22.03	$25.74	$37.26	$43.54		($35.98)	$1.75	$1.80	$44.00	10.16%
PINNACLE WEST	PNW	$3.48	NA	$3.54	$3.60	$3.66	1.70%	$53.19	$58.63	$79.24	$87.35		($76.63)	$3.54	$3.60	$88.26	7.90%
PORTLAND GENERAL	POR	$1.88	NA	$1.99	$2.11	$2.24	6.01%	$31.76	$35.61	$48.89	$54.82		($47.48)	$1.99	$2.11	$55.38	8.11%
SOUTHERN COMPANY	SO	$2.78	NA	$2.88	$2.99	$3.10	3.70%	$27.29	$31.43	$69.58	$80.14		($67.50)	$2.88	$2.99	$80.92	9.08%
WEC ENERGY GROUP	WEC	$3.12	NA	$3.33	$3.56	$3.80	6.79%	$36.91	$41.50	$94.79	$106.59		($92.45)	$3.33	$3.56	$107.54	7.62%
XCEL ENERGY	XEL	$2.07	NA	$2.21	$2.36	$2.52	6.78%	$30.53	$35.68	$67.44	$78.84		($65.89)	$2.21	$2.36	$79.47	8.71%
Maximum		$4.30	$0.00	$4.52	$4.75	$5.00	13.58%	$63.19	$71.99	$108.33	$125.74	$0.00	($35.98)	$4.52	$4.75	$126.99	14.27%
Minimum		$1.44	$0.00	$1.49	$1.54	$1.60	1.54%	$20.31	$24.38	$37.26	$43.54	$0.00	($105.89)	$1.49	$1.54	$44.00	4.53%
Median		$2.71	#NUM!	$2.80	$2.99	$3.10	5.86%	$40.13	$45.75	$70.09	$78.84	#NUM!	($67.50)	$2.80	$2.99	$79.47	8.19%
Average		$2.65	#DIV/0!	$2.79	$2.95	$3.11	5.69%	$39.40	$45.33	$71.72	$82.89	#DIV/0!	($69.48)	$2.79	$2.95	$83.67	**9.06%**

Sources:

[A] Value Line: Most current data available at time of schedule preparation. 2026 data is VL forecast for 2025-27.

[B] Straight line interpolation based on Value Line data, assuming constant dividend growth for 2023-26.

[C] Straight line interpolation based on Value Line data, assuming constant book value growth for 2023-26.

[D] EOD Data: Market Data as of March 31, 2023.

[E] Stock Price projected assuming constant Market to Book Ratio (Exhibit ALR-5, page 1) and using VL projected Book Value.

[F] Cash Flow from purchasing stock on April 1, 2023, receiving dividends through 2026, and selling on March 31, 2026.
Negative number in 2023 reflects cash outflow required to purchase stock.
Cash flow sources are 1) dividends and 2) proceeds of stock sale.
3 of 4 dividends assumed received in 2023 and 1 of 4 in 2026 based on purchase and sale date.

[G] Total return on equity to investor who purchased, held, and sold stock as described above,
assuming Value Line projections of Dividends and Book Value are correct and
assuming Stock Price grows at same rate as Book Value.
DCF result is an Internal Rate of Return computation made using the "IRR" function built into Microsoft Excel
based on projected cash flows from 2023 to 2026.

NON-CONSTANT GROWTH DISCOUNTED CASH FLOW (DCF) - INDICATED COST OF EQUITY

(BASED ON VALUE LINE FORECASTS AND LTM AVERAGE STOCK PRICE)

RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
		Forecasted Dividends per Share					Growth	LTM Avg. Book Value		LTM Avg. Stock Price		Cash Flow From Buying and Selling Stock (At LTM Average Price)					
		2023	2024	2024	2025	2026	2023-26	2023	2026	3/31/23	3/31/26		2023	2024	2025	2026	IRR / DCF
		[A]	[A]	[B]	[B]	[A]	[B]	[C]	[C]	[D]	[E]	[F]	[F]	[F]	[F]	[F]	[G]
AMEREN	AEE	$2.52	NA	$2.76	$3.02	$3.30	9.41%	$39.20	$53.63	$86.24	$117.99		($84.35)	$2.76	$3.02	$118.82	14.27%
AMERICAN ELEC. PWR.	AEP	$3.35	NA	$3.60	$3.87	$4.16	7.49%	$46.56	$55.37	$92.95	$110.53		($90.44)	$3.60	$3.87	$111.57	9.94%
ALLETE	ALE	$2.71	NA	$2.80	$2.90	$3.00	3.45%	$46.68	$51.34	$58.12	$63.91		($56.08)	$2.80	$2.90	$64.66	8.22%
AVISTA CORP.	AVA	$1.83	NA	$1.90	$1.97	$2.05	3.86%	$30.73	$33.77	$41.16	$45.24		($39.79)	$1.90	$1.97	$45.75	7.98%
CMS ENERGY CORP.	CMS	$1.95	NA	$2.06	$2.18	$2.30	5.66%	$23.49	$24.24	$63.09	$65.09		($61.62)	$2.06	$2.18	$65.66	4.43%
DOMINION ENERGY	D	$2.75	NA	$2.92	$3.11	$3.30	6.27%	$32.32	$40.95	$70.41	$89.21		($68.34)	$2.92	$3.11	$90.04	12.47%
DUKE ENERGY	DUK	$4.06	NA	$4.14	$4.22	$4.30	1.93%	$62.52	$67.85	$100.05	$108.58		($97.00)	$4.14	$4.22	$109.65	7.02%
CON. EDISON	ED	$3.24	NA	$3.39	$3.55	$3.72	4.71%	$57.93	$65.65	$90.16	$102.18		($87.73)	$3.39	$3.55	$103.11	8.13%
EDISON INTERNAT'L	EIX	$2.95	NA	$3.12	$3.31	$3.50	5.86%	$40.16	$43.31	$63.89	$68.89		($61.67)	$3.12	$3.31	$69.77	7.66%
EVERSOURCE ENERGY	ES	$2.71	NA	$2.95	$3.20	$3.48	8.69%	$43.81	$52.05	$82.59	$98.13		($80.55)	$2.95	$3.20	$99.00	9.60%
ENTERGY CORP.	ETR	$4.30	NA	$4.52	$4.75	$5.00	5.16%	$60.05	$70.08	$110.88	$129.40		($107.65)	$4.52	$4.75	$130.65	9.48%
EVERGY, INC.	EVRG	$2.53	NA	$2.69	$2.87	$3.05	6.43%	$41.39	$46.04	$63.62	$70.77		($61.73)	$2.69	$2.87	$71.54	8.01%
HAWAIIAN ELECTRIC	HE	$1.44	NA	$1.49	$1.54	$1.60	3.57%	$20.86	$25.03	$38.95	$46.74		($37.87)	$1.49	$1.54	$47.14	10.18%
IDACORP, INC.	IDA	$3.25	NA	$3.48	$3.73	$4.00	7.17%	$54.90	$62.89	$106.23	$121.68		($103.79)	$3.48	$3.73	$122.68	8.01%
ALLIANT ENERGY	LNT	$1.81	NA	$1.96	$2.12	$2.29	8.16%	$24.78	$29.77	$56.28	$67.62		($54.92)	$1.96	$2.12	$68.19	9.89%
MGE ENERGY INC.	MGEE	NA	NA	NA	NA	NA	NA	NA	NA	$73.97	NA		NA	NA	NA	NA	NA
NEXTERA ENERGY	NEE	$1.87	NA	$2.12	$2.41	$2.74	13.58%	$19.75	$26.74	$79.29	$107.38		($77.88)	$2.12	$2.41	$108.07	13.39%
NORTHWESTERN	NWE	$2.56	NA	$2.60	$2.64	$2.68	1.54%	$44.32	$47.86	$55.87	$60.33		($53.95)	$2.60	$2.64	$61.00	7.40%
OGE ENERGY CORP.	OGE	$1.70	NA	$1.75	$1.80	$1.85	2.86%	$21.36	$24.96	$38.10	$44.52		($36.82)	$1.75	$1.80	$44.98	10.05%
PINNACLE WEST	PNW	$3.48	NA	$3.54	$3.60	$3.66	1.70%	$52.82	$58.22	$69.82	$76.96		($67.21)	$3.54	$3.60	$77.87	8.55%
PORTLAND GENERAL	POR	$1.88	NA	$1.99	$2.11	$2.24	6.01%	$31.16	$34.93	$49.31	$55.28		($47.90)	$1.99	$2.11	$55.84	8.07%
SOUTHERN COMPANY	SO	$2.78	NA	$2.88	$2.99	$3.10	3.70%	$26.89	$30.97	$70.64	$81.36		($68.56)	$2.88	$2.99	$82.14	9.02%
WEC ENERGY GROUP	WEC	$3.12	NA	$3.33	$3.56	$3.80	6.79%	$36.02	$40.51	$94.61	$106.38		($92.27)	$3.33	$3.56	$107.33	7.63%
XCEL ENERGY	XEL	$2.07	NA	$2.21	$2.36	$2.52	6.78%	$29.79	$34.83	$67.28	$78.65		($65.72)	$2.21	$2.36	$79.28	8.72%
Maximum		$4.30	$0.00	$4.52	$4.75	$5.00	13.58%	$62.52	$70.08	$110.88	$129.40	$0.00	($36.82)	$4.52	$4.75	$130.65	14.27%
Minimum		$1.44	$0.00	$1.49	$1.54	$1.60	1.54%	$19.75	$24.24	$38.10	$44.52	$0.00	($107.65)	$1.49	$1.54	$44.98	4.43%
Median		$2.71	#NUM!	$2.80	$2.99	$3.10	5.86%	$39.20	$43.31	$70.11	$78.65	#NUM!	($67.21)	$2.80	$2.99	$79.28	8.55%
Average		$2.65	#DIV/0!	$2.79	$2.95	$3.11	5.69%	$38.59	$44.39	$71.81	$83.34	#DIV/0!	($69.73)	$2.79	$2.95	$84.12	$\boxed{9.05\%}$

Sources:

[A] Value Line: Most current data available at time of schedule preparation. 2026 data is VL forecast for 2025-27.

[B] Straight line interpolation based on Value Line data, assuming constant dividend growth for 2023-26.

[C] Straight line interpolation based on Value Line data, assuming constant book value growth for 2023-26.

[D] EOD Data: Market Data as of March 31, 2023.

[E] Stock Price projected assuming constant Market to Book Ratio (Exhibit ALR-5, page 1) and using VL projected Book Value.

[F] Cash Flow from purchasing stock on April 1, 2023, receiving dividends through 2026, and selling on March 31, 2026.
Negative number in 2023 reflects cash outflow required to purchase stock.
Cash flow sources are 1) dividends and 2) proceeds of stock sale.
3 of 4 dividends assumed received in 2023 and 1 of 4 in 2026 based on purchase and sale date.

[G] Total return on equity to investor who purchased, held, and sold stock as described above,
assuming Value Line projections of Dividends and Book Value are correct and
assuming Stock Price grows at same rate as Book Value.
DCF result is an Internal Rate of Return computation made using the "IRR" function built into Microsoft Excel
based on projected cash flows from 2023 to 2026.

COMMON SHARES OUTSTANDING AND EXTERNAL FINANCING RATE
RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		Common Stock Outstanding (Millions of Shares)								Annual Growth Rate		
		2017	2018	2019	2020	2021	2022	2023	2026	2017-21	2021-26	2017-26
		[A]	[A]	[A]	[A]	[A]	[A]	[A]	[A]	[B]	[B]	[B]
AMEREN	AEE	242.6	244.5	246.2	253.3	257.7	262.0	267.0	285.0	1.52%	2.03%	1.80%
AMERICAN ELEC. PWR.	AEP	492.0	493.3	494.2	496.6	504.2	513.9	523.0	550.0	0.61%	1.75%	1.25%
ALLETE	ALE	51.1	51.5	51.7	52.1	53.2	56.0	58.0	61.0	1.01%	2.77%	1.99%
AVISTA CORP.	AVA	65.5	65.7	67.2	69.2	71.5	74.5	77.0	83.0	2.22%	3.03%	2.67%
CMS ENERGY CORP.	CMS	281.7	283.4	283.9	288.9	289.8	291.3	292.0	300.0	0.71%	0.70%	0.70%
DOMINION ENERGY	D	644.6	680.9	838.0	805.6	810.4	835.0	842.0	870.0	5.89%	1.43%	3.39%
DUKE ENERGY	DUK	700.0	727.0	733.0	769.0	769.0	770.0	770.0	770.0	2.38%	0.03%	1.06%
CON. EDISON	ED	310.0	321.0	332.6	342.3	354.0	355.0	355.0	355.0	3.37%	0.06%	1.52%
EDISON INTERNAT'L	EIX	325.8	325.8	362.0	378.9	380.4	382.0	382.0	390.0	3.95%	0.50%	2.02%
EVERSOURCE ENERGY	ES	316.9	316.9	329.9	343.0	344.4	348.3	351.5	360.0	2.10%	0.89%	1.43%
ENTERGY CORP.	ETR	180.5	189.1	199.2	200.2	202.7	211.2	214.0	230.0	2.93%	2.56%	2.73%
EVERGY, INC.	EVRG	--	255.3	226.6	226.8	229.3	229.9	230.0	230.0	-3.52%	0.06%	-1.30%
HAWAIIAN ELECTRIC	HE	108.8	108.9	109.0	109.2	109.3	110.0	110.5	113.0	0.12%	0.67%	0.42%
IDACORP, INC.	IDA	50.4	50.4	50.4	50.5	50.5	50.7	51.0	52.0	0.05%	0.58%	0.34%
ALLIANT ENERGY	LNT	231.4	236.1	245.0	249.9	250.5	251.1	255.8	257.0	2.01%	0.52%	1.18%
MGE ENERGY INC.	MGEE	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
NEXTERA ENERGY	NEE	1,884.0	1,912.0	1,956.0	1,960.0	1,963.0	1,987.2	2,025.0	2,050.0	1.03%	0.87%	0.94%
NORTHWESTERN	NWE	49.4	50.3	50.5	50.6	54.1	58.0	62.0	62.0	2.29%	2.78%	2.56%
OGE ENERGY CORP.	OGE	199.7	199.7	200.1	200.1	200.1	200.2	200.2	200.2	0.05%	0.01%	0.03%
PINNACLE WEST	PNW	111.8	112.1	112.4	112.8	113.0	113.2	113.5	118.0	0.28%	0.87%	0.61%
PORTLAND GENERAL	POR	89.1	89.3	89.4	89.5	89.4	89.3	94.5	100.0	0.08%	2.26%	1.29%
SOUTHERN COMPANY	SO	1,007.6	1,033.8	1,053.3	1,056.5	1,060.0	1,070.0	1,070.0	1,070.0	1.28%	0.19%	0.67%
WEC ENERGY GROUP	WEC	315.6	315.5	315.4	315.4	315.4	315.4	315.4	315.4	-0.01%	0.00%	0.00%
XCEL ENERGY	XEL	507.8	514.0	524.5	537.4	544.0	547.5	550.0	561.0	1.74%	0.62%	1.11%
Maximum		1,884.0	1,912.0	1,956.0	1,960.0	1,963.0	1,987.2	2,025.0	2,050.0	5.89%	3.03%	3.39%
Minimum		49.4	50.3	50.4	50.5	50.5	50.7	51.0	52.0	-3.52%	0.00%	-1.30%
Median		262.1	255.3	246.2	253.3	257.7	262.0	267.0	285.0	1.28%	0.70%	1.18%
Average		371.2	372.9	385.7	389.5	392.0	396.6	400.4	407.9	1.40%	1.09%	1.23%
								Sustainable Growth [C]				1.35%

Sources:
[A] Value Line: Most current data available at time of schedule preparation.
[B] Annualized Growth Rate calculation.
[C] Estimated Sustainable Growth in Common Stock based on analysis of historical and projected growth rates.

CAPITAL ASSET PRICING MODEL (CAPM) - INDICATED COST OF EQUITY

WEIGHTED - All Inputs Weighted From January 2023 to March 2023

RFC Electric Proxy Group

	3-Month Treasury Bill		30-Year Treasury Bond	
	Historical Blended Beta	Forward Beta	Historical Blended Beta	Forward Beta
Risk-Free Rate	4.82%	4.82%	3.75%	3.75%
Beta	0.77	0.67	0.77	0.67
Risk Premium	4.94%	4.94%	6.01%	6.01%
CAPM (Weighted)	8.60%	8.13%	8.35%	7.78%

CAPITAL ASSET PRICING MODEL (CAPM) - RISK-FREE RATE

Spot (Mar. 31, 2023)	
3-Month Treasury Bill	4.85%
30-Year Treasury Bond	3.67%
3-Mo. Weighted Average (Jan. to Mar. 2023)	
3-Month Treasury Bill	4.82%
30-Year Treasury Bond	3.75%

Source: www.treasury.gov

CAPITAL ASSET PRICING MODEL (CAPM) - BETAS
(BASED ON HISTORICAL AND OPTION-IMPLIED RETURNS)
RFC Electric Proxy Group

Betas	12/27/2022	01/03/2023	01/10/2023	01/17/2023	01/24/2023	01/31/2023	02/07/2023	02/14/2023	02/21/2023	02/28/2023	03/07/2023	03/14/2023	03/21/2023	03/28/2023	Average	Time Avg.
Forward (6 months)	0.71	0.72	0.70	0.70	0.71	0.75	0.69	0.70	0.64	0.66	0.67	0.60	0.58	0.74	0.685	0.671
Historical (6 months)	0.81	0.81	0.85	0.83	0.82	0.81	0.80	0.81	0.82	0.81	0.81	0.80	0.73	0.76	0.807	0.795
Historical (2 yrs)	0.72	0.72	0.73	0.72	0.73	0.73	0.73	0.73	0.73	0.72	0.72	0.72	0.72	0.72	0.723	0.721
Historical (5 yrs)	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.758	0.759
Weighting																
Forward (6 months)	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%		
Historical (6 months)	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%		
Historical (2 yrs)	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%		
Historical (5 yrs)	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%		
Historical Blended Beta	**0.77**	**0.78**	**0.80**	**0.78**	**0.78**	**0.77**	**0.77**	**0.78**	**0.78**	**0.77**	**0.77**	**0.77**	**0.73**	**0.75**	0.772	0.766
Slope	15%															
Points	0.00	1.00	1.15	1.32	1.52	1.75	2.01	2.31	2.66	3.06	3.52	4.05	4.65	5.35		
Time Weight	0.0%	2.9%	3.3%	3.8%	4.4%	5.1%	5.9%	6.7%	7.7%	8.9%	10.2%	11.8%	13.5%	15.6%		

CAPM Betas	Spot (Mar 28, 2023)	Weighted (Jan - Mar 2023)
Forward	0.74	0.67
Historical Blended	0.75	0.77

Note: Historical betas are calculated on Tuesdays, following Value Line's methodology. Forward (option-implied) betas are also calculated on Tuesdays for the sake of compatibility.

CAPITAL ASSET PRICING MODEL (CAPM) - MARKET RISK PREMIUM

WEIGHTED - All Inputs Weighted From January 2023 to March 2023

Cumulative Probability	50.00%	
S&P 500 Option-Implied Growth Rate	8.08%	
S&P 500 Dividend Yield	1.68%	
S&P 500 Market Return	9.76%	
	3-Month Treasury Bill	**30-Year Treasury Bond**
Risk-Free Rate	4.82%	3.75%
Option-Implied Market Risk Premium (Weighted)	4.94%	6.01%

CAPITAL ASSET PRICING MODEL (CAPM) - INDICATED COST OF EQUITY

SPOT - All Inputs Based on Last Available Data as of March 31, 2023

RFC Electric Proxy Group

	3-Month Treasury Bill		30-Year Treasury Bond	
	Historical Blended Beta	Forward Beta	Historical Blended Beta	Forward Beta
Risk-Free Rate	4.85%	4.85%	3.67%	3.67%
Beta	0.75	0.74	0.75	0.74
Risk Premium	4.92%	4.92%	6.10%	6.10%
CAPM (Spot)	8.54%	8.48%	8.25%	8.17%

CAPITAL ASSET PRICING MODEL (CAPM) - MARKET RISK PREMIUM

SPOT - All Inputs Based on Last Available Data as of March 31, 2023

Cumulative Probability	50.00%	
S&P 500 Option-Implied Growth Rate	8.11%	
S&P 500 Dividend Yield	1.66%	
S&P 500 Market Return	9.77%	
	3-Month Treasury Bill	**30-Year Treasury Bond**
Risk-Free Rate	4.85%	3.67%
Option-Implied Market Risk Premium (Spot)	4.92%	6.10%

MARKET TO BOOK RATIO AND DIVIDEND YIELD

RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
		Book Value per Share															
		Actual				Estimated			Market Price			Mkt. to Book Ratio		Dividend Rate		Dividend Yield	
		12/31/19	12/31/20	12/31/21	12/31/22	3/31/22	3/31/23	12/31/23	3/31/23	LTM High	LTM Low	3/31/23	LTM Avg.	MRQ	Annual	3/31/23	LTM Avg.
		[A]	[A]	[A]	[A]	[B]	[B]	[A]	[C]	[C]	[C]	[D]	[D]	[A]	[E]	[F]	[F]
AMEREN	AEE	$32.73	$35.29	$37.64	$40.11	$38.26	$40.13	$40.20	$86.39	$99.20	$73.28	2.15	2.20	$0.630	$2.520	2.92%	2.92%
AMERICAN ELEC. PWR.	AEP	$39.73	$41.38	$44.49	$46.60	$45.02	$48.10	$52.60	$90.99	$105.60	$80.30	1.89	2.00	$0.830	$3.320	3.65%	3.57%
ALLETE	ALE	$43.17	$44.04	$45.36	$47.06	$45.79	$47.57	$49.10	$64.37	$68.46	$47.77	1.35	1.25	$0.678	$2.710	4.21%	4.66%
AVISTA CORP.	AVA	$28.87	$29.31	$30.14	$30.90	$30.33	$31.13	$31.80	$42.45	$46.60	$35.72	1.36	1.34	$0.440	$1.760	4.15%	4.28%
CMS ENERGY CORP.	CMS	$17.68	$19.02	$22.11	$24.10	$22.61	$24.38	$25.20	$61.38	$73.76	$52.41	2.52	2.69	$0.488	$1.950	3.18%	3.09%
DOMINION ENERGY	D	$35.33	$29.46	$31.50	$32.45	$31.74	$32.90	$34.25	$55.91	$88.78	$52.03	1.70	2.18	$0.668	$2.670	4.78%	3.79%
DUKE ENERGY	DUK	$61.20	$59.82	$61.55	$62.75	$61.85	$63.19	$64.50	$96.47	$116.33	$83.76	1.53	1.60	$1.005	$4.020	4.17%	4.02%
CON. EDISON	ED	$54.18	$55.06	$56.60	$58.40	$57.05	$58.80	$60.00	$95.67	$102.21	$78.10	1.63	1.56	$0.810	$3.240	3.39%	3.59%
EDISON INTERNAT'L	EIX	$36.75	$37.08	$36.57	$41.90	$37.90	$42.43	$44.00	$70.59	$73.32	$54.45	1.66	1.59	$0.738	$2.952	4.18%	4.62%
EVERSOURCE ENERGY	ES	$38.29	$41.01	$42.39	$44.20	$42.84	$44.78	$46.50	$78.26	$94.63	$70.54	1.75	1.89	$0.638	$2.550	3.26%	3.09%
ENTERGY CORP.	ETR	$51.34	$54.56	$57.42	$61.40	$58.42	$61.69	$62.55	$107.74	$126.82	$94.94	1.75	1.85	$1.070	$4.280	3.97%	3.86%
EVERGY, INC.	EVRG	$37.82	$38.50	$40.32	$41.86	$40.71	$42.07	$42.70	$61.12	$73.13	$54.12	1.45	1.54	$0.613	$2.450	4.01%	3.85%
HAWAIIAN ELECTRIC	HE	$20.93	$21.41	$21.87	$20.00	$21.40	$20.31	$21.25	$38.40	$44.72	$33.18	1.89	1.87	$0.350	$1.400	3.65%	3.59%
IDACORP, INC.	IDA	$48.88	$50.73	$52.82	$55.50	$53.49	$56.31	$58.75	$108.33	$118.92	$93.53	1.92	1.93	$0.790	$3.160	2.92%	2.97%
ALLIANT ENERGY	LNT	$21.24	$22.76	$23.91	$24.99	$24.18	$25.38	$26.55	$53.40	$65.37	$47.19	2.10	2.27	$0.453	$1.810	3.39%	3.22%
MGE ENERGY INC.	MGEE	NA	NA	NA	NA	NA	NA	NA	$77.67	$86.27	$61.67	NA	NA	NA	NA	NA	NA
NEXTERA ENERGY	NEE	$18.92	$18.63	$18.95	$19.74	$19.15	$20.34	$22.15	$77.08	$91.35	$67.22	3.79	4.02	$0.425	$1.700	2.21%	2.14%
NORTHWESTERN	NWE	$40.42	$41.10	$43.28	$44.60	$43.61	$45.03	$46.30	$57.86	$63.06	$48.68	1.29	1.26	$0.630	$2.520	4.36%	4.51%
OGE ENERGY CORP.	OGE	$20.69	$18.15	$20.27	$21.95	$20.69	$22.03	$22.25	$37.26	$42.91	$33.28	1.69	1.78	$0.414	$1.656	4.45%	4.35%
PINNACLE WEST	PNW	$48.30	$49.96	$52.26	$53.00	$52.45	$53.19	$53.75	$79.24	$80.60	$59.03	1.49	1.32	$0.865	$3.460	4.37%	4.96%
PORTLAND GENERAL	POR	$28.99	$29.18	$30.28	$31.35	$30.55	$31.76	$33.00	$48.89	$57.03	$41.58	1.54	1.58	$0.453	$1.810	3.70%	3.67%
SOUTHERN COMPANY	SO	$26.11	$26.48	$26.30	$27.05	$26.49	$27.29	$28.00	$69.58	$80.57	$60.71	2.55	2.63	$0.680	$2.720	3.91%	3.85%
WEC ENERGY GROUP	WEC	$32.06	$33.19	$34.60	$36.76	$35.14	$36.91	$37.35	$94.79	$108.39	$80.82	2.57	2.63	$0.780	$3.120	3.29%	3.30%
XCEL ENERGY	XEL	$25.24	$27.12	$28.70	$30.15	$29.06	$30.53	$31.65	$67.44	$77.66	$56.89	2.21	2.26	$0.488	$1.950	2.89%	2.90%
Maximum		$61.20	$59.82	$61.55	$62.75	$61.85	$63.19	$64.50	$108.33	$126.82	$94.94	3.79	4.02	$1.070	$4.280	4.78%	4.96%
Minimum		$17.68	$18.15	$18.95	$19.74	$19.15	$20.31	$21.25	$37.26	$42.91	$33.18	1.29	1.25	$0.350	$1.400	2.21%	2.14%
Median		$35.33	$35.29	$36.57	$40.11	$37.90	$40.13	$40.20	$70.09	$80.59	$57.96	1.75	1.87	$0.638	$2.550	3.70%	3.67%
Average		$35.17	$35.79	$37.36	$38.99	$37.77	$39.40	$40.63	$71.72	$82.74	$60.88	1.90	1.97	$0.649	$2.597	3.69%	3.69%

Sources:
[A] Value Line: Most current data available at time of schedule preparation.
[B] Straight-line interpolation of Actual and Estimated VL year-end values.
[C] EOD Data: Market Data as of March 31, 2023.
[D] Market Price divided by Book Value per Share.
[E] Most Recent Quarterly Dividend multiplied by 4.
[F] Dividend Rate divided by Market Price.

EARNINGS PER SHARE AND RETURN ON EQUITY
RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
		Earnings per Share				Return on Equity			
		2019	2020	2021	2022	2020	2021	2022	VL Future Exp.
		[A]	[A]	[A]	[A]	[B]	[B]	[B]	[A]
AMEREN	AEE	$3.35	$3.50	$3.84	$4.14	10.29%	10.53%	10.65%	10.00%
AMERICAN ELEC. PWR.	AEP	$4.08	$4.42	$4.96	$4.51	10.90%	11.55%	9.90%	11.00%
ALLETE	ALE	$3.33	$3.35	$3.23	$3.38	7.68%	7.23%	7.31%	9.00%
AVISTA CORP.	AVA	$2.97	$1.90	$2.10	$1.90	6.53%	7.06%	6.23%	8.00%
CMS ENERGY CORP.	CMS	$2.39	$2.64	$2.58	$2.84	14.39%	12.55%	12.29%	14.00%
DOMINION ENERGY	D	$4.24	$3.54	$3.86	$4.10	10.93%	12.66%	12.82%	11.50%
DUKE ENERGY	DUK	$5.06	$5.12	$5.24	$5.30	8.46%	8.63%	8.53%	9.00%
CON. EDISON	ED	$4.37	$4.17	$4.38	$4.55	7.63%	7.85%	7.91%	8.50%
EDISON INTERNAT'L	EIX	$3.98	$1.72	$2.00	$4.60	4.66%	5.43%	11.72%	11.00%
EVERSOURCE ENERGY	ES	$3.45	$3.64	$3.86	$4.10	9.18%	9.26%	9.47%	10.00%
ENTERGY CORP.	ETR	$6.30	$6.90	$6.87	$5.37	13.03%	12.27%	9.04%	9.00%
EVERGY, INC.	EVRG	$2.79	$2.72	$3.83	$3.26	7.13%	9.72%	7.93%	10.00%
HAWAIIAN ELECTRIC	HE	$1.99	$1.81	$2.25	$2.15	8.55%	10.40%	10.27%	12.50%
IDACORP, INC.	IDA	$4.61	$4.69	$4.85	$5.10	9.42%	9.37%	9.42%	9.50%
ALLIANT ENERGY	LNT	$2.33	$2.47	$2.63	$2.73	11.23%	11.27%	11.17%	12.00%
MGE ENERGY INC.	MGEE	NA	NA	NA	NA	NA	NA	NA	NA
NEXTERA ENERGY	NEE	$1.94	$2.31	$2.55	$2.90	12.30%	13.57%	14.99%	14.50%
NORTHWESTERN	NWE	$3.53	$3.21	$3.50	$3.35	7.88%	8.30%	7.62%	8.00%
OGE ENERGY CORP.	OGE	$2.24	$2.08	$2.36	$2.25	10.71%	12.29%	10.66%	13.00%
PINNACLE WEST	PNW	$4.77	$4.87	$5.47	$4.25	9.91%	10.70%	8.08%	9.00%
PORTLAND GENERAL	POR	$2.39	$2.75	$2.72	$2.80	9.46%	9.15%	9.09%	9.50%
SOUTHERN COMPANY	SO	$3.17	$3.25	$3.42	$3.55	12.36%	12.96%	13.31%	14.50%
WEC ENERGY GROUP	WEC	$3.58	$3.79	$4.11	$4.46	11.62%	12.13%	12.50%	13.00%
XCEL ENERGY	XEL	$2.64	$2.79	$2.96	$3.15	10.66%	10.61%	10.71%	11.00%
Maximum		$6.30	$6.90	$6.87	$5.37	14.39%	13.57%	14.99%	14.50%
Minimum		$1.94	$1.72	$2.00	$1.90	4.66%	5.43%	6.23%	8.00%
Median		$3.35	$3.25	$3.50	$3.55	9.91%	10.53%	9.90%	10.00%
Average		$3.46	$3.38	$3.63	$3.68	9.78%	10.24%	10.07%	10.76%

Sources:
[A] Value Line: Most current data available at time of schedule preparation.
[B] Earnings per Share divded by average Book Value. Book Values shown on Exhibit ALR-5, page 1.

RETURN ON EQUITY IMPLIED BY ZACKS GROWTH RATES
RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
				Annual	Analyst	Analyst-Implied		Analyst-Implied		Implied	Analyst-
		Book Value	EPS	Dividend	5 Year	Book Value before SV		Book Value Incl. SV		EPS	Implied
		12/31/22	2022	Rate	Growth Rate	12/31/2026	12/31/2027	12/31/2026	12/31/2027	2027	ROE
		[A]	[A]	[A]	[B]	[C]	[C]	[C]	[C]	[C]	[C]
AMEREN	AEE	$40.11	$4.14	$2.520	6.90%	$47.79	$50.05	$57.50	$63.07	$5.78	9.59%
AMERICAN ELEC. PWR.	AEP	$46.60	$4.51	$3.320	6.10%	$52.13	$53.73	$59.13	$62.90	$6.06	9.94%
ALLETE	ALE	$47.06	$3.38	$2.710	7.30%	$50.27	$51.22	$55.04	$57.37	$4.81	8.55%
AVISTA CORP.	AVA	$30.90	$1.90	$1.760	5.20%	$31.54	$31.72	$36.13	$37.59	$2.45	6.64%
CMS ENERGY CORP.	CMS	$24.10	$2.84	$1.950	8.00%	$28.43	$29.74	$31.11	$33.29	$4.17	12.96%
DOMINION ENERGY	D	$32.45	$4.10	$2.670	14.90%	$40.64	$43.51	$43.76	$47.71	$8.21	17.95%
DUKE ENERGY	DUK	$62.75	$5.30	$4.020	5.40%	$68.60	$70.26	$68.60	$70.26	$6.89	9.93%
CON. EDISON	ED	$58.40	$4.55	$3.240	2.00%	$63.91	$65.35	$63.91	$65.35	$5.02	7.77%
EDISON INTERNAT'L	EIX	$41.90	$4.60	$2.952	3.00%	$49.00	$50.91	$51.30	$53.92	$5.33	10.14%
EVERSOURCE ENERGY	ES	$44.20	$4.10	$2.550	6.50%	$51.48	$53.60	$54.41	$57.45	$5.62	10.04%
ENTERGY CORP.	ETR	$61.40	$5.37	$4.280	6.00%	$66.45	$67.91	$78.49	$83.62	$7.19	8.87%
EVERGY, INC.	EVRG	$41.86	$3.26	$2.450	5.20%	$45.54	$46.59	$45.54	$46.59	$4.20	9.12%
HAWAIIAN ELECTRIC	HE	$20.00	$2.15	$1.400	4.30%	$23.34	$24.26	$24.69	$26.03	$2.65	10.47%
IDACORP, INC.	IDA	$55.50	$5.10	$3.160	3.00%	$63.86	$66.11	$67.11	$70.34	$5.91	8.60%
ALLIANT ENERGY	LNT	$24.99	$2.73	$1.810	6.10%	$29.27	$30.50	$29.65	$31.01	$3.67	12.10%
MGE ENERGY INC.	MGEE	NA	NA	NA	5.30%	NA	NA	NA	NA	NA	NA
NEXTERA ENERGY	NEE	$19.74	$2.90	$1.700	9.00%	$25.72	$27.57	$27.36	$29.78	$4.46	15.62%
NORTHWESTERN	NWE	$44.60	$3.35	$2.520	6.50%	$48.50	$49.63	$48.50	$49.63	$4.59	9.35%
OGE ENERGY CORP.	OGE	$21.95	$2.25	$1.656	10.20%	$24.99	$25.96	$24.99	$25.96	$3.66	14.35%
PINNACLE WEST	PNW	$53.00	$4.25	$3.460	5.40%	$56.61	$57.64	$61.14	$63.46	$5.53	8.87%
PORTLAND GENERAL	POR	$31.35	$2.80	$1.810	6.10%	$35.95	$37.28	$40.35	$43.07	$3.76	9.03%
SOUTHERN COMPANY	SO	$27.05	$3.55	$2.720	4.00%	$30.72	$31.73	$30.72	$31.73	$4.32	13.83%
WEC ENERGY GROUP	WEC	$36.76	$4.46	$3.120	5.80%	$42.94	$44.72	$42.94	$44.72	$5.91	13.49%
XCEL ENERGY	XEL	$30.15	$3.15	$1.950	6.60%	$35.80	$37.45	$37.94	$40.27	$4.34	11.09%
Maximum		$62.75	$5.37	$4.280	14.90%	$68.60	$70.26	$78.49	$83.62	$8.21	17.95%
Minimum		$19.74	$1.90	$1.400	2.00%	$23.34	$24.26	$24.69	$25.96	$2.45	6.64%
Median		$40.11	$3.55	$2.550	6.05%	$45.54	$46.59	$45.54	$47.71	$4.81	9.94%
Average		$38.99	$3.68	$2.597	6.20%	$44.06	$45.54	$46.97	$49.35	$4.98	10.80%

Sources:
[A] Value Line: Most current data available at time of schedule preparation.
[B] Zacks: Data as of April 11, 2023.
[C] Analyst-Implied Book Value and Return on Equity is obtained by escalating both Dividends and Earnings per Share by the stated Analyst Growth Rate and adding Earnings and subtracting Dividends for each projected year.
"SV" = S X V, where S = rate of continuous new stock financing and V = rate of return on common equity investment.

CAPITAL STRUCTURE WITH SHORT TERM DEBT
RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
		% Common Equity					($ millions)						Percentage			
		2018	2019	2020	2021	2022	Total Debt	LT Debt	ST Debt	Pfd Stock	Equity	Total Capital	LT Debt	ST Debt	Pfd Stock	Equity Ratio
		[A]	[A]	[A]	[A]	[A]	[A]	[A]	[A]	[A]	[A]	[A]	[B]	[B]	[B]	[B]
AMEREN	AEE	48.8%	47.1%	44.3%	43.3%	44.0%	$ 15,095.0	$ 13,685.0	$ 1,410.0	$ 129.0	$ 10,853.9	$ 26,077.9	52.5%	5.4%	0.5%	41.6%
AMERICAN ELEC. PWR.	AEP	46.8%	43.9%	41.5%	41.7%	42.0%	$ 39,735.0	$ 35,623.0	$ 4,112.0	$ -	$ 25,796.0	$ 65,531.0	54.4%	6.3%	0.0%	39.4%
ALLETE	ALE	60.1%	61.4%	59.0%	57.8%	60.5%	$ 1,869.5	$ 1,648.2	$ 221.3	$ -	$ 2,524.5	$ 4,394.0	37.5%	5.0%	0.0%	57.5%
AVISTA CORP.	AVA	49.5%	50.6%	49.6%	52.5%	51.0%	$ 2,562.3	$ 2,281.8	$ 280.5	$ -	$ 2,374.9	$ 4,937.2	46.2%	5.7%	0.0%	48.1%
CMS ENERGY CORP.	CMS	30.7%	29.4%	28.6%	34.2%	34.5%	$ 14,289.0	$ 13,190.0	$ 1,099.0	$ 224.0	$ 7,065.4	$ 21,578.4	61.1%	5.1%	1.0%	32.7%
DOMINION ENERGY	D	39.2%	45.0%	39.5%	38.5%	39.5%	$ 43,994.0	$ 38,162.0	$ 5,832.0	$ 1,783.0	$ 26,079.8	$ 71,856.8	53.1%	8.1%	2.5%	36.3%
DUKE ENERGY	DUK	46.2%	44.1%	44.4%	43.1%	42.0%	$ 72,915.0	$ 66,060.0	$ 6,855.0	$ 1,962.0	$ 49,257.3	$ 124,134.3	53.2%	5.5%	1.6%	39.7%
CON. EDISON	ED	48.9%	49.3%	48.0%	47.0%	48.0%	$ 25,164.0	$ 22,350.0	$ 2,814.0	$ -	$ 20,630.8	$ 45,794.8	48.8%	6.1%	0.0%	45.1%
EDISON INTERNAT'L	EIX	38.3%	39.9%	39.5%	33.2%	33.5%	$ 30,331.0	$ 25,145.0	$ 5,186.0	$ 3,878.0	$ 14,620.6	$ 48,829.6	51.5%	10.6%	7.9%	29.9%
EVERSOURCE ENERGY	ES	46.9%	46.6%	47.1%	45.3%	43.0%	$ 22,298.0	$ 20,242.0	$ 2,056.0	$ 155.6	$ 15,387.7	$ 37,841.3	53.5%	5.4%	0.4%	40.7%
ENTERGY CORP.	ETR	35.9%	37.1%	33.7%	31.7%	35.2%	$ 26,759.0	$ 23,623.0	$ 3,136.0	$ 254.4	$ 12,970.4	$ 39,983.8	59.1%	7.8%	0.6%	32.4%
EVERGY, INC.	EVRG	60.0%	49.4%	48.7%	49.9%	48.0%	$ 10,344.8	$ 9,905.7	$ 439.1	$ -	$ 9,143.7	$ 19,488.5	50.8%	2.3%	0.0%	46.9%
HAWAIIAN ELECTRIC	HE	51.7%	54.6%	52.7%	52.8%	49.0%	$ 2,601.4	$ 2,430.3	$ 171.1	$ 34.3	$ 2,367.9	$ 5,003.6	48.6%	3.4%	0.7%	47.3%
IDACORP, INC.	IDA	56.4%	58.7%	56.1%	57.2%	57.5%	$ 2,150.8	$ 2,071.4	$ 79.4	$ -	$ 2,802.5	$ 4,953.3	41.8%	1.6%	0.0%	56.6%
ALLIANT ENERGY	LNT	45.7%	47.6%	44.9%	47.1%	45.0%	$ 8,718.0	$ 7,668.0	$ 1,050.0	$ -	$ 6,273.8	$ 14,991.8	51.1%	7.0%	0.0%	41.8%
MGE ENERGY INC.	MGEE	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
NEXTERA ENERGY	NEE	56.0%	49.6%	46.5%	42.2%	41.5%	$ 64,966.0	$ 55,256.0	$ 9,710.0	$ -	$ 39,198.7	$ 104,164.7	53.0%	9.3%	0.0%	37.6%
NORTHWESTERN	NWE	47.8%	47.5%	47.2%	47.8%	50.0%	$ 2,566.1	$ 2,418.6	$ 147.5	$ -	$ 2,418.6	$ 4,984.7	48.5%	3.0%	0.0%	48.5%
OGE ENERGY CORP.	OGE	58.0%	56.4%	51.0%	47.4%	53.0%	$ 4,548.6	$ 3,548.7	$ 999.9	$ -	$ 4,001.7	$ 8,550.3	41.5%	11.7%	0.0%	46.8%
PINNACLE WEST	PNW	53.0%	52.9%	47.2%	46.1%	45.0%	$ 7,782.3	$ 7,241.3	$ 541.0	$ -	$ 5,924.7	$ 13,707.0	52.8%	3.9%	0.0%	43.2%
PORTLAND GENERAL	POR	53.5%	48.7%	46.4%	43.2%	44.5%	$ 3,623.0	$ 3,582.0	$ 41.0	$ -	$ 2,872.1	$ 6,495.1	55.1%	0.6%	0.0%	44.2%
SOUTHERN COMPANY	SO	37.6%	39.5%	38.1%	35.6%	36.0%	$ 55,066.0	$ 50,427.0	$ 4,639.0	$ 242.0	$ 28,501.3	$ 83,809.3	60.2%	5.5%	0.3%	34.0%
WEC ENERGY GROUP	WEC	49.4%	47.4%	47.1%	44.6%	44.5%	$ 17,294.5	$ 14,766.2	$ 2,528.3	$ 30.4	$ 11,863.9	$ 29,188.8	50.6%	8.7%	0.1%	40.6%
XCEL ENERGY	XEL	43.6%	43.2%	42.6%	41.8%	42.0%	$ 24,118.0	$ 23,309.0	$ 809.0	$ -	$ 16,878.9	$ 40,996.9	56.9%	2.0%	0.0%	41.2%
Maximum		60.1%	61.4%	59.0%	57.8%	60.5%	$ 72,915.0	$ 66,060.0	$ 9,710.0	$ 3,878.0	$ 49,257.3	$ 124,134.3	61.1%	11.7%	7.9%	57.5%
Minimum		30.7%	29.4%	28.6%	31.7%	33.5%	$ 1,869.5	$ 1,648.2	$ 41.0	$ -	$ 2,367.9	$ 4,394.0	37.5%	0.6%	0.0%	29.9%
Median		48.8%	47.5%	46.5%	44.6%	44.5%	$ 15,095.0	$ 13,685.0	$ 1,099.0	$ -	$ 10,853.9	$ 26,077.9	52.5%	5.5%	0.0%	41.6%
Average		48.0%	47.4%	45.4%	44.5%	44.7%	$ 21,686.6	$ 19,331.9	$ 2,354.7	$ 377.9	$ 13,904.7	$ 35,969.3	51.4%	5.7%	0.7%	**42.3%**

Sources:

[A] Value Line: Most current data available at time of schedule preparation.

[B] Percentage calculated on Total Capital including Short Term Debt.

CAPITAL STRUCTURE WITHOUT SHORT TERM DEBT
RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
		% Common Equity					($ millions)						Percentage			
		2018	2019	2020	2021	2022	Total Debt	LT Debt	ST Debt	Pfd Stock	Equity	Total Capital	LT Debt	ST Debt	Pfd Stock	Equity Ratio
		[A]	[A]	[A]	[A]	[A]	[A]	[A]	[B]	[A]	[A]	[A]	[B]	[B]	[B]	[B]
AMEREN	AEE	48.8%	47.1%	44.3%	43.3%	44.0%	$ 15,095.0	$ 13,685.0		$ 129.0	$ 10,853.9	$ 24,667.9	55.5%	0.0%	0.5%	44.0%
AMERICAN ELEC. PWR.	AEP	46.8%	43.9%	41.5%	41.7%	42.0%	$ 39,735.0	$ 35,623.0		$ -	$ 25,796.0	$ 61,419.0	58.0%	0.0%	0.0%	42.0%
ALLETE	ALE	60.1%	61.4%	59.0%	57.8%	60.5%	$ 1,869.5	$ 1,648.2		$ -	$ 2,524.5	$ 4,172.7	39.5%	0.0%	0.0%	60.5%
AVISTA CORP.	AVA	49.5%	50.6%	49.6%	52.5%	51.0%	$ 2,562.3	$ 2,281.8		$ -	$ 2,374.9	$ 4,656.7	49.0%	0.0%	0.0%	51.0%
CMS ENERGY CORP.	CMS	30.7%	29.4%	28.6%	34.2%	34.5%	$ 14,289.0	$ 13,190.0		$ 224.0	$ 7,065.4	$ 20,479.4	64.4%	0.0%	1.1%	34.5%
DOMINION ENERGY	D	39.2%	45.0%	39.5%	38.5%	39.5%	$ 43,994.0	$ 38,162.0		$ 1,783.0	$ 26,079.8	$ 66,024.8	57.8%	0.0%	2.7%	39.5%
DUKE ENERGY	DUK	46.2%	44.1%	44.4%	43.1%	42.0%	$ 72,915.0	$ 66,060.0		$ 1,962.0	$ 49,257.3	$ 117,279.3	56.3%	0.0%	1.7%	42.0%
CON. EDISON	ED	48.9%	49.3%	48.0%	47.0%	48.0%	$ 25,164.0	$ 22,350.0		$ -	$ 20,630.8	$ 42,980.8	52.0%	0.0%	0.0%	48.0%
EDISON INTERNAT'L	EIX	38.3%	39.9%	39.5%	33.2%	33.5%	$ 30,331.0	$ 25,145.0		$ 3,878.0	$ 14,620.6	$ 43,643.6	57.6%	0.0%	8.9%	33.5%
EVERSOURCE ENERGY	ES	46.9%	46.6%	47.1%	45.3%	43.0%	$ 22,298.0	$ 20,242.0		$ 155.6	$ 15,387.7	$ 35,785.3	56.6%	0.0%	0.4%	43.0%
ENTERGY CORP.	ETR	35.9%	37.1%	33.7%	31.7%	35.2%	$ 26,759.0	$ 23,623.0		$ 254.4	$ 12,970.4	$ 36,847.8	64.1%	0.0%	0.7%	35.2%
EVERGY, INC.	EVRG	60.0%	49.4%	48.7%	49.9%	48.0%	$ 10,344.8	$ 9,905.7		$ -	$ 9,143.7	$ 19,049.4	52.0%	0.0%	0.0%	48.0%
HAWAIIAN ELECTRIC	HE	51.7%	54.6%	52.7%	52.8%	49.0%	$ 2,601.4	$ 2,430.3		$ 34.3	$ 2,367.9	$ 4,832.5	50.3%	0.0%	0.7%	49.0%
IDACORP, INC.	IDA	56.4%	58.7%	56.1%	57.2%	57.5%	$ 2,150.8	$ 2,071.4		$ -	$ 2,802.5	$ 4,873.9	42.5%	0.0%	0.0%	57.5%
ALLIANT ENERGY	LNT	45.7%	47.6%	44.9%	47.1%	45.0%	$ 8,718.0	$ 7,668.0		$ -	$ 6,273.8	$ 13,941.8	55.0%	0.0%	0.0%	45.0%
MGE ENERGY INC.	MGEE	NA	NA	NA	NA	NA	NA	NA		NA	NA	NA	NA	NA	NA	NA
NEXTERA ENERGY	NEE	56.0%	49.6%	46.5%	42.2%	41.5%	$ 64,966.0	$ 55,256.0		$ -	$ 39,198.7	$ 94,454.7	58.5%	0.0%	0.0%	41.5%
NORTHWESTERN	NWE	47.8%	47.5%	47.2%	47.8%	50.0%	$ 2,566.1	$ 2,418.6		$ -	$ 2,418.6	$ 4,837.2	50.0%	0.0%	0.0%	50.0%
OGE ENERGY CORP.	OGE	58.0%	56.4%	51.0%	47.4%	53.0%	$ 4,548.6	$ 3,548.7		$ -	$ 4,001.7	$ 7,550.4	47.0%	0.0%	0.0%	53.0%
PINNACLE WEST	PNW	53.0%	52.9%	47.2%	46.1%	45.0%	$ 7,782.3	$ 7,241.3		$ -	$ 5,924.7	$ 13,166.0	55.0%	0.0%	0.0%	45.0%
PORTLAND GENERAL	POR	53.5%	48.7%	46.4%	43.2%	44.5%	$ 3,623.0	$ 3,582.0		$ -	$ 2,872.1	$ 6,454.1	55.5%	0.0%	0.0%	44.5%
SOUTHERN COMPANY	SO	37.6%	39.5%	38.1%	35.6%	36.0%	$ 55,066.0	$ 50,427.0		$ 242.0	$ 28,501.3	$ 79,170.3	63.7%	0.0%	0.3%	36.0%
WEC ENERGY GROUP	WEC	49.4%	47.4%	47.1%	44.6%	44.5%	$ 17,294.5	$ 14,766.2		$ 30.4	$ 11,863.9	$ 26,660.5	55.4%	0.0%	0.1%	44.5%
XCEL ENERGY	XEL	43.6%	43.2%	42.6%	41.8%	42.0%	$ 24,118.0	$ 23,309.0		$ -	$ 16,878.9	$ 40,187.9	58.0%	0.0%	0.0%	42.0%
Maximum		60.1%	61.4%	59.0%	57.8%	60.5%	$ 72,915.0	$ 66,060.0		$ 3,878.0	$ 49,257.3	$ 117,279.3	64.4%	0.0%	8.9%	60.5%
Minimum		30.7%	29.4%	28.6%	31.7%	33.5%	$ 1,869.5	$ 1,648.2		$ -	$ 2,367.9	$ 4,172.7	39.5%	0.0%	0.0%	33.5%
Median		48.8%	47.5%	46.5%	44.6%	44.5%	$ 15,095.0	$ 13,685.0		$ -	$ 10,853.9	$ 24,667.9	55.5%	0.0%	0.0%	44.5%
Average		48.0%	47.4%	45.4%	44.5%	44.7%	$ 21,686.6	$ 19,331.9		$ 377.9	$ 13,904.7	$ 33,614.6	54.5%	0.0%	0.7%	**44.7%**

Sources:
[A] Value Line: Most current data available at time of schedule preparation.
[B] Percentage calculated on Total Capital excluding Short Term Debt.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2022-3037368
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Aaron L. Rothschild, hereby state that the facts set forth in my Direct Testimony, OCA Statement 2, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 25, 2023
*344776

Signature: ______________________________
Aaron L. Rothschild

Consultant Address: Rothschild Financial Consulting
15 Lake Road
Ridgefield, CT 06877

OCA St. 2SR

BEFORE THE

Pennsylvania Public Utility Commission

Pennsylvania Public Utility Commission	:	Docket Numbers
v.	:	R-2022-3037368
UGI Utilities, Inc. - Electric Division	:	
	:	

Surrebuttal Testimony

of

Aaron L. Rothschild

on Behalf of

the Pennsylvania Office of Consumer Advocate

June 7, 2023

Contents

I. INTRODUCTION AND SUMMARY OF MR. MOUL'S COMMENTS

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my Surrebuttal Testimony is to respond to the following issues addressed in Company witness Paul Moul's Rebuttal Testimony, specifically, his assertions that:

- I make inconsistent statements regarding the use of analyst forecasts, historical data, and forward-looking market data
- My cost of equity recommendation fails to reflect higher interest rates
- Application and reasonableness of my Constant Growth DCF Model
- My application of the CAPM is defective
- My erroneous conclusions regarding Mr. Moul's leverage adjustment
- I have not shown that UGI Electric is not entitled to some form of management performance recognition by the Commission
- The appropriate capital structure for UGI Electric

As addressed below, Mr. Moul's criticisms are invalid and should be rejected.

Q. ON PAGES 8-10 OF HIS REBUTTAL TESTIMONY, MR. MOUL CLAIMS THAT YOU MAKE INCONSISTENT CLAIMS REGARDING THE USE OF ANALYST FORECASTS, HISTORICAL DATA, AND FORWARD-LOOKING MARKET DATA. PLEASE RESPOND.

A. Below I respond to the following eight claims made my Mr. Moul:

1. On page 8, lines 20-21 of Mr. Moul's rebuttal testimony, he claims that my recommendation that the ROE should be "market-based" and "forward-looking contradicts my criticisms of using forecasts.

My response: First, I did not say that forecasts are "unreliable." On page 19 of my direct testimony, I explain that analyst forecasts "have proven to be unrealistic." The main point I make throughout my direct testimony, is that there is a difference between expert forecasts (e.g., analyst 5-year EPS growth rate forecasts) and investors' expectations (e.g., option-implied growth). Expert forecasts are based on the opinions of a relatively small group of people and publications. On the other hand, investor expectations are based on the market behavior of millions of people around the world. Investors' expectations should be given priority over expert forecasts because they are based on more extensive data and, after all, investors are the ones providing the capital to utility companies.

2. On page 8, lines 22-6 and page 9, lines 1-5 of Mr. Moul's rebuttal testimony, he states that I use historical data despite claiming that I use primarily forward-looking market data.

My response: I do use historical data, as does every rate of return witness that I know of; however, it is preferable to measure a utility's cost of equity (COE) by measuring investors' expectations directly using current capital market data (e.g., stock prices, stock option prices). My COE calculations did also incorporate historical data, which is something that all rate of return witnesses/financial modelers have to do to some degree, including me, because of inevitable limitations of capital market data.

3. On page 9, lines 6-9 of Mr. Moul's rebuttal testimony, he implies that my stated preference for forward-looking data contradicts my conclusion that using analyst's forecasts would be speculative. Additionally, he implies that I am contradicting myself by claiming that my market-based method is forward-looking on the one hand, and on the other hand I believe capital markets are unpredictable.

My response: As discussed in response to claim 1 above, my forward-looking market-based COE is based on investors' expectations. Measuring investor expectations directly using capital market data is different than using analyst forecasts. Also, investors have forward-looking expectations that we can investigate despite the unpredictable nature of capital markets. There is nothing inconsistent or contradictory in my statements.

4. On page 9, lines 10-11 of Mr. Moul's rebuttal testimony, he claims that I contradict myself by relying on historic data in my DCF model, yet I criticize his use of historical data.

My response: Please see my response to Mr. Moul's claim 2 above.

5. On page 9, lines 12-15 of Mr. Moul's rebuttal testimony, he claims that I contradict myself by criticizing his use of non-market data when I use non-market data (i.e., book value data in my DCF and historical data for my CAPM risk-free rate).

My response: First, regarding the risk-free rate components of my CAPM, Mr. Moul's claim that I use historical data is misleading. As explained on page 60, lines 8-15 of my direct testimony, I use both the spot market yields of U.S. treasury bond/bills as of March 31, 2023, and a weighted average over the 3-month ending on that date. The spot data that I use, by any standard, is not historical. I also use 3 month "historical" averages because the value of a particular input on a specific day can lead to COE results that can vary over short periods of time. Therefore, using data over a recent period, such as 3 months, is a process of smoothing capital market data, which is often turbulent.

I also use historical book value returns in my DCF analysis for "smoothing" purposes to make sure current future expected returns on book equity are sustainable.

6. On page 9, lines 16-19 of Mr. Moul's rebuttal testimony, he claims that I use analyst forecasts despite criticizing him for using them.

My response: Please see my response to claim 1 above.

7. On page 9, lines 20-22 of Mr. Moul's rebuttal testimony, he claims that I contradict myself by stating that rising interest rates generally mean that the COE will increase while stating that despite recent increases in interest rates the cost of equity has remained about the same.

My response: As stated below, Mr. Moul's claims regarding my position on the interrelationship between interest rates and the COE are misleading. As interest rates have increased, my COE recommendations have as well. My COE recommendation in this case is 127 basis points higher than I recommend in a case in Connecticut in 2021.

8. On page 9, lines 23-25 and page 10, lines 1-3 of Mr. Moul's rebuttal testimony, he states that my claim that "forecasts as being unreliable" contradicts my recommendation that UGI's authorized ROE should be based on current market data and not on historical authorized ROEs in other proceeding.

My response: Please see my response to claim 1 and 2 above.

II. APPLICATION OF CONSTANT GROWTH DCF

Q. PLEASE SUMMARIZE MR. MOUL'S CRITICISM OF YOUR APPLICATION OF THE DCF METHOD.

A. Mr. Moul makes the following criticisms of my constant growth DCF method:

1. My constant growth DCF model produces unreliable results;
2. Growth rate component should be based on analyst Earnings Per Share (EPS) growth rates;
3. My approach is inferior to his because it relies on non market-based data,

Q. MR. MOUL CLAIMS THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL ARE NOT REASONABLE. DO YOU AGREE?

A. No. Mr. Moul claims that the results of my Constant Growth DCF Model are not reasonable because, among reasons, they are not higher than the cost of debt by a reasonable margin. He does not explain how much higher the cost of equity should be than the cost of debt or what metrics his criticism is based on. The cost of equity expectations of major financial institutions indicate that the margin between my 8.44% cost of equity recommendation and the cost of debt is reasonable.

My 8.44% cost of equity recommendation is 477 basis points[1] higher than the market yield on the 30-year U.S. Treasury bond. The margin between my 8.44% recommendation and the cost of debt (e.g., market yield on U.S. Treasury bonds) is about the same as the cost of equity recommendations of major financial institutions and published research, including publications relied on extensively by Mr. Moul. He uses data from the SBBI Yearbook (owned by Kroll) to determine the appropriate equity risk premium for public utilities starting on page 34 of his direct testimony. As shown on page 14, Table 4 of my direct testimony, Kroll determined the cost of equity for the overall market is 9.5%, which is 562 basis points higher than the market yield on the 30-year U.S.

[1] 8.44% - 3.67% (yield on 30-year U.S. Treasury bond as of March 31, 2023).

Treasury bond. However, as explained on pages 14-15 of my direct testimony, Kroll's 9.5% cost of equity is for the overall stock market (e.g., US Large Cap, S&P 500[2]), which should be higher than the return expectations for buying utility stocks because regulated monopoly utilities are lower risk than most, if not all, unregulated companies in the S&P 500, like Tesla and Amazon. Additionally, defensive stocks like utilities have been outperforming the overall market in the current capital market environment which indicates, along with other financial data, that the relative COE for utility companies has been decreasing since Kroll's 9.5% cost of equity was published in January 2023.

Q. MR. MOUL CLAIMS ON PAGE 8 OF HIS REBUTTAL TESTIMONY THAT YOU DO NOT SEEM TO BELIEVE THAT THE COST OF EQUITY HAS REMAINED THE SAME GIVEN A MOVE UP IN YOUR COST OF EQUITY ANALYSIS BETWEEN TWO RATE CASES IN CONNECTICUT. WHAT IS YOUR RESPONSE?

A. Mr. Moul mischaracterized page 20 of my direct testimony in a highly misleading manner.

First, Mr. Moul leaves out the fact that I stated as follows in context of my discussion of Connecticut COE rates:

> However, as discussed above, despite recent increases in interest rates and market volatility, capital market data show that investors expect the COE to remain about the same for a stock they plan to sell in 5 years than for a stock they plan to sell in 1 year. In other words, stock option prices show a flat term structure for the COE.[3]

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[2] The S&P 500 is a stock market index that includes 500 of the largest U.S. companies, including 11 sectors to show the health of the U.S. stock market and broader economy. The Dow Jones Industrial Average, 30 of the largest U.S. companies, is another commonly used measure of equity markets in general.

[3] Direct Testimony, page 20, lines 13-16.

As I base my COE analysis on stock option prices, it is reasonable to reach the conclusion that a flat term structure for the COE in this proceeding is appropriate.

Secondly, Mr. Moul states that applying the same 127 basis point increase between two rate cases in Connecticut to my UGI COE results in a cost of equity that is 11.12%. Mr. Moul is merely adding numbers together (over different time periods and contexts) that have no relation to each other. My COE determination was based on all of the factors that I discussed in my direct testimony, adding 127 basis points to UGI's last authorized ROE, as Mr. Moul is proposing, would result in an excessive ROE.

Q. STARTING ON PAGE 24 OF HIS REBUTTAL TESTIMONY, MR. MOUL CLAIMS THAT IT IS MORE APPROPRIATE TO USE EPS GROWTH RATES AS THE GROWTH COMPONENT OF A DCF MODEL THAN RETENTION GROWTH RATES. HOW DO YOU RESPOND?

A. I disagree. It does not make mathematical sense to use analyst five-year EPS growth rate forecasts without attempting to investigate what percentage of earnings companies are likely to pay out as dividends and what percentage they are likely to retain in the business (i.e., the retention rate). This is analogous to failing to reconcile the money you are taking out of your checking account with your future balance, i.e., the basic balancing of a checkbook.

J.P. Morgan explained that its equity assumptions methodology considers five return drivers (including earnings growth and dividends). Pertinently, J.P. Morgan explained that its equity return assumptions methodology:

> ties together complex interrelationships among these factors to ensure that retained earnings and gross dilution imply a future book value that is consistent with projected return on equity and future earnings. This framework – analogous to Robert Higgins' sustainable growth rate (SGR)

> concept – ensures that higher shareholder payouts, for instance, would come at the expense of slower earnings growth, all else the same. Our methodology uses trailing, not forward, earnings, which tend to be more stable.[4]

Thus, exclusive reliance on analysts' 5-year EPS growth rates, as Mr. Moul has done, without considering multiple factors that ensure sustainable growth, is inappropriate. As reflected in my Exhibit ALR-3, page 1, consistent with the multi-factor approach relied upon by J.P. Morgan in its 2019 Long-Term Capital Market report, I have also used a sustainable growth rate method to compute my DCF results.

Q. ON PAGE 24, LINES 22-23 OF HIS REBUTTAL TESITMONY, MR. MOUL CLAIMS THAT YOU ARE INCORRECT TO BELIEVE THAT DIVIDENDS PER SHARE (DPS) AND BOOK VALUE PER SHARE (BPS) HAVE ANY ROLE IN THE DCF MODEL. PLEASE RESPOND.

A. As discussed above, it is not appropriate to mechanically use analysts' 5-year EPS growth rates as the growth component of a constant growth DCF model. Instead, we must consider multiple factors to make sure that the growth rate component is consistent with a reasonable expectation of sustainable growth. DPS and BPS are important factors to consider because they can both be used to better understand how much money a company is likely to pay out as dividends and how much they are likely to retain in the business. A company cannot use money it has given to investors to grow its earnings.

Q. ON PAGE 27, LINES 1-7 OF HIS REBUTTAL TESITMONY, MR. MOUL CLAIMS THAT YOU SHOULD HAVE DIRECTLY USED THE EARNINGS PER SHARE

[4] J.P. Morgan contributes to the Blue Chip Economic Forecasts relied on by Mr. Moul in his rebuttal and direct testimonies.

GROWTH RATE FORECAST OF 6.20% BY ZACKS IN YOUR DCF APPROACH. PLEAE RESPOND.

A. I strongly disagree. As discussed above, it is not appropriate to mechanically use analyst EPS growth rate forecasts in a constant growth DCF model because it does not ensure that the mathematical relationship between earnings, dividends, book value and stock price are respected. If a utility company is experiencing a short-term period of high earnings growth because they are recovering from a period of low earnings, for example, using analyst 5-year EPS growth rate forecasts in a DCF model will overstate the COE because these growth rates are not sustainable. In other words, the company's relatively high growth rate will not continue indefinitely. Investors know that short-term growth rates that result from a recovery will eventually slow.

Q. ARE THERE ADDITIONAL REASONS WHY IT IS NOT APPROPRIATE TO USE ANALYST 5-YEAR EPS GROWTH RATE FORECASTS AS THE GROWTH COMPONENT IN A DCF MODEL?

A. Yes. A study conducted by McKinsey & Company in 2010 found that "analysts have been persistently over optimistic for the past 25 years with estimates ranging from 10 to 12 percent a year, compared with actual earnings growth."[5]

On average, analysts' forecasts have been almost 100 percent too high.[6] Additionally, the further a projection predicts into the future, the likelihood of the

[5] Marc H. Goedhart, Rishi Raj and Abhishek Saxena, *Equity Analysts: Still too bullish*, Spring 2010.

[6] Ibid.

projection being correct decreases. Capital markets, on the other hand, are notably less giddy in their predictions. Except during the market bubble of 1999-2001, actual price-to-earnings ratios have been 25 percent lower than implied P/E ratios based on analyst forecasts.

To my knowledge, financial publications do not recommend using EPS growth rates to calculate the cost of equity in a DCF model. McKinsey & Company continues to advise its clients to be cautious about the reliability of analysts' forecasts. On May 16, 2022, McKinsey stated that "analysts' near-term forecasts are often overly optimistic and don't always correctly reflect operating performance."[7]

Q. ARE YOU SAYING THAT ANALYSTS' CONSENSUS EARNINGS PER SHARE GROWTH RATES ARE USELESS AS AN AID TO PROJECTING THE FUTURE?

A. No. Analysts' EPS growth rates are, however, very dangerous if used in a simplified DCF without proper interpretation. That is, use of EPS growth rates without considering factors such as dividend per-share growth and book value per share growth, could lead to unsustainable growth rates. For example, if a company has a slow earnings year followed by a strong recovery, this potentially high earnings growth rate is unlikely to be maintained in the long-term, and therefore unrealistic and/or unsustainable projection. Analysts' five-year earnings-per-share growth rates forecasts are not useful if used without considering other sensitivities. However, if used as part of a holistic analysis that considers other factors, the analysts' five-year earnings-per-share growth rates forecasts can be useful in

[7] David Kohn, Vartika Gupta, Tim Koller, Werner Rehm, *Do consensus estimates accurately reflect operating performance?*, May 16, 2022.

computing estimates of what earned return on equity investors expect will be sustained in the future, and as such, are useful in developing long-term sustainable growth rates.

Q. MR. MOUL CLAIMS ON PAGE 27, LINES 8-13 OF HIS REBUTTAL TESTIMOY THAT A FUNDAMENTAL TENET OF FINANCE IS THAT THE COST OF EQUITY MUST BE HIGHER THAN THE COST OF DEBT BY A MEANINGFUL MARGIN TO COMPENSATE FOR THE HIGHER RISK ASSOCIATED WITH A COMMON EQUITY INVESTMENT. PLEASE RESPOND.

A. I agree with Mr. Moul that equity is riskier than debt and therefore it is reasonable for investors to demand a higher return to invest in equity than debt. However, I disagree with Mr. Moul regarding how much of a premium investors need to invest in equity. My COE recommendation in UGI is 409 basis points higher than my cost of debt recommendation (8.44% - 4.35%) which is based on a careful analysis of market data. If investors required a greater premium my COE models would have produced a higher COE result.

Q. MR. MOUL STATES ON PAGE 26, LINES 3-6 OF HIS REBUTTAL TESTIMONY THAT MR. ROTHSCHILD DOES NOT AND CANNOT EXPLAIN WHY AN INVESTOR EXPECTED RETURN OF 10.30% SHOULD BE REDUCED TO 8.12% OR 8.26% IN THIS CASE, PARTICULARLY SINCE RATES ARE SET ON BOOK VALUE (NET ORIGINAL COST). PLEASE RESPOND.

A. Mr. Moul is conflating accounting returns and market-based returns. The 10.30% Mr. Moul is referring to is the future expected return on book equity published by Value Line and implied by Zack's forecasts. In other words, this 10.30% is an accounting figure (based on expected return on the <u>book</u> value of equity), not investors' returns (based on expected return on the market value of equity). I provided an explanation of the difference between expected return on book equity (accounting returns) and expected return on the market price of a stock on page 92, and page 93, lines 1-3 of my direct testimony. If Pennsylvania consumers' rates are set based on expected accounting returns instead of market returns, they will be significantly overcharged. An authorized ROE should be commensurate with the returns the investors expect to earn when investing in other enterprises having corresponding risks. This investment is made at the market price of a utility's stock, not the accounting value.[8] The average market price of the electric utility stocks in my proxy group is between 1.90- and 1.97-times book value. If investors are willing to pay between nearly 2 times the book value for an expected 10.30% return on book value for electric utilities, they are expecting to earn a return significantly less than 10.30% on market value. Therefore, it makes sense that my Constant Growth DCF indicates a market-based cost of equity of between 8.12% and 8.26%.[9]

If Mr. Moul were correct that we should use investors' expected *accounting* returns to determine UGI's authorized ROE, there would be no purpose in producing rate of return testimonies and conducting hearings. Using Mr. Moul's logic, setting UGI's authorized ROE would be a mechanical exercise of looking up published accounting returns. In other words, stock prices, interest rates, and other capital market data would be irrelevant.

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[8] For example, if you were to log in to your brokerage account you would not be able to purchase American States Water's stock for $19.45 (it's current book value according to Value Line). Instead, you would have to pay $87.76 (the closing price of its on August 1, 2022, according to Yahoo Finance).

[9] Mr. Rothschild's direct testimony, Exhibit ALR-3, page 1.

Q. PLEASE EXPLAIN WHY A MARKET TO BOOK RATIO OF BETWEEN 1.90 AND 1.97 INDICATES THAT THE COST OF EQUITY FOR ELECTRIC UTILITY COMPANIES IS LOWER THAN THE EXPECTED RETURN ON BOOK EQUITY?

A. Calculating the cost of equity (investors' equity return expectations) is more complicated than calculating the return on a rental property, but the same concept applies regarding the relationship between market returns and book returns. If an investor purchases an apartment for $100,000 and expects to receive $500 per month ($500 X 12 = $6,000 per year) in rent, he or she will expect an annual return of 6% ($6,000/$100,000) on their investment. When the investor purchases the apartment, he would record the book value as $100,000 and the market value as $100,000 unless he determined that the purchase price was higher or lower than the market value. If the value of the apartment increases to $200,000, for example, the market to book ratio would increase to 2.0, and therefore, his return on book value would remain at about 6% while his return on the market value of the apartment would decrease to about 3.0%.

In this rental property example, an increasing market value results in a lower expected return on market (3.0%) compared to expected return on book (6%) if the rent price remains constant. Rent prices do not increase to maintain an expected 6% return on book value; they are set by what the rental market reasonably can bear. The same is true of utility stocks. You do not establish an ROE based on a constant return on book (accounting) returns, it is set based on what investors in the market expect that market to return. In the case of a utility stock, an increasing market value results in a lower return on market for the same expected return on book. As this rental property example demonstrates, there is nothing inconsistent about investors expecting a lower return on the market price of an investment than on the book value of an investment. In fact, with market to book ratios of electric utility companies significantly above one it would be surprising if investors expected a return on market equal, or anywhere close, to return on book.

Q. ON PAGE 27, LINES 14-26 AND PAGE 28, LINES 1-9 OF HIS REBUTTAL TESTIMONY, MR. MOUL CLAIMS THAT I AM MISTAKEN THAT MARKET-TO-BOOK RATIOS ABOVE 1 INDICATES THAT THE COE FOR ELECTRIC UTILITY COMPANIES IS LOWER THAN THE EXPECTED RETURN ON BOOK EQUITY. PLEASE RESPOND.

A. I strongly disagree. Mr. Moul tries to demonstrate that my position on the relationship between market-to-book ratios, authorized ROEs, and the market-based COE is false by pointing to historical data. He claims that if investors expected to receive a lower market return than book return then utility stock prices would have reverted to their book value over time. I would agree with Mr. Moul that the market-to-book ratios of electric utility stocks have not reverted to their book value. However, the fact that market-to-book ratios for utility companies has remained above 1 persistently for many decades indicates that authorized ROEs for electric utility companies have been higher than their market-based COE and therefore, consumers have been overpaying for a long time. Please see Appendix A of my direct testimony regarding why market-to-book ratios for electric utility companies indicates that their COE is lower than their authorized ROEs.

III. CAPM ANALYSIS

Q. PLEASE SUMMARIZE MR. MOUL'S CRTICISMS OF YOUR CAPM METHODOLOGY.

A. Regarding my CAPM results (7.78% - 8.60%), Mr. Moul states "[by] any reasonable standard, such low returns are simply not credible."[10] The only evidence he provides for this conclusion is by referring to the results of his and Mr. Patel's CAPM, of 15.95% and 11.55% respectively.

Mr. Moul spends considerable time claiming that my CAPM is not reliable because it is "non-standard", "unconventional", and "unique." He criticizes many of the specific components of my CAPM, including using stock options to calculate forward betas.

Q. ON PAGE 35, LINES 5-7 OF HIS REBUTTAL TESITMONY, MR. MOUL CLAIMS THAT YOU USE AN INAPPROPIRATE YIELD ON 30-TREASURY BONDS IN OUR CAPM ANALYSIS. PLEASE RESPOND.

A. I disagree. I use the yield on the 30-year U.S. Treasury bond as of March 31, 2023, and a weighted average over the 3 months ending on that date as one of the risk-free rates I use in my CAPM analysis. This rate is appropriate because it is based on the market yields of bonds that are determined by investors who are buying and selling bonds in the market.

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[10] Mr. Moul's rebuttal testimony, page 39, line 26.

Q. WHAT IS YOUR GENERAL RESPONSE TO MR. MOUL'S CRITICISMS OF YOUR CAPM METHODOLOGY?

A. Throughout his testimony, Mr. Moul changes his criteria for determining the appropriate ROE for UGI Electric, continues to use COE models that have been proven to be flawed, and criticizes my approach in ways that are illogical and inconsistent with the facts (e.g., he claims that my methods have not been supported in other cases, but my testimony clearly describes that it was adopted by the SC Commission). As stated on page 12, lines 6-12 of my direct testimony, on April 9, 2020, the South Carolina Public Service Commission stated the following regarding my CAPM methodology:

> Amongst the three witnesses, Consumer Affairs Rothschild's approach was unique in that he included the use of both historical and forward-looking, market-based data in his analysis. Based on the testimony and facts presented, the Commission therefore adopts the recommended ROE of 7.46% proposed by witness Rothschild.

Mr. Moul claims that my CAPM should not be relied upon because it is "unusual" and "non-standard" among other reasons. According to Mr. Moul, the Commission should only rely on common models that he claims are used by Rate of Return witnesses and investors, despite their obvious flaws (e.g., Value Line's 5-year historical betas that vary based on arbitrary data choice). On the other hand, I have been testing models for years and continually eliminate the ones that prove to be flawed. My work to continually improve COE models led to the development of my CAPM methodology, which includes measuring investors' expectations directly using stock option prices. My improved methods have been empirically tested using capital market data, applied for many years, and as stated above, have been adopted in previous cases. Continuous improvement of COE models is required to ensure that regulated utility companies have access to the capital they need while also protecting consumers.

Mr. Moul's criticisms of my CAPM are based on his outright denial of the possibility of progress in COE modeling. This is at the expense of not adjusting to changing capital market conditions, including the massive, expanded use of stock options by investors and the continuing results of research focusing on improving statistical techniques to best measure complex systems with power law distributions, including stock markets.

The Federal Energy Regulatory Commission (FERC) has recognized that it is important to evaluate and revise COE models. FERC concluded that it may not be appropriate to use Value Line betas in a CAPM analysis because the beta component should be based on the same exchange as the risk premium component of the model. Value Line is based on the New York Stock exchange. According to FERC, Mr. Moul's CAPM is not appropriate because it is not based on the S&P 500.

Q. PLEASE RESPOND TO MR. MOUL'S CLAIM THAT YOUR METHOD IS UNUSUAL AND NON-STANDARD.

A. As explained in my direct testimony, my CAPM is based on methodologies used by Value Line, the Chicago Board of Options Exchange (CBOE), and published in peer-reviewed academic journals (e.g., The Review of Financial Studies). Additionally, it is far from unusual to use stock options to measure investor expectations. For example, the Federal Reserve Bank of Minneapolis uses stock options to measure implied probability distributions on the S&P 500. The Federal Reserve Bank of Atlanta uses options and futures contracts to measure investors' expectations regarding the federal funds rate.

There are thousands of papers published every year regarding the use of stock options. In 2023 alone, Google scholar reports over 12,000 papers related to the following search term "using stock options to measure investors' expectations regarding stock returns."[11]

Q. PLEASE RESPOND TO MR. MOUL'S CLAIM THAT YOUR CAPM RESULTS ARE UNREASONABLE BY ANY STANDARD.

A. My CAPM results (7.78% - 8.60%) are in the middle to upper part of the range of the expectations published by major banks and brokerage houses (6.6% to 9.5%). These equity return expectations are for the overall stock market (e.g., US Large Cap, S&P 500), which should be higher than the return expectations for buying utility stocks because regulated monopoly utilities are lower risk than most, if not all, unregulated companies in the S&P 500, like Tesla and Amazon.

Q. MR. MOUL CLAIMS THAT I SHOULD HAVE USED BETAS THAT ARE WIDELY USED BY INVESTORS INSTEAD OF MANUFACUTRING MY OWN "PHANTOM" BETAS. PLEASE RESPOND.

A. Implementing a COE model, including the CAPM, does not require an analyst to know what model(s) or beta coefficients investors use. Some investors buy stocks because of a friend's recommendation, a comment made on cable news or a late-night tweet. The number of models used by investors is unknowable and arguably as numerous as individual investors and constantly changing over time. Mr. Moul's claim that a CAPM methodology should be implemented mechanically with Value Line's published 5-year historical betas

[11] https://scholar.google.com/scholar?hl=en&as_sdt=0%2C7&as_ylo=2023&q=using+stock+options+to+measure+investors%27+expectations+regarding+stock+returns&btnG=

because "it is well known" that investors use them ignores the complexity of how billions of human beings make decisions. Regardless of what models investors use, or how they make their investment decisions, their return expectations, and the appropriate cost of equity for UGI Electric, are represented in the prices investors are willing to pay for stocks, bonds, and options. As such, Mr. Moul's criticisms are without merit.

Q. PLEASE RESPOND TO MR. MOUL'S CLAIM THAT IT IS "WELL KNOWN" THAT INVESTORS RELY ON VALUE LINE DATA AND I SHOULD HAVE USED VALUE LINE BETAS IN MY CAPM.

A. Mr. Moul provides no source of his assertion that it is well known that investors rely on value line data to measure the cost of equity. In my experience this is not the case and I am highly skeptical of the assertion that the average investor uses Value Line betas to determine the cost of equity or determine what stock to purchase.

Q. ARE YOU AWARE OF RESEARCH THAT PUTS INTO QUESTION THE USEFULNESS OF VALUE LINE'S PROJECTIONS?

A. Yes. As stated on page 84 of my direct testimony, a research report published by the Journal of Banking & Finance found that "Value Line's long-term stock return projects are extremely overoptimistic and have no predictive power…" The results of this report provide additional evidence that investors are unlikely to blindly rely on Value Line's data as Mr. Moul suggests.

IV. LEVERAGE ADJUSTMENT

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING MR. MOUL'S LEVERAGE ADJUSTMENT?

A. No. As stated in on pages 79-80 of my Direct Testimony, Mr. Moul's leverage adjustment goes against original cost rate making and should be rejected.

V. COMPARABALE EARNINGS APPROACH

Q. ON PAGE 43 OF HIS REBUTTAL TESTIMONY, MR. MOUL CONTINUES TO DEFEND HIS COMPARABLE EARINGS APPROACH BY CLAIMING THAT IT SATISFIES THE COMPARABILITY STANDARD ESTABLISHED IN THE HOPE CASE. DO YOU AGREE WITH MR. MOUL?

A. No. Mr. Moul's Comparable earnings approach does not satisfy the comparability standard established in the Hope Case, as he claims, because investors are not able to earn the return on book equity figures used in this method. As discussed on page 5 of my direct testimony, the legal standards set by the United State Supreme Court require that "The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[12] Investors are not able to earn the return on book equity unless the market-to-book ratios of these companies are the same. Mr. Moul has not demonstrated that the market-to-book rations of the companies that he uses in his analysis

[12] Fed. Power Comm'n v. Hope Nat. Gas Co., 320 U.S. 591, 603 (1944).

are anywhere near 1. Therefore, I continue to support my recommendation that the results of Mr. Moul's Comparable Earnings Approach should be disregarded.

VI. MANAGEMENT PERFORMANCE RECOGNITION

Q. DID MR. MOUL PROVIDE ANY ADDITIONAL EVIDENCE IN HIS REBUTTAL TESTIMONY THAT LEADS YOU TO CHANGE YOUR RECOMMENDAITON THAT UGI ELECTRIC'S ROE SHOULD NOT RECEIVE AN ADDER FOR MANAGEMENT PERFORMANCE?

A. No. As stated on page 88 of my direct testimony, UGI Electric should not receive extra profit for doing its job. Regulated utility companies are obligated to provide safe and reliable service as cheaply as possible. Additionally, the Commission should consider the burden on consumers.

VII. CAPITAL STRUCTURE

Q. ON PAGE 10 OF HIS REBUTTAL TESIMONY, MR. MOUL CLAIMS THAT YOUR RECOMMENDED CAPITAL STRUCTURE IS CLEARLY CONTRARY TO LONG-STANDING COMMISSION POLICY. PLEASE RESPOND.

A. I disagree with Mr. Moul that my capital structure recommendation is contrary to Commission policy. On page 11 of his rebuttal testimony, Mr. Moul explains that the "Commission will accept a utility's actual capital structure ratios as long as they are reasonable." I agree, but the problem in this case is that UGI's capital structure is unreasonable and unfairly prejudices ratepayers. As shown on Exhibit ALR-5, page 5 of my direct testimony, the average common equity ratio used by the 24 companies in my proxy group is 44.7%, significantly less than the 55.25% common equity ratio recommended by Mr. Moul. Only two of the 24 companies in my proxy group have a common equity ratio that is greater than 55.25%. Mr. Moul's recommended capital structure is not reasonable because it is fundamentally inconsistent with the capital structure ratios used by electric companies to raise capital. Therefore, I continue to recommend that UGI Electric's regulatory capital structure should have a common equity ratio of 44.7%.

VIII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REACTION TO MR. MOUL'S REBUTTAL TESTIMONY.

A. Mr. Moul's criticisms of my Direct Testimony are unsupported and should be rejected. If adopted, my cost recommendations would allow UGI Electric to raise the capital it needs to provide safe and reliable service because my recommendations are consistent with investors' return expectations.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes. I reserve the right to supplement this testimony in response to receipt of additional information.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2022-3037368
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Aaron L. Rothschild, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 2SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Aaron L. Rothschild

DATED: June 7, 2023
*347160

Signature: ____________________
Aaron L. Rothschild

Consultant Address: Rothschild Financial Consulting
15 Lake Road
Ridgefield, CT 06877

OCA Statement No. 3

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**Docket No. R-2022-3037368**
UGI Utilities, Inc. – Electric Division	)	

DIRECT TESTIMONY OF

KARL RICHARD PAVLOVIC

Public Version

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

April 25, 2023

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I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Karl Richard Pavlovic. My business address is 22 Brooks Avenue, Gaithersburg, MD 20877.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am Managing Director of and a Senior Consultant with PCMG and Associates LLC ("PCMG"). PCMG is an association of experts in economics, accounting, finance, and utility regulation and policy, with over 75 years of collective experience providing assistance to counsel and expert testimony regarding the regulation of electric, gas, water, and wastewater utilities.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Exhibit KRP-1 to my testimony summarizes my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Exhibit KRP-1 also contains a complete list of my engagements as an expert and/or expert witness in matters before state and federal regulatory agencies. I have submitted testimony to the Federal Communications Commission, the Federal Energy Regulatory Commission, the Alaska Public Utilities Commission, the Alberta Utilities Commission, the California Public Utilities Commission, the Kansas Corporation Commission, the Delaware Public Service Commission, the Hawaii Public Utilities Commission, the Maryland Public Service Commission, the Massachusetts Department of Public Utilities, the Illinois Commerce Commission, the Maine Public Utilities Commission, the Missouri

Public Service Commission, the North Dakota Public Service Commission, and the Public Service Commission of the District of Columbia.

Q. PLEASE SUMMARIZE YOUR ELECTRIC AND GAS REGULATORY EXPERIENCE.

A. For most of my career I have performed analyses and submitted testimony regarding electric and gas utility least-cost planning, reliability, cost of service, rate design, and weather-emergency response. Specifically regarding electric utilities, I have testified on: (a) integrated resource planning, (b) class cost of service and rate design, and (c) various infrastructure-related expense and investment recovery mechanisms.

II. PURPOSE OF TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony responds to UGI Utilities, Inc. - Electric Division's ("UGI") proposed allocated class cost of service study, revenue allocation, and rate design in this proceeding.

III. DISCUSSION

A. SUMMARY

Q. PLEASE SUMMARIZE THE SUBSTANCE OF YOUR TESTIMONY.

A. As detailed below, I find that:

- There is no basis in theory, system design and operation practice, or empirical quantitative data to support UGI's use of the minimum-size method to classify as customer-related any portion of its distribution costs in Accounts 364, 365, 366, 367 and 368 in its ACOSS and recommend that the Commission reject UGI'S ACOSS results as a guide for revenue allocation;

- UGI's ACOSS without minimum-size classification produces results that are consistent with the principle of cost causation and recommend that the Commission accept the results of UGI's ACOSS <u>without</u> minimum-size classification as a guide for revenue allocation;
- Revenue allocation to UGI's rate classes based on UGI's ACOSS <u>without</u> minimum size classification is just and reasonable;
- To provide residential customers with (1) an incentive to engage in conservation and (2) the ability to exercise control over a significant portion of their monthly electric distribution bill, and (3) to avoid the deleterious impact on low-income customers, the residential customer charge should remain at its current level of $9.50.

B. TARIFF RATE CLASSES AND RATE STRUCTURES

Q. WHAT TARIFF RATE CLASSES AND RATE STRUCTURES DOES UGI PROPOSE?

A. UGI proposes nine tariff rate classes. UGI's proposed rate structures consist of a fixed monthly customer charge and a kWh volumetric distribution charge. Three of the rate classes also have a kW demand charge. The outdoor lighting class consists of four subclasses, the customer charges and distribution charges of which are distinguished by the type and size of the lamps used in the service. Similarly, the street lighting class consists of five subclasses, the customer charges and distribution charges of which are also distinguished by the type and size of the lamps used in the services.

Q. ARE ALL NINE RATE CLASSES INCLUDED IN UGI'S ACOSS?

A. No. In UGI's ACOSS the nine outdoor and street lighting classes are combined as a single rate class for costing purposes. The GS-1 and GS-5 classes are also combined in a single class for costing purposes. The high tension power class that takes service at 69 kV or higher at negotiated rates is not included in the ACOSS**.** Both the rate classes and rate structures are summarized in Table 1 below.

Table 1 - UGI Rate Classes and Tariff Rate Structures				
Rate Class	**Customer Charge**	**Distribution Charge kWh**	**Demand Charge kW**	**Notes**
Rate R Residential Service	X	X		Included in ACOSS
Rate GS-1 General Service	X	X		Rates GS-1 and GS-5 combined in ACOSS
Rate GS-5 General Service	X	X		
Rate GS-4 Service	X	X	X	Included in ACOSS
Rate LP Large Power Service	X	X	X	Included in ACOSS
Rate OL Outdoor Lighting Service	X	X		Rates OL,SOL,MHOL,LED and SL,SSL,MHSL,LED, LED-OL combined in ACOSS
Rate SL Street Lighting Service	X	X		
Rate HTP High Tension Power Service	X	X	X	Customer Charge, Distribution Charge and Demand Charge negotiated; not included in ACOSS
Rate FCP Flood Control Power Service	X	X		Included in ACOSS

Q. DO YOU HAVE ANY CRITICISMS OF THE UGI'S PROPOSED RATE CLASSES AND RATE STRUCTURES?

A. I do not have any criticisms of UGI's proposed rate classes, but as outlined more fully below, I have concerns about UGI's rate structure for residential customers in so far as it proposes to increase the residential customer charge.

C. ALLOCATED CLASS COST OF SERVICE STUDY

Q. HAVE YOU EXAMINED UGI's CLASS COST OF SERVICE STUDY?

A. Yes. UGI's allocated class cost of service study ("ACOSS") (Exhibit D Schedules 1 – 8) is based on UGI's Fully Projected Future test year ending September 30, 2024. The ACOSS consists of three Excel workbooks each containing multiple linked worksheets.[1] The ACOSS follows a four-step procedure of (1) functionalization of costs, (2) classification of functionalized costs as demand-related, commodity-related or customer-related, (3) allocation to classes of the classified functionalized costs using demand, commodity and customer allocators, and (4) calculation of class rates of return under both present and proposed rates as a guide to revenue allocation. The ACOSS uses the minimum-size method to classify the distribution facilities in plant accounts 364-368 as consisting of both a customer-related component and a demand-related component, with the customer component allocated to classes on number of customers and the demand component allocated to classes on non-coincident peak ("NCP") demand.[2]

Q. WHAT FACILITIES ARE CONTAINED IN PLANT ACCOUNTS 364 TO 368?

A. Plant accounts 364-368 contain the overhead and underground wires, supporting structures and line transformers that constitute the distribution system. They are facilities that deliver electric energy from the transmission system to the customer equipment contained in plant accounts 369-371 – services, meters and other installations at customer premises.

[1] Exhibit D Schedules 1 and 4-8 (Attachment OSBA-II-1.2.xlsx); Exhibit D Schedule 2 (Attachment OSBA-II-18.xlsx); Exhibit D Schedule 3 (Attachment OSBA-1-2.xlsx).

[2] Direct Testimony of John D. Taylor (Statement No. 6), page 10 line 5 to page 11 line 3; Exhibit D Sections II.3 and II.4 Customer Allocation Factors and Demand Allocation Factors.

Q. WHAT IS THE MINIMUM-SIZE METHOD OF CLASSIFICATION AND ALLOCATION?

A. It is one of two methods for classification of distribution costs that are described in the NARUC Manual: (1) the minimum-size method,[3] which UGI uses and (2) the minimum-intercept method,[4] which UGI calls the "zero-intercept method."[5] The objective of the minimum-size method is to classify distribution rate base items and operating costs to determine the cost driver of each rate base item and operating cost — namely demand or customers — and allocate the rate base items and operating costs purportedly consistent with the principle of cost causation. UGI applies the minimum-size method to accounts 364, 365, 366, 367 and 368; it does not apply the minimum-size method to the customer equipment accounts 369-371. The minimum-size method assumes that a minimum-size distribution system can be built to serve the minimum loading requirements of the system's customers.[6] This assumption is addressed below. The NARUC Manual describes how to calculate the minimum size and cost of a given distribution system.[7] The calculated minimum-size system costs for each distribution plant type are classified as customer-related and allocated to classes based on the number of customers. The remaining cost of each plant type is classified as demand-related and allocated based on demand.

Q. HAVE YOU IDENTIFIED ANY ERRORS IN THE ACOSS?

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[3] National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual (Manual) 1992, pages 90-92.
[4] NARUC Manual, pages 92-94.
[5] Taylor Direct, page 11, lines 6-8.
[6] NARUC Manual, page 90.
[7] NARUC Manual, pages 91-92.

A. Yes. In the classification step, UGI uses the minimum-size method to classify the primary and secondary portions of distribution plant accounts 364, 365, 366 and 368[8] as both demand-related and customer-related. Classifying any portion of these distribution accounts as customer-related contravenes the principle of cost causation, which UGI asserts is the guiding principle of its ACOSS.[9]

Q. WHAT SUPPORT DOES UGI OFFER FOR ITS USE OF THE MINIMUM-SIZE METHOD OF CLASSIFICATION?

A. UGI witness Taylor testifies that:

1. UGI relies on the minimum-size method as described in the NARUC Manual,[10]
2. the minimum-size method is based on the specific design and operating characteristics of UGI's distribution system, [11]
3. the minimum-size method was used in UGI Electric's recent base rate cases at Docket Nos. R-2017-2640058 and R-2021-3023618 and in PPL Electric Utilities Corporation's ("PPL") base rate case at Docket No. R-2015-2469275[12]

Q. ARE YOU RECOMMENDING REVISIONS TO THE MINIMUM-SIZE METHOD OF CLASSIFICATION IN UGI'S ACOSS?

A. No. As I explain below. I am recommending that UGI's minimum-size classification of a portion of its distribution costs as customer-related be rejected, because UGI has not

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[8] Exhibit D Schedule 2.
[9] Taylor Direct, page 7 lines 1-8.
[10] Taylor Direct page 10 lines 8-18.
[11] Taylor Direct page 11 lines 15-18.
[12] Taylor Direct page 11 line18 to page 12 line 1.

provided any evidence that customers are the cause or driver of any portion of its distribution costs.

Q. IS THE MINIMUM-SIZE METHOD COMMONLY USED BY ELECTRIC UTILITIES?

A. At the time that the NARUC Manual was written, the minimum-size method was commonly used by electric utilities in North America, hence its inclusion in the NARUC Manual, which has not been revised since 1992. Today, however, it is less used by major electric utilities. For example, none of the Exelon electric operations use the minimum-size method. That said, in Pennsylvania the minimum-size method is still widely used by electric utilities – only PECO Energy does not utilize the minimum-size method.

Q. IS THE COMMON USE OF THE MINIMUM-SIZE METHOD OF CLASSIFICATION IN PENNSYLVANIA RELEVANT TO DETERMINING THE PROPER CLASSIFICATION OF DISTRIBUTION SYSTEM COSTS FOR UGI IN THIS PROCEEDING?

A. No. As witness Taylor notes, selection of the appropriate classification method(s) for a utility's electric distribution system for costing purposes depends on the specific design and operating characteristics of the distribution system consistent with the principle of cost causation,[13] not on whether other utilities in a jurisdiction use a specific classification method nor on whether the utility has used a specific classification method in prior proceedings. The only relevant question is whether the classification method reflects the cost causation inherent in the design and operation of UGI's distribution system. Again,

[13] Taylor Direct page 11 lines 15-16 and page 7 lines 4-6.

as I demonstrate below, the minimum-size method of classification does not reflect the design and operation of UGI's distribution system.

Q. WHAT DISTRIBUTION COSTS ARE CAUSED BY CUSTOMERS?

A. Principles of Public Utility Rates (Bonbright), the canonical regulatory rate making text, defines electric distribution customer costs as "those operating and capital costs found to vary with the number of customers.[14] Bonbright points out that the distribution system costs that satisfy this definition are "the minimum service, metering, accounting, etc. costs of connecting another customer or the savings in costs of not connecting the customer," viz., the costs of the customer equipment recorded in plant accounts 369-371 Thus, this is not an arbitrary or theory-driven definition, but rather a definition based on a practical and empirically verifiable cause — namely, the act of adding a customer to or dropping a customer from the distribution system.

Q. DOES BONBRIGHT ADDRESS MINIMUM-SIZE AND MINIMUM-INTERCEPT CLASSIFICATION OF DISTRIBUTION COSTS?

A. Yes. Bonbright describes both methods as assuming "hypothetical" and "phantom" distribution systems that rest on the erroneous assumption that "since [the minimum system costs] vary directly with the area of the distribution system (or else with the lengths of the lines, depending on the type of distribution system), they therefore vary directly with the number of customers," which "makes no allowance for the density factor (customers per linear mile or square mile)."[15] In simpler terms, the costs of distribution Accounts 364, 365, 366, 367 and 368 for a given system will be the same if the system serves X number

[14] Principles of Public Utility Rates 1988 (Bonbright), page 490; NARUC Electric Manual, page 90.
[15] Bonbright, page 491.

of customers or 2X number of customers. Electric utilities design the components of their distribution system that are upstream of the equipment required to connect a customer to the system to meet the peak load on the system. Otherwise, the utility would not be able to deliver firm service to customers at peak demand. Regarding the minimum-intercept system, Bonbright adds that a systematic regression analysis found no statistical association between distribution costs and number of customers.[16] I note that I have never seen an analysis of empirical utility data that demonstrates either that distribution system costs vary with the number of customers on a distribution system or that there is a statistical association between distribution system costs and the number of customers.

Q. DOES UGI DESIGN AND OPERATE ITS DISTRIBUTION SYSTEM TO MEET PEAK LOAD?

A. Yes. UGI designs the components of its distribution system that are **BEGIN HIGHLY CONFIDENTIAL** [redacted]

[redacted] **END HIGHLY CONFIDENTIAL**

[16] Bonbright, page 491.
[17] UGI response to OCA-III-4 (HIGHLY CONFIDENTIAL) UGI Utilities, Inc. Electric Division Planning Principles and Practices, Section 2 Principles and Section 3 Practices.
[18] *Id.*

Q. DOES UGI DESIGN AND OPERATE ITS DISTRIBUTION SYSTEM TO MEET THE NUMBER OF CUSTOMERS FORECAST ON ITS DISTRIBUTION SYSTEM?

A. No. The only occurrence of the phrase **BEGIN HIGHLY CONFIDENTIAL** [redacted]

> [redacted] **END HIGHLY CONFIDENTIAL**

Q. HOW DOES THE NARUC MANUAL DEFINE DISTRIBUTION CUSTOMER COSTS?

A. Consistent with Bonbright. the NARUC Manual defines "the customer component of distribution facilities [as] that portion of costs which varies with the number of customers." The Manual then immediately follows, however, with a *non-sequitur*, viz., the unsupported assertion that "[t]hus, the number of poles, conductors, transformers, services and meters are <u>directly related to the number of customers</u> on the utility's system" (emphasis added).[21] Note that this is exactly the same assumption debunked by Bonbright above. The number of customers directly causes the amount and costs of the customer equipment (services, meters and other installations on customer premises) recorded in plant accounts 369-371, not the amount and cost of the distribution system facilities in plant accounts 364-368

[19] UGI response to OCA-III-4 (HIGHLY CONFIDENTIAL) UGI Utilities, Inc. Electric Division Planning Principles and Practices, Section 4.2.2 Overhead Three-Phase Lines.
[20] *Id*.
[21] NARUC Electric Manual, page 90.

(overhead and underground wires, supporting structures and line transformers). **BEGIN HIGHLY CONFIDENTIAL** [redacted] **END HIGHLY CONFIDENTIAL** In this regard, the NARUC Manual is simply wrong. The amounts and costs of the facilities recorded in accounts 364-368 are not "directly related to the number of customers." They are rather directly related to the load or demand of customers.

Q. DOES THE NARUC MANUAL PROVIDE ANY EXPLANATION OR DEMONSTRATION THAT A PORTION OF DISTRIBUTION COSTS VARIES WITH OR IS CAUSED BY THE NUMBER OF CUSTOMERS?

A. No. As I explained above, the NARUC Manual simply assumes without explanation or demonstration that the minimum-size method and the minimum-intercept method identify and quantify a portion of distribution costs that varies with or is caused by the number of customers.

Q. HAS UGI PROVIDED ANY EMPIRICAL QUANTITATIVE EVIDENCE THAT ANY PORTION OF ITS DISTRIBUTION COSTS VARY WITH THE NUMBER OF CUSTOMERS?

A. No. Nor has UGI provided any evidence to support its reliance on the NARUC Manual's minimum-size classification, contrary to (1) Bonbright's demonstration that minimum-size classification contradicts the principle of cost causation which UGI claims underlies its

[22] UGI response to OCA-III-4 (HIGHLY CONFIDENTIAL) UGI Utilities, Inc. Electric Division Planning Principles and Practices, Section 2 Principles and Section 3 Practices.

ACOSS[23] and **BEGIN HIGHLY CONFIDENTIAL** [redacted] **END HIGHLY CONFIDENTIAL**

Q. WHAT DO YOU CONCLUDE REGARDING UGI'S ACOSS'S USE OF THE MINIMUM-SIZE METHOD TO CLASSIFY A PORTION OF ITS DISTRIBUTION COSTS AS CUSTOMER-RELATED AND ALLOCATE THOSE COSTS TO CUSTOMER CLASSES BASED ON THE NUMBER OF CUSTOMERS?

A. As explained above, there is no basis in theory, system design and operation practice, or empirical quantitative data to support UGI's use of the minimum size method to classify as customer-related any portion of its distribution costs in Accounts 364, 365, 366, 367 and 368. UGI's distribution costs do not vary with the number of customers – additions and deletions of customers do not cause those costs to increase or decrease. Thus, I conclude that the Company's distribution costs in Accounts 364, 365, 366, 367 and 368 are properly classified as 100 percent demand-related and properly allocated to classes using UGI's NCP demand allocation factors.

Q. WHAT IS THE IMPACT ON UGI'S RATE CLASSES OF ELIMINATING THE MINIMUM-SIZE CLASSIFICATION OF UGI'S DISTRIBUTION ACCOUNTS 364, 365, 366, 367 AND 368 IN ITS ACOSS?

A. As a general matter, minimum-size classification of distribution costs increases the costs allocated to rate classes with large numbers of customers and low peak demand and

[23] Taylor Direct, page 7 lines 1-8.
[24] UGI response to OCA-III-4 (HIGHLY CONFIDENTIAL) UGI Utilities, Inc. Electric Division Planning Principles and Practices, Section 2 Principles, Section 3 Practices and Section 4.2.2 Overhead Three-Phase Lines.

decreases costs allocated to rate classes with small numbers of customers and high peak demand. Because the number of customers in a rate class is not a cause or driver of distribution costs, minimum-size classification over allocates costs to rate classes with large numbers of customers and low peak demand and under allocates costs to rate classes with small numbers of customers and high peak demand. The effect of this misallocation of costs can be seen by comparing the class rates of return and relative rates of return calculated by UGI's ACOSS to those calculated by eliminating minimum-size classification from UGI's ACOSS. Table 2 below compares the class rates of return and relative rates of return under UGI's ACOSS with and without minimum-size classification. As can be seen, the ACOSS without minimum-size classification, which allocates distribution costs on NCP demand, results in higher rates of return and relative rates of return for the Residential and General Service rate classes and lower rates of return for the General Service-4, Flood Control Power, Large Power and Lighting rate classes. It should be noted that these results are returns calculated under current revenues.

Table 2 - Comparison of Relative Rate of Return by Rate Class – ACOSS w/ and w/o Minimum-Size Classification				
	UGI ACOSS w/ Minimum-Size[25]		UGI ACOSS w/o Minimum-Size[26]	
Customer Classes	**Rate of Return on Rate Base under Current Rates**	**Relative Rate of Return under Current Rates**	**Rate of Return on Rate Base under Current Rates**	**Relative Rate of Return under Current Rates**
Residential	-0.18%	(0.05)	1.66%	0.44
General Service	3.23%	0.86	13.99%	3.71
General Service-4	17.29%	4.59	4.91%	1.30
Flood Control Power	4.42%	1.17	-3.98%	(1.06)
Large Power	22.68%	6.02	7.78%	2.07
Lighting	38.14%	10.12	28.73	7.63
Total Company	3.77%	1.00	3.77%	1.00

Q. WHAT IS THE PURPOSE OF THE RELATIVE RATE OF RETURN METRIC?

A. Relative rate of return is the metric by which fair cost apportionment is measured and evaluated. UGI's ACOSS calculates the overall rate of return for UGI's distribution system and the rates of return for each class.[27] Class relative rates of return are then calculated by dividing the class rates of return by the overall rate of return. A class relative rate of return of 1.00 indicates that the class is earning the overall rate of return. A class relative rate of return less than 1.00 indicates that the class is underearning or under recovering its cost of service, i.e., the revenue generated by its rates is not covering the full cost of service to the class. A class relative rate of return greater than 1.00 indicates that the class is overearning or over recovering its cost of service, i.e., the revenue generated by its rates is more than

[25] Taylor Direct, page 23 Table 4; Exhibit D, Schedule 6, line 29, line 30.
[26] Exhibit KRP-2, Schedule 6, line 29, line 30.
[27] Exhibit D, Schedule 6 lines 29-30.

covering the full cost of service to the class. Relative rates of return are used as a guide to allocating the revenue increase to classes so as to move each class closer to full recovery.

Q. WHAT DO YOU CONCLUDE AND RECOMMEND FROM THIS?

A. I conclude that UGI's ACOSS produces results inconsistent with the principle of cost causation, because contrary to the minimum-size method's assumption, the number of customers is neither a cause nor a driver of distribution costs. I also conclude that UGI's ACOSS without minimum-size classification produces results consistent with the principle of cost causation, because demand is both a cause and a driver of distribution costs. I recommend that the Commission adopt the ACOSS without minimum-size classification as a guide in determining UGI's class revenue allocation and tariff distribution rates.

D. CLASS REVENUE ALLOCATION

Q. WHAT IS UGI'S PROPOSED CLASS REVENUE ALLOCATION?

A**.** UGI proposes to allocate its proposed revenue increase to classes based on its ACOSS' class rate of return results, moving all rate classes closer to the overall system rate of return and thereby reducing subsidies between classes.[28] Table 3 shows for each class UGI's proposed movement to cost of service (measured by relative rate of return), allocated revenue, and resulting revenue increase percentage.

[28] Taylor Direct, page 21 lines 4-8.

Table 3 UGI's Proposed Class Revenue Allocation[29]				
Customer Class	**Present Relative Rate of Return**	**Proposed Relative Rate of Return**	**Revenue Increase Allocation ($000)**	**Proposed Percent Increase**
Residential	(0.05)	0.73	10,705	27.5%
General Service	0.86	0.96	714	26.3%
General Service-4	4.59	1.78	-	-
Flood Control Power	1.17	1.04	5	27.7%
Large Power	6.02	2.34	-	-
Lighting	10.12	3.91	-	-
Total Company	1.00	1.00	11,425	20.9%

Q. WHAT ARE THE "SUBSIDIES" BETWEEN CLASSES TO WHICH UGI REFERS?

A. What UGI refers to as "subsidies" are the dollar differences between each class's revenues and the ACOSS's calculated cost of service, calculated by subtracting the class' cost of service from the class' revenue. A negative number measures the amount by which the class' revenues (current or proposed) are deficient in recovering the class' costs. A positive number measures the amount by which the class' revenues are in excess of recovering the class' costs. Table 4 shows the class excesses and deficiencies calculated by UGI's ACOSS with minimum size classification under its current and proposed rates.

[29] Taylor Direct, page 23 Table 4 (Exhibit D, Schedule 6, line 29, line 30, line 73, line 74) and page 22 Table 3 (Exhibit D, Schedule 6, line 12, line 64, line 60, line 68).

Table 4 - Comparison of Present and Proposed Revenue Excess (Deficiency) Per UGI's ACOSS w/ Minimum-Size Classification ($000)[30]			
Customer Class	**Class Excess (Deficiency) under Current Revenues**	**Class Excess (Deficiency) under Proposed Revenues**	**Change in Excess (Deficiency)**
Residential	(6,237)	(3,986)	2,251
General Service	(59)	(25)	34
General Service-4	2,129	1,160	(969)
Flood Control Power	0.778	0.668	(0.110)
Large Power	3,352	2,211	(1,141)
Lighting	814	639	(175)
Total	(0)	(0)	0

Q. DO YOU AGREE WITH UGI'S PROPOSED REVENUE ALLOCATION TO THE CLASSES?

A. No. First, because UGI's proposed revenue allocation is based on its minimum-size ACOSS, which as I explained above does not calculate class costs on the basis of cost causation. Second, because the class percentage increases are so large that they contravene the ratemaking principle of gradualism. Thus, the resulting class revenue increases are neither just nor reasonable.

Q. WHAT DO YOU PROPOSE AS A FAIR AND REASONABLE ALLOCATION OF REVENUE TO UGI'S CLASSES?

A. I propose to use the ACOSS without minimum-size classification relative rates of return to move the classes toward full cost recovery. Specifically, I propose to allocate the revenue

[30] Taylor Direct, page 24 Table 5 (Exhibit D, Schedule 6, line 40, line 66.

increase so as to move the class relative rates of return approximately 60 percent towards 1.00 or parity. The exception is the Flood Control Power class where 60 percent movement would create unreasonable rate shock. Tables 5 and 6 show, for each class, my proposed movement toward cost of service (measured by relative rate of return), allocated revenue, resulting revenue increase percentage and change in class excess or deficiency.

Table 5 OCA Recommended Class Revenue Allocation[31]						
Customer Class	**Present Relative Rate of Return**	**Proposed Relative Rate of Return**	**Percent Movement Toward Parity**	**Revenue Increase Allocation ($000)**	**Proposed Percent Increase**	**Percent Distribution of Proposed Increase**
Residential	0.44	0.77	59%	7,643	6.5%	66.9%
General Service	3.71	2.07	60%	445	6.7%	3.9%
General Service-4	1.30	1.12	60%	1,454	10.2%	12.7%
Flood Control Power	(1.06)	(0.21)	41%	3	15.7%	0.0%
Large Power	2.07	1.44	59%	1,684	14.4%	14.7%
Lighting	7.63	3.68	59%	195	10.6%	1.7%
Total	1.00	1.00		11,425	7.5%	100%

[31] Exhibit KRP -2, Schedule 6 lines 30, 74, 74B, 60, 67, 60A.

Table 6 - Comparison of Present and Proposed Excess (Deficiency) Per UGI ACOSS w/o Minimum-Size Classification ($000)[32]			
Customer Class	**Class Excess (Deficiency) under Current Revenues**	**Class Excess (Deficiency) under Proposed Revenues**	**Change in Excess (Deficiency)**
Residential	(3,020)	(3,061)	41
General Service	792	768	(24)
General Service-4	328	351	23
Flood Control Power	(13)	(18)	5
Large Power	1,190	1,240	50
Lighting	723	720	(3)
Total	0	0	0

Q. WHY ARE THE CHANGES IN THE CLASS EXCESSES AND DEFICIENCIES RELATIVELY SMALL IN TABLE 6 COMPARED TO THOSE IN TABLE 4.

A. There is an inherent trade-off between movement towards parity and the percentage increase in class revenue. The 60 percent movement used in my class revenue allocation achieves significant movement to parity while avoiding rate shock to any of the rate classes. Thus, it represents a balancing of the principle of fair cost apportionment and the principle of gradualism.

Q. HAVE YOU CALCULATED YOUR PROPOSED ALLOCATION BASED ON OCA'S RECOMMENDED REVENUE REQUIREMENT?

A. Yes. Table 7 shows the revenue increase allocation for the OCA recommended revenue requirement of $3,540,663[33] based on the distribution percentages in Table 5 above.

[32] Exhibit KR -2, Schedule 6 lines 40 and 66.
[33] Direct Testimony of Dante Mugrace (OCA Statement No. 1) Schedule DM-1.

Table 7 – Revenue Increase Allocation for OCA Recommended Revenue Requirement ($000)[34]		
Customer Classes	**OCA Percent Distribution of Revenue Increase**	**OCA Revenue Increase allocation**
Residential	66.9%	2.368
General Service	3.9%	138
General Service-4	12.7%	451
Flood Control Power	0.0%	1
Large Power	14.7$	522
Lighting	1.7%	61
Total	100%	3,541

Q. DO YOU HAVE A SCALE BACK PROPOSAL?

A. Yes. I recommend that if the Commission does not adopt the OCA's proposed revenue requirement that, for whatever revenue increase is ultimately adopted by the Commission, the revenue increase be scaled back and allocated based on the distribution percentages in Table 5 above.

E. CLASS RATE DESIGN CHANGES

Q. WHAT IS UGI's PROPOSAL REGARDING CHANGES TO ITS TARIFF RATE SCHEDULES?

A. UGI proposes the following changes to its tariff rates:

- Residential: increase Customer Charge from $9.50 to $13.50 with remainder of increase to the Distribution Charge;

[34] Exhibit KRP-2, Schedule 6, line 60B.

- General Service: increase Customer Charge from $13.00 to $14.00 with remainder of increase to the Distribution Charge;
- General Service-4: no change to the Customer, Distribution and Demand Charges;
- Flood Control Power: recover the increase in the Distribution Charge
- Large Power: no change to the Customer, Distribution and Demand Charges;
- Lighting: no change to the Customer and Distribution Charges.

Q. DO YOU AGREE WITH UGI'S PROPOSED CHANGES TO THE TARIFF RATES?

A. No. The tariff rates for all UGI's rate classes should be increased consistent with the allocated revenue increases in Table 7 above.

Q. WHAT SPECIFIC CHANGE DOES UGI PROPOSE REGARDING THE RESIDENTIAL MONTHLY CHARGE?

A. UGI proposes to increase the residential customer charge from $9.50 to $13.50 with the remainder of the revenue increase to be recovered through the volumetric kWh distribution charge.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE RESIDENTIAL MONTHLY CHARGE?

A. UGI's proposed Residential customer charge represents an increase of 42% over the current charge, which represents significant and unacceptable rate shock to no ratemaking benefit. A fixed monthly customer charge sends no real actionable price signal to Residential customers. No residential customer chooses either to take service or to take a given amount of service based on the customer charge. Thus, the ratemaking principle of efficiency, to which UGI subscribes,[35] provides no basis to set the customer charge at one level or another. On the other hand, if the Residential customer charge is left unchanged, the increased revenue approved in this proceeding will be recovered through the volumetric distribution charge, where it will definitely send a real actionable price signal regarding conservation and customers' control over their monthly bill. Placing all of the increase in the volumetric distribution charge will provide Residential customers with both (1) an increased incentive to engage in conservation and (2) the ability to exercise control over a larger portion of their monthly electric distribution bill. Finally, OCA witness Colton details in his testimony the extraordinary deleterious impacts that any increase in the customer charge will have on low-income Residential customers.[36] For all these reasons I recommend that the Residential customer charge remain at its current level of $9.50.

Q. HAS THE COMMISSION RECENTLY ISSUED ANY DECISIONS AS TO INCREASED CUSTOMER CHARGES?

A. Yes. Columbia proposed an increase in its existing monthly customer charge in Docket No. R-2020-3018835. In that proceeding the Administrative Law Judge (ALJ) found that Columbia's proposed increase in the Residential customer charge was contrary to the Commission's goal of encouraging customers to conserve energy and denied the Company's requested increase in the monthly customer charge. The Commission adopted the ALJ's decision regarding the Residential customer charge.[37]

[35] Taylor Direct, page 19 line 4 to page 20 line 2.
[36] Direct testimony of Roger D. Colton (Statement No. 4), pages 21-30.
[37] *Pa. P.U.C. v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835, Order at 264-65 (Feb. 19, 2021).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, I reserve the right to supplement this testimony if further information is provided by UGI.

Exhibit KRP-1

KARL RICHARD PAVLOVIC, Ph.D.

Education

Purdue University – MA and Ph.D. in Philosophy

Karl-Ruprecht Universität, Heidelberg, Germany – graduate study

Yale University – BA in Philosophy

Positions

Senior Consultant – PCMG and Associates	2015-Present
Senior Consultant – Snavely King Majoros and Associates	2010-2014
Director – FTI Consulting	2008-2010
President – DOXA, Inc	1994-2008
Partner – Snavely King and Associates	1983-1994
Assistant Professor – University of Florida-Gainesville	1978-1983

Professional Experience

Dr. Pavlovic provides clients with economic and policy analyses of commercial operations and expert testimony in support of litigation, negotiation and strategic planning. His analyses and testimony are distinguished by systematic articulation and testing of assumptions, thorough evaluation of data, innovative application of statistical tools and economic principles, and clarity and precision of presentation. Dr. Pavlovic has provided expert testimony on the operations, costs and revenues of gas and electric utilities, the impacts of restructuring wholesale and retail electric markets, effects of mergers, the operation and competitiveness of petroleum and electric markets, the market valuation of crude oil, electric and gas reliability, and the performance of energy efficiency, renewable energy, and peak reduction programs.

Major projects directed by Dr. Pavlovic have included: analytical assistance to counsel and testimony on all aspects of the restructuring of wholesale and retail electric markets in the Eastern Interconnection; technical representation of the District of Columbia People's Counsel on the DC PSC's Pepco Productivity Improvement Working Group and various PJM working groups; impact evaluation study of pilot energy efficiency and renewable energy programs in the District of Columbia; analysis of petroleum markets, expert testimony, and coordination of technical testimony in the Trans-Alaska Pipeline quality bank litigation; Independent Technical Review of the economic models used by the US Army Corps of Engineers for the Ohio River System Investment Plan; assistance to a major independent telephone company in the formulation and implementation of corporate strategic plans, applications for long-distance authority, and settlement negotiations with major domestic and foreign carriers.

By education and professional experience Dr. Pavlovic has expertise in formal and mathematical logic, statistics, economics, financial analysis, econometrics, and computer modeling. With 33 years' experience as a consultant and expert witness, Dr. Pavlovic has in-depth knowledge of commercial and industrial operations in the energy, transportation, and telecommunications industries and is familiar with a wide range of experimental and investigative methods in science and engineering.

Regulatory Projects and Appearances

1. In re: Application of Hawaii Water Service Company, Inc. for Approval of a General Rate Increase for its Pukalani Wastewater Diviion and Certain Tariff Changes (2023) – (Appearance: cost of service and rate design on behalf of the Hawaii Division of Consumer Advocacy)
   HI Public Utilities Commission Docket No. 2022-0186

2. In re: Application of Lanai Water Company, Inc. for Review and Approval of Rate Increases; Revised Rate Schedules; and Changes to its Tariff (2023) – (Appearance: cost of service and rate design on behalf of the Hawaii Division of Consumer Advocacy)
   HI Public Utilities Commission Docket No. 2022-0233

3. In re: Application of Southern Maryland Electric Cooperative, Inc., for Authority to Revise Its Rates and Charges for Electric Service and Certain Rate Design Changes (2023) – (Appearance: cost of service and rate design on behalf of the Maryland Office of the People's Counsel)
   MD PSC Case No. 9688

4. In re: Application of San Diego Gas & Electric Company for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2023 (2022) – (Appearance: business risk and cost of equity on behalf of Utility Consumers' Action Network)
   CA Public Utilities Commission Application 22-04-012

5. In re: Valley Energy, Inc. General Base Rate Increase Filing (2022) – (Appearance: gas and electric cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
   PA Public Utility Commission Docket Nos. R-2022-3032300

6. In re: Citizens' Electric Company General Base Rate Increase Filing (2022) – (Appearance: gas and electric cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
   PA Public Utility Commission Docket Nos. R-2022-3032369

7. In re: PECO Energy Company (Gas Division) General Base Rate Increase Filing (2022) – (Appearance: gas and electric cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
   PA Public Utility Commission Docket Nos. R-2022-3031113

8. In re: Petition of Eversource Gas Company of Massachusetts d/b/a Eversource Energy

for Approval of its 2021 Gas System Enhancement Plan Reconciliation Filing (2022) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 22-GREC-06

9. In re: Petition of Liberty Utilities (New England Natural Gas Company Corp.) d/b/a Liberty for Approval of its 2021 Gas System Enhancement Plan Reconciliation Filing (2022) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 22-GREC-04

10. In re: Petition of Berkshire Gas Company for Approval of its 2021 Gas System Enhancement Plan Reconciliation Filing (2022) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 22-GREC-02

11. In re: Nova Scotia Power 2022-2024 General Rate Application (2022) - (Appearance: cost of service on behalf of the Nova Scotia Utility and Review Board)
NS UARB M10431

12. In re: the Application of Northern States Power Company for Authority to Increase Rates for Natural Gas Service in North Dakota (2021) - (Appearance: cost of service and rate design on behalf of the North Dakota Public Service Commission Advocacy Staff)
ND PSC Case No. PU-20-441

13. In re: Application of San Diego Gas & Electric Company for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2022 and to Reset the Annual Cost of Capital Mechanism (2021) – (Appearance: wildfire risk accounting and ratemaking on behalf of Utility Consumers’ Action Network)
CA Public Utilities Commission Application 21-08-014

14. In re: Petition of HPBS, Inc. for review and approval of Central Scheduling System (CSS) charge increase and revised CSS schedule (2021) – (Appearance: rate design on behalf of the Hawaii Department of Commerce and Consumer Affairs)
HI DCCA Docket No. PTP-2021-001

15. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2020 Gas System Enhancement Plan Reconciliation Filing (2021) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 21-GREC-06

16. In re: Petition of Eversource Gas Company of Massachusetts d/b/a Eversource Energy for Approval of its 2020 Gas System Enhancement Plan Reconciliation Filing (2021) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 21-GREC-05

17. In re: Petition of Berkshire Gas Company for Approval of its 2020 Gas System Enhancement Plan Reconciliation Filing (2021) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 20-GREC-02

18. In re: the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota (2021) - (Appearance: cost of service and rate design on behalf of the North Dakota Public Service Commission Advocacy Staff)
    ND PSC Case No. PU-20-441

19. In re: Pike County Light & Power Company 2020 General Base Rate Increase Filing – (Appearance: gas and electric cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    PA Public Utility Commission Docket Nos. R-2020-3022134 and R-2020-3022135

20. In re: Young Brothers LLC's Application for Approval of a New Cost of Service Model (2020) – (Appearance: cost of service on behalf of the Hawaii Division of Consumer Advocacy)
    HI Public Utilities Commission Docket No. 2020-0135

21. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2019 Gas System Enhancement Plan Reconciliation Filing (2020) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 20-GREC-06

22. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2019 Gas System Enhancement Plan Reconciliation Filing (2020) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 20-GREC-05

23. In re: Petition of Berkshire Gas Company for Approval of its 2019 Gas System Enhancement Plan Reconciliation Filing (2020) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 20-GREC-02

24. In re: Pittsburgh Water and Sewer Authority 2020 General Base Rate Increases 2020 – (Appearance: multi-year rate plan and performance-based ratemaking on behalf of the Pennsylvania Office of Consumer Advocate)
    PA Public Utility Commission Docket Nos. R-2020-3017970 and R-2020-3017951

25. In re: Commonwealth Edison Company Petition for approval of a Revision to Integrated Distribution Company Implementation Plan Creation of Rate Residential Time of Use Pricing Pilot ("Rate RTOUP") – On Rehearing (2020) – (Appearance: price signal and customer response on behalf of the Illinois Attorney General)
    IL Commerce Commission Docket Nos. 18-1725/18-1824

26. In re: Hawaii Electric Company, Inc. Application for Approval of a General Rate Increase and Revised Rate Schedules and Rules (2019) - (Appearance: cost of service and rate design on behalf of the Hawaii Division of Consumer Advocacy)
    HI Public Utilities Commission Docket No. 2019-0085

27. In re: Application of San Diego Gas & Electric Company for Authority to: (i) Adjust its Authorized Return on Common Equity, (ii) Adjust its Authorized Embedded Costs of Debt and Preferred Stock, (iii) Adjust its Authorized Capital Structure; (iv) Increase its Overall Rate of Return, (v) Modify its Adopted Cost of Capital Mechanism Structure, and (vi) Revise its Electric Distribution and Gas Rates Accordingly, and for Related Substantive and Procedural Relief (2019) – (Appearance: wildfire risk accounting and ratemaking on behalf of Utility Consumers' Action Network)
    CA Public Utilities Commission Application 19-04-017

28. In re: Proposed Amendments to N.J.A.C. 14:9 Adoption of Water and Sewer Uniform System of Accounts (2019) – (Assistance to counsel: water and sewer accounting on behalf of the Division of Rate Counsel)
    NJ Board of Public Utilities Docket Nos. WX19050612 and WX19050613

29. In re: Petition of Public Service Electric and Gas Company for Approval of Gas Base Rate Adjustments Pursuant to its Gas System Modernization Program (2019) – (Assistance to Counsel: infrastructure replacement accounting)
    NJ Board of Public Utilities Docket No. GE19040522

30. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2018 Gas System Enhancement Plan Reconciliation Filing (2019) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 19-GREC-06

31. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2018 Gas System Enhancement Plan Reconciliation Filing (2019) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 19-GREC-05

32. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2019) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9602

33. In re: PECO Energy Company Non-Bypassable Transmission Service Charge (NBT) Semiannual Adjustment (2019) - (Appearance: accounting, cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    PA Public Utility Commission Docket No. M-2018-3005860

34. In re: PECO Energy Company Transmission Formula Rate Application (2018) - (Appearance: accounting, cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    Federal Energy Regulatory Commission Docket ER17-1519-000

35. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2017 Gas System Enhancement Plan Reconciliation Filing (2018) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 18-GREC-06

36. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2017 Gas System Enhancement Plan Reconciliation Filing (2018) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 18-GREC-05

37. In re: The Application of the Potomac Edison Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2018) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9490

38. In re: Rate Applications of Kansas City Power & Light – Missouri and Kansas City Power & Light – Greater Missouri Operations (2018) – (Appearance: consolidated operations, cost of service and rate design on behalf of the Missouri Office of Public Counsel)
    MO Public Service Commission Case Nos. ER-2018-0145 and ER-2018-0146

39. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2018) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9472

40. In re: Mid-Atlantic Interstate Transmission, L.L.C. 2018 Transmission Formula Rate Protocol Filings (2018) - (Analysis and Advice to Counsel: accounting)
    Federal Energy Regulatory Commission Docket ER17-211-000

41. In re: The Gas Company d/b/a Hawaii Gas Application for Approval of Rate Increases and Revised Rate Schedules and Rules (2017) - (Appearance: cost of service and rate design on behalf of the Hawaii Division of Consumer Advocacy)
    HI Public Utilities Commission Docket No. 2017-0105

42. In re: Montana-Dakota Utilities Co., Application to Increase Natural Gas Rates (2017) - (Appearance: cost of service and rate design on behalf of the North Dakota Public Service Commission Staff)
    ND Public Service Commission Case No. PU-12-813

43. In re: The Application of Delmarva Power and Light Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2017) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9455

44. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2016 Gas System Enhancement Plan Reconciliation Filing (2017) - (Appearance: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 17-GREC-06

45. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2016 Gas System Enhancement Plan Reconciliation Filing (2017) - (Appearance: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 17-GREC-05

46. In re: In the matter of the application of Columbia Gas of Maryland, Inc. for Authority to Increase Rates and Charges (2017) - (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9447

47. In re: PJM Interconnection, L.L.C. - PECO Energy Company Transmission Formula Rate Application (2017) - (Analysis and Advice to Counsel: accounting, cost of service and rate design)
    Federal Energy Regulatory Commission Docket ER17-1519-000

48. In re: Northern Illinois Gas Company d/b/a Nicor Gas Company Proposed General Increase in Gas Rates (2017) - (Appearance: prudence/used and useful and plant accounting re. accelerated asset replacement program on behalf of the Illinois Citizens Utility Board)
    IL Commerce Commission Docket No. 17-0124

49. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2017) - (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9443

50. In re: PJM Interconnection, L.L.C. - Rockland Electric Company Transmission Rate Application (2017) (Analysis and Advice to Counsel: accounting, cost of service and rate design on behalf of the New Jersey Division of Rate Counsel)
    Federal Energy Regulatory Commission Docket ER17-856-000

51. In re: PJM Interconnection, L.L.C. - Mid-Atlantic Interstate Transmission, L.L.C. Transmission Formula Rate Application (2016) - (Analysis and Advice to Counsel: accounting, cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    Federal Energy Regulatory Commission Docket ER17-211-000

52. In re: The Application of Delmarva Power and Light Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2016) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9424

53. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2016) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9418

54. In re: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Analysis and Advice to Counsel: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 16-GREC-01

55. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Appearance: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 16-GREC-05

56. In re: Petition for Approval of Gas Infrastructure Contract Between Public Service Company of New Hampshire d/b/a Eversource Energy and Algonquin Gas Transmission, LLC (2016) - (Appearance: compliance with statutes and regulations, prudence, cost/benefit, and ratemaking on behalf of the New Hampshire Office of Consumer Advocate)
    NH Public Utilities Commission Docket No. DE 16-241

57. In re: Central Maine Power Company, Annual Compliance Filing and Price Change (2016) - (Analysis and Advice to Counsel: tax normalization regulatory asset on behalf of the Maine Office of the Public Advocate)
    ME Public Service Commission Docket No. 2016-00035

58. In re: Bulletin 2015-10 Generic Proceeding to Establish Parameters for the Next Generation PBR Plans (2016) - (Appearance: productivity adjustments/performance based ratemaking on behalf of the Alberta Utilities Consumer Advocate)
    Alberta Utilities Commission Proceeding 20414

59. In re: Emera Maine, Proposed Rate Increase in Rates (2016) - (Analysis and Advice to to Counsel: evaluation of management audit of implementation of Customer Information System on behalf of the Maine Office of the Public Advocate)
    ME Public Service Commission Docket No. 2015-00360

60. In re: The Merger of the Southern Company and AGL Resources Inc.- Joint Application of the Southern Company, AGL Resources Inc., and Pivotal Utility Holdings, Inc., d/b/a Elkton Gas (2015-2016) - (Appearance: earnings, synergy savings, rates, operations, supply procurement, safety, and reliability on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9404

61. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of Firm Transportation Agreements with Millennium Pipeline Company, LLC (2015-2016) - (Analysis, Advice to Counsel, and Assistance on Brief: compliance with gas supply plan, rates, and reliability on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-142

62. In re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Precedent Agreements with Millennium Pipeline Company, LLC (2015-2016)
    - (Analysis, Advice to Counsel, and Assistance on Brief: compliance with gas supply plan, rates, and reliability on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-130

63. In re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Agreements for LNG or Liquefaction Services with GDF Suez Gas NA, LLC; Northeast Energy Center, LLC; Gaz Metro LNG, L.P.; and National Grid LNG (2015- 2016) - (Analysis and Advice to Counsel: compliance with gas supply plan, rates, and reliability on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-129

64. In re: Columbia Gas of Massachusetts CY2014 Targeted Infrastructure Reinvestment Factor Compliance Filing (2015) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-55

65. ENMAX Energy Corporation (EEC) 2015-2016 Regulated Rate Option Non-Energy Tariff Application (2015-2016) - (Appearance: cost allocation, rate design, non-energy risk on behalf of the Alberta Utilities Consumer Advocate)
    Alberta Utilities Commission Proceeding 20480

66. In the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc. (2014) - (Advice to Counsel: impact on customers on behalf of the New Jersey Division of Rate Counsel)
    NJ Board of Public Utilities BPU Docket No. EM1406

67. In re: Application of Baltimore Gas and Electric Company For Adjustments To Its Electric and Gas Base Rates (2014) (Analysis and Advice to Counsel in Settlement: earnings, investment tracker, cost allocation and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9355

68. In re: Columbia Gas of Massachusetts CY2013 Targeted Infrastructure Reinvestment Factor Compliance Filing (2014) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 14-83

69. In re: Potential Business Combination of Entergy Louisiana, LLC and Entergy Gulf States Louisiana, L.L.C. (2014-2015) - (Analysis and Advice to Counsel: impact on rates and consolidation of rates on behalf of the Louisiana Public Service Commission Staff)
    LA Public Service Commission Docket No.U-33244

70. In the Matter of the Application of Ohio Power Company to Adopt a Final Implementation Plan for the Retail Stability Rider (2014) - (Analysis and Advice to Counsel: rate design)
    OH Public Utilities Commission Case No. 14-1186-EL-RDR

71. In re: Examination of Long-Term Natural Gas Hedging Proposals (2014-2015) - (Analysis and Advice to Counsel: natural gas procurement on behalf of the Louisiana Public Service Commission Staff)
    LA Public Service Commission Docket No.R-32975-LPSC, ex parte

72. In re: 2013 Integrated Resource Planning Process for Southwestern Electric Power Company Pursuant to General Order Dated April, 20, 2012 (2014-2015 - (Analysis and Advice to Counsel: IRP design and evaluation on behalf of the Louisiana Public Service Commission Staff)
    LA Public Service Commission Docket No.I-33013 SWEPCO, ex parte

73. In the Matter of the Application of Columbia Gas of Maryland, Inc. for Authority to Adopt an Infrastructure Replacement Surcharge Mechanism (2013-2014) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9332

74. In the Matter of the Application of Baltimore Gas and Electric Company for Approval of a Gas System Strategic Infrastructure Development and Enhancement Plan and Accompanying Cost Recovery Mechanism (2013-2014) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9331

75. In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Changes (2013-2014) - (Appearance: earnings, investment tracker design/rates, cost allocation and rate design on behalf of the Delaware Public Service Commission Staff)
    DE Public Service Commission Docket No. 13-115

76. In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota (2013) - (Appearance: cost allocation and rate design on behalf of the North Dakota Public Service Commission Staff)
    ND Public Service Commission Case No. PU-12-813

77. In the Matter of the Application of Columbia Gas of Maryland, Inc. for Authority to Increase Rates and Charges (2013) - (Appearance: expense tracker design/rates and evaluation on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9316

78. In the Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates (2012) - (Appearance: earnings, investment tracker design/rates, cost allocation and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9299

79. In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Changes (2012) - (Appearance: earnings, investment tracker design/rates, cost allocation and rate design on behalf of the Delaware Public Service Commission Staff)
    DE Public Service Commission Docket No. 11-528

80. ENMAX Energy Corporation (EEC) 2012-2014 Regulated Rate Option Non-Energy Tariff Application (2012-2013) - (Analysis and Advice to Counsel: rate design and non-energy risk on behalf of the Alberta Utilities Consumer Advocate)
    Alberta Utilities Commission Application #1608745 Proceeding 2069

81. In the Matter of the Petition of Atlantic City Electric Company for Approval of Amendments to Its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to *N.J.S.A.* 48:2-21 and *N.J.S.A.* 48:2-21.1 and for Other Appropriate Relief (2011) - (Analysis and Advice to Counsel: depreciation on behalf of the New Jersey Division of Rate Counsel)
    NJ Board of Public Utilities Docket No. ER11080469

82. In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service (2011) - (Appearance: investment tracker design/rates, cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1087

83. Electric Transmission Formula Rate Annual Informational Filing of Central Maine Power Company (2011) - (Advice to Counsel: formula transmission rates, cost allocation and rate design on behalf of the Maine Attorney General)
    Federal Energy Regulatory Commission Docket No. ER09-934-000 (2011)

84. Electric Transmission Formula Rate Annual Informational Filing of Bangor Hydro Electric Company (2011) - (Analysis, Report and Advice to Counsel: formula rate on behalf of the Massachusetts Attorney General)
    Federal Energy Regulatory Commission Docket No. ER09-938-000

85. Pennsylvania Public Utility Commission Office of Consumer Advocate Office of Small Business Advocate v. City of Bethlehem – Bureau of Water (2011) - (Appearance: cost allocation and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    Pennsylvania PUC Docket Nos. R-2011-2244756, C-2011-2246910, and C-2011- 2248241

86. Southern California Edison Company Transmission Owners Tariff (2011) - (Analysis and Advice to Counsel: depreciation on behalf of M-S-R Public Power Agency)
    Federal Energy Regulatory Commission Docket No. ER11-2061-000

87. In the Matter of the Petition of Kansas City Power & Light Company for Determination of the Ratemaking Principles and Treatment that Will Apply to the Recovery in Rates of the Cost to be Incurred by KCP&L for Certain Electric Generation Facilities under K.S.A. 66- 1239 (2011) - (Appearance: advance determination of prudence on behalf of the Kansas Citizens' Utility Ratepayer Board)
    Kansas Corporation Commission Docket No. 11-KCPE-581-PRE

88. Midwest Independent Transmission System Operator, Inc., and Ameren Illinois Company (2011) - (Analysis and Advice to Counsel: depreciation on behalf of the Wholesale Distribution Service Customer Group)
    Federal Energy Regulatory Commission Docket No. ER11-2788-000

89. Electric Generation Plant Valuation Study (2010-2012) - (Analysis: generation plant valuation)
    California Department of Water Resources

90. Tampa Electric Company Wholesale Power Tariff (2010-2011) - (Analysis and Advice to Counsel: depreciation on behalf of the Orlando Utilities Commission)
    Federal Energy Regulatory Commission Docket No. ER10-2061-000

91. Pacific Gas & Electric Company, Transmission Owner Tariff (2010-2011) - (Analysis and Advice to Counsel: depreciation on behalf of the Transmission Agency of Northern California)
    Federal Energy Regulatory Commission Docket No. ER10-2026-000

92. Natural Gas Price Forecast Model Consulting (2008-2010) - (line of business development) FTI Consulting

93. Impact Evaluation Study of the District of Columbia Department of the Environment's Two-Year Pilot Reliable Energy Trust Fund Programs (2007-2008) - (Appearance: evaluation of implementation and cost effectiveness of energy efficiency, renewable energy, and demand response pilot programs on behalf of the District of Columbia Department of the Environment)
    D.C. Public Service Commission Formal Case No. 945

94. In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service (2007-2008)- Appearance: cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1053

95. In the Matter of the Investigation of Interconnection Standards in the District of Columbia (2006) - (Analysis and Advice to Counsel: interconnection standards and tariff design on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1050

96. In the Matter of the Investigation into the Omnibus Utility Emergency Amendment Act of 2005, Specifically Regarding the Establishment of the Natural Gas Trust Fund Programs (2006) - (Analysis and Advice to Counsel: program design on behalf of the District of Columbia Department of the Environment)
    D.C. Public Service Commission Formal Case No. 1037

97. Emergency Application of the Potomac Electric Power Company For A Certificate of Public Convenience and Necessity To Construct Two 69kV Overhead Transmission Lines and Notice of The Proposed Construction of Two Underground 230kV Transmission Lines (2005-2006) - (Appearance: facilities need on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1044

98. Investigation Into Potomac Electric Power Company's Distribution Service Rates (2003- 2005) - (Appearance: cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1032

99. Investigation of the Feasibility of Removing Pre-Existing Aboveground Utility Lines and Cables and Relocating Them Underground in the District of Columbia (2003) - (Analysis and Advice to Counsel: cost/benefit analysis on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1026

100. Guadalupe L. Garcia v. Ann Veneman, Secretary, US Department of Agriculture (2003- 2006) - (Appearance: statistical analysis on behalf of the Plaintiff)
    U.S. District Court for the District of Columbia

101. Mirant Corporation, et al., Debtors (2003-2005) - (Analysis and Advice to Counsel: cost of service on behalf of the People's Counsel for the District of Columbia)
    U.S. District Court for the Northern District of Texas

102. Complaint: Office of the People's Counsel of the District of Columbia v. Mirant Americas Energy Marketing, L.P. (2003) - (Analysis and Advice to Counsel: cost of service on behalf of the People's Counsel for the District of Columbia)
    Federal Energy Regulatory Commission

103. Investigation into the Effect of the Bankruptcy of Mirant Corporation on Retail Electric Service in the District of Columbia (2003-2005) - (Appearance: customer and rate impact on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1023

104. Development and Designation of Standard Offer Service in the District of Columbia (2003- 2007) - (Appearance: cost of service allocation and rate design on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1017

105. Independent Review Panel, Project Management Plan, Ohio River Main Stem Study (2003- 2005) - (50 year economic simulation model evaluation)
    U.S. Army Corps of Engineers

106. Investigation into Affiliated Activities, Promotional Practices, and Codes of Conduct of Regulated Gas and Electric Companies (2002-2004) - (Analysis and Advice to Counsel: cost allocation on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1009

107. Independent Review Panel, Ohio River Main Stem Study, System Investment Plan (2001) - (50 year economic simulation model evaluation)
    U.S. Army Corps of Engineers

108. Joint Application of PEPCO and New RC, Inc. for Authorization and Approval of Merger Transaction (2001-2002) - (Appearance: cost allocation and affiliate transactions on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 1002

109. Investigation into Explosions Occurring in Underground Distribution Systems of PEPCO (2001-2006) - (Analysis and Advice to Counsel: electric systems operation and planning on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 991

110. Pennsylvania-New Jersey-Maryland Power Pool/PJM LLC (ISO/RTO) (2000-2005) - (Member Working Group technical representation on behalf of The People's Counsel for the District of Columbia)

111. Trans Alaska Pipeline System 1996 Quality Bank Complaint Remand (2000-2008) - (Appearance: crude oil valuation and tariff rate design on behalf of ExxonMobil)
    Federal Energy Regulatory Commission

112. Ohio River Main Stem Study, Independent Technical Review (1999) - (50 year economic simulation model evaluation)
    U.S. Army Corps of Engineers

113. Investigation of January 1999 Electric Service Interruption (1999-2004) - (Appearance: emergency response evaluation on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 982

114. Trans Alaska Pipeline System 1996 Quality Bank Complaint Appeal (1998-2000) - (Analysis and Advice to Counsel: technical record below on behalf of ExxonMobil)
    U.S. Court of Appeals for the District of Columbia

115. Electric Retail Competition Investigation (1997-2006) - (Appearance: electric utility restructuring, electric energy procurement, cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 945

116. Trans Alaska Pipeline System 1996 Quality Bank Complaint (1996-1998) - (Appearance: crude oil valuation and tariff rate design on behalf of ExxonMobil)
    Federal Energy Regulatory Commission

117. Trans Alaska Pipeline System 1989 Quality Bank Complaint Remand (1995-1998) - (Appearance: crude oil valuation and tariff rate design on behalf of ExxonMobil)
    Federal Energy Regulatory Commission

118. Prudhoe Bay Unit Operating Agreement Hearings (1995) - (Analysis and Advice to Counsel: cost of service on behalf of ExxonMobil)
    Alaska Oil and Gas Conservation Commission

119. Prudhoe Bay Unit Natural Gas Liquids Hearings (1995) - (Analysis and Advice to Counsel: liquids valuation on behalf of ExxonMobil)
    Alaska Department of Natural Resources/Department of Revenue (1995)

120. Potomac Electric Power Co. 3rd Integrated Least-Cost Plan (1995) - (Appearance: forecast operations and costs on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 917, Phase II

121. All American Pipeline Quality Bank Complaint (1994-1995) - (Appearance: crude oil valuation and tariff rate design on behalf of ExxonMobil)
    Federal Energy Regulatory Commission

122. Trans Alaska Pipeline System 1989 Quality Bank Complaint Appeal (1994-1995) - (Analysis and Advice to Counsel: technical record below on behalf of ExxonMobil)
    U.S. Court of Appeals for the District of Columbia

123. Investigation of the January 1994 Energy Crisis (1994) - (Appearance: emergency response evaluation on behalf of the People's Counsel for the District of Columbia)
    D.C. Public Service Commission Formal Case No. 936

124. Washington Gas Light Co. Gas Rate Case (1994) - (Appearance: cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
     D.C. Public Service Commission Formal Case No. 934

125. Washington Gas Light Co. 3rd Integrated Least-Cost Plan (1994) - (Appearance: forecast operations and costs on behalf of the People's Counsel for the District of Columbia)
     D.C. Public Service Commission Formal Case No. 921

126. Potomac Electric Power Co. Electric Rate Case (1993) - (Appearance: cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
     D.C. Public Service Commission Formal Case No. 929

127. Washington Gas Light Co. Gas Rate Case (1993) - (Appearance: cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
     D.C. Public Service Commission Formal Case No. 922

128. Trans Alaska Pipeline System Pumpability Complaint (1992) - (Analysis and Advice to Counsel: cost of service and rate design on behalf of ExxonMobil)
     Federal Energy Regulatory Commission

129. Potomac Electric Power Co. 2nd Integrated Least-Cost Plan (1992) - (Appearance: forecast operations and costs on behalf of the People's Counsel for the District of Columbia)
     D.C. Public Service Commission Formal Case No. 917

130. Potomac Electric Power Co. Electric Rate Case (1992) - (Appearance: cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
     D.C. Public Service Commission Formal Case No. 912

131. Potomac Electric Power Co. Fuel Clause Audit and Productivity Improvement Plan (1991- 2005) (Analysis, Participation in Technical Sessions, and Advice to Counsel; electric utility plant investment and operating costs productivity and benefit/cost analysis on behalf of the People's Counsel for the District of Columbia)
     D.C. Public Service Commission Formal Case No. 766

132. Potomac Electric Power Co. Electric Rate Case (1991) - (Appearance: cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
     D.C. Public Service Commission Formal Case No. 905

133. Anchorage Telephone Utility (1991-1995) - (Analysis and Advice to Counsel: cost of service)
     Federal Communications Commission

134. Trans Alaska Pipeline System 1989 Quality Bank Complaint (1990-1993) - (Appearance: crude oil valuation and tariff rate design on behalf of ExxonMobil)
    Federal Energy Regulatory Commission

135. Telefonica Larga Distancia de Puerto Rico International Service Tariffs (1990-1992) - (Appearance: cost of service and rate design)
    Federal Communications Commission

136. Southern Bell Intrastate Depreciation Study (1989-1990) - (Analysis and Advice to Counsel: telecommunications operation)
    Florida Public Service Commission

137. Lake Erie Iron Ore Antitrust Litigation: Erie-Western Pennsylvania Port Authority v. Penn Central et al. (1988-1989) - (Analysis and Advice to Counsel: truck operations and damages on behalf of the Norfolk and Western Railroad)
    U.S. District Court for the Eastern District of Pennsylvania

138. Unimar International Chapter 11 Reorganization (1988) - (Analysis and Advice to Counsel: cost of service on behalf of Unsecured Creditors)
    U.S. Bankruptcy Court for the Western District of Washington at Seattle

139. National Forest Road Cost Analysis System (1986) - (Analysis: cost allocation system design)
    U.S. Department of Agriculture, Forest Service

140. Puerto Rico Telephone Company Long Distance Facilities and Service Applications (1985- 1990) - (Appearance: cost of service and rate design on behalf of the Puerto Rico Telephone Company)
    Federal Communications Commission

141. All American Cable and Radio/AT&T de Puerto Rico International Rate Complaint (1985- 1990) - (Appearance: cost of service and rate design on behalf of the Puerto Rico Telephone Company)
    Federal Communications Commission

142. Caribbean Telecommunications Facilities Planning Docket (1984-1990) - (Appearance: operations forecast and planning on behalf of the Puerto Rico Telephone Company)
    Federal Communications Commission

Exhibit KRP-2

UGI Utilities, Inc. - Electric Division
Electric Class Cost of Service Study
Fully Projected Future Test Year September 30, 2024
Schedule 6 - Summary of Cost of Service and Rate of Return Under Present and Proposed Rates
($ in thousands)

Line No.	Revenue Requirement Summary	Total System	Total Check	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
1	**Rate Base**								
2	Plant in Service	$ 275,001	-	$ 188,886	$ 11,101	$ 34,219	$ 204	$ 35,912	$ 4,678
3	Accumulated Reserve	(85,745)	-	(60,122)	(3,901)	(10,185)	(51)	(9,512)	(1,975)
4	Other Rate Base Items	(17,015)	-	(11,408)	(705)	(2,321)	(13)	(2,277)	(291)
5	**Total Rate Base**	**$ 172,242**	-	**$ 117,356**	**$ 6,495**	**$ 21,713**	**$ 140**	**$ 24,124**	**$ 2,413**
6	**Revenue at Current Rates**								
7	Total Distribution Margin	$ 44,268	-	$ 30,111	$ 2,545	$ 4,688	$ 17	$ 5,713	$ 1,193
8	STAS Revenue	15	-	12	1	1	0	1	0
9	DSIC Revenue	2,604	-	1,856	129	242	1	315	60
10	USP Rider	6,656	-	6,656	-	-	-	-	-
11	EEC Rider	1,152	-	360	43	153	1	587	9
12	**Total Base and Rider Revenue**	**$ 54,695**	-	**$ 38,996**	**$ 2,718**	**$ 5,084**	**$ 19**	**$ 6,617**	**$ 1,262**
13	Forfeited Discounts	$ 520	-	$ 329	$ 49	$ 80	$ -	$ 57	$ 6
14	Miscellaneous Revenues	582	-	392	19	81	0	86	4
15	**Total Base, Rider, and Other Revenue**	**$ 55,798**	-	**$ 39,717**	**$ 2,786**	**$ 5,245**	**$ 20**	**$ 6,760**	**$ 1,271**
16	Purchased Power Revenue	$ 96,893	-	$ 78,084	$ 3,928	$ 9,237	$ -	$ 5,063	$ 581
17	**Total Current Revenue**	**$ 152,691**	-	**$ 117,801**	**$ 6,714**	**$ 14,482**	**$ 20**	**$ 11,823**	**$ 1,852**
18	**Total Base, Rider, and Purchased Power Revenue**	**$ 151,589**	-	**$ 117,080**	**$ 6,647**	**$ 14,321**	**$ 19**	**$ 11,680**	**$ 1,843**
19	**Expenses at Current Rates**								
20	O&M and A&G Expenses	$ 35,930	-	$ 28,376	$ 1,257	$ 2,745	$ 18	$ 3,264	$ 271
21	Purchased Power Expense	91,176	-	73,477	3,696	8,692	-	4,764	547
22	Depreciation and Amortization Expense	8,553	-	6,028	355	969	6	1,016	179
23	Purchased Power GRT Expense	5,717	-	4,607	232	545	-	299	34
24	Taxes Other Than Income	901	-	907	(4)	40	1	(11)	(32)
25	Gross Receipts Tax	3,101	-	2,211	154	288	1	375	72
26	Income Taxes	823	-	247	115	135	(1)	238	88
27	**Total Expenses at Current Rates**	**$ 146,201**	-	**$ 115,852**	**$ 5,805**	**$ 13,415**	**$ 25**	**$ 9,945**	**$ 1,159**
28	**Operating Income - Current**	$ 6,490	-	$ 1,949	$ 909	$ 1,067	$ (6)	$ 1,878	$ 693
29	Current Rate of Return	3.77%	-	1.66%	13.99%	4.91%	-3.98%	7.78%	28.73%
30	Relative Rate of Return	1.00		0.44	3.71	1.30	(1.06)	2.07	7.63
31	Current Revenue to Cost Ratio	0.93		0.92	1.05	0.93	0.48	0.96	1.40
32	Current Parity Ratio	1.00		0.99	1.13	1.00	0.52	1.04	1.50
33	**Current Revenue at Equal Rates of Return**								
34	Current Rate of Return	3.77%	-	3.77%	3.77%	3.77%	3.77%	3.77%	3.77%
35	Current Operating Income at Equal ROR	$ 6,490	-	$ 4,422	$ 245	$ 818	$ 5	$ 909	$ 91
36	Income Taxes - Equal ROR	823	-	561	31	104	1	115	12
37	Gross Receipts Tax	3,101	-	2,444	111	240	2	277	27
38	Other Expenses - Equal ROR	142,277	-	113,394	5,536	12,991	25	9,331	999
39	**Total Margin @ Equal Rates of Return**	**$ 152,691**	**-**	**$ 120,821**	**$ 5,922**	**$ 14,154**	**$ 32**	**$ 10,633**	**$ 1,129**
40	Present (Subsidies)/Excesses	-	-	(3,020)	792	328	(13)	1,190	723

UGI Utilities, Inc. - Electric Division
Electric Class Cost of Service Study
Fully Projected Future Test Year September 30, 2024
Schedule 6 - Summary of Cost of Service and Rate of Return Under Present and Proposed Rates
($ in thousands)

Line No.	Revenue Requirement Summary	Total System	Total Check	Residential	General Service	General Service-4	Flood Control Power	Large Power	Lighting
41	**Revenue Requirement at Equal Rates of Return**								
42	Required Return	8.15%	-	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%
43	Required Operating Income	$ 14,038	$ -	$ 9,565	$ 529	$ 1,770	$ 11	$ 1,966	$ 197
44	**Expenses at Required Return**								
45	O&M and A&G Expenses	$ 35,930	$ -	$ 28,376	$ 1,257	$ 2,745	$ 18	$ 3,264	$ 271
46	Purchased Power Expense	91,176	-	73,477	3,696	8,692	-	4,764	547
47	Depreciation and Amortization Expense	8,553	-	6,028	355	969	6	1,016	179
48	Purchased Power GRT Expense	5,717	-	4,607	232	545	-	299	34
49	Taxes Other Than Income	901	-	674	39	88	1	87	12
50	Gross Receipts Tax	3,101	-	2,444	111	240	2	277	27
51	Income Taxes	823	-	561	31	104	1	115	12
52	Gross Up - Income Taxes	2,951	-	2,011	111	372	2	413	41
53	Gross Up - Gross Receipts	716	-	565	26	56	0	64	6
54	Gross Up - Uncollectibles	210		200	4	4	-	2	1
55	**Total Expenses - Required**	**$ 150,079**	**-**	**$ 118,942**	**$ 5,862**	**$ 13,814**	**$ 29**	**$ 10,301**	**$ 1,131**
56	**Total Revenue Requirement at Equal Return**	**$ 164,116**	**-**	**$ 128,506**	**$ 6,391**	**$ 15,584**	**$ 41**	**$ 12,267**	**$ 1,327**
57	Current Miscellaneous Revenue	1,102	-	721	68	161	0	143	9
58	**Total Revenue @ Equal Rates of Return**	**$ 163,014**	**-**	**$ 127,785**	**$ 6,324**	**$ 15,423**	**$ 40**	**$ 12,124**	**$ 1,318**
59	**Revenue (Deficiency)/Surplus**	**$ (11,425)**	**-**	**$ (10,705)**	**$ 323**	**$ (1,102)**	**$ (21)**	**$ (444)**	**$ 525**
60	Proposed Margin Increase	$ 11,425		$ 7,643	$ 445	$ 1,454	$ 3	$ 1,684	$ 195
60A	Percent Distribution			66.90%	3.90%	12.73%	0.03%	14.74%	1.71%
60B	OCA Revenue Requirment	$ 3,540,663		2,368,713	138,036	450,577	932	521,904	60,501
61	Total Base and Miscellaneous Revenue as Proposed	$ 67,223	-	$ 47,361	$ 3,231	$ 6,699	$ 23	$ 8,444	$ 1,466
62	Purchased Power Revenue	96,893	-	78,084	3,928	9,237	-	5,063	581
63	**Total Revenue as Proposed**	**$ 164,116**	-	**$ 125,445**	**$ 7,159**	**$ 15,936**	**$ 23**	**$ 13,507**	**$ 2,047**
64	**Total Base Revenue as Proposed**	**$ 66,120**	-	**$ 46,639**	**$ 3,164**	**$ 6,538**	**$ 22**	**$ 8,301**	**$ 1,457**
65	**Total Base and Purchased Power Revenue as Proposed**	**$ 163,014**	-	**$ 124,723**	**$ 7,092**	**$ 15,775**	**$ 22**	**$ 13,364**	**$ 2,038**
66	Proposed (Subsidies)/Excesses	$ -	-	$ (3,061)	$ 768	$ 351	$ (18)	$ 1,240	$ 720
67	Proposed Percentage Change	7.54%		6.53%	6.70%	10.15%	15.73%	14.42%	10.59%
68	Proposed Margin Percentage Change	20.89%		19.60%	16.39%	28.60%	15.73%	25.45%	15.47%
69	Gross Receipts Tax	$ 3,817	$ -	$ 2,693	$ 183	$ 377	$ 1	$ 479	$ 84
70	Income Prior to Taxes	17,812	-	9,390	1,394	2,515	(3)	3,596	919
71	Income Taxes	3,774	-	1,990	295	533	(1)	762	195
72	Operating Income	$ 14,038	-	$ 7,401	$ 1,098	$ 1,982	$ (2)	$ 2,834	$ 724
73	Proposed Return	8.15%	-	6.31%	16.91%	9.13%	-1.73%	11.75%	30.02%
74	Relative Rate of Return	1.00		0.77	2.07	1.12	(0.21)	1.44	3.68
74A	**Change in Relative Rate of Return**			0.33	(1.64)	(0.18)	0.85	(0.62)	(3.94)
74B	**Percent Movement in Relative ROR Toward Unity ROR**			0.60	0.60	0.60	0.41	0.59	0.59
75	Proposed Revenue to Cost Ratio	1.00		0.98	1.12	1.02	0.55	1.10	1.54
76	Proposed Parity Ratio	1.00		0.98	1.12	1.02	0.55	1.10	1.54

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2022-3037368
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Karl R. Pavlovic, hereby state that the facts set forth in my Direct Testimony, OCA Statement 3, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 25, 2023

*344780

Signature: Karl R. Pavlovic

Karl R. Pavlovic

Consultant Address: PCMG and Associates, LLC.
22 Brookes Avenue
Gaithersburg, MD 20877

OCA St. 3SR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**Docket No. R-2022-3037368**
UGI Utilities, Inc. – Electric Division	)	

SURREBUTTAL TESTIMONY OF

KARL RICHARD PAVLOVIC

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

June 7, 2023

TABLE OF CONTENTS

I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Karl Richard Pavlovic. My business address is 22 Brookes Avenue, Gaithersburg, MD 20877.

Q. ARE YOU THE SAME KARL RICHARD PAVLOVIC WHO SUBMITTED DIRECT TESTIMONY ON APRIL 25, 2023 AND REBUTTAL TESTIMONY ON MAY 25, 2023 IN THIS PROCEEDING?

A. Yes. Exhibit KRP-1 to my direct testimony summarizes my qualifications and experience.

II. PURPOSE OF TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A**.** I am testifying on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the rebuttal testimony of OSBA Witness Robert Knecht (OSBA Statement No. 1-R) regarding my class cost and revenue allocation direct testimony and the rebuttal testimony of John D. Taylor (UGI Statement No. 6-R) regarding my class cost allocation and residential customer charge direct testimony.

III. DISCUSSION

A. SUMMARY

Q. PLEASE SUMMARIZE THE SUBSTANCE OF YOUR TESTIMONY.

A. As detailed below, the rebuttal testimony of OSBA and UGI provide no reason for me to either withdraw or modify my testimony that UGI's ACOSS with minimum-size classification is inconsistent with the principle of cost causation, that class revenue allocation should be guided by UGI's ACOSS without minimum-size classification with uniform movement to cost parity, and that leaving the residential customer charge unchanged will provide residential customers with more of an incentive to conserve and the ability to control their bills.

B. CLASS COST ALLOCATION

Q. WHAT IS YOUR DIRECT TESTIMONY PROPOSAL REGARDING UGI CLASS COST ALLOCATION IN THIS PROCEEDING?

A. In my direct testimony I demonstrated that UGI's minimum-size ACOSS, which classifies a portion of its distribution system in accounts 364-368 as customer-related, produces class cost allocations that are not based on cost causation.[1] Specifically, I demonstrated that UGI designs and operates its distribution facilities to meet the peak load or demand on its distribution system, not the number of customers connected to its distribution system.[2] These costs are recorded in accounts 364-368. Thus, demand is the cause and driver of UGI's costs in account's 364-368 and the class cost allocations that result from UGI's

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[1] Direct Testimony of Karl Richard Pavlovic, page 10 line 3 to page 17 line 10.
[2] Pavlovic Direct, page 11 line 10 to page 12 line 9 and page 13 line 16 to page 14 line 15.

minimum-size ACOSS's customer-related classification do not accurately reflect cost-causation on UGI's distribution system. Based on the specific circumstances of UGI's design and operation of its distribution system, the Commission should reject UGI's minimum-size ACOSS and class cost allocations as guides to class revenue allocation.

1. OSBA Rebuttal

Q. WHAT IS OSBA'S REBUTTAL OF YOUR CLASS COST ALLOCATION PROPOSAL?

A. In rebuttal, OSBA witness Knecht (1) refers to a passage in Bonbright that states that customer costs include "a portion of the distribution system [i.e., accounts 364-368],"[3] (2) states that citations from Bonbright have been rejected by the Commission in prior UGI cases,[4] (3) states that UGI's planning documents do not refer to the number of customers because "it is simply too obvious to mention" and (4) states that the economies of scale argument in his direct testimony is implicitly recognized in UGI's planning documents.[5]

Q. WHAT IS YOUR RESPONSE TO OSBA'S REBUTTAL?

A. As regards Bonbright, the citation to which witness Knecht refers is in fact Bonbright's summary of the position of Charles F. Phillips regarding which costs are notionally recovered through three-part rates, not the basis for cost-causative allocation.[6] As I explained in my direct testimony, Bonbright decisively refutes the unsupported assumption that a portion of distribution system costs are caused by the number of customers.[7]

[3] Rebuttal Testimony of Robert D. Knecht, page3 lines 1-11; see Bonbright page 401.
[4] Knecht Rebuttal, page 3 lines 11-14.
[5] Knecht Rebuttal, page 4 lines 6-16.
[6] Charles F. Phillips, The Regulation of Public Utilities, page 406; see Bonbright, page 401.
[7] Pavlovic Direct, page 10 line 15 to page 11 line 10.

Moreover, as I also explained in my direct testimony, the question as to the proper classification of distribution costs is answered, not by reference to common practice or past precedence, but rather by reference to the specific design and operating characteristics of the distribution system consistent with the principle of cost causation.[8] As regards UGI's planning documents, it is simply not credible to say that number of customers and the referenced economies of scale are too obvious to explicitly acknowledge. The purpose of engineering documents is to codify <u>all</u> factors involved in the design and operation of distribution systems. Specifically regarding witness Knecht's economies of scale argument, I explicitly rebutted that argument in my rebuttal testimony.[9]

Q. DOES OSBA'S REBUTTAL PROVIDE ANY REASON TO WITHDRAW OR MODIFY YOUR RECOMMENDATION THAT THE COMMISSION REJECT UGI'S MINIMUM-SIZE ACOSS AND CLASS COST ALLOCATION?

A. No.

2. UGI Rebuttal

Q. WHAT IS UGI'S REBUTTAL OF YOUR CLASS COST ALLOCATION PROPOSAL?

A. UGI witness Taylor offers in rebuttal a series of ten loosely connected propositions. In the list below the numbering reflects the order in which the propositions appear in witness Taylor's rebuttal testimony, but I have arranged the propositions under three thematic

[8] Pavlovic Direct, page 9 line 11 to page 10 line 2.
[9] Pavlovic Rebuttal, page 3 line 1 to page 4 line 2.

headings: appeals to precedence and common practice, appeals to authority, and appeals to substance.

Appeals to Precedence and Common Practice

1. In UGI's last litigated rate case, while OCA proposed a non-minimum system ACOSS, the Commission explicitly rejected OCA's proposal and adopted UGI's minimum-system ACOSS.[10]
6. The minimum system study is consistently used by Pennsylvania electric distribution companies.[11]
7. PECO Energy - Electric classifies a portion of its secondary distribution system as customer related.[12]
8. 23 electric utilities in 23 states adopt a customer component of the distribution system.[13]

Appeals to Authority

4. Bonbright states that "examples of these customer costs are the expenses associated with local connection facilities, metering equipment and meter reading, billing and accounting, and a portion of the distribution system."[14]
3. The key conclusion from the NARUC Manual is "[w]hen the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution data separately into demand- and customer-related costs."[15]
5. James Suelflow in Public Utility Accounting: Theory and Application[16] and Henry L. Doherty in Equitable, Uniform and Competitive Rates are authoritative sources that support the recognition of the customer component of upstream distribution facilities.[17]

[10] Rebuttal Testimony of John D. Taylor, page 7 lines 8-24.
[11] Taylor Rebuttal, page 12 line 13 to page 13 line 8.
[12] Taylor Rebuttal, page 13 line 10 to page 14 line 2,
[13] Taylor Rebuttal, page 14 lines 8-13.
[14] Taylor Rebuttal, page 10 line 17 to page 11 line 17.
[15] Taylor Rebuttal, page 10 lines 6-16.
[16] Witness Taylor misquotes the title as Public Utility Accounting: Theory and Practice.
[17] Taylor Rebuttal, page 11 line 21 to page 12 line 11.

Appeals to Substance

2. There are economies of scale between small customers and large customers that the non-minimum system ACOSS does not reflect.[18]
9. I provide no evidence that distribution costs do not vary with the number of customers.[19]
10. There is an 84% correlation between UGI customer growth and distribution plant investment over the period 2004 to 2022.[20]

Q. WHAT IS YOUR RESPONSE TO UGI'S PRECEDENCE AND COMMON PRACTICE REBUTTAL?

A. As a prefatory observation, I note that in a 2022 order the Commission stated that "even in cases in which the revenue allocation methodology is litigated, a determination regarding which ACOSS should be used should be determined on a case-by-case basis … the best-suited ACOSS may depend on the circumstances of the situation on a case-by-case basis."[21] Thus, it is the circumstances of UGI's situation as established in the record that are relevant in this proceeding.

My response to the first, sixth, seventh and eighth propositions concerning past Commission UGI decisions and the use of minimum system classification in Pennsylvania and other states is that, as I explained in my direct testimony and witness Taylor acknowledged in his direct testimony, the question as to the proper classification of distribution costs is answered, not by reference to common practice or past precedence, but rather by reference to the specific design and operating characteristics of UGI's distribution

[18] Taylor Rebuttal, page 8 line 11 to page 9 line 16.
[19] Taylor Rebuttal, page 15 lines 2-17.
[20] Taylor Rebuttal, page 15 line 19 to page 16 line 4.
[21] *PUC v. Columbia Gas of Pennsylvania, Inc.* Dock. No. R-2022-3031211, 12/8/22 Order at 107, footnote 30.

system consistent with the principle of cost causation.[22] As I demonstrated in my direct testimony, UGI does not design and operate its distribution system based on number of customers. Thus, minimum-size classification of UGI's distribution system costs is not consistent with cost causation and the Commission's 2022 Order.

Q. WHAT IS YOUR RESPONSE TO UGI'S AUTHORITY REBUTTAL?

A. Regarding the fourth proposition's citation of Bonbright, as noted above, the text attributed to Bonbright is actually Bonbright's summary of the position of Charles F. Phillips regarding which costs are notionally recovered through three-part rates, not the basis for cost-causative allocation.[23] As I explained in my direct testimony, Bonbright decisively refutes the unsupported assumption that a portion of distribution system costs are caused by the number of customers .[24]

Regarding the third proposition's citation of the NARUC Manual, my response is that Bonbright decisively refutes the unsupported assumption that a portion of distribution system costs are caused by the number of customers.

Regarding the fifth proposition's citations to Suelflow and Doherty for support of the proposition that a portion of distribution costs is customer-related, my response is two-fold. First, regarding Suelflow, he first defines customer costs as "those which vary with the number of customers served … the service drop, or connection from the distribution line to the point of consumption … ; metering equipment; and meter reading, billing, and accounting,"[25] but then without offering any support follows with the non-sequitur that

[22] Pavlovic Direct, page 9 line 11 to page 10 line 2; Taylor Direct page 11 lines 15-16 and page 7 lines 4-6.
[23] The Regulation of Public Utilities, page 406.
[24] Pavlovic Direct, page 10 line 15 to page 11 line 10.
[25] Public Utility Accounting: Theory and Application, 1973, page 237.

"distribution transformers and primary and secondary lines … all contain capacity and customer costs."[26] As I just noted, that proposition is decisively refuted by Bonbright. Second, while Doherty's paper analyzes seven different rate structures from the perspectives of cost recovery and incentivizing increased consumption, it does not address at all cost-causative allocation of distribution system costs.[27]

Q. WHAT IS YOUR RESPONSE TO UGI'S SUBSTANTIVE POINTS OF REBUTTAL?

A. Regarding the second proposition's claim of economies of scale between large and small customers, my response is that, as I explained in my direct testimony, the cause and driver of the costs of a distribution system is the aggregate demand on the system, not the number of customers or the size of the demand or load of individual customers.[28]

As for the ninth proposition's claim that I provide no evidence that distribution costs do not vary with the number of customers, my response is that I provided the strongest possible evidence that UGI's distribution costs do not vary with the number of customers when I provided UGI's own evidence that it does not design and operate its distribution system based on the number of customers.

Regarding the tenth proposition's purported demonstration of a correlation between its average number of customers and its distribution plant investment shown in witness Taylor's Table 3, my response is that this data does not demonstrate that the portion of distribution plant investment that UGI's ACOSS classifies as customer-related varies

[26] Public Utility Accounting: Theory and Application, 1973, page 241.
[27] Proceedings of the National Electric Light Association, 23rd Convention, May 1900, pages 289-321.
[28] Pavlovic Direct (Public Version) page 10 line 3 to page 11 line 9.

directly with its number of customers, which is the point on which evidence is required to support UGI's minimum-size ACOSS.

Q. DOES UGI'S REBUTTAL PROVIDE ANY REASON TO WITHDRAW OR MODIFY YOUR RECOMMENDATION THAT THE COMMISSION REJECT UGI'S MINIMUM-SIZE ACOSS AND CLASS COST ALLOCATION?

A. No.

C. OSBA'S REBUTTAL OF OCA'S CLASS REVENUE ALLOCATION

Q. WHAT IS YOUR PROPOSAL REGARDING UGI CLASS REVENUE ALLOCATION IN THIS PROCEEDING?

A. In my direct testimony, I noted that UGI's proposed class revenue is based on its minimum-size ACOSS which does not calculate class costs on the basis of cost causation and that UGI's proposed class percentage increases are so large as to contravene the ratemaking principle of gradualism.[29] For those reasons, I concluded that UGI's class revenue allocation was neither just nor reasonable. Instead, I proposed a class revenue allocation based on UGI's ACOSS without minimum-size classification with a uniform movement toward cost parity measured by relative rate of return.[30]

Q. WHAT IS OSBA'S REBUTTAL OF YOUR CLASS REVENUE ALLOCATION PROPOSAL?

A. Witness Knecht in his direct testimony takes issue with the use of the relative rate of return metric to measure progress towards parity, advocating instead the use of the revenue-cost

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[29] Pavlovic Direct, page 17 line 13 to page 19 line 9.
[30] Pavlovic Direct, page 19 line 10 to page 21 line 8.

ratio metric to measure progress to parity .[31] Witness Knecht purports to show that taking the revenue to cost ratios from the UGI ACOSS without minimum-size classification and making minimal adjustments to the ratios produces little or no progress to cost parity for UGI's rate classes and concludes that my proposed class revenue allocation is inconsistent with the ACOSS without minimum-size classification.[32]

Q. WHAT IS YOUR RESPONSE TO OSBA'S REBUTTAL

A. My response is two-fold. First, I do not agree that the revenue-cost ratio is the appropriate metric to measure progress to parity. Second, even if revenue to cost ratios were the appropriate measure for progress to parity, the revenue to cost ratios that witness Knecht proposes do not appear to produce significant and uniform progress to parity for the classes and would likely produce rate shock to the Residential, GS-4 and Large Power classes.[33]

Q. DOES OSBA'S REBUTTAL PROVIDE ANY REASON TO WITHDRAW OR MODIFY YOUR RECOMMENDATION REGARDING CLASS REVENUE ALLOCATION?

A. No.

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[31] Knecht Direct, page 16 lines 3-11 and Appendix A.
[32] Knecht Rebuttal, page 5 line 5 to page 7 line 9.
[33] Knecht Rebuttal, Table RDK-R2, "OCA Proposed Base Rate increase" column.

D. RESIDENTIAL CUSTOMER CHARGE

Q. WHAT IS YOUR PROPOSAL REGARDING THE RESIDENTIAL CUSTOMER CHARGE?

A. In my direct testimony, I explained (1) that UGI's proposed 42% increase to the residential customer charge represents significant and unacceptable rate shock, (2) that a fixed monthly customer charge sends no real actionable price signal, and (3) that placing all of the residential revenue increase in the volumetric distribution charge will provide Residential customers with both an increased incentive to engage in conservation and the ability to exercise control over a larger portion of their monthly electric distribution bill.[34] Finally, I noted that OCA witness Colton's direct testimony regarding the deleterious impact on low-income customers of an increase in the customer charge is yet another reason to reject UGI's proposed increase in the customer charge.[35]

Q. WHAT IS UGI'S REBUTTAL?

A. UGI witness Taylor offers in rebuttal of my residential customer charge testimony a series of seven loosely connected propositions.

1. On a total bill basis, an increase in the customer charge does not represent an increase because the increase corresponds to a decrease in the volumetric distribution charge.[36]
2. With regard to efficiency the customer charge cannot be reviewed in isolation from the volumetric distribution charge.[37]

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[34] Pavlovic Direct, page 23 line 16 to page 24 line 19.
[35] Pavlovic Direct, page 24, lines 8-11.
[36] Taylor Rebuttal, page 24 lines 11-22.
[37] Taylor Rebuttal, page 28 lines 5-17.

3. My direct testimony assumes that the only reason for conservation is a price signal and that customers will respond to the lower customer charge with consideration of total bill impact.[38]

4. A failure to collect all of fixed costs through the customer charge represents a loss to either other customers or the utility.[39]

5. Energy efficiency gains and reductions in usage are based several factors that will not go away with a customer charge increase.[40]

6. The conclusion that an increase in the customer charge will reduce consumers' desire to reduce usage is based on incorrect interpretation of price elasticity.[41]

7. An increase in the residential customer charge would produce lower bills for low-income customers.[42]

Q. WHAT IS YOUR RESPONSE TO UGI'S REBUTTAL?

A. As a prefatory observation, none of witness Taylor's rebuttal points directly addresses the three points in my residential customer charge testimony.

Regarding the first and second propositions, while it is true that the proposed residential customer charge will not produce a 42% increase in a residential customer's bill, it nonetheless represents a 42% increase in the customer charge rate that customers see on their monthly bill.

Regarding the third and fifth propositions, my testimony neither assumes that the volumetric distribution charge price signal is the only motivator of conservation nor that customers will respond to changes in the customer charge. Rather my testimony assumes

[38] Taylor Rebuttal, page 28 line 19 to page 29 line 12.
[39] Taylor Rebuttal, page 29 line 14 to page 30 line 7.
[40] Taylor Rebuttal, page 30 lines 9-15.
[41] Taylor Rebuttal, page 30 line 15 to page 31 line 20.
[42] Taylor Rebuttal, page 25 line 1 to page 28 line 3.

that customers respond to changes in the volumetric distribution charge regarding conservation and control of their monthly bill.

Regarding the sixth proposition, the conclusion that follows from my testimony is, not that an increase in the customer charge will decrease customer's desire to reduce usage, but rather that an increase in the customer charge will reduce the volumetric distribution charge and thereby reduce customers' incentive to conserve and ability to control their bills.

Regarding the fourth proposition, given that the customer charge and the volumetric distribution charge represent in fact a zero-sum game, a decrease or an increase in the customer charge will have no impact on cost recovery – certainly a decrease will not result in a loss to either other customers or the utility.

Finally, regarding the seventh pproposition's claim of a purported benefit to low-income customers, OCA witness Colton's surrebuttal testimony demonstrates that this claim is false and rests on an unrepresentative and biased sample of low-income customers.[43]

Q. DOES UGI'S REBUTTAL PROVIDE ANY REASON TO WITHDRAW OR MODIFY YOUR RECOMMENDATION REGARDING THE RESIDENTIAL CUSTOMER CHARGE?

A. No.

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[43] Surrebuttal Testimony of Roger D. Colton, OCA St. 4SR at page 37 to page 41.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, I reserve the right to supplement this testimony if further information is provided by UGI.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2022-3037368
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Karl R. Pavlovic, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 3SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: June 7, 2023
*347169

Signature: Karl R. Pavlovic

Karl R. Pavlovic

Consultant Address: PCMG and Associates, LLC.
22 Brookes Avenue
Gaithersburg, MD 20877

Pennsylvania Public Utility Commission

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Pennsylvania Public Utility Commission	*	
	*	
v.	*	Docket No. R-2022-3037368
	*	
UGI Utilities, Inc. – Electric Division	*	
	*	
	*	

Direct Testimony of

Roger D. Colton

OCA Statement No. 4

April 25, 2023

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Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, MA 02478.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am the owner of the firm Fisher Sheehan & Colton, Public Finance and General Economics of Belmont, Massachusetts. In that capacity, I provide technical assistance to a variety of federal and state agencies, consumer organizations and public utilities on rate and customer service issues involving water/sewer, natural gas and electric utilities.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate (OCA).

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I work primarily on low-income utility issues. This involves regulatory work on rate and customer service issues, as well as research into low-income usage, payment patterns, and affordability programs. At present, I am working on various projects in the states of Connecticut, Maryland, Pennsylvania, Ohio, Michigan, Illinois, and Washington. My clients include state agencies (e.g., Pennsylvania Office of Consumer Advocate, Maryland Office of People's Counsel, Connecticut Office of Consumers General), federal agencies (e.g., the U.S. Department of Health and Human Services), community-based organizations (e.g., National Housing Trust, Natural Resources Defense Council, Sierra Club), and private utilities (e.g., Toledo Water).

Not all of my work involves rate case testimony. For example, I recently completed, under contract to the City of Toledo (OH), a draft Water Affordability Plan for that city. In May of last year, I completed a detailed report examining the affordability of water service in Knoxville (KY) for a community-based organization, Knoxville Water and Energy for All (KWEA). In October of 2022, I completed an evaluation of the Electric Assistance Program (EAP) for the New Hampshire Public Utilities Commission.

In addition to state-specific and utility-specific work, I engage in national work throughout the United States. For example, in 2020, I represented a coalition of major national consumer organizations to comment on the Environmental Protection Agency's proposed framework by which to judge community financial capability. I also continue to be "Of Counsel" to the National Coalition for Legislation on Affordable Water (NCLA-Water). A brief description of my professional background is provided in Appendix A.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. After receiving my undergraduate degree in 1975 (Iowa State University), I obtained further training in both law and economics. I received my law degree in 1981 (University of Florida). I received my Master's Degree (Regulatory Economics) from the MacGregor School at Antioch University in 1993.

Q. HAVE YOU EVER PUBLISHED ON PUBLIC UTILITY REGULATORY ISSUES?

A. Yes. I have published three books and more than 80 articles in scholarly and trade journals, primarily on low-income utility and housing issues. I have published three times that number of technical reports for various clients on energy, water, telecommunications and other associated low-income utility issues. My most recent publication (2018) was a chapter in a book published by the London-based Edward Elgar Publishing, which book was titled "Energy Justice: US and International Perspectives." My chapter, "The equities of efficiency: distributing energy usage reduction dollars," set forth a methodology grounded in law and economics by which to objectively measure whether utility investments in energy efficiency are being equitably distributed.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS OR OTHER UTILITY COMMISSIONS?

A. Yes. I have testified before the Pennsylvania Public Utility Commission ("PUC" or "Commission") on numerous occasions over the past 35 years on issues affecting universal service and customer service for electric, natural gas, water and telecommunications providers. In addition, I have testified before other state utility regulations commissions on more than 320 occasions regarding utility issues affecting low-income customers and customer service. I have testified in regulatory proceedings in 43 states and various Canadian provinces on a wide range of utility issues. A list of the jurisdictions in which I have testified as an expert witness is listed in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my Direct Testimony in this proceeding is as follows:

- To assess the affordability of electric service for low-income customers in the UGI service territory;
- To assess the impact that UGI's proposal to increase its fixed monthly customer charge will have on low-income customers;
- To review potential remedies to the low-income harms that arise because of the increased rates proposed in this proceeding;
- To review UGI's performance with respect to Settlement agreements reached in the Company's 2018 and 2021 rate cases;
- To review the reasonableness of universal service cost recovery through UGI's Rider C; and
- To review the reasonableness of the Company's request for a performance management adder bonus to its return on equity.

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS YOU MAKE THROUGHOUT YOUR TESTIMONY.

A. Based on the data and analysis I present throughout my testimony, I recommend that the Commission:

- Adopt the return on equity recommendation of OCA witness Aaron Rothschild;
- Adopt the residential customer charge recommendation of OCA witness Karl Pavlovic;
- Direct an increase in LIURP funding sufficient to provide 66 additional LIURP electric baseload jobs per year;
- Direct an increase in LIURP funding sufficient to provide 66 additional LIURP heating jobs per year;

- Direct an increase in LIURP funding sufficient to provide 27 additional LIURP heating jobs for customers with annual income exceeding 150% of Poverty but not exceeding 200% of FPL;
- Consider the long-term cost reductions flowing from the recommended increased LIURP spending as offsets to the short-term expense increases;
- Direct UGI compliance with all Settlement paragraphs regarding universal service and low-income issues in the 2018 and 2021 UGI Electric rate proceedings;
- Consider the UGI non-compliance with the 2018 and 2021 Settlement provisions in setting the UGI return on equity in this proceeding;
- Approve the universal service Rider modifications as proposed by UGI Witness Epler; and
- Deny the requested 20 basis point adder to the Company's requested return on equity to reflect exemplary or strong management performance.

This is a summary of my recommendations. Each recommendation is presented in more detail in the body of my testimony.

Part 1. The Affordability of UGI Service.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

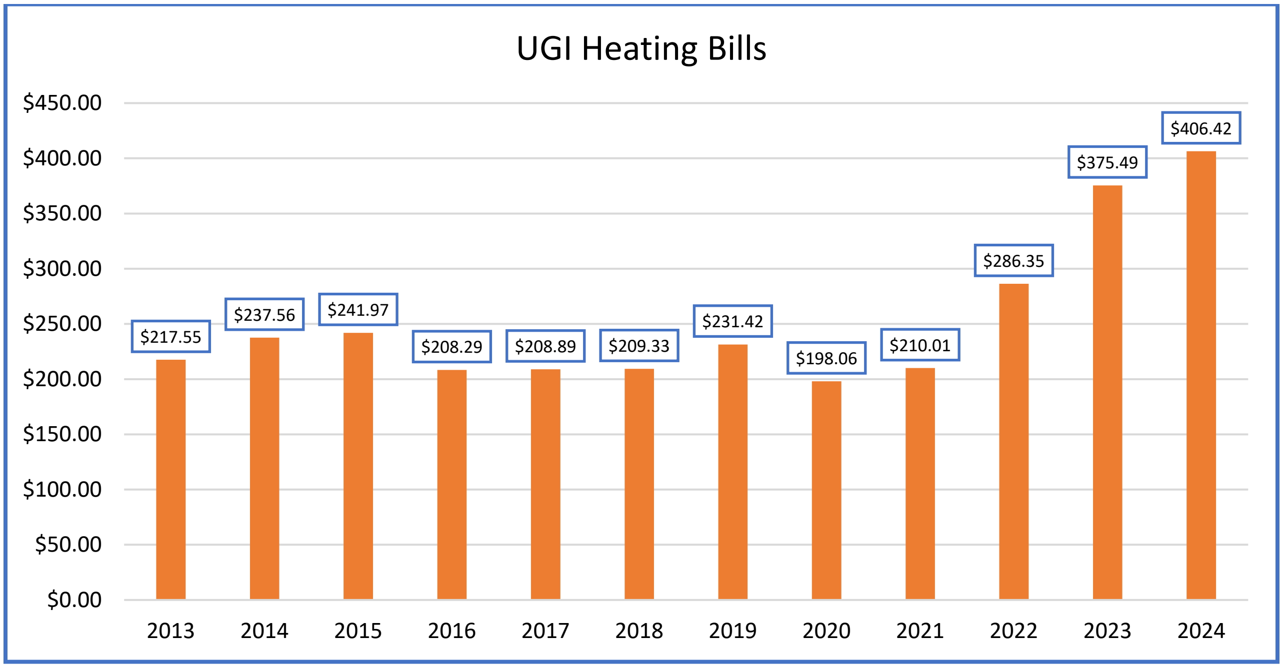
A. In this section of my testimony, I assess the ongoing affordability of service provided by UGI. I begin with a review of the level of UGI rates over the past ten years (2013 through 2023). I then examine the bill burdens which result from those UGI rates. "Bill burden" is a concept that is well accepted as a means by which to measure utility bill affordability in Pennsylvania. It measures electric bills (in this instance) as a percentage of income. Identifying a bill burden is a simple ratio. One places the customer's annual bill in the numerator, and places the customer's annual income in the denominator. For example, if a customer has an annual income of $12,000 and an annual bill of $900, that customer has an electric bill burden of 7.5% ($900 / $12,000 = 0.075).

Q. HAVE YOU HAD OCCASION TO REVIEW THE HISTORY OF UGI BILLS?

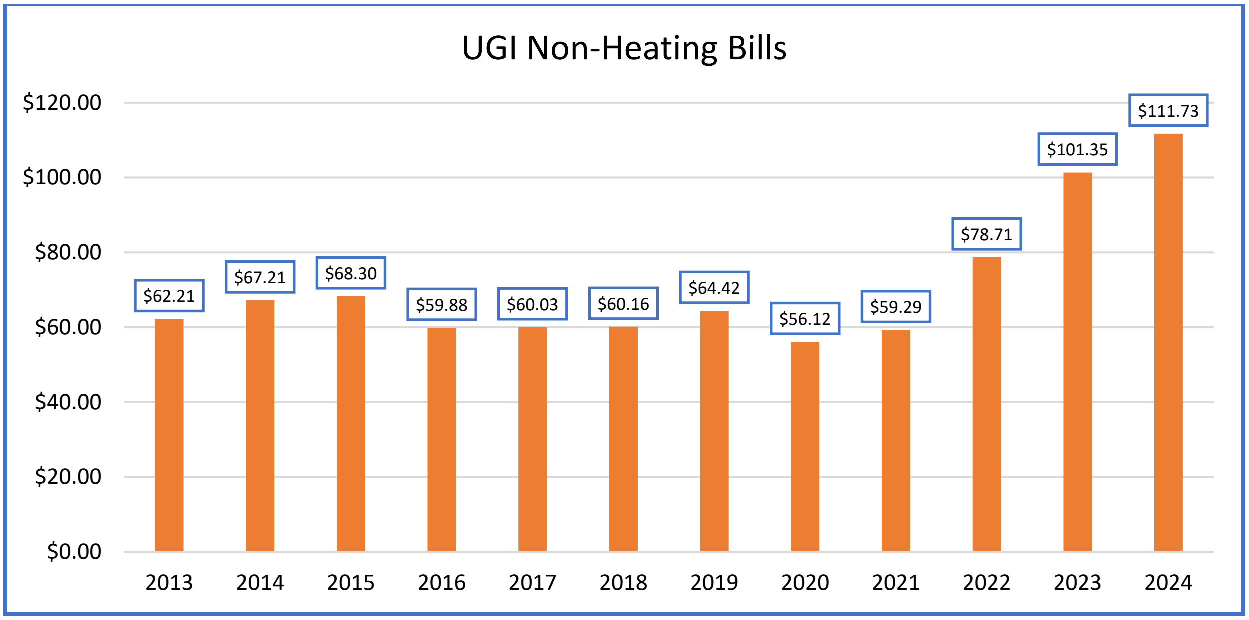
A. Yes. In preparing my testimony, I examined both the heating bills and the non-heating bills for UGI. I obtained my data from the Pennsylvania PUC's annual "Rate Comparison Report" for each of the study years.[1] In order to ensure that data from a different year is comparable, I rely on the PUC's definition presented in those reports for a typical heating consumption (2,000 kWh) and non-heating consumption (500 kWh). I examine bills –by using uniform usage amounts, the PUC portrays changes in rates by looking at bills—separately for heating and for non-heating customers. The data is set forth in the two Charts below. As can be seen in the Chart below, the rates proposed by

[1] Available at https://www.puc.pa.gov/filing-resources/reports/rate-comparison-reports/

UGI in this proceeding, when applied to *heating* consumption, yield a heating bill that is more than twice as high as the heating bill in 2020 ($406.42 / $198.06 = 2.05) and nearly twice as high as the heating bill in 2016 ($406.42 / $208.29 = 1.95).



The same observation can be made from the second chart, set forth below, regarding the *non-heating* bills for UGI. The Pennsylvania PUC identifies a non-heating bill as based on 500 kWh of consumption. The change in UGI non-heating bills over time can be seen in the Chart below. Non-heating bills at 2024 rates proposed by UGI in this proceeding would yield a bill that is 200% the bill at 2020 rates ($111.73 / $59.88 = 1.99). The 2024 bill would be somewhat short of the non-heating bill in 2016 ($111.73 / $59.88 = 1.86).



Q. HAVE YOU HAD AN OPPORTUNITY TO COMPARE THESE UGI BILLS TO THE INCOMES OF LOWER-INCOME HOUSEHOLDS?

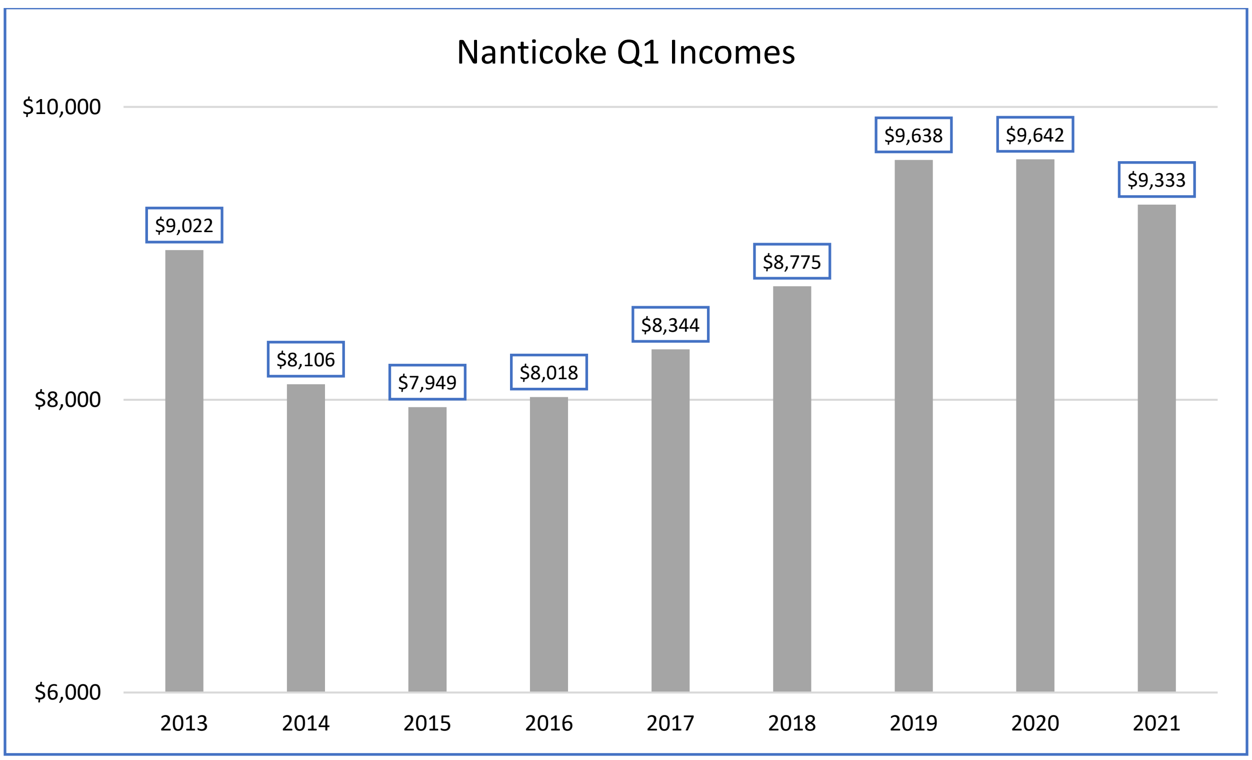
A. Yes. In the Chart below, I track the average (mean) income, by year, for the First Quintile (Q1) of income[2] from 2013 through 2021.[3] The mean incomes I track are for the community of Nanticoke, one of the primary population centers served by UGI.[4] Two important observations flow from this Chart. First, the average Q1 incomes in Nanticoke are consistently less than $10,000 per year. The income in the *highest* year (2020) was only $9,642, with the 2019 average Q1 income nearly the same ($9,638). In contrast, the

[2] The Census Bureau rank orders, from lowest to highest, all households in the geographic area being studied by the level of household income. The Census Bureau then divides that ordering into five equal components, each of which is called a "quintile." The quintile with the lowest income (sometimes called the "bottom quintile") is known as the "first quintile" (Q1), while the quintile with the highest income (sometimes called the "top quintile") is known as the fifth quintile. The median income (that point at which half of all households have higher incomes and half of lower incomes) falls into the third quintile (40th to 60th percentile).

[3] U.S. Census Bureau, American Community Survey, 1-year data, 2013 – 2021, Table B19081. 2021 is the most recent data available for Table B19081.

[4] See, UGI Tariff Supplement No. 56, cover page, March 23, 2023).

average Q1 income in the lowest year (2015) was only $7,949. This means that one-fifth of the households in a major UGI community have annual incomes that are lower than $10,000. Second, the Chart clearly demonstrates that it is not reasonable to assume that incomes will increase from one year to the next. While Q1 incomes increased from $7,949 in 2014 to $9,642 in 2020, those Q1 incomes had decreased from $9,022 in 2013 to only $8,106 in 2014. In fact, Q1 incomes in Nanticoke decreased from $9,638 in 2019 to $9,333 in 2021. Simply because UGI rates (and thus UGI bills) increase from one year to the next, in other words, does not mean that incomes for the lowest households in the UGI service territory will correspondingly increase, let alone increase at a corresponding rate.



Q. HAVE YOU EXAMINED ELECTRIC BURDENS IN THE UGI SERVICE TERRITORY?

A. Yes. I have examined electric burdens from four different perspectives. Using existing and proposed bills as provided by UGI (OCA-IV-44), I have examined bills as a percentage of income (i.e., "bill burdens") for both heating customers and for non-heating customers. I convert the average monthly non-heating and heating bills to an annual bill by using the average monthly consumption (October 2021 through September 2022), which UGI has said is the most recent twelve months available (OCA-IV-44(a)), and multiplying it times the rates provided by UGI (OCA-IV-44(b) – 44(c)). The average monthly bills may differ somewhat from the numbers I used above since, in this discussion, I use actual average usage provided by UGI rather than the uniform usage (500 kWh for non-heating; 2000 kWh for heating) used in the PUC's Annual Rate Comparison.

Monthly (Annual) Bills (OCA-I-44)	Non-Heating	Heating
Current rates	$126.76 ($1,749)	$271.87 ($3,343)
Proposed rates	$139.04 ($1,914)	$295.03 ($3,627)

I then calculate average electricity burdens for each zip code served by UGI at differing ranges of the Federal Poverty Level (given average household size in each zip code).[5] The results of this analysis are presented in Table 1 and Table 2 below.

[5] The Census data I use is for Zip Code Tabulation Areas (ZCTAs). ZCTAs are nearly, but not quite, identical to Zip Codes. ZCTAs are used by the U.S. Census Bureau, while Zip Codes are creatures of the U.S. Postal Service.

Table 1 shows the unreasonable burdens imposed on the low-income non-heating customers in the UGI service territory. Of the 22 zip codes studied, average non-electric heating burdens fell between 22% and 23% of income for households with income less than 50% of Poverty at existing rates. No zip code has a non-heating burden exceeding 26% at existing rates. However, if UGI's requested rate hike is approved, average non-heating burdens fall between 24% and 26% of income in 16 zip code, with one zip code having an average burden approaching 29%.

As would be expected, as incomes increase, the non-heating burdens decline. Even with the decline, non-heating burdens never reach an affordable level. Even at incomes between 100% and 150% of Poverty, average non-heating burdens are between 7% and 8% of income in 19 zip codes at existing rates. If the rates which UGI proposes in this proceeding are approved, in the highest income bracket (100% to 150% of Poverty), non-heating burdens fall between 8% and 9% of income in 11 zip codes, with burdens falling between 7% and 8% of income in the other 11 zip codes.

According to the U.S. Census Bureau: "ZIP Code Tabulation Areas (ZCTAs) are generalized areal representations of United States Postal Service (USPS) ZIP Code service areas. The USPS ZIP Codes identify the individual post office or metropolitan area delivery station associated with mailing addresses. USPS ZIP Codes are not areal features but a collection of mail delivery routes. The term ZCTA was created to differentiate between this entity and true USPS ZIP Codes." For a generalized discussion of the differences between Zip Codes and ZCTA, *See* U.S. Census Bureau, *ZIP Code Tabulation Areas*, https://www.census.gov/programs-surveys/geography/guidance/geo-areas/zctas.html (accessed August 19, 2022).

Table 1. UGI Non-Heating Burdens at Existing and Proposed Rates
and Elected Ranges of Federal Poverty Level (FPL)

Existing Rates						*Proposed Rates*					
<50% FPL		*50 – 100% FPL*		*100 – 150% FPL*		*<50% FPL*		*50 – 100% FPL*		*100 – 150% FPL*	
Burden	*No. Zip Codes*	*Burden*	*No. Zip Codes*	*Burden*	*No. Zip Codes*	*Burden*	*No. Zip Codes*	*Burden*	*No. Zip Codes*	*Burden*	*No. Zip Codes*
<20%	*0*	*<10%*	*0*	*<6%*	*0*	*Below 20%*	*0*	*<11%*	*0*	*<7%*	*0*
20–21%	*1*	*10-11%*	*1*	*6-7%*	*2*	*20–21%*	*0*	*11-12%*	*1*	*7-8%*	*11*
21- 22%	*3*	*11-12%*	*7*	*7-8%*	*19*	*21–22%*	*0*	*12-13%*	*4*	*8-9%*	*11*
22 –23%	*8*	*12-13%*	*12*	*8-9%*	*1*	*22–23%*	*1*	*13-14%*	*15*	*>9%*	*0*
23–24%	*8*	*13-14%*	*2*	*>9%*	*0*	*23–24%*	*2*	*14-15%*	*2*		
24–25%	*1*	*>14%*	*0*			*24–25%*	*8*	*>15%*	*0*		
25–26%	*1*					*25–26%*	*8*				
26–27%	*0*					*26-27%*	*2*				
27–28%	*0*					*27–28%*	*0*				
28–29%	*0*					*28–29%*	*1*				
>29%	*0*					*>29%*	*0*				

The energy affordability problems in the UGI service territory are even more pronounced for UGI's low-income electric heating customers. Table 2 shows that at the lowest range of Poverty Level (<50% FPL), the heating burdens for UGI customers reach as high as 49% of income at existing rates. Of the 22 zip codes studied, 18 have average heating burdens exceeding 42% of income (i.e., out of every $100 of income, a person living below 50% of Poverty would devote $42 to their UGI heating bill). If the rate increase sought by UGI is approved, the zip code with the highest burden experiences an increase to a burden of 54%.

Again, as incomes increase, the resulting bill burdens decrease. For the customers in the highest range of Poverty Levels examined (100 to 150% FPL), burdens at existing rates fall between 13% and 15% of income in 20 of the 22 zip codes, with no burden exceeding

16% of income. At the rates proposed by UGI in this proceeding, however, heating burdens would fall primarily (in 19 of 22 zip codes) between 14 and 16% of income, with the zip code having the highest heating burden approaching 18% of income.

Table 2. UGI Heating Burdens at Existing and Proposed Rates and Selected Ranges of Federal Poverty Level

Existing Rates						Proposed Rates					
<50% FPL		*50 – 100% FPL*		*100 – 150% FPL*		*<50% FPL*		*50 – 100% FPL*		*100 – 150% FPL*	
Burden	*No. Zip Codes*	*Burden*	*No. Zip Codes*	*Burden*	*No. Zip Codes*	*Burden*	*No. Zip Codes*	*Burden*	*No. Zip Codes*	*Burden*	*No. Zip Codes*
<30%	0	<20%	0	<12%	0	<42%	0	<22%	0	<13%	0
38-39%	1	20-21%	1	12-13%	1	42-43%	1	22-23%	1	13-14%	1
39-40%	0	21-22%	1	13-14%	10	43-44%	0	23-24%	1	14-15%	8
40-41%	1	22-23%	6	14-15%	10	44-45%	1	24-25%	7	15-16%	11
41-42%	2	23-24%	10	15-16%	1	45-46%	3	25-26%	9	16-17%	1
42-43%	4	24-25%	3	>16%	0	46-47%	4	26-27%	2	17-18%	1
43-44%	4	25-26%	0			47-48%	5	27-28%	1	>18%	0
44-45%	6	26-27%	1			48-49%	5	28-29%	1		
45-46%	2	>27%	0			49-50%	1	>29%	0		
46-47%	1					50-51%	1				
47-48%	0					51-52%	0				
48-49%	1					52-53%	0				
>49%	0					53-54%	1				

While I do not specifically discuss the burdens for the middle-range of Poverty above (50% to 100% of FPL), for both heating and non-heating bills, and at both existing and proposed UGI rates, the burdens in this middle range of Poverty fall between the upper and lower boundaries which I discuss for the lowest income and highest income customers.

Q. ARE THERE SUBSTANTIAL NUMBERS OF CUSTOMERS AFFECTED BY THESE HIGH ELECTRIC BURDENS IN THE SELECTED POVERTY RANGES YOU EXAMINED IN THE UGI SERVICE TERRITORY?

A. Yes. I estimate that there are 11,444 customers with income at or below 150% of the Federal Poverty Level in the UGI service territory.[6] I estimate this number by multiplying the Census Bureau's percentage of population at the selected Poverty ranges[7] in each UGI zip code times the total number of UGI customers in each zip code. Of the customers with income at or below 150% of FPL, I estimate that 30.4% have income less than 50% of FPL, 31.0% have income between 50% and 100% of FPL, and 38.6% have income between 100% and 150% of FPL.

Table 3.
Estimated Number and Percent of UGI Customers
with Income at or Below 150% of Federal Poverty Level (FPL)
At Selected Poverty Ranges in UGI Service Territory

0 – 50% FPL	50 – 100% FPL	100 – 150% FPL
3,483	3,548	4,413
30.4%	31.0%	38.6%

The high burdens I identified above for the selected Poverty ranges, in other words, affect a significant number of UGI customers.

[6] The BCS annual report on Collections Performance and Universal Service Programs does not present an estimated number of low-income customers for UGI.

[7] U.S. Census Bureau, American Community Survey, 5-year data, Table C17002.

Q. IS THERE A SECOND WAY TO EXAMINE THE AFFORDABILITY, OR UNAFFORDABILITY, OF ELECTRIC BURDENS FOR UGI LOW-INCOME CUSTOMERS?

A. I have also examined UGI bill burdens using absolute dollars of income as the metric for "low-income" rather than using a multiplier of the Federal Poverty Level. I examine three different income ranges: (1) below $10,000; (2) between $10,000 and $15,000; and (3) between $15,000 and $20,000. For each income range, I use the mid-point of the range as the denominator in the calculation. As Table 4 demonstrates, when one examines UGI bill burdens using absolute dollars of income, electricity burdens, both heating and non-heating, are well above an affordable level.

- Non-heating customers with income below $10,000 have a bill burden of 35% at existing rates, increasing to more than 38% at UGI's proposed rates. Non-heating customers with income between $15,000 and $20,000 have bill burdens of 10% at existing rates, increasing to nearly 11% at the Company's proposed rates.

- Annual heating burdens are overwhelmingly high, approaching 67% at existing rates and exceeding 70% at UGI's proposed rates. Even at the highest income range ($15,000 to $20,000), heating burdens are more than 19% at existing rates, increasing to nearly 21% at the Company's proposed rates.

Table 4. UGI Heating and Non-Heating Burdens at Selected Incomes
Given Existing and Proposed Rates

	Existing Rates			Proposed Rates		
Income Ranges	<$10,000	$10,000 - $15,000	$15,000-$20,000	<$10,000	$10,000 - $15,000	$15,000-$20,000
Non-Heating	35.0%	14.0%	10.0%	38.3%	15.3%	10.9%
Heating	66.9%	26.7%	19.1%	72.5%	29.0%	20.7%

Similar to what I demonstrated above with respect to the selected ranges of Poverty, there are substantial numbers of UGI customers with annual income in these three selected income ranges identified immediately above. Using the same methodology I employed above, I find that UGI has an estimated: (1) 3,457 residential customers with income less than $10,000; (2) 2,720 residential customers with income between $10,000 and $15,000; and (3) 2,288 residential customers with income between $15,000 and $20,000.

Q. PLEASE EXPLAIN WHY THE UGI CUSTOMER ASSISTANCE PROGRAM (CAP) IS NOT ADEQUATE TO PROTECT LOW-INCOME CUSTOMERS FROM THE HIGH (AND INCREASING) BILL BURDENS YOU HAVE IDENTIFIED.

A. Programs such as UGI's CAP can only protect low-income customers if those customers participate in the program. In order for participation to occur, UGI first needs to identify its low-income customers. It then needs to enroll those customers in CAP. UGI has confirmed the low-income status of less than half of its estimated number of low-income customers. While UGI has an estimated 11,444 low-income customers, it has only 5,633 confirmed low-income customers (49.2%). UGI has then enrolled only 3,259 of those *confirmed* low-income customers into CAP (57.9%).[8]

Table 5. Confirmed Low-Income as Percent of Total Customers and CAP as Percent of Customer with Income <150% FPL and as Percent of Confirmed Low-Income

CLI as Pct Cust<150	CAP as Pct CLI	CAP as Pct Cust<150
49.2%	57.9%	28.5%

[8] Of course, if one looks at the percentage of estimated low-income customers enrolled in CAP the numbers are worse, a mere 28.5% (3,259/11,44).

Overall, therefore, only somewhat more than one-in-four of UGI's low-income customers are protected from the Company's proposed increase in rates through participation in the Company's CAP.

Q. HOW DO THESE HIGH ELECTRIC BURDENS ADVERSELY AFFECT UGI'S LOW-INCOME CUSTOMERS?

A. The high burdens facing UGI's low-income customers affect these customers in at least two ways. First, high burdens impede the ability of low-income customers to sustainably pay their bills. With UGI, for example, from October 2020 through February 2023, while 46% of all residential customers in arrears are 90+ days old (OCA-IV-8), 75% of confirmed low-income customers in arrears are 90+ days old (OCA-IV-9). While 61% of residential dollars in arrears are 90+ days old (OCA-IV-8), 73% of confirmed low-income dollars in arrears are 90+ days old (OCA-IV-9). On average, over that 29 month period (October 2020 through February 2023), confirmed low-income customers are consistently in greater payment difficulty.

Table 6. Arrearages of Residential Customers as a Whole
Compared to Arrearages of Confirmed Low-Income Customers
(October 2020 – February 2023)
(OCA-IV-42 and OCA-IV-43)

	All Residential	Confirmed Low-Income
Mean arrearage of those with arrearages	$591	$862
Median arrearages of those with arrearages	$258	$513
Percent billed accounts having arrearages	23.3%	52.3%

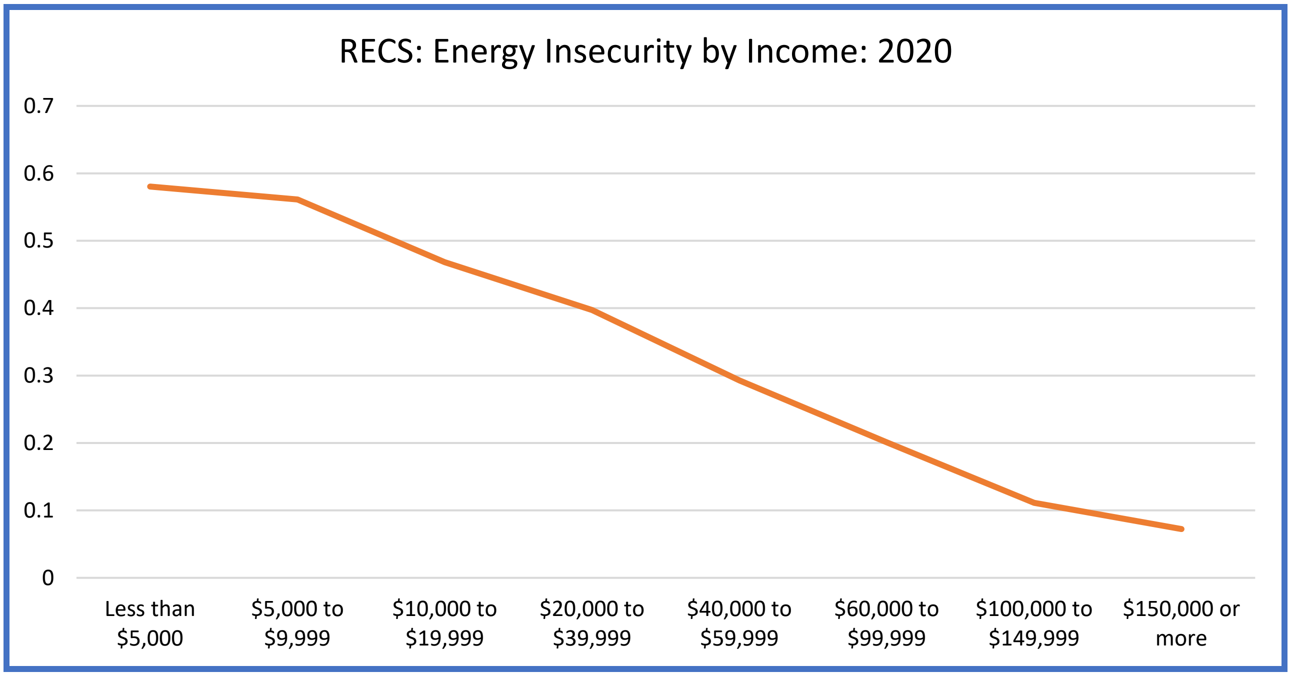
As Table 6 above shows, over the study period, not only are more confirmed low-income customers in arrears (52.3% compared to 23.3% for residential customers), but they are deeper in arrears as well.

Second, high energy burdens adversely affect the quality of life for low-income households. While there is not data specific to UGI, these results nonetheless have been well-documented. The relationship that exists between low-income status and this degradation in quality of life has been documented by the U.S. Department of Energy/Energy Information Administration (DOE/EIA). The EIA/DOE convincingly established the relationship between income and "energy insecurity" in nationwide data from its 2020 Residential Energy Consumption Survey (RECS). The data is presented in Table 7.

Table 7. Household Energy Insecurity, 2020 EIA/DOE Residential Energy Consumption Survey (RECS)[9]					
2020 annual household income	Any household energy insecurity[b]	Reducing or forgoing food or medicine to pay energy costs	Leaving home at unhealthy temperature	Receiving disconnect or delivery stop notice	Unable to use heating equipment[c]
Less than $5,000	58.0%	46.9%	24.8%	26.6%	11.2%
$5,000 to $9,999	56.1%	46.6%	21.2%	19.5%	9.5%
$10,000 to $19,999	46.8%	37.7%	20.7%	18.1%	8.0%
$20,000 to $39,999	39.7%	31.3%	15.0%	14.4%	6.3%
$40,000 to $59,999	29.3%	21.5%	8.9%	11.5%	4.2%
$60,000 to $99,999	20.1%	12.8%	5.7%	7.0%	2.0%
$100,000 to $149,999	11.1%	6.1%	4.1%	3.7%	1.2%
$150,000 or more	7.2%	2.6%	3.1%	1.5%	0.8%

The data shows that as household income increases, home energy insecurity decreases. The Figure below shows the relationship between household income and "any household energy insecurity." Nearly half of households with income less than $20,000 had experienced an energy insecurity, while that number falls to less than 20% for households with income of $80,000 or more. When income increases to more than $140,000, the percentage experiencing any type of energy insecurity falls below 10%.

[9] https://www.eia.gov/consumption/residential/data/2015/hc/php/hc11.1.php (accessed April 13, 2023).



The 2020 RECS results were not unique, nor surprising given similar examinations of earlier RECS data. In 2005, the federal agency administering LIHEAP funded a one-time special set of questions through the 2005 RECS. A resulting review of the 2005 data was undertaken for the federal LIHEAP office.[10] The LIHEAP study reported that households with income below the Federal Poverty Level had higher rates of energy insecurity than other households (*e.g.*, households with income at 100% to 150% of Poverty; households with income above 150% of Poverty). Poverty Level, rather than income, is associated with all types of energy insecurity, the study found (concluding that

[10]APPRISE, Inc. (Feb. 2010). LIHEAP Special Study of the 2005 Residential Energy Consumption Survey, Dimensions of Energy Insecurity for Low-Income Households, Final Report, prepared for U.S. Department of Health and Human Services, Administration for Children and Families, Office of Community Services, Division of Energy Assistance, http://www.appriseinc.org/resource-library/selected-reports/energy-survey-research-and-policy-analysis/ (accessed April 13, 2023).

it is important to consider household size).[11] The study found that higher residential energy burdens are associated with all types of energy insecurity, including both service interruptions and "financial energy insecurity."[12]

Q. WHY IS THIS DATA IMPORTANT TO CONSIDER IN THIS RATE PROCEEDING?

A. Most of utility ratemaking involves a balancing of investor interests and customer interests. Issues involving return on equity, revenue requirement, and rate design all involve a balancing of interests. Establishing a return on equity, in particular, is fundamentally predicated on balancing customer and investor interests. It is necessary for the PUC to understand the customer interests in order to appropriately balance them against the competing investor interests. For these reasons, my discussion above supports the return on equity recommendation advanced by OCA witness Aaron Rothschild, OCA Statement No. 2.

Finally, while I do not address revenue requirement issues in my testimony, the needs of low-income customers as I have identified above, along with the additional burdens created by this rat-e increase, would support the conclusions of other witnesses who have presented carefully reasoned adjustments to the Company's reported revenue requirement.

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[11] Poverty Level is income considering household size. In 2022, for example, 100% of Poverty for a 1-person household is $13,590, while 100% of Poverty for a 2-person household is $18,310, and for a 3-person household is $23,030. https://aspe.hhs.gov/topics/poverty-economic-mobility/poverty-guidelines (accessed April 13, 2023).

[12] Dimensions of Energy Insecurity, *supra*, at 33, 34.

The above discussion is also important in that it demonstrates how and why, even though there may be a short-term increase in expense associated with certain remedies to the problems I identify with respect to UGI's various rate proposals, there will be an ongoing, longer-term reduction in expenses associated with adoption of the remedies which I recommend. It would be inappropriate, and unreasonable, to focus on the short-term costs without considering the offsetting long-term benefits.

Part 2. The Low-Income Impacts of Increasing the Residential Customer Charge.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to the Company's proposal to increase its residential fixed monthly customer charge from $9.50 per month to $13.50 per month, an increase of 42%. This proposed increase in the fixed monthly customer charge will have particularly adverse impacts on low-income customers.

It cannot be assumed that all customers who are income-eligible for CAP, but who do not participate, do not participate because they choose not to participate. Non-participation in CAP can occur for any number of reasons other than by customer choice. In some instances, there are information barriers. Some customers may not know of the existence of CAP. Other customers may know of the existence of CAP, but not know how to access the program. Some customers may mistakenly believe they are not eligible for CAP, either because they receive other public assistance, because they are homeowners, or for other reasons. Some customers may receive LIHEAP and not realize that LIHEAP and CAP are different programs. Some customers may mistakenly believe that if they receive LIHEAP, they may not also enroll in CAP.

Outside of information failures, some customers do not participate in CAP because they cannot negotiate the administrative processes necessary to apply for the program. In any of these situations, the existence of CAP does not protect the customer against the harms of UGI's proposed increased customer charge. For whatever reason, as I discuss above, the data clearly shows that UGI enrolls only roughly one-in-four (3,259 of 11,444, 28%) of its estimated number of income-eligible customers into CAP. Nearly three-in-four of its low-income customers would not be protected by CAP participation.

In addition to those customers who are eligible for, but who do not participate in, CAP are those customers who do *not* qualify for CAP but who have insufficient household income to consistently have an ability to pay their UGI bills. These customers, frequently known as the "near poor," are often seen as households who have annual income between 150% and 250% of Federal Poverty Level. Because these customers are not eligible for CAP, they will bear the burden of increased fixed charges imposed in the form of increased customer charges.

Q. PLEASE EXPLAIN THE ACTIONS LOW-INCOME CUSTOMERS TAKE TO REDUCE THEIR BILLS TO MORE AFFORDABLE LEVELS.

A. While reducing usage possibly includes investing in energy efficiency measures –why low-income customers don't do that is an issue I will discuss further below—it does not exclusively include efficiency measures. The National Energy Assistance survey, performed by the National Energy Assistance Directors Association (NEADA) (the national association of state agencies that administer the federal LIHEAP fuel assistance program), examined what low-income households do when they cannot afford to pay their bills. The 2018 NEADA survey is the most recent NEADA survey reported.[13] The 2018 NEADA survey reported that customers take dramatic, and unhealthy or dangerous, steps in their efforts to reduce bills to more affordable levels:

- 36% of low-income households "closed off part of [their] home because they could not afford to heat or cool it due to not having enough money for the energy bill during the year" either: (1) almost every month (10%); (2) some months (16%); or (3) 1 or 2 months (10%). Households with income less than 50% of Poverty (i.e., the lowest income) undertook this action the most frequently (almost every month: 10%; some months: 24%; 1 or 2 months: 12%).

- More than 1-in-4 low-income households (26%) "kept home at temperature you felt was unsafe or unhealthy due to not having enough money for the energy bill during the past year" (almost every month: 4%; some months: 13%; 1 or 2 months: 9%). Nearly 1-in-4 seniors took this action (almost every month: 4%; some months: 11%; 1 or 2 months: 8%), as did households with at least one child under age 18 (almost every month: 4%; some months: 12%; 1 or 2 months: 8%).

- Nearly one-third of low-income households (29%) used the kitchen stove or oven to provide heat due to not having enough money for the energy bill during the past year (almost every month: 1%; some months: 11%; 1 or 2 months: 18%). The disabled (almost every month: 1%; some months: 12%; 1 or 2 months: 19%), and households with at least one child under age 18 (almost every month: 2%; some months: 11%; 1 or 2 months: 20%) took this action more frequently, but not much more so, than seniors (almost every month: <1%; some months: 9%; 1 or 2 months: 14%).

The lesson here is that the UGI proposal to substantially increase its fixed monthly customer charge makes these low-income responses to inability-to-pay less efficacious. Having a low-income household close-off part of their home or reduce the temperature in their home to unsafe or unhealthy levels will not reduce the bill as much if the UGI

[13] NEADA (December 2018). 2018 National Energy Assistance Survey, Final Report, available at http://www.appriseinc.org/resource-library/selected-reports/energy-survey-research-and-policy-analysis/ (last accessed April 6, 2022).

proposal is approved to increase the portion of the bill that is a fixed monthly charge and thus unavoidable.

Low-income households, particularly vulnerable low-income households (e.g., elderly, disabled, families with children), will take actions to try to reduce their bills to more affordable levels, frequently involving substantial household deprivation or the undertaking of substantial risks. These actions can be dangerous, such as when a low-income household uses its natural gas stove or oven as a supplemental heating source in order to reduce the heating usage in the home as a whole. Even these dramatic actions will not reduce a low-income customer's bill to more affordable levels should the UGI proposal to increase the fixed monthly charge be approved. UGI's proposed increase in its fixed monthly charge means that these dangerous efforts will be less and less effective.

Q. DOES THE IMPACT ON UGI'S CAP CUSTOMERS AFFECT LOW-INCOME CUSTOMERS NOT PARTICIPATING IN CAP?

A. Yes. Even though the percentage of low-income customers participating in CAP is small, increasing the customer charge to these customers has an adverse impact on other low-income customers. When the residential customer charge is increased, the total cost of the CAP program increases as well. This occurs because the increased bills to the CAP customers participating in the percentage of income program component of UGI's CAP will be passed through to other ratepayers on a dollar-for-dollar basis. While the individual (percentage of income) CAP participants are protected from the increased fixed customer charge, in other words, the CAP program as a whole is not. Other ratepayers, including non-participating low-income ratepayers, will pay this increase.

Even with LIURP and other conservation activities by CAP customers, these increased costs will remain higher. They cannot be avoided through energy conservation investments.

Q. CAN YOU PLACE THE PROPOSED INCREASE TO THE FIXED MONTHLY CUSTOMER CHARGE INTO SOME CONTEXT FOR LOW-INCOME CUSTOMERS OF UGI?

A. Yes. I consider inability-to-pay by reference to Pennsylvania's Self-Sufficiency Standard.[14] The Self-Sufficiency Standard provides the dollar amount needed to live a basic quality of life given the household size and composition, considering cost-of-living by county within the state. The Self-Sufficiency Standard varies not only by geographic location and family size, but also by family composition. A 3-person family with an adult, an infant and a school-age child, for example, has a different self-sufficiency income than a 3-person family with an adult, a school-age child, and a teenager does. For each county in Pennsylvania, the Self-Sufficiency Standard provides the costs of a minimum quality of life for 719 different family sizes and compositions.

Table 8 below presents the Self-Sufficiency Standard for a 3-person household with various family compositions. I then compare that Self-Sufficiency Income to 150% of the Federal Poverty Level, the maximum income-eligibility for CAP. I examine Luzerne County, which is the primary county which UGI serves. As can be seen, in this county, income for a three-person household at 150% of Poverty Level is substantially less than

[14] The Self-Sufficiency Standard determines the amount of income required for working families to meet basic needs at a minimally adequate level, considering family composition, ages of children, and geographic differences in costs. Available at https://selfsufficiencystandard.org/pennsylvania/ (last accessed April 13, 2023).

the income needed for typical three-person families in the UGI service territory to be self-sufficient. In Luzerne County, the amount of the shortfall between a self-sufficiency income and a household income at 150% of Poverty (3-person household) varies from $25,942 (adult + 1 preschool + 1 school-age) to $29,556 (adult + infant + pre-school) to $34,951 (2 adults + school-age) short of what the Self-Sufficiency Income is.

Table 8. Self-Sufficiency Income (2021) Compared to 150% Poverty Level (2021)
Three-Person Household with Selected Compositions for Luzerne County

		Self-Sufficiency Income			Difference Between 150% of FPL And Self-Sufficiency Income		
	150% FPL	Adult / Infant / Preschool	Adult / Preschool / School-age	2 Adults / School-age	Adult / Infant / Preschool	Adult / Preschool / School-age	2 Adults / School-age
Luzerne County	$25,260	$54,816	$51,202	$60,211	$29,556	$25,942	$34,951

As can be seen in this Table, with incomes significantly higher than what is considered low-income for purposes of the CAP, households struggle to pay their bills. Households that are deemed low income have even greater inability to pay. Quite literally, each month they are faced with the dilemma of which bills to pay and which they must forgo paying. And yet, UGI proposes to increase the portion of their electric bill which they cannot avoid paying through a reduction in electricity usage by 42%.

Q. IS THERE ANY FURTHER CONTEXT THAT YOU CAN OFFER?

A. Yes. UGI proposes to increase its fixed monthly customer charge by 42% (from $9.50 to $13.50 a month, an increase of $48 a year). Given the estimated 11,444 low-income customers served by UGI, this increase in the fixed monthly customer charge will impose an unavoidable increase in costs to UGI's low-income customer base of $549,312 ($48/customer x 11,444 customers). In contrast, the *total* amount of LIHEAP received by

UGI's low-income customers in the 2022-2023 LIHEAP program year (through February 28, 2023) was $626,596. (CAUSE-PA-I-11). UGI's proposed increase in the fixed monthly customer charge, in other words, removes nearly 90% of the value of LIHEAP from the Company's low-income population. For every $100 in benefits that LIHEAP delivers to UGI's low-income customers, UGI is taking $90 away in increased monthly charges that cannot be avoided by reducing usage.

Q. WHY ISN'T THIS PROBLEM ASSOCIATED WITH THE RATE INCREASE AS A WHOLE RATHER THAN ASSOCIATED WITH THE INCREASED CUSTOMER CHARGE IN PARTICULAR?

A. In part, the problem is associated with the rate increase as a whole. In large part, however, the problem is associated with the increased customer charge because there is nothing that a household can do to avoid this monthly fee. Even if low-income customers could reduce their usage, they would not be able to avoid any part of the proposed increase in the fixed monthly customer charge.

Q. DOES THE INCREASED CUSTOMER CHARGE IMPOSE ANY ADDITIONAL HARDSHIPS ON LOW-INCOME CUSTOMERS IN PARTICULAR?

A. Yes. Aside from the usage reduction techniques I discuss above, the proposed increase in the fixed monthly customer charge will impede the ability of low-income customers to rely on efficiency investments to reduce consumption as a means by which to control bills and improve affordability.[15] Increasing the unavoidable fixed monthly charge

[15] As I discuss in detail above, "reducing consumption" is not merely associated with energy efficiency improvements. Available research documents that low-income households also seek to reduce bills, by reducing consumption, through dangerous actions such as closing parts of their home; reducing heating temperatures, even if

impedes low-income ability to pursue energy efficiency and/or weatherization as a mechanism to reduce bills. This is not simply a matter of changing "price signals." Increasing the fixed monthly customer charge impedes energy efficiency in direct ways.

First, one implication of the very fact of low incomes for poverty level customers is that it is difficult for such customers to invest money in energy efficiency, even if that investment would be "cost-effective" in the medium to long-term. Given the scarce nature of their financial resources, low-income customers need to have their financial investment return their money in a short-time frame. That payback is known as a "hurdle rate." Low-income customers have been found to have energy efficiency hurdle rates of close to 100%, meaning that they require a payback of no more than one-year. I have discussed in detail above the income scarcity of low-income customers in the UGI service territory. By increasing the portion of a low-income customer's bill that the customer is not able to reduce through an energy efficiency investment, UGI lengthens the period of time before energy efficiency would return the initial investment to the low-income customer, making it less likely that the low-income hurdle rate will be achieved.

Second, one impediment to low-income investments in energy efficiency is the frequent mobility of low-income households. A low-income household will not invest in energy efficiency measures with paybacks that exceed the time they anticipate remaining in their home. A low-income household, in other words, would not invest in measures with a three-year payback if they do not expect to remain in their home for three years. In Luzerne County, for example, the percentage of households with income less than

to unsafe or unhealthy levels; or substituting the use of ovens or stoves to heat limited areas of their homes rather than using their heating systems to heat the entire home.

$10,000 that did not live in the same home they did one year ago was two times higher than the percentage of households with income greater than $75,000 (13.5% vs. 6.7%).[16] In Luzerne County in 2021, the median move-in date for renters was 2019,[17] while the median move-in date for homeowners was 2015.[18] As I note above, by increasing the portion of a low-income customer's bill that the customer is not able to reduce through an energy efficiency investment, UGI lengthens the period of time before energy efficiency would return the initial investment to the low-income customer. This makes it less likely that a payback will occur during the occupancy of a unit by the low-income household.

Q. DO YOU HAVE A FINAL OBSERVATION ABOUT THE IMPACT OF INCREASING CUSTOMER CHARGES ON LOW-INCOME EFFICIENCY INVESTMENTS?

A. Yes. The adverse impact on low-income energy efficiency investments is not simply on the investments that might be made by the customers themselves. Increasing the fixed customer charge will also make the Low Income Usage Reduction Program (LIURP) investment less effective. The point of LIURP is to save energy and reduce bills. While energy reduction through LIURP investments would occur even with a higher customer charge, the bills for low-income customers assisted through LIURP would not decrease as much as they would with a lower customer charge. The higher fixed customer charge

[16] U.S. Census Bureau, American Community Survey, 1-year data, Table B07010, available at B07010: GEOGRAPHICAL MOBILITY IN ... - Census Bureau Table (last accessed April 13, 2023).

[17] There is no question that low-income households are disproportionately renters in Luzerne County. See, U.S. Census Bureau, American Community Survey, Table B25074 and Table B25095.

[18] U.S. Census Bureau, American Community Survey, 1-year data, Table B25039, available at B25039: MEDIAN YEAR HOUSEHOLDER ... - Census Bureau Table (last accessed April 13, 2023).

thereby erodes the effectiveness of LIURP. Moreover, by PUC regulation, LIURP investments must meet a prescribed payback term. By increasing the fixed portion of a bill, and thus lengthening the payback term, fewer LIURP investments will be able to achieve those payback terms. LIURP is one of the suite of programs that is designed to assist low-income households' abilities to remain connected to and afford service. By increasing the customer charge, LIURP is less effective at the task of reducing bills.

Q. WHAT DO YOU CONCLUDE?

A. The low-income customers of UGI have difficulty in paying their electricity bills. Increasing the UGI fixed monthly customer charge will increase the difficulties which those low-income customers of the Company will face. Not only will the increased customer charge take a higher proportion of household resources out of incomes that fall substantially short of allowing the customers to be self-sufficient with which to begin, but it will also make it more difficult for low-income customers to control their exposure to unaffordable bills through the implementation of energy efficiency measures. In addition, the damaging actions which low-income customers are forced to take as efforts to control their bills (e.g., keeping their homes too hot or too cold, shutting off their home but for a limited space) will have less of an impact on reducing their bills to more affordable levels.

Moreover, the simple reality is that low-income households do not have the money to spend on energy efficiency even if doing so would reduce their bills in the long term. Affordability is a month-to-month struggle. Low-income customers have zero margin in their budget and it is simply irrelevant to them that spending money on energy efficiency today will save you more money down the road.

For all these reasons, I recommend that the residential customer charge should be no higher than that proposed by OCA witness Karl Pavlovic, OCA Statement No. 3.

In addition, I will explain below why it is appropriate to increase the UGI budget for its LIURP as a response to the difficulties that I have documented above.

Part 3. Remedies to Redress the Low-Income Harms from Rate Hike Proposals.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I recommend a series of actions that UGI should take to remedy the harms that I have identified as arising from the increased rates proposed in this base rate proceeding.

Q. WHY SHOULDN'T THESE PROPOSALS BE CONFINED TO CONSIDERATION IN THE COMMISSION'S PERIODIC REVIEW OF UGI'S UNIVERSAL SERVICE AND ENERGY CONSERVATION PLAN (USECP)?

A. While I acknowledge the role that the Commission's periodic review of UGI's Universal Service and Energy Conservation Plan (USECP) plays, that periodic review does not address the issues I present in this testimony. The Commission's review of UGI's USECP is limited to the circumstances that existed at the time of that review. In contrast, the recommendations I advance below are recommendations that are specifically in response to the harms that flow from ***this*** rate proceeding. Particularly given that the review of each utility's USECP occurs only once every five years, that USECP review is not, and cannot, be responsive to the interceding changing needs that the Company, itself, substantially contributes to.

Q. WHAT IS YOUR FIRST RECOMMENDATION?

A. My first recommendation is that UGI fund a portion of its LIURP program directed specifically toward non-heating electric users. UGI's existing LIURP eligibility guidelines effectively exclude baseload electric users. According to the Company's USECP, while the Company asserts that, to be eligible for LIURP, a customer must have annual consumption "above average" –a term defined to be "a customer who exceeded the average residential threshold by 25% for electric customer (baseload and heat)"—UGI continues on to state that the "minimum usage criteria" for UGI customers to receive LIURP services is 12,788 kWh. (USECP, at Table 6, page 30). This "minimum usage criteria" is 43% higher than the average non-heating consumption for the 12-month period October 2021 through September 2022 (8,920 kWh) (OCA-IV-44).

No reason exists to exclude electric baseload customers from receiving LIURP services. The PUC's review of LIURP savings over an extended period of time found that, "The most common jobs in the study's data set are classified as electric baseload."[19] The Long-Term LIURP Evaluation reported that 64.5% of electric baseload jobs resulted in customers reducing their consumption.[20] Moreover, in the three most recent years for

[19] Singler (2009). Long Term Study of Pennsylvania's Low-Income Usage Reduction Program: Results of Analyses and Discussion, at 13 (hereafter, Long-Term LIURP Evaluation).

[20] Id., at 27.

which data is available, the average usage reduction for electric baseload jobs ranged from 5.6%. to 7.3%.[21] The resulting average annual bill reduction ranged from a low of $84/year in 2018 to a high of $114/year in 2019.[22] Unfortunately, when asked to provide more recent data specific to UGI's LIURP program, the Company responded, that given its size, it does not provide LIURP reports to the BCS. (OCA-IV-11).[23] Nonetheless, an average electric baseload bill reduction in this range for UGI low-income customers would help offset the increased bills to those customers resulting from this rate proceeding.

In funding a LIURP electric baseload program, UGI should be required to devote funding that is incremental to that LIURP funding which it currently has committed to. If UGI were simply to redirect electric heating LIURP funding to baseload jobs, there would be no net gain to offset the impacts of this rate case.

UGI reported that it budgeted to serve 66 households a year through LIURP for the years 2023 through 2025. (UGI USECP, at 30).[24] Serving an additional 66 jobs with funding explicitly targeted to baseload units, given typical LIURP baseload costs of roughly

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[21] 2021 Annual BCS Report on Universal Service Programs and Credit and Collection Performance, supra, at 58.

[22] Id., at 59.

[23] Given that UGI stated that it does not report data to BCS, it is not clear where or how BCS obtained data on UGI's CAP and LIURP to be reported in the annual BCS report on Universal Service Programs and Credit and Collection. 2021 BCS Annual Report on Universal Service Programs and Credit and Collection Performance, at 85.

[24] UGI's USECP makes clear that its LIURP investments are not directed toward electric baseload customers. The USECP states that "Eligible electric non heating customers may receive an in home or telephonic energy education sessions. For the 2020 - 2025 USECP, UGI will begin to provide UGI weatherization participants with an Energy Conservation Kit containing items they may install to reduce electric consumption." Such "kits" with self-install measures do not represent an effort to deliver meaningful baseload usage reduction services.

$2,000,[25] would require an annual budget of $132,000. I recommend that UGI commit to fund 66 electric baseload jobs per year in addition to the electric heating jobs it has already budgeted to complete. The electric baseload jobs, in other words, should supplement and not supplant UGI's LIURP existing electric heating investments.

Q. WHAT IS YOUR SECOND RECOMMENDATION?

A. Through its LIURP, UGI currently has budgeted for a treatment of 66 homes each year for the years 2023 through 2025. (UGI USECP, at 30). That is a reduction from the 71 LIURP jobs per year in 2014 through 2016. (UGI USECP, at 28). Even if UGI maintained a constant LIURP production of 66 heating jobs per year for 20 years, it would treat only 1,320 low-income homes. If, however, UGI would double its heating job production, and assuming that low-income homes have electric heating in the same proportion as all UGI customers have electric heating (20%, OCA-IV-I-1), it could serve its low-income customer heating base in just over 15 years.

I describe the ways in which this rate case increases the need for outside assistance to help fund usage reduction investments in detail above. I recommend that UGI increase its LIURP funding by a sufficient amount ($298,379 if LIURP costs remain what UGI projected them to be in its current USECP) (UGI USECP, at 30) to fund 66 additional heating jobs per year.

Q. WHAT IS YOUR THIRD RECOMMENDATION?

A. I documented in detail how the harms imposed by this rate proceeding will fall not only on households with income at or below 150% of FPL, but will fall on households with

[25] 2021 Annual BCS Report on Universal Service Programs and Credit and Collection Performance, supra, at 57.

income below Pennsylvania's Self-Sufficiency Income. The Self-Sufficiency Income substantially exceeds 150% of FPL.

The LIURP program offered by UGI's gas distribution companies includes an expansion of LIURP eligibility for investments directed toward households with income greater than 150%, but less than 200%, of FPL. (UGI USECP, at 30). It is not unusual for Pennsylvania utilities to offer an earmark from their LIURP budget for households with income at between 150% and 200% of Poverty. Accordingly, to address the harms that are directly imposed on UGI customers in this income range by this rate proceeding, I recommend that UGI increase its LIURP budget sufficiently so that it can treat a number of customers in this income range equal to 20% of the total customers served. The LIURP spending, in other words, will supplement and not supplant the existing LIURP investment for customers at or below 150% of Poverty. Given the expanded LIURP budget I recommend above, the number of customers with income between 150% and 200% of Poverty that LIURP should treat will equal 27 customers per year. At UGI's budgeted cost per job included in its most recent USECP, this program expansion would require an annual budget of $298,379. (UGI USECP, at A-2).

Q. DO YOU HAVE ANY FINAL OBSERVATION ABOUT THE COST TO RATEPAYERS ARISING FROM THE THREE REMEDIES YOU RECOMMEND ABOVE?

A. Yes. It would be inappropriate to conclude that the total net cost to ratepayers of the three remedies I recommend above is equal to the total gross costs that I have identified. As documented in the Long-Term Study of LIURP that I discussed above, prepared by

Penn State University for the PUC, the delivery of LIURP services has a significant impact on reducing arrearages. The Long-Term Study reported:

> the percent of LIURP households with an arrearage increases by 26 points during the year prior to receiving weatherization services. By the end of the year following weatherization, 68 percent of the households have an energy bill arrearage, a decrease of 29 points.

(Long-Term Study, at 39). The Long Term Study reported that, for electric utilities in particular, 37% of recipients of LIURP service reduced their arrearages. (Long-Term Study, at 42). According to the Long-Term Study, in the year following the installation of LIURP measures, arrearages decreased by 12% per participant. (Long Term Study, at 40). As can be seen, even if there may be a short-term increase in costs borne by ratepayers due to the LIURP investments I recommend, there is a substantial *ongoing* reduction in costs to ratepayers attributable to the impacts of those LIURP investments. These reduced costs include the costs of reduced credit and collection, reduced bad debt, and reduced working capital. Reductions in working capital are of particular significance given that working capital is a capital expense. Reducing the working capital expense, therefore, would also reduce the return on equity (along with the associated income tax associated with that equity return) that would be paid on the working capital.

Part 4. Reviewing the 2018 and 2021 UGI Rate Case Settlements.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. UGI entered into a Settlement Agreement in its 2021 electric rate case (Docket R-2021-3023618) to resolve, amongst other things, issues regarding universal service that were presented in that proceeding (Joint Petition for Settlement of All Issues, July 19, 2021).[26] In that UGI 2021 base rate proceeding, the Office of Consumer Advocate (OCA St. 4, at 52 – 60) presented extensive testimony regarding the critical need for UGI to provide more attention to outreach both to confirm the low-income status of UGI customers and to enroll low-income customers in the Company's CAP. In this Section of my testimony, I first review whether the 2021 Settlement provisions jointly agreed to by the Company and the OCA were complied with.

Q. PLEASE IDENTIFY THE PART OF THE 2021 SETTLEMENT YOU HAVE REVIEWED.

A. I reviewed Paragraph 68 of the 2021 Settlement Agreement. That paragraph reads as follows in total:

> 68. WARM Initiative: The Company agrees to include the following provisions in its WARM Initiative:
>
> a. Perform a solicitation of customers who received LIHEAP in the prior 12 months for enrollment in the Company's CAP 2 times a year.
>
> b. Perform a solicitation of customers who self-reported Level 1 income in the prior 12 months for enrollment in the Company's CAP 2 times a year.
>
> c. Accept verbal self-reported income eligibility for customers at or below 250% of the Federal Poverty Level during the Winter Moratorium for purposes of winter shutoff protections, requests for deferred payment arrangements, or any other customer contact with the call center for an unpaid bill. Normal income verification requirements maintained by the Company shall apply upon the end of the Winter Moratorium period.
>
> d. Accept verification of income eligibility by any community-based organization ("CBO") in the Company's service territory delivering public or private assistance.

[26] Available at https://www.puc.pa.gov/pcdocs/1712144.pdf

e. Contact of administrators of applicable PA DHS public assistance programs, requesting that they ask DHS applicants enrolling in their public assistance programs to designate whether the DHS applicants want UGI Electric to be informed of their income eligibility for various customer service protections propounded by the Commission. Each household who the program administrators identify to UGI Electric as answering in the affirmative shall be deemed by UGI Electric as a Confirmed Low-Income customer and/or a customer eligible for winter shutoff protections. Normal income verification requirements maintained by the Company shall apply thereafter (for enrollment/participation in UGI Electric Universal Service programs).

f. Provide written materials, which solicit participation in UGI Electric's CAP and/or identification of customers eligible for winter shutoff protections, to:

   i. Public school districts in the Company's service territory, so that they can distribute the materials to school households with students eligible for the federal free and reduced school meals program; and/or Head Start programs; and

   ii. Community and faith-based food pantries, soup kitchens, and emergency shelters.

g. Provide written CAP solicitation materials to be delivered by local and/or county offices delivering benefits through the federal Supplemental Nutrition Assistance Program ("SNAP") (Food Stamps), as well as through local Public Housing Authorities.

h. Only include earned income from household occupants aged 18 years and older when verifying household income.

i. Any incremental costs incurred by the Company in the administration of items (e)-(h) will be deferred for recovery, without interest, in the Company's next base rate case.[27]

Q. WHAT IS THE FIRST PART OF THAT SETTLEMENT PARAGRAPH YOU REVIEWED?

A. The 2021 Settlement provided that UGI would "accept verification of income eligibility <u>*by any community organization in the Company's service territory delivering public or*</u>

[27] Id., at pages 14 – 16.

private assistance.” (Joint Settlement, para. 68(d)(emphasis added). In this proceeding, however, when CAUSE-PA asked the following of UGI: “Please identify all categories or identifiers that UGI Electric includes when calculating its “confirmed low income customer” count,” UGI responded: “The Company assigns a "confirmed low income" attribute to a customer when the customer confirms income-eligible status with a Community-Based Organization (CBO) and/or the following criteria are met:

- customer enrolls in CAP[;]
- customer receives LIURP services and weatherization measures are installed and completed[;]
- customer receives an Operation Share grant[;]
- customer receives a LIHEAP Cash or Crisis payment[.]”

(CAUSE-PA-I-3).

Clearly, rather than accepting verification of income eligibility “by any community organization delivering public or private assistance,” this requirement by UGI limits income eligibility to public assistance programs providing energy assistance. In fact not only does UGI limit the CBOs from which it will accept verification of low-income status, it won’t accept income verification at all without a corresponding receipt of the types of energy assistance identified by UGI. In direct conflict to the Settlement agreement, UGI continues to limit the means by which a customer may confirm their low-income status. For example, CBOs providing food assistance, childcare assistance, employment assistance, or any assistance other than enrollment in CAP, LIURP, Operation Share, or LIHEAP (cash or crisis) are, in contravention to the Settlement, excluded.

I recommend that UGI be directed to comply with Paragraph 68(d) of the 2021 Settlement.

Q. IS THERE A SECOND ELEMENT OF THE 2021 SETTLEMENT YOU HAVE REVIEWED?

A. Yes. In the 2021 UGI Settlement, UGI agreed: (1) to perform a solicitation of customers who received LIHEAP in the prior 12 months for enrollment in the Company's CAP 2 times a year; (2) perform a solicitation of customers who self-reported Level 1 income in the prior 12 months for enrollment in the Company's CAP 2 times a year; (3) provide written materials, which solicit participation in UGI's CAP and/or identification of customers eligible for winter shutoff protections to public school districts in the Company's service territory, so that they can distribute the materials to school households with students eligible for the federal free and reduced school meals programs; (4) provide written materials, which solicit participation in UGI's CAP and/or identification of customers eligible for winter shutoff protections, to Head Start programs; and (5) provide written CAP solicitation materials to be delivered by local and/or county offices delivering benefits through the federal Supplemental Nutrition Assistance Program (SNAP) (Food Stamps), as well as through local Public Housing Authorities. (2021 Settlement, para. 68(a), 68(b), 68(f), and 68(g)). In addition, UGI agreed that it would contact administrators of applicable PA Department of Human Services (DHS) public assistance programs, requesting that they ask DHS applicants enrolling in their public assistance programs to designate whether the DHS applicants want UGI to be informed of their income eligibility for various customer service protections propounded by the Commission. The Settlement provided that "Each household who the program administrators identify to UGI as answering in the affirmative *shall be deemed* by UGI as a Confirmed Low-Income customer and/or a customer eligible for winter shutoff protections." (2021 Settlement, para. 68(e)(emphasis added).

UGI is not implementing this agreement, as evidenced by how the Company states it identifies Confirmed Low-Income customers. As the Company's discovery response indicates, a perquisite to being designated a Confirmed Low-Income customer is for a customer: (1) to enroll in CAP; (2) to receive LIURP services and weatherization measures are installed and completed; (3) to receive an Operation Share grant; or (4) receive a LIHEAP Cash or Crisis payment. (CAUSE-PA-I-3),

In addition, when asked to provide how it measures the outcomes of its "outreach seeking to confirm the low-income status of customers," UGI explicitly conceded that "while the Company presents messaging about low income programs to *all* residential customers (through email, direct mail, UGI.com content, and on-hold messages), *the Company has not done a specific targeted campaign to confirm the low income status of customers other than interactions with UGI's Call Center Representatives, UGI Outreach Team members and Company's CBOs*." (OCA-IV-32) (emphasis added). Despite the detailed actions which UGI *agreed* to pursue as a precondition to settling its 2021 rate proceeding, the Company pursued none of them.

I recommend that UGI be directed to comply with the obligations set forth in the 2021 Settlement Agreement as I have identified above.

Q. IS THERE ANY FURTHER SETTLEMENT PROVISION THAT YOU HAVE EXAMINED?

A. Yes. In addition to reviewing the Settlement of the 2021 UGI rate case, I reviewed the Settlement of the 2018 UGI electric base rate case. (Docket R-2017-2640058, Partial Stipulation Resolving Certain Contested Issues, June 20, 2018).[28] In that 2018 Settlement, UGI agreed as follows: "UGI *will accept self-certification of low income status* for purposes of identifying 'confirmed low-income customers' in the same way that self-certification is required to be accepted by the UGI gas affiliates." (2018 Partial Settlement, at para. 11(c), page 3(emphasis added).

UGI has not complied with that portion of the 2018 Settlement Agreement. In fact, UGI's actions are directly contrary both to the letter and the intent of that Settlement Agreement. The Company states that it "assigns a 'confirmed low income' attribute to a customer *when the customer confirms income-eligible status with a Community-Based Organization* and/or the following criteria are met": (1) customer enrolls in CAP; (2) customer receives LIURP services and weatherization measures are installed and completed; (3) customer receives an Operation Share grant; or (4) customer receives a LIHEAP Cash or Crisis grant." (CAUSE-PA-I-3) (emphasis added). Clearly, the Company's response indicates that, despite its agreement to do so, it does *not* accept self-certification of low-income status for purposes of identifying confirmed low-income customers.

[28] Available at https://www.puc.pa.gov/pcdocs/1573541.pdf

I recommend that UGI be directed to comply in the future with the provisions of paragraph 11(c) of the Partial Settlement of its 2018 rate proceeding. Accepting self-certification, of course, is above and beyond the 2021 Settlement, which UGI also has not complied with, to accept the certification "by *any* community organization delivering public or private assistance," as I discuss above.

Q. DO YOU HAVE ANY FURTHER RECOMMENDATION?

A. In addition to requiring future compliance with both the 2021 and the 2018 Settlement Agreements, the Commission should consider whether UGI has fully complied with the pre-conditions to parties agreeing to the Settlement of the two previous rate proceedings (2018, 2021) in assessing UGI's request for an equity adder for strong company management. A utility should not be permitted to agree to take certain actions to help protect its most vulnerable customers as a precondition to increasing its electricity rates, and then fail to comply with those preconditions despite increasing its rates. In addition to taking this Company inaction into account in assessing the equity adder, the Commission should also consider these compliance issues in assessing the overall UGI return on equity.

Part 5. Rider C: Universal Service Cost Recovery.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I address the recovery of UGI universal service costs. As with other Pennsylvania utilities, UGI recovers its universal costs through a reconcilable rate rider. For UGI, Rider C provides for a quarterly adjustment in the universal service cost recovery coupled with an annual reconciliation of actual expenditures to the projected expenditures upon which the Rider C charge was based. In this testimony, I first address the “offsets” provided in Rider C.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I review the modification proposed by UGI witness Sharon Epler to the offset to be applied to CAP credits and arrearage forgiveness credits. Ms. Epler proposed to retain the value of the offset, but proposes to modify the population against which the offset is applied to that number of CAP participants exceeding the number of participants on September 30, 2023. That is a change from applying the offset to the number of participants exceeding the number of CAP participants as of September 30, 2021.

This modification proposed by Ms. Epler does not present a change of policy. The modification simply updates the Tariff to reflect the timing of the current rate proceeding. Agreeing to set the offset threshold in this manner is reasonable. Establishing a fixed CAP participation rate, however well-grounded, nonetheless involves estimating future performance that may or may not occur. In December 2022, for example, UGI estimated its 2023 electric CAP participation to reach 4,099 low-income customers. (UGI USECP, at Appendix A-1). In contrast, as of February 28, 2023, just two months later, its electric CAP participation was still only 3,261. (OCA-IV-1). The process updated by Ms. Epler will use actual known data as of September 2023.

Part 6. Proposed Equity Adder for Management Performance.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to UGI's proposal to include an adder of 20 basis points to its return on equity to reflect what UGI witness Paul Moul refers to as "strong" management performance. (UGI St. 9, at 1, 6 – 7; see also, UGI St. 4, at 9 -12; UGI St. 1,at 12 - 16). After reviewing UGI's performance with respect to universal service and credit and collections, I conclude that the proposed adder is not merited.

Q. PLEASE EXPLAIN THE FIRST ELEMENT OF MANAGEMENT PERFORMANCE THAT YOU HAVE REVIEWED.

A. The first element of management performance I have reviewed involves the performance of UGI regarding its low-income customers. In particular, I examine the extent that UGI is reasonably implementing Pennsylvania's universal service programs.

As I discussed in detail above, UGI enrolls a low percentage of its estimated customers into its CAP. While UGI has an estimated 11,356 customers with income at or below 150% of Poverty, it enrolls only 3,257 (28.8%) of those customers into CAP. Even though UGI enrolls 58% of its Confirmed Low-Income customers into CAP, it confirms the low-income status of fewer than half of its estimated low-income customer base.

This performance fails to exhibit strong Company management given the collections performance of UGI's low-income customers. From October 2020 through February 2023, more than half of UGI's Confirmed Low-Income customers (excluding CAP) had an arrearage balance on their bill. (OCA-IV-43(i)). Indeed, over that 29 month period, an average of 81% of the total Confirmed Low-Income dollars billed (excluding CAP) constituted arrearages. (OCA-IV-43(h)).

The Confirmed Low-Income performance is substantially worse than the Company's residential collections performance overall. While the average arrearage of a Confirmed Low-Income customer in arrears reached $862 in the period October 2020 through February 2023 (OCA-IV-23(e)), the average residential arrearage (of those with an arrearage)was "only" $591 (OCA-IV-42(e)).

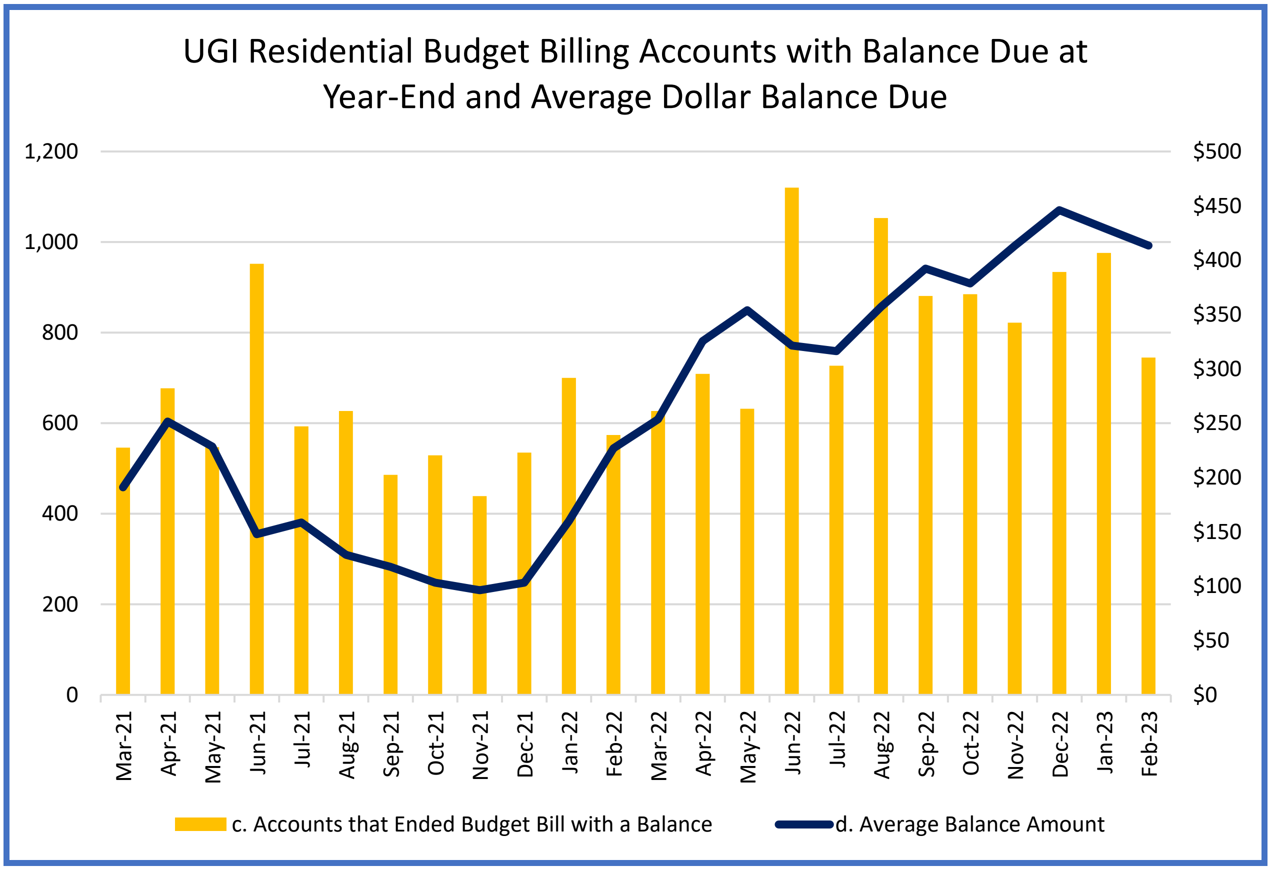
Q. PLEASE EXPLAIN THE SECOND ELEMENT OF MANAGEMENT PERFORMANCE THAT YOU HAVE REVIEWED.

A. The second element of management performance that I have reviewed involves the credit and collection outcomes generated by UGI. The UGI collections performance is substantially worse than the performance of other Pennsylvania electric utilities. For the 29 months October 2020 through February 2023, 23.3% of UGI's billed residential accounts had an arrearage. (OCA-IV-42(i)). This compares to a statewide average for Pennsylvania's electric utilities of only 10.0%.[29] Moreover, UGI carries many customers with very high arrearage balances. While the mean (average) arrears for Company accounts in arrears is $591 for that 29-month period, the median arrears was only $258. The median is the mid-point, that point at which half of all accounts in arrears have smaller balances and the other half have larger balances. When the average is more than two times higher than the median, that means that the number of accounts with very high

[29] BCS 2021 Report on Universal Service Program and Collections Performance, supra, at 20.

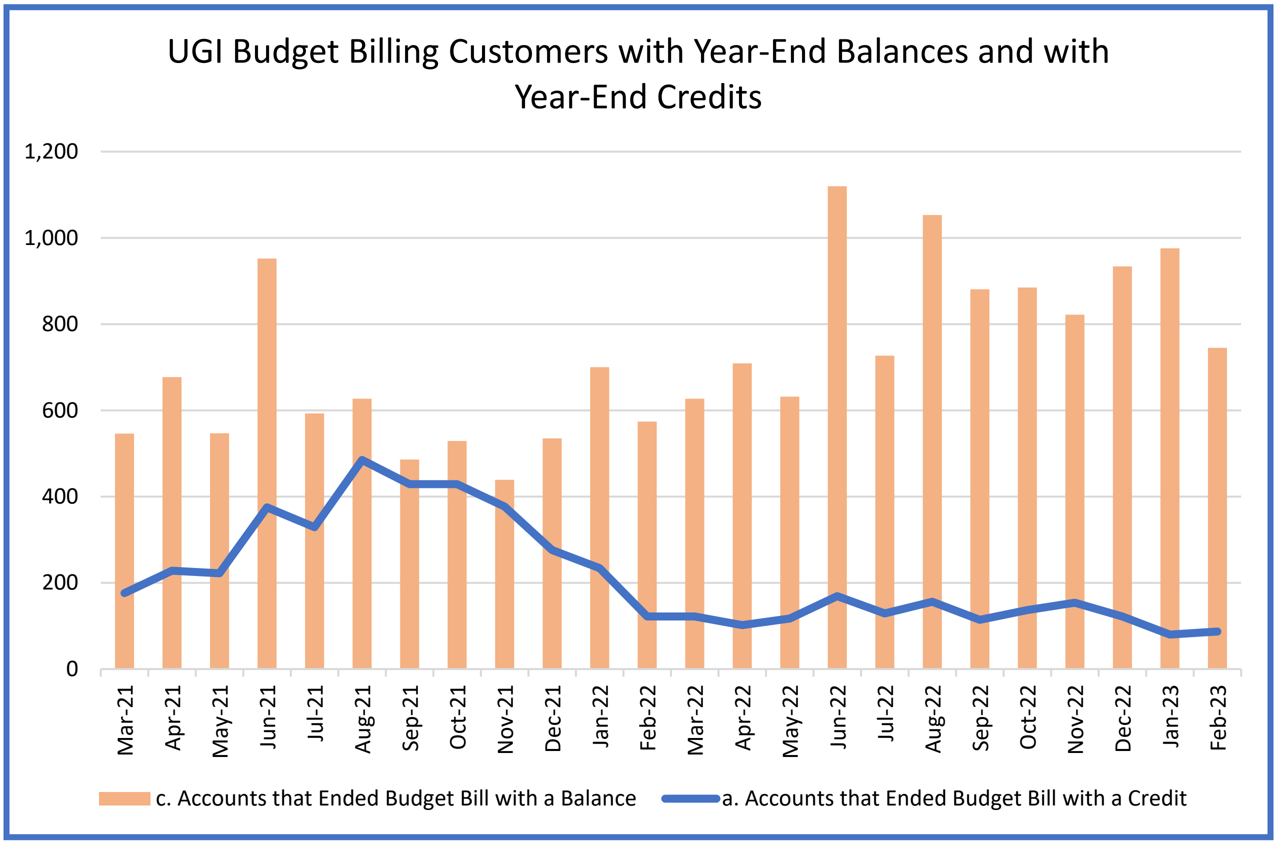
arrears is sufficiently big to more than offset those accounts with small arrearage balances (to more than double the average balance).

UGI does not do a good job of using its budget billing plan to control arrearages. The Chart below shows, for the period March 2021 through February 2023 (the most recent 24 months available) the number of budget billing accounts that have ended their year with an amount owing, along with the average balance owing at the end of the year. The bars show the number of residential accounts with a balance due at the end of their budget billing year. The line represents the average balance due (in dollars). As can be seen, not only has UGI experienced a sharp increase in the number of customers with a balance due at the end of their budget billing year, but the amount of money they owe at the end of the year has sharply increased as well. Not only has the average balance due at the end of budget billing years more than doubled since March 2021, but the increase in the number of accounts having these balances can be readily seen by comparing the bars for the first twelve months (March 2021 through February 2022) to the bars for the second twelve months (March 2022 through February 2023). In each of the most recent four months (November 2022, December 2022, January 2023, February 2023), the balance due at the end of the budget billing years has exceeded $400 ($413, $436, $430, $413 respectively). In the corresponding four months for the preceding time period (November 2021, December 2021, January 2022, February 2022), the average balance due at the end of the budget billing years $96, $103, $160, and $227 respectively).



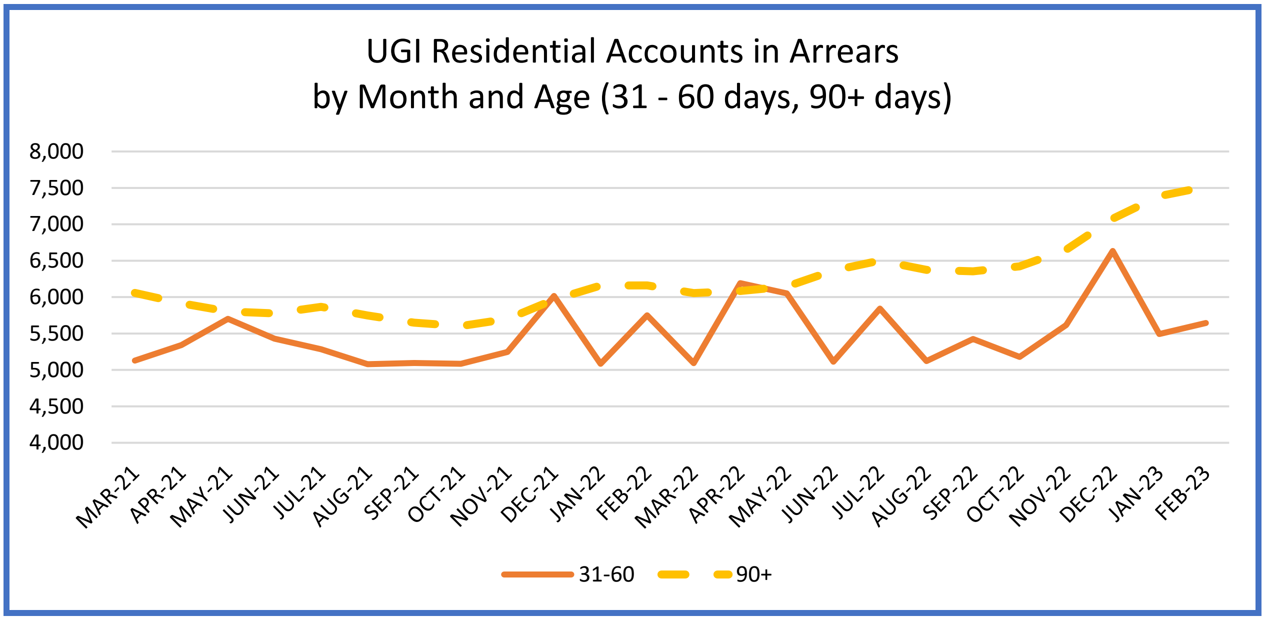
Even if UGI were to spread the average year-end balance due at the end of a budget billing year over the next twelve months (OCA-IV-18), that balance would add more than $34 a month ($400 / 12 = $34.46) to a customer's bill.

These failure of UGI's budget billing program to closely track actual bills by the end of the budget billing year does not fall equally on budget billing customers who experience bill balances that must still be paid in the future and those that experience bill credits that can be applied to future bills. The solid line Chart below tracks the number of budget billing customers who end their budget billing year with a credit balance. The bars show the number of accounts ending the year with a balance. As can be seen, over the most recent 24 months, the number of customers with a credit balance has sharply decreased, while the number with a balance owing has sharply increased.

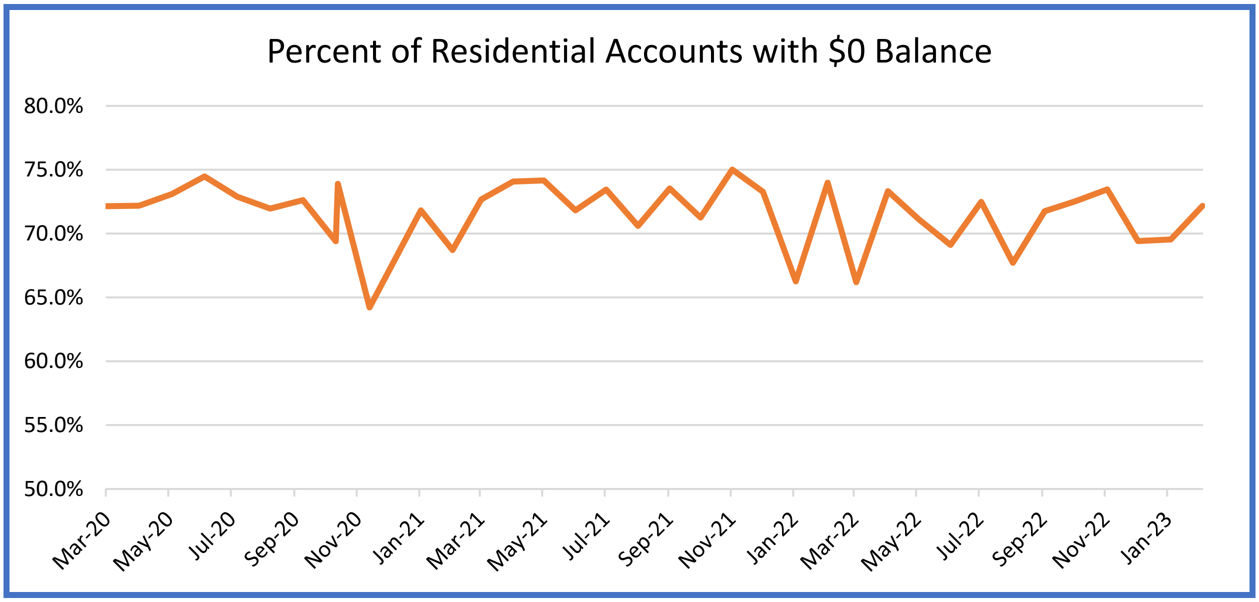


The failure of UGI to help customers manage their budget bills so that they do not end their budget billing year with substantial credits or balances is not an indication of good management performance with respect to helping customers manage their accounts. Budget billing is a mechanism which allows residential customers to smooth their bills over the course of a 12-month period. By reducing, if not completely removing, the month-to-month fluctuation in bills, budget billing allows customers to plan their payments more capably. By reducing the seasonal fluctuation in bills, budget billing helps to minimize the seasonal fluctuation in arrears.

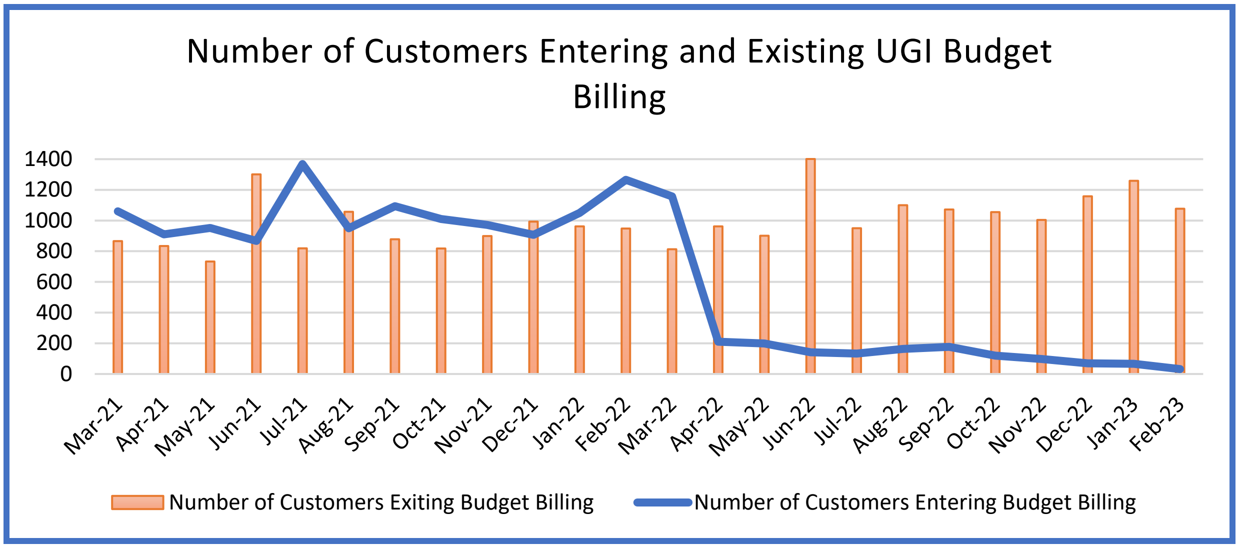
The seasonal fluctuation in the presence of short-term and long-term arrears of UGI residential customers can be seen in the Chart below. The solid line shows the seasonal variation in short-term arrears (31-60 days old). Even though UGI is experiencing an increase in its long-term arrears (90-days old or older), those long-term arrears do not vary based on seasonal fluctuations in customer bills. (OCA-IV-8).



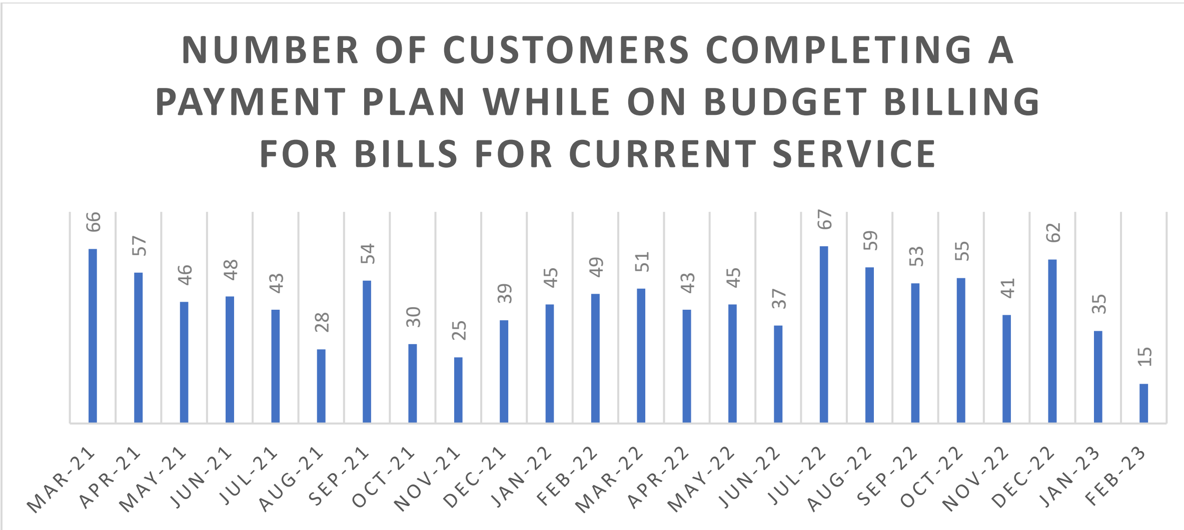
The same results can be seen in the converse way. Rather than looking at the percentage of accounts *with* arrears, one can examine the percentage of accounts with a $0 balance. (OCA-IV-40). The Chart below clearly shows how the percentage of UGI residential accounts having a $0 balance noticeably dips in response to seasonal fluctuations in bills.



Despite the role that budget billing can play in helping to control short-term arrears by levelizing bills, UGI does not effectively promote the use of budget billing. The Chart below shows the number of residential accounts entering into budget billing by month for the most recent 24 months available. (OCA-IV-19(a)). As can be seen, in the most recent five months, fewer than 400 accounts have entered into budget billing. In the eleven months April 2022 through March 2023, 1,410 customers entered budget billing (while 11,939 exited budget billing).



Finally, UGI certainly does not use its budget billing program to assist customers who may be facing seasonal arrears. When asked for the number of customers who entered into budget billing with a pre-existing arrears, UGI responded "The Company does not permit a delinquent account to enter into a levelized budget billing plan." (OCA-IV-19(c)). When asked for the number of customers who completed a payment plan while using budget billing for current service each month, UGI provided data showing that fewer than 100 such customers completed payment plans for arrears while on budget bills. The data is shown in the Chart below.



In sum, it is clear that UGI is not seeking to manage its residential arrears through the offer of budget billing. Not only are few customers entering budget billing in any given month, but budget billing is not being coupled with deferred payment plans to help customers who may have fallen into arrears due to the substantial seasonal fluctuations in UGI seasonal bills.

Q. HAVE YOU REVIEWED THE GROUNDS FOR UGI'S CLAIMS OF STRONG MANAGEMENT PERFORMANCE?

A. Yes. I find that UGI's claims of strong management performance are over-stated. Company witness Brown sets forth multiple bases for his claims of strong management performance.

Q. HAVE YOU REVIEWED UGI'S CLAIM OF STRONG MANAGEMENT PERFORMANCE WITH RESPECT TO "SAFETY"?

A. Yes. UGI witness Brown claims that the Company engages in activities that enhance employee and customer safety. (UGI St. 1, at 13). Witness Sorber testifies that the

Company's management performance is reflected in UGI's "safety culture." (UGI St. 4, at 9 -12). According to Mr. Sorber, safety is enhanced by UGI actions such as (1) "[p]reventing would-be facility failures," (2) "meet[ing] with local first responders (e.g., volunteer fire departments) to provide an electrical safety awareness training program"; (3) "distribut[ing] safety-related news releases that provide seasonal safety tips via traditional media outlets, through social media, and on UGI's website. UGI's website further includes tips on electrical safety: and (4) "provid[ing] both safety and conservation information to fourth grade students. . ." (UGI St. 4, at 11 – 12). Moreover, UGI supports its claims for an increased return on equity (i.e., profit) because it has established a process to "identify, discuss, investigate and address employee safety concerns." (UGI St. 4, at 10). None of these actions are sufficiently substantial to merit an equity adder. As I documented in work on utility responses to storm damage, meeting with first responders is standard industry practice.[30] Such meetings are not particularly innovative nor new. Neither the use of "social media" and "traditional media." nor use of the Company's website, to provide "tips on electric safety" is neither innovative nor strong management performance. Indeed, electric industry associations such as the American Public Power Association (APPA)[31] and the National Fire Protection Association[32] have standard templates for doing precisely this. Finally, working to

[30] Colton (2013). White Paper: Utility Communications with Residential Customers and Vulnerable Residential Customers in Response to Severe Weather Related Outages," available at https://fsconline.com/05_FSCLibrary/lib2.html

[31] See, APPA Customer Service Communication Templates, available at https://www.publicpower.org/communication-templates

[32] National Fire Protection Association, Public Education, Electric Social Media Posts, Electrical Safety Social Share Images, available at https://www.nfpa.org/Public-Education/Fire-causes-and-risks/Top-fire-causes/Electrical/Electrical-social-media-posts

prevent “would-be facility failures” and establishing a process to address “employee safety concerns” would seem to be standard practice. A failure to prevent facility failures or to address employee safety concerns would be a failure of management. Engaging in such actions does not represent strong management.

Q. HAVE YOU REVIEWED THE UGI CLAIM OF STRONG MANAGEMENT PERFORMANCE WITH RESPECT TO PROMOTING CUSTOMER ELECTRONIC PAYMENTS?

A. UGI witness Brown cites the Company’s “UNITE” project as a cause for increasing “electronic payments for UGI’s gas and electric customers. . .by approximately 81% and customer portal profiles increased by approximately 106%.” (UGI St. 1, at 10). In making this statement, UGI seeks to claim credit for social and economic developments that have little, if anything, to do with UGI management or UGI management decision-making.

The U.S. Federal Reserve Bank (FRB) publishes two annual studies on consumer payment choices. On the one hand, there is the *Survey of Consumer Payment Choice*, prepared each year since 2009. On the other hand, there is the *Diary of Consumer Payment Choice*, prepared each year since 2016. I have examined the last three years of each publication (*Survey*: 2018, 2019, 2020; *Diary*: 2020, 2021, 2022). The *2022 Diary of Consumer Payment Choice* reports that consumers use credit and debit cards for more than half of their payments in 2021. In 2021, credit and debit cards accounted for 57% of total payments, contrasting to 55% in 2020 and 54% in 2019. (2022 *Diary of Consumer*

Choice, at 5).[33] The Federal Reserve Bank's reports on consumer payment choices also support the observation that the trend in consumer payment practices today is away from the use of paper checks and increasingly toward the various electronic means of payment. The *2020 Diary*, for example, reported that, while "checks are most commonly used for bill paying," they are *not* the most common method of bill payment. The Fed's *2020 Diary* reported:

> checks are most commonly used for bill paying: 23 percent of bills by number were paid by BANP, 21 percent by OBBP, and 19 percent by check, totaling 6 in 10 of all bill payments for the three methods. . .In addition, 15 percent of bill payments were made with a debit card. Half of the value of all bills (51 percent) was paid using electronic payments (BANP and OBBP).[34]

(*2020 Diary*, at 8). The share of paper payments being made, compared to payments by debit or credit card or by electronic means (BANP, OBBP) is steadily declining. (Id., at 4). According to the Federal Reserve Bank's most recent (2020) *Survey of Consumer Payment Choices*, "the share of consumers using checks at least once in a typical month has declined in every year since 2010." (*2020 Survey*, at 10 – 11).

I do not dispute whether the number and percentage of UGI customers making electronic payments have been increasing in recent years. However, that increase in electronic

[33] Part of this uptick can be attributed to a decline in the use of cash for payments during the COVID pandemic rather than an increase in the use of credit cards. This was in large part due to a consumer unwillingness to shop in person. *See generally*, Green, Merry and Stavins (2022). Has COVID Changed Consumer Payment Behavior," Federal Reserve Bank of Atlanta.

[34] "OBBP refers to "online bank bill payment." BANP refers to "bank account number payment." BANP involves the consumer providing a vendor, such as a utility, with his/her bank account number and having automatic payments withdrawn. OBBP involves a consumer contacting the bank and arranging online for a payment to be sent.

payments, the extent to which such payments increase the ease of making payments, has little, if anything, to do with UGI's management performance. Increasing electronic payments represent a societal-wide trend, not a UGI-specific customer response to management decisions.

Q. IS THERE ANY OTHER ASPECT OF THE UNITE PROJECT THAT FALLS SHORT OF THE "EXCEPTIONAL MANAGEMENT" THAT MR. BROWN CLAIMS?

A. Yes. Mr. Brown cites the UNITE investments as evidence of strong management because, amongst other things, it results in "improved data quality." (UGI St. 1, at 1). Despite these claims, UGI falls well-short of collecting data that is essential to responding to the needs of its residential customers. One area of fundamental shortcoming is UGI's failure to collect tracking data disaggregated by heating and non-heating residential accounts regarding: (1) the mean or median bills for residential customers; (2) the mean or median bills of residential customer in arrears; (3) the mean or median arrears of residential customers in arrears; (4) the total dollars of arrears; (5) the percentage of billed residential accounts in arrears; or (5) the average arrears of accounts being disconnected for nonpayment. (OCA-IV-42). Rather than exemplifying strong management with respect to data quality, UGI lacks basic data needed to support customer service and collections activities.

Q. HAVE YOU REVIEWED UGI'S CLAIM OF STRONG MANAGEMENT PERFORMANCE TIED TO ITS ENERGY CONSERVATION PROGRAM?

A. Yes. UGI witness Brown cites UGI's voluntary implementation of its electric Energy Efficiency and Conservation Plan (EE&C Plan) as an indication of its strong management performance. (UGI St. 1, at 14). According to Mr. Brown, the UGI EE&C Plan results in "material cost savings for customers." (Id.). The Company's EE&C Plan, however, does not provide services to low-income customers. The Company instead restricts its low-income energy efficiency investments to its LIURP program.

Mr. Brown cites as strong management performance UGI's LIURP budget of $220,400. (UGI St. 1, at 15). As I discuss above, the Company's usage reduction services directed toward its low-income customers is quite limited. With its current budget, the Company will serve 66 low-income households a year through its LIURP. To show the limited extent of this effort, UGI has an estimated 11,444 customers with income at or below 150% of FPL.

Q. HAVE YOU RECEIVED UGI'S CLAIM OF STRONG MANAGEMENT PERFORMANCE TIED TO ITS CLAIM TO PROVIDE LIHEAP GRANTS?

A. Yes. UGI witness Brown claims, as evidence of UGI's strong management performance, that "for program year 2022, *UGI Electric provided* 1,396 Low Income Home Energy Assistance Program ("LIHEAP") grants totaling more than $1 million. . ." (UGI St. 1, at 15) (emphasis added). This claim, of course, is false. UGI does not "provide LIHEAP grants." LIHEAP is a federal public assistance program, administered by the U.S. Department of Health and Human Services (DHHS) at the federal level, and by the

Pennsylvania Department of Human Services (DHS) at the state level. UGI's claiming credit for "providing LIHEAP grants" is factually incorrect.

Indeed, when it comes to assistance provided by and through the Company, UGI's management falls short. As I discussed in detail above, even though UGI agreed in its settlement of prior rate cases (2018, 2021) to engage in prescribed outreach both to identify its Confirmed Low-Income customers and to promote enrollment in the UGI CAP, the Company failed to abide by those agreements. UGI's management performance with respect to promoting, let alone providing, low-income assistance is not one of strong performance meriting financial reward.

Q. HAVE YOU REVIEWED MR. BROWN'S CLAIM OF STRONG MANAGEMENT PERFORMANCE REGARDING THE PROVISION OF HARDSHIP GRANTS?

A. Mr. Brown cites as evidence of strong management the fact that UGI provided 287 Operation Share Grants for more than $85,000 in program year 2022. (UGI St. 1, at 15). Program years for Operation Share run from October 1 of one year to September 30 of the following year. (OCA-IV-21). Mr. Brown fails to note that the data he cites is not representative. Data on Operation Share grants was provided in response to discovery and is set forth in the Table below. Program Year 2021 is not representative (i.e., the year with grant dollars most closely approximating Mr. Brown's statement of $85,000 in assistance provided) is more than four times higher than 2020 (October 2019 - September 2020) (the heart of COVID-19), and nearly 50% higher than Program Year 2022. Moreover, Mr. Brown did not acknowledge that during Program Year 2021 (October 2020 – September 2021), the Company distributed more money to more people because from August 2020 through June 2021, UGI had ***temporarily*** raised the income guidelines for hardship grants from 200% to 250% of Poverty and had *temporarily* increased the maximum grant from $400 to $600. (OCA-IV-38).

Operational Share Hardship Grants to Non-CAP Participants
Operation Share Program Year 2020 through Program YTD (2/28/23)
(OCA-IV-21)

Program Year	# of Customers	Grant Dollars	Average Grant Amount (Dollars / # Customers)
2020	123	$18,484.39	$150.28
2021	323	$85,965.68	$266.15
2022	336	$58,631.97	$174.50
2023	98	$19,235.46	$196.28

To place the data cited by Mr. Brown into some context, in the 12 month period March 2022 through February 2023, UGI issued 14,388 residential notices of involuntary disconnection for nonpayment, and actually disconnected 1,600 residential accounts. (OCA-IV-4). At the same time UGI was providing hardship grants of roughly $200 (out of a maximum hardship grant of $400, OCA-IV-38), the average residential arrears (of accounts in arrears) was $591, and the average residential arrears at the time of a shutoff was $1,969. (OCA-IV-42).

Q. WHAT DO YOU CONCLUDE?

A. When UGI management performance is reviewed from either a universal service, or from a credit and collection perspective, the Company is not exhibiting strong management performance. Fundamental efforts that should be taken to serve the Company's low-income customer base, and to manage its outstanding arrearage balances, are not being pursued. Moreover, I conclude that areas and activities argued by Company witness Brown to represent "strong management" do not support his conclusion that UGI management merits an increase in the Company's equity return. I conclude that the recommendation of OCA witness Aaron Rothschild (OCA Statement No. 2) to deny UGI's requested adder to reflect "strong" Company management should be adopted.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

Appendix

Colton Vitae

Appendix RDC-A: Summary Vitae
Roger Colton
Fisher, Sheehan & Colton
Public Finance and General Economics
Belmont, MA

* * * * * * * * * * * * * * * * * * * *

EDUCATION:

J.D. (Order of the Coif), University of Florida (1981)

M.A. (Regulatory Economics), McGregor School, Antioch University (1993)

B.A. Iowa State University (1975) (journalism, political science, speech)

PROFESSIONAL EXPERIENCE:

Fisher, Sheehan and Colton, Public Finance and General Economics: 1985 – present.

As a co-founder of this economics consulting partnership, Colton provides services in a variety of areas, including: regulatory economics, poverty law and economics, public benefits, fair housing, community development, energy efficiency, utility law and economics (energy, telecommunications, water/sewer), government budgeting, and planning and zoning.

Colton has testified in state and federal courts in the United States and Canada, as well as before regulatory and legislative bodies in more than forty (40) states. He is particularly noted for creative program design and implementation within tight budget constraints.

PROFESSIONAL AFFILIATIONS:

Past Chair:	Belmont Zoning By-law Review Working Committee (climate change)
Member:	Board of Directors, Massachusetts Rivers Alliance
Columnist:	Belmont Citizen-Herald
Producer:	Belmont Media Center: BMC Podcast Network
Host:	Belmont Media Center: Belmont Journal
Member:	Belmont Town Meeting
Vice-chair:	Belmont Light General Manager Screening Committee
Past Chair:	Belmont Goes Solar
Coordinator:	BelmontBudget.org (Belmont's Community Budget Forum)
Coordinator:	Belmont Affordable Shelter Fund (BASF)
Past Chair:	Belmont Solar Initiative Oversight Committee
Past Member:	City of Detroit Blue Ribbon Panel on Water Affordability
Past Chair:	Belmont Energy Committee

Member:	Massachusetts Municipal Energy Group (Mass Municipal Association)
Past Chair:	Housing Work Group, Belmont (MA) Comprehensive Planning Process
Past Chair:	Board of Directors, Belmont Housing Trust, Inc.
Past Chair:	Waverley Square Fire Station Re-use Study Committee (Belmont MA)
Past Member:	Belmont (MA) Energy and Facilities Work Group
Past Member:	Belmont (MA) Uplands Advisory Committee
Past Member:	Advisory Board: Fair Housing Center of Greater Boston.
Past Chair:	Fair Housing Committee, Town of Belmont (MA)
Past Member:	Aggregation Advisory Committee, New York State Energy Research and Development Authority.
Past Member:	Board of Directors, Vermont Energy Investment Corporation.
Past Member:	Board of Directors, National Fuel Funds Network
Past Member:	Board of Directors, Affordable Comfort, Inc.
Past Member:	National Advisory Committee, U.S. Department of Health and Human Services, Administration for Children and Families, Performance Goals for Low-Income Home Energy Assistance.
Past Member:	Editorial Advisory Board, International Library, *Public Utility Law Anthology*.
Past Member:	ASHRAE Guidelines Committee, GPC-8, *Energy Cost Allocation of Comfort HVAC Systems for Multiple Occupancy Buildings*
Past Member:	National Advisory Committee, U.S. Department of Housing and Urban Development, Calculation of Utility Allowances for Public Housing.
Past Member:	National Advisory Board: Energy Financing Alternatives for Subsidized Housing, New York State Energy Research and Development Authority.

PROFESSIONAL ASSOCIATIONS:

National Association of Housing and Redevelopment Officials (NAHRO)
National Society of Newspaper Columnists (NSNC)
Association for Enterprise Opportunity (AEO)
Iowa State Bar Association
Energy Bar Association
Association for Institutional Thought (AFIT)
Association for Evolutionary Economics (AEE)
Society for the Study of Social Problems (SSSO)
Association for Social Economics

BOOKS

Colton, *et al., **Access to Utility Service***, National Consumer Law Center: Boston (4th edition 2008).

Colton, *et al.*, ***Tenants' Rights to Utility Service***, National Consumer Law Center: Boston (1994).

Colton, ***The Regulation of Rural Electric Cooperatives***, National Consumer Law Center: Boston (1992).

BOOK CHAPTERS

Colton (2018). The equities of efficiency: distributing energy usage reduction dollars, Chapter in Energy Justice: US and International Perspectives (Edited by Raya Salter, Carmen Gonzalez and Elizabeth Ann Kronk Warner), Edward Elgar Publishing (London, England).

JOURNAL PUBLICATIONS

65 publications in industry and academic journals, primarily involving utility regulation and affordable housing. (list available upon request)

TECHNICAL REPORTS

200 technical reports for public-sector and private-sector clients (list available upon request)

JURISDICTIONS IN WHICH EXPERT WITNESS PROVIDED

1. Maine
2. New Hampshire
3. Vermont
4. Massachusetts
5. Rhode Island
6. Connecticut
7. New Jersey
8. Maryland
9. Pennsylvania
10. Washington D.C.
11. Virginia
12. North Carolina
13. South Carolina
14. Florida (Federal Court)
15. Alabama
16. Mississippi
17. Tennessee
18. Kentucky
19. Ohio
20. Indiana
21. Michigan
22. Wisconsin
23. Illinois
24. Minnesota
25. Iowa
26. Missouri
27. Kansas
28. Louisiana
29. Arkansas
30. Texas (Federal Court)
31. South Dakota
32. North Dakota
33. Montana
34. Colorado
35. New Mexico
36. Arizona
37. Utah
38. Idaho
39. Nevada
40. Washington
41. Oregon
42. California
43. Hawaii

Canadian Provinces

1. Nova Scotia
2. Ontario
3. Manitoba
4. British Columbia

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2022-3037368
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 4, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 25, 2023
*344777

Signature: ______________________
Roger D. Colton

Consultant Address: Fisher, Sheehan, & Colton
34 Warwick Road
Belmont, MA 02478

Pennsylvania Public Utility Commission

Pennsylvania Public Utility Commission	*	
v.	*	Docket No. R-2022-3037368
UGI Utilities, Inc. – Electric Division	*	

Surrebuttal Testimony of

Roger D. Colton

OCA Statement No. 4SR

June 7, 2023

Table of Contents

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, MA 02478.

Q. ARE YOU THE SAME ROGER COLTON WHO PREVIOUSLY PREPARED DIRECT TESTIMONY ON BEHALF OF THE OFFICE OF CONSUMER ADVOCATE IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my Surrebuttal Testimony in this proceeding is as follows:

- To respond to the Rebuttal Testimony of I&E Witness Christopher Keller (I&E St. 2-R);
- To respond to the Rebuttal Testimony of UGI witness Christopher Brown (UGI St. 1-R);
- To respond to the Rebuttal Testimony of UGI witness Daniel Adamo (UGI St. 11-R); and
- To respond to the Rebuttal Testimony of UGI witness John Taylor (UGI St. 6-R).

Part 1. Response to I&E Witness Christopher Keller.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to the Rebuttal Testimony of Christopher Keller regarding my recommended adjustments to UGI's budget for Low-Income Usage Reduction Program (LIURP) investments. (I&E St. 2-R)

Q. PLEASE SUMMARIZE MR. KELLER'S OPPOSITION TO YOUR PROPOSED LIURP BUDGET ADJUSTMENT.

A. Mr. Keller states that while my recommended increase in UGI's LIURP budget is "well-intentioned," he recommends that no increase to the budgeted LIURP amount be allowed. (I&E St. 2-R, at 3). He agues that I do not provide support for how UGI would complete the additional jobs. He further argues that no increase should be allowed "without consideration and evaluation of the program's performance indicators and provision of comments by all stakeholders and interested parties." (Id., at 4)

Q. WHAT IS YOUR RESPONSE?

A. Mr. Keller cites UGI's failure to spend its LIURP budget during the years of 2021 through 2022 in support of his claim that the Company lacks the capacity to increase its LIURP spending. He fails to acknowledge that the years he cites included the height of the COVID pandemic. During these years, the economic sector, particularly those involving home visits such as installing energy efficiency measures, was largely shutdown. The delivery or non-delivery of usage reduction services during those COVID years is not evidence of the inability to provide such services during more typical times.

In fact, the capacity of Pennsylvania's weatherization providers to ramp up capacity to deliver usage reduction services has been repeatedly exhibited. In response to COVID, for example, Congress enacted the America Rescue Plan Act (ARPA), providing $44.6 million in additional weatherization funding to Pennsylvania.[1] Similarly, in response to

[1] Weatherization Assistance Program Funding Report, 2021, Table 7, https://nascsp.org/wap/weatherization-publications/wap-annual-funding-surveys/

the Great Recession, the Recovery Act provided $5 billion to the Weatherization Assistance Program (WAP), adding $4,746,249,999 to the network for use between April 1, 2009 to March 31, 2012.[2] While the expectation was that low-income weatherization providers would be able to expand capacity to weatherize 634,956 additional homes, in fact, the network expanded to weatherize 806,000 homes, exceeding the predicted goal by 171,000 homes. When that money was gone, however, production capacity was scaled back to reflect current funding levels. Mr. Keller's reliance on production levels during the height of a public health emergency that constrained all economic sectors, particularly those that included in-home visits, should be rejected. When provided with additional funding, Pennsylvania weatherization providers have exhibited their ability to ramp up their capacity to deliver those services.

In any event, Mr. Keller's argument about production capacity fails to provide a reason to disallow my recommended increase in the LIURP budget. While LIURP spending charged to ratepayers is based on the projected number of LIURP homes to be weatherized, the Company's Rider C provides that:

> On or before November 1 of each year, the Company shall file with the PUC data showing the reconciliation of actual revenues received under this Rider and actual recoverable costs incurred for the preceding twelve months ended September. The resulting over/undercollection (plus interest calculated at 6% annually) will be reflected in the CAP quarterly rate adjustment to be effective December 1. *Actual recoverable costs shall reflect* actual CAP costs, actual application costs, actual pre-program arrearage forgiveness, *actual LIURP costs*, actual Hardship Administrative costs.

[2] Weatherization Assistance Program Funding Report, 2014, at 3, https://nascsp.org/wap/weatherization-publications/wap-annual-funding-surveys/

(UGI Electric Tariff, Rider C) (emphasis added). If Mr. Keller is correct –which historical performance indicates will not be the case—and UGI is unable to spend an increased LIURP budget, those dollars are never recovered from ratepayers. My recommended increase to the LIURP budget are only recovered if actually expended. Rider C is explicitly limited to "actual LIURP costs." Ratepayers will only pay for the increased LIURP budget in the event, and to the extent, that Mr. Keller is in error about UGI's ability to ramp up delivery capacity.

Mr. Keller's argument that changes in the LIURP budget should not occur without the "provision of comments by all stakeholders and interested parties" (Id., at 4) should be rejected as a basis for his recommendation of no funding change. What Mr. Keller does not acknowledge is that this rate proceeding involves not only the participation of all stakeholders who are involved with the USECP proceedings, but involves the participation of additional stakeholders who do *not* participate in the USECP proceeding. Furthermore, since LIURP budgets are in fact rates charged to customers, it would be inapposite to suggest that the appropriateness of the budget should not be addressed in a rate case.

Finally, Mr. Keller argues that he finds it "unlikely" that the USECP proceeding "lacked the foresight to contemplate any intervening cost of living escalation that would impact affordability for low-income customers." (Id., at 4). In making this argument, Mr. Keller does not respond to my Direct Testimony. My Direct Testimony recommends an increase in UGI's LIURP spending as a response to mitigate the harms of UGI actions proposed in *this* rate proceeding. My recommendation is not tied to any amorphous "intervening cost of living escalation." It is a UGI response to harms imposed by actions proposed by UGI to be taken in this rate case (including not merely the size of the rate increase, but the manner in which the increased rates are structured, such as substantial increases in the fixed monthly customer charge).

Part 2. Response to UGI Rebuttal Witness Christopher Brown.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to Company Rebuttal Witness Christopher Brown regarding whether UGI's management performance is sufficiently exemplary to merit an adder to the Company's return on equity (UGI St. 1-R).

Q. PLEASE SUMMARIZE THE REBUTTAL TESTIMONY TO WHICH YOU RESPOND.

A. Mr. Brown argues that UGI management performance merits additional compensation in the Company's return on equity whether that performance is particularly exemplary or whether it simply involves doing the same things that are standard practice in the industry. (UGI St. 1-R, at 8 – 9). For example, he argues with respect to a substantial number of the "safety" activities in which UGI engages, "while these activities may not be new or innovative, their importance should not be ignored." (Id., at 9). He cites what he characterizes as UGI's "dedication to safety" as reason for UGI's request for an equity adder, but then argues that rather than looking at specific UGI actions or decisions, "the Commission should consider the Company's safety program in totality. . ." (Id.).

Q. WHAT IS YOUR RESPONSE?

A. Overall, Mr. Brown continues to assert that UGI's actions which are not generally considered to be exemplary decisions, but rather routine expectations of an electric utility, support UGI's request for an equity adder to compensate the Company for exemplary management. In his rebuttal testimony, for example, Mr. Brown cites his claim that UGI has a "well-defined and executed vegetative management program" as evidence of exemplary management (Id., at 9), as though *not* having a well-defined and executed vegetative management program is the electric industry norm. He does not dispute my Direct Testimony that engaging in the safety activities he identified are "standard industry practice" rather than being evidence of exemplary management. Moreover, an electric distribution utility service's "dedication to safety" should not be elevated to an example of exemplary management performance, but should be the norm as the Company is expected to provide safe and reliable service as a regulated public utility operating in the Commonwealth of Pennsylvania. This should especially be the case when the Company's own witness admits that UGI's safety activities are neither new nor innovative. Indeed, these are standard practices in the industry.

Mr. Brown seeks to have UGI take credit for exemplary management by the fact that UGI made investments in the Company's UNITE (UGI Next Information Technology Enterprise) program. He summarily asserts, without supporting data or reasoning, that "[c]learly, the increase in electronic payments made by UGI customers since the implementation of UGI's customer billing system, and other customer portal enhancements made as part of the UNITE program, have significantly increased the number of electronic payments being made by UGI customers. . ." (Id.). Indeed, Mr.

Brown also asserts, again without data or reasoning that the increase in electronic payments "*would not have occurred* without UGI Electric's foresight and investments in UNITE to serve its customer's (sic) interests." (Id., at 10) (emphasis added). Mr. Brown's testimony suffers the logical fallacy that because something follows an action that it was caused by the action. The data presented in my Direct Testimony, however, which Mr. Brown does not dispute, indicates that the increase in electronic payments is occurring throughout the economy. The implementation of UNITE cannot be shown to have caused that increase if it is consistent with the overall trends in the economy.

Mr. Brown's argument that UGI's increase in electronic payments *as a whole* exceeds the total increase in *credit and debit cards* standing alone is a false equivalency. As I explained in my Direct Testimony, credit and debit cards are *not* considered to be "electronic payments." Finally, Mr. Brown's comparison of the three-year increase in credit and debit card payments (3%) to the UGI increase in electronic payments (20% to 22%) compares two different numbers. The increase in credit and debit card payments is the increase in such payments as a percentage of the *total* payments made by consumers. Mr. Brown's increase in the number of credit and debit card payments was the increase of one year's use of such payments to a prior year's use of such payments. In sum, Mr. Brown fails to establish that implementation of UNITE contributed to the increase in electronic payments, let alone support his explicit assertion that that increase "would not have occurred" in the absence of UNITE.

Mr. Brown argues that UGI's inability to provide critical data on its customer payment practices should be excused because the Commission does not *require* the Company to report such data. (Id., at 11). He further argues that the Company could not have predicted what data would be requested by other parties in a rate case when it built its information system. (Id.) Both of these responses, unto themselves, indicate a basis for denying the requested management adder. Instead, as I noted in my Direct Testimony, UGI "lacks basic data needed to support customer service and collections activities." Note the *__nature__* of data that the Company said that it could not provide for large sectors of its residential customer population (e.g., heating customers). These include but are not necessarily limited to:

- What is your *__mean and median bill__* for residential heating customers: Sorry, our IT system doesn't track that (OCA-IVV-42(a) – 42(b));
- What is your *__mean or median arrears__* for residential heating customers: Sorry, our IT system doesn't track that (OCA-IV-42(e) – 42(f));
- What is the *__total dollars of arrears__* from your heating customers: Sorry, our IT system doesn't track that (OCA-IV-42(g)).
- What *__percentage of your heating accounts are in arrears__*: Sorry, our IT system doesn't track that (OCA-IV-42(h)).
- When you disconnect a residential customer, what is the *__average arrears at the time of that disconnection__*: Sorry, our IT system doesn't track that. (OCA-IV-42(j))

The problem is not simply that UGI does not have this data, but that UGI is not capable of *__generating__* that information. It does not represent exemplary management for UGI to build its IT system only to provide data that the Commission *__requires__* it to provide. (UGI St. 1-R, at 11). That is the least they are required to do. Moreover, it does not represent good management for UGI for Mr. Brown to argue that the *__only__* purpose of knowing data about its customers is to be able to respond to rate case discovery. (Id., at 11)

Q. ARE THERE OTHER ARGUMENTS CONTAINED IN MR. BROWN'S REBUTTAL TESTIMONY THAT YOU DO NOT RESPOND TO IN THIS SECTION?

A. Yes. As Mr. Brown notes, while he identifies certain disagreements with my Direct Testimony, UGI's response to other aspects of my Direct Testimony were presented by other witnesses. I will respond to those arguments when I respond to each specific UGI Rebuttal Witness.

Part 3. Response to UGI Rebuttal Testimony of Daniel Adamo.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to the Rebuttal Testimony of UGI Witness Daniel Adamo (UGI St. 11-4).

Q. PLEASE SUMMARIZE THE REBUTTAL TESTIMONY TO WHICH YOU RESPOND.

A. Mr. Adamo opposes all but one of the recommendations I present in my Direct Testimony. He disputes my conclusion that:

1. UGI did not comply with the terms of the 2018 and 2021 rate case settlements.
2. UGI does not include any low-income weatherization component in its Energy Efficiency and Conservation (EE&C) Plan;
3. UGI bills are largely unaffordable to the vast majority of UGI low-income customers;
4. UGI's proposed increase to its residential customer charge will adversely affect low-income customers;

5. UGI is under-performing in its control of low-income arrearages; and
6. UGI should expand its LIURP funding to offset the harms created by the Company's rate case.

I will address each of his rebuttal arguments in turn.

Q. WHAT IS YOUR RESPONSE TO MR. ADAMO'S RELIANCE ON THE EXISTENCE OF FEDERAL FUNDING THROUGH THE INFLATION REDUCTION ACT OF 2022 AS A BASIS NOT TO ADJUST LIURP FUNDING?

A. Mr. Adamo argues that Pennsylvania will receive $258 million in funding through the federal Inflation Reduction Act of 2022. He asserts, with no back-up data or source, that "the highest level of benefits [will be] provided to the lowest income customers." (UGI St. 11-R). His argument fails on two grounds. First, the Inflation Reduction Act funding is intended to *supplement not to supplant* existing funding. If and to the extent that this funding is used simply to supplant funding that would otherwise have been provided through UGI, UGI's low-income customers are no better off with the federal funding than they would have been without it. Increases in *total* funding have occurred over time. In 2008, for example, as I describe above in response to the testimony of I&E rebuttal Witness Keller, Congress appropriated greater weatherization funding in response to the Great Recession. In addition, in response to COVID, Congress enacted the America Rescue Plan Act (ARPA), providing additional weatherization funding for Pennsylvania.[3] In each instance, those federal funds were intended to be *in addition to*, not in

[3] In 2021, 21 states used $355 million in ARPA funds for weatherization assistance. Weatherization Assistance Program, Funding Report, Program Year 2021, at 1. Pennsylvania was one of those states, with $44,560,572 in ARPA funds used for weatherization. Those funds were expected to be depleted by PY2022. Id.

replacement of, existing sources of funding.[4] In addition, while Mr. Adamo argues (without data or analysis) that this federal funding will make it not possible for low-income service providers to have the capacity to deliver UGI LIURP services (UGI St. 11-R, at 6), as I explained in response to Mr. Keller, this argument does not recognize the weatherization network's ability to ramp up its capacity when provided additional federal funding in the past.

Second, Mr. Adamo argues (without data or citation to any source) that the highest level of funding from the Inflation Reduction Act will be provided to the lowest income customers. (Id., at 5). What Mr. Adamo does not account for is that the Inflation Reduction Act defines "low-income" to be substantially higher than the PUC defines "low-income." Rather than defining low-income to be at or below 150% of the Federal Poverty Level (as the PUC does), the federal programs define low-income to be up to 80% of Area Median Income (AMI). The difference is significant. In 2022,[5] for example, 80% of AMI for Luzerne and Wyoming Counties –the two counties UGI

[4] Funding directed toward weatherization from ARPA involved allocations from the ARPA LIHEAP appropriations. According to the House Report on ARPA, "The legislation provides LIHEAP with *__additional funds in order to keep up with the growing need__* for assistance *__resulting from the pandemic__*." (America Rescue Plan Act of 2021, Report of the Committee on the Budget, House of Representatives, To Accompany H.R. 1319, February 24, 2021, at 304). Three things are clear from this language, (1) the intent of ARPA was to provide "additional funds," not to replace existing funds; (2) the purpose of the "additional funds" was "to keep up with the growing need for assistance," again not to replace existing sources of funding; and (3) the purpose of the additional funds was to address the "need for assistance" that was "resulting from the pandemic," again, not replace existing sources of funding. To the extent that Mr. Adamo's approach is taken, none of these Congressional three purposes will be achieved: (1) the ARPA funding would simply supplant existing funding rather than providing "additional funding"; (2) the ARPA funding would not be used to meet any "growing need," but rather used simply to replace existing funds directed toward a pre-existing need; and (3) the point of ARPA, to address the needs "resulting from the pandemic" would be frustrated since the ARPA funds would simply be used to meet pre-existing needs.

[5] 2023 HUD income limits have not yet been released as of the date this testimony was written.

serves (UGI St. 11-R, at 10)—was $53,400 for a three-person household.[6] In contrast, 150% of Federal Poverty Level for a 3-person household in 2023 is $37,290. Mr. Adamo's testimony makes it sound like LIURP and the federal statute serve the same population (which he labels as "low-income"), which is not even close to being accurate.

Q. PLEASE RESPOND TO MR. ADAMO'S TESTIMONY REGARDING UGI'S COMPLIANCE WITH THE 2018 AND 2021 RATE CASE SETTLEMENT AGREEMENTS.

A. Mr. Adamo argues that I drew "mistaken inferences" from UGI responses to discovery requests regarding universal service outreach and eligibility determinations. He does not mention which "inference" was "mistaken." The only "inference" I made from UGI responses was that the Company meant what it said when UGI stated "the Company *has not done a specific targeted campaign to confirm the low income status of customers other than interactions with UGI's Call Center Representatives, UGI Outreach Team members and Company's CBOs.*" (OCA-IV-32) (emphasis added).

In particular, Mr. Adamo argues that UGI complied with its agreement to perform a solicitation of customers who received LIHEAP in the prior 12 months two times a year. He states that UGI sent a solicitation to 144 UGI Electric customers who had received LIHEAP in the twelve months preceding February 28, 2022. He states that UGI sent a solicitation to 492 UGI Electric customers who had received LIHEAP in the twelve months preceding December 26, 2022. The problem with that is that in Program Year 2022, UGI had 2,093 customers that received LIHEAP (1,785 receiving LIHEAP Cash

[6] https://www.dhs.pa.gov/ERAP/Documents/AMIs_for_2022_2021_2020.pdf

grants; 64 receiving LIHEAP Crisis grants; 244 receiving both Cash and Crisis grants). Historically, however, UGI reported that roughly 36% of its LIHEAP recipients did *not* also participate in CAP. Applying that figure to the 2022 LIHEAP participation number would yield an expected LIHEAP/non-CAP number of more than 750 LIHEAP non-CAP participants (2,093 x 0.36 = 753). Mr. Adamo provides no information that leads me to conclude that when it stated in response to discovery that it "has not done a specific targeted campaign" it did not mean what it said.

Q. IS THERE ANY ADDITIONAL REBUTTAL TESTIMONY THAT MR. ADAMO PROVIDED REGARDING THE PRIOR RATE CASE SETTLEMENTS TO WHICH YOU WISH TO RESPOND?

A. Yes. Mr. Adamo seeks to deny the plain meaning of UGI's description of its verification of confirmed low-income status. The response to CAUSE-PA-1-3 states in its entirety:

> The Company assigns a "confirmed low income" attribute to a customer when the customer confirms income-eligible status with a Community-Based Organization (CBO) and/or the following criteria are met:
>
> - customer enrolls in CAP[;]
> - customer receives LIURP services and weatherization measures are installed and completed[;]
> - customer receives an Operation Share grant[;]
> - customer receives a LIHEAP Cash or Crisis payment[.]"

(CAUSE-PA-I-3). When parsed, the UGI response identifies two circumstances where UGI will "assign a 'confirmed low-income' attribute to a customer" when: (1) the customer confirms income eligible status with a Community-Based Organization (CBO) *and* the following criteria are met: the customer enrolls in CAP; the customer receives

LIURP; the customer receives an Operation Share grant; the customer receives a LIHEAP Cash or Crisis payment; *or* (2) the customer does not confirm their income eligible status with a Community-Based Organization (CBO) *and* the following criteria are met: the customer enrolls in CAP; the customer receives LIURP; the customer receives an Operation Share grant; the customer receives a LIHEAP Cash or Crisis payment". In either instance, the list program participation criteria must be met. This process is at odds with Mr. Adamo's testimony.

Moreover, Mr. Adamo's testimony does not comport with UGI's other discovery responses. UGI was asked as follows: "For 2018 to present, disaggregated by month and year, how many UGI Electric customers were/are categorized as a confirmed low-income customer? Please provide this data in a live excel spreadsheet." (CAUSE-PA-I-4). The Company's response, in its entirety, stated:

> The Company began extracting and recording confirmed low-income counts at month end, beginning in October 2022. Monthly data prior to October 2022 is not available. The Confirmed Low-Income indicator is date sensitive. *The date is updated when specific activities occur. Activities include a customer receiving LIHEAP grants, enrolling in CAP, receiving an Operation Share grant, or participating in LIURP*.
>
> However, the company has fiscal year end 'snapshots' that were previously provided in the 2021 Electric Base Rate Case.
>
> Please see Attachment CAUSE-PA-I-4.

(CAUSE-PA-I-4) (emphasis added). Three things are noteworthy about this response. *First*, like the other discovery response upon which I relied in reaching my conclusion (CAUSE-PA-I-3), this response does not provide for a customer to "update" (and continue) their confirmed low-income status in the absence of "*a customer receiving*

LIHEAP grants, enrolling in CAP, receiving an Operation Share grant, or participating in LIURP." That is not, as Mr. Adamo claims, an "inference" from the discovery response. It is a direct quote. *Second*, this discovery response is at odds with Mr. Adamo's testimony. There is no mention, no implication, and no basis upon which to reach an implication, that one of the "specific activities" that will result in a customer's "Confirmed Low-Income indicator" being "updated" will occur based upon the confirmation of such status by any CBO. *Third*, the process outlined in this discovery response, which mirrors the process outlined in the immediately preceding discovery response, is not in compliance with the Joint Settlement (para. 68(d)) of the 2021 base rate proceeding.

Q. PLEASE RESPOND TO MR. ADAMO'S REBUTTAL TESTIMONY REGARDING PARAGRAPH 68(e) OF THE 2021 SETTLEMENT.

A. In paragraph 68(e) of the settlement of the 2021 UGI rate proceeding, UGI agreed in relevant part that it would contact administrators of applicable PA Department of Human Services (DHS) public assistance programs, requesting that they ask DHS applicants enrolling in their public assistance programs to designate whether the DHS applicants want UGI to be informed of their income eligibility for various customer service protections propounded by the Commission. The Settlement went on to state that "Each household who the program administrators identify to UGI as answering in the affirmative *shall be deemed* by UGI as a Confirmed Low-Income customer and/or a customer eligible for winter shutoff protections." (2021 Settlement, para. 68(e)(emphasis added).

In responding to my testimony with respect to paragraph 68(e) of the 2021 settlement agreement, Mr. Adamo cites one phrase from a February 2022 e-mail from Brian Whorl as evidence that it complied with the Settlement. That phrase ("DHS will not provide this information"), however, was not the total response. The Settlement required more than this. The response does not capture *why* DHS said it "will not provide" that information. DHS went on to state "there is no permission collected from these households to perform any data sharing with their utility. This is one of the key parts of the discussions occurring with the [LIHEAP Advisory Committee] subcommittee is that before DHS will share any information, we would have to make appropriate updates to our LIHEAP application to accurately capture the household's specific consent to share any data information with their selected utility." (UGI Exh. DVA-6R).

Three aspects of this exchange evidence the fact that UGI did not comply with the provisions that UGI *agreed to* in its 2021 Settlement. First, the Settlement did not address data sharing for the purposes of enrolling customers in UGI's CAP program. That data sharing, for example, would require the sharing of customer-specific information on household income and household size. Mr. Whorl's response evidenced that UGI did not comply with the agreement in the Settlement. He specifically noted that his response to UGI was in response to UGI's "requests from DHS *in response to UGI's CAP program*." (UGI Exh. DVA-6R). The Settlement provision did not relate to detailed data sharing required for CAP enrollment. The Settlement was limited to the yes/no toggle about whether a customer would qualify as a Confirmed Low-Income customer or be eligible for winter shutoff protections. The fact that the Settlement was not intended to address data sharing sufficient to enroll customers in CAP is evident in the plain language of the Settlement ("Normal income verification requirements maintained by the company shall apply ***thereafter*** [for enrollment/participation in UGI Electric Universal Service programs].") (emphasis added).

Second, in a related fashion, the Settlement did not relate to sharing of detailed personal information needed for CAP enrollment. For CAP program enrollment to be based on DHS data sharing, DHS would need to share personal household information such as income and household size. Whether or not such data sharing is beneficial or appropriate is not the issue here. That issue was not presented by the Settlement. Instead, the Settlement was limited to asking whether DHS would be willing to ask customers for permission to share the *fact* of various programs with UGI. DHS would not even have needed to share *which* program the customer qualified for. Even without the detailed data sharing involving personal information such as income and household size, the mere *fact* of enrollment in any *one* of a number of programs would entitle the customers providing such permission to gain protections such as winter shutoff protections and the return of any cash security deposit. Because of UGI's failure to comply with the clear terms of the Settlement[7], it continues to under-identify its Confirmed Low-Income customer base. Because of UGI's failure to comply with the Settlement, UGI will potentially continue to collect deposits from customers who should not be required to pay deposits. Because of UGI's failure to comply with the Settlement, UGI will potentially continue to fail to extend winter shutoff protections to those who are entitled to them.

[7] Available at https://www.puc.pa.gov/pcdocs/1712144.pdf

Finally, the DHS response ("DHS will not provide this information. . .there is no permission collected from these households") indicates that UGI did not request from DHS what the Settlement provided for. The Settlement provision involved UGI *agreeing to* ask DHS whether it would be willing to ask DHS applicants for permission ("contact administrators of applicable PA DHS public assistance programs, *requesting that they ask DHS applicants enrolling in their public assistance programs to designate whether the DHS applicants want UGI to be informed*. . .")(emphasis added). If UGI had only complied with the Settlement, the response from DHS may well have been different.

My Direct Testimony did not assert that UGI had no conversations with DHS as part of the continuing conversations with DHS to achieve a data sharing agreement through which DHS information could be used to enroll in CAP. My Direct Testimony supported the conclusion that UGI did not comply with the plain language of the Settlement of the 2021 rate case. Mr. Adamo's rebuttal, including the Exhibit which he provides, lends further support to that failure.

Q. HAVE YOU HAD OCCASION TO REVIEW ANY SIMILAR FORM AUTHORIZING THE RELEASE OF SUCH INFORMATION IN PENNSYLVANIA?

A. Yes. Attached to this Surrebuttal Testimony as Appendix 1SR is a copy of Pennsylvania's Form PA-4 used by the Pennsylvania Department of Human Services.[8] Through the use of this form, the client authorizes the disclosure of "any information concerning the age, residence, citizenship, employment, applications for employment,

[8] Authorization for Release of Information (pa.gov)

education and training activities, income, resources and any additional information involving eligibility for public myself. . ." While not directly applicable to the Settlement, the Form PA-4 is certainly precedential for allowing Pennsylvania households to allow the release of the fact of their income eligibility for purposes of qualifying for the consumer protections (e.g., winter shutoff protections, exemption from or refund of cash security deposits) available through the regulations of the Pennsylvania PUC.

Q. PLEASE RESPOND TO MR. ADAMO'S REBUTTAL TESTIMONY ABOUT UGI'S ACCEPTANCE OF SELF-CERTIFICATION FOR PURPOSES OF CONFIRMING THE LOW-INCOME STATUS OF CUSTOMERS.

A. Mr. Adamo argues in his Rebuttal that "UGI Electric's self-certification practices are consistent with UGI Gas' practices." (UGI St. 11-R, at 11). That statement, however, conflicts with how UGI explained its process for confirming low-income status in response to discovery. When specifically asked to "Please identify all categories or identifiers that UGI Electric includes when calculating its "confirmed low income customer" count, UGI's response (CAUSE-PA-1-3 stated in its entirety:

> The Company assigns a "confirmed low income" attribute to a customer when the customer confirms income-eligible status with a Community-Based Organization (CBO) and/or the following criteria are met:
>
> - customer enrolls in CAP[;]
> - customer receives LIURP services and weatherization measures are installed and completed[;]
> - customer receives an Operation Share grant[;]
> - customer receives a LIHEAP Cash or Crisis payment[.]"

(CAUSE-PA-I-3). Moreover, as I note above, when asked "how many UGI Electric customers were/are categorized as a confirmed low-income customer?," the Company's response, in its entirety, stated:

> The Company began extracting and recording confirmed low-income counts at month end, beginning in October 2022. Monthly data prior to October 2022 is not available. The Confirmed Low-Income indicator is date sensitive. *The date is updated when specific activities occur. Activities include a customer receiving LIHEAP grants, enrolling in CAP, receiving an Operation Share grant, or participating in LIURP*.
>
> However, the company has fiscal year end 'snapshots' that were previously provided in the 2021 Electric Base Rate Case.
>
> Please see Attachment CAUSE-PA-I-4.

(CAUSE-PA-I-4) (emphasis added). At no point in either of these responses (i.e., describing how UGI "assigns a low-income attribute to a customer", describing how UGI "updates" the Confirmed Low-Income statute) does UGI reference self-certification.

Mr. Adamo does not directly respond to the terms to which UGI agreed with respect to the Settlement provision regarding self-certification. He states that "UGI Electric's self-certification practices are consistent with UGI Gas's practices." (UGI St. 11-R, at 11). The Settlement provision, however, requires not merely consistency with UGI Gas practices, but rather, in the terms of the Settlement, UGI *will accept self-certification of low income status* for purposes of identifying 'confirmed low-income customers' in the same way that *self-certification is required to be accepted* by the UGI gas affiliates." (emphasis added). That "requirement" is not set forth in the "UGI Gas practices," but rather in the Commission's regulations, which states in relevant part:

> Accounts where the NGDC has obtained information that would reasonably place the customer in a low-income designation. This information may

> include receipt of LIHEAP funds (Low-Income Home Energy Assistance Program), *self-certification by the customer*, income source or information obtained in § 56.97(b) (relating to procedures upon rate-payer or occupant contact prior to termination).

52 Pa. Code § 62.2 ("definitions" of "confirmed low-income residential account"). Whether or not UGI Gas is in compliance with this regulatory provision is not presented in this proceeding. The question presented in this proceeding is whether UGI *Electric* is in compliance with this provision, a compliance which they *agreed to* in 2018.[9] The evidence in this proceeding is that they have not complied with the settlement provision making this requirement applicable to the Company.

Q. PLEASE RESPOND TO MR. ADAMO'S TESTIMONY REGARDING UGI'S PERFORMANCE RELATIVE TO IDENTIFYING ITS LOW-INCOME CUSTOMERS, ENROLLING THEM IN UNIVERSAL SERVICE PROGRAMS, AND IMPROVING THEIR COLLECTION PATTERNS.

A. Mr. Adamo argues that UGI has "performed well" in terms of its CAP participation rate as a percentage of its Confirmed Low-Income customers. (UGI St. 11-R, at 16). He argues that the average CAP participation rate of 63% over the years 2019 through 2023 evidences good performance. What he doesn't acknowledge is that he is implying that the process works the opposite of what it does. UGI does *not* (1) identify Confirmed Low-Income customers; and then (2) enroll those customers in CAP. UGI instead enrolls customers in CAP and then uses that CAP enrollment as confirmation of the low-income status of its

[9] Available at https://www.puc.pa.gov/pcdocs/1573541.pdf

customers. Accordingly, it is not only not surprising that UGI has an average CAP enrollment rate of 63%,of Confirmed Low-Income customers, it is surprising that, given the four ways that UGI confirms low-income status (CAP enrollment, LIHEAP enrollment, LIURP enrollment, hardship fund grant participant), the percentage is not higher than it is.

Q. DOES UGI PERFORM AS "WELL" AS MR. ADAMO CLAIMS IN HIS REBUTTAL TESTIMONY?

A.. No. The Table below compares the CAP enrollment rate presented in Mr. Adamo's Table 1 (UGI St. 11-R, at 16) to UGI's ***projected*** participation rate included in its most recent USECP (CAUSE-PA-I-22, at page 88 of 98). As can be seen, UGI is falling further and further behind its own projections of the number of low-income customers it should be enrolling in CAP. The two year percentages of actual participation to projected participation in 2022 – 2023 (85% and 88%) were noticeably lower than the two year percentages in 2020 (87%) and 2021 (102%). The 2020-2021 two-year average (94% actual of total) was substantially higher than the 2022-2023 two-year average (83%). These declining rates of actual participation (relative to projected participation do not evidence a "well performing" utility.

Actual CAP Participation Compared to Projected CAP Participation			
	Column 1	Column 2	Column 3
Year	Actual Participation*	Projected Participation**	Actual Participation as Percent of Projected Participation***
2020	3,205	3,702	87%
2021	3,236	3,179	102%
2022	2,986	3,664	81%
2023	3,492	4,099	85%
Avg	3,230****	3,661****	88%

*UGI St. 11-R, at 16.
**Attachment CAUSE-PA-I-22, at 88 of 98.
***Column 1 / Column 2
****Average of four years

Moreover, while Mr. Adamo claims that UGI enrolls a high percentage of its Confirmed Low-Income customers he did not to compare UGI's performance on the percentage of estimated low-income customers that are enrolled in CAP to other electric utilities. UGI had an estimated 21,726 low-income customers as identified by the PUC. (CAUSE-PA-I-12). Using UGI's most recent complete year of data (2022) for CAP participation UGI enrolled 2,986 customers in CAP, or only 13.7% (2,986 / 21,726 = 0.137) of its estimated low-income customer population. When compared to Pennsylvania's other electric utilities, UGI's enrollment is the *lowest.*. Thus, not only does it not perform better than other utilities, it is 10% below the statewide average. On a percentage basis, it enrolls less than half the CAP participants that well-performing utilities such as Duquesne and PECO-Electric enroll.

CAP Enrollment as Percentage of Estimated Low-Income Customers

Utility	Estimated LI*	CAP Participation**	Percent CAP of Estimated LI*
Duquesne	121,772	35,229	28.9%
Met-Ed	109,201	21,280	19.5%
PECO-Electric	373,840	121,408	32.5%
Penelec	146,334	28,463	19.5%
Penn Power	34,284	6,281	18.3%
PPL	337,091	64,673	19.2%
West Penn	150,562	24,792	16.5%
State average	1,273,084	302,126	23.7%

*BCS 2021 Annual Report, at 8.
**BCS 2021 Annual Report, at 59.

In sum, not only does UGI fail to perform well with respect to other Pennsylvania utilities in its enrollment of CAP participants, it fails to perform well even when measured against its own publicly stated expectations.

Q. PLEASE RESPOND TO MR. ADAMO'S TESTIMONY REGARDING UGI'S PERFORMANCE ON LIHEAP SINCE 2019.

A. Mr. Adamo claims an increase in LIHEAP receipts is evidence of good universal service performance *by the Company*, but fails to acknowledge that the level of total LIHEAP funding is set by Congressional appropriation. Moreover, in the years of COVID, along with the years of residential harms associated with high inflation, Congressional funding for LIHEAP has been set at levels substantially higher than they were set historically.[10]

Mr. Adamo's attempt to have UGI claim credit for increased LIHEAP funding is simply one more instance where UGI seeks an equity adder for events that were not driven by UGI management.

Q. PLEASE RESPOND TO MR. ADAMO'S REBUTTAL TESTIMONY REGARDING THE UGI ENERGY EFFICIENCY AND CONSERVATION PLAN.

A. Mr. Adamo's Rebuttal Testimony regarding UGI's Energy Efficiency and Conservation (EE&C) Plan describes the investments that UGI makes. His testimony, however, does not rebut the testimony I offered with respect to UGI's failure to offer a program component making investments in low-income weatherization through its EE&C Plan.

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[10] The White stated:

> Pennsylvania has received a record $480.5 million for the Low Income Home Energy Assistance Program (LIHEAP) available this fiscal year (October 2021 to September 2022). As part of a state-by-state breakdown of funding, the Administration reported that in addition to an annual appropriation of $182.8 million for Pennsylvania, the state received an additional $297.7 million in funds from the American Rescue Plan – more than double the state's typical annual funding. The total of $480.5 million is the highest amount Pennsylvania has ever received in LIHEAP to help families struggling with the costs of home heating.

LIHEAP-pennsylvania.pdf (whitehouse.gov) According to a White House announcement, the American Rescue Plan more than doubled LIHEAP funding nationally. It noted that "This is the largest appropriation in a single year since the program was established in 1981." (Id.)

In My Direct Testimony, I noted both that: (1) "the Company's EE&C Plan. . .does not provide services to low-income customers"; and (2) "[t]he Company instead restricts its low-income energy efficiency investments to its LIURP program."

Mr. Adamo argues that UGI's EE&C Plan has a specific low-income section, an assertion that I do not dispute. However, Section 2.1.5 of the UGI Electric EE&C Plan makes clear that the bulk of UGI Electric's efforts toward low-income customers involves an "array of no-cost energy-saving equipment and/or education to help reduce their energy costs" rather than providing "energy efficiency investments." While the Plan states that it offers "additional and/or different measures than those offered through the Company's Low-Income Usage Reduction Program ("LIURP")," the EE&C Plan specifically states that rather than providing energy efficiency investments, the ***only*** "eligible measures" available through the EE&C Plan are Smart Thermostats and Energy Star Heat Pump Water Heaters. Even with those thermostats and heat pump water heaters, UGI Electric proposes to provide only nine (9) of each per year.

In contrast, UGI's most recent Universal Service and Energy Conservation Plan (USECP) states that:

> Energy saving measures for. . . electric space heat customers may include, but are not limited to, the following: insulation, furnace repair/replacement, water heater repair/replacement, furnace efficiency modification, windows and baseboard caulking, door and window weather stripping, door sweeps and thresholds, replacement of broken window panes, storm windows, attic ventilation, electrical outlet and switch plate gaskets on outside walls, water conservation measures, energy education, infiltration measures and incidental repairs (necessary to the effective performance of weatherization materials). Low cost energy saving measures for electric non-heating customers may include but are not limited to refrigerator replacement, high efficiency lighting, window air conditioner replacement and other measures necessary

> to the effective performance of weatherization materials within the job limit costs.

(UGI USECP, at 28). As I correctly testified in my Direct Testimony, and as Mr. Adamo did not dispute, low-income customers who need weatherization services cannot obtain those services through UGI Electric's EE&C plan. The Company does not provide such services to low-income customers through its EE&C Plan.

Q. PLEASE RESPOND TO MR. ADAMO'S REBUTTAL TESTIMONY CRITIQUING YOUR BILL IMPACT ANALYSIS.

A. Mr. Adamo presents a series of criticisms to my bill impact analysis, arguing that my analysis is "incorrect and overstated." (UGI St. 11-R, at 21). For example, he objects to the 2024 data I use because, he asserts, that I unreasonably assume that "the Company's rate case proposal will be approved in its entirety." (Id.). Given that the objective of my analysis was to consider the Company's rates, as proposed, assessing the impacts of the rate (as proposed) was reasonable. Mr. Adamo did not suggest what percentage of the Company's rate case was filed with the Commission that it did not expect to be approved.

Mr. Adamo also argued that UGI's actual rates prior to 2018 were "stagnant" and thus should not be considered. He does not dispute that the rates I used in my analysis were, in fact, actual rates. Given that it is the Company's decision on whether it is earning a fair rate of return given existing rates, the fact that rates were relatively flat prior to 2018 is not material to my analysis.

Mr. Adamo criticizes the fact that I used the Commission's Rate Report to compare rates between time periods and between companies. (Id., at 22). Mr.

Adamo does not acknowledge that the Rate Comparison Reports I used are used not only by the Commission, but also by the Governor and the General Assembly for that very purpose.[11]

He argues that the Commission's Rate Comparison Reports I use are "not representative." (Id., at 22). However, I use the Rate Comparison Reports for precisely the objective that they are prepared. The introduction to the 2021 Report, for example, presents a letter from PUC Chair Gladys Brown Dutrieuille to the Governor, Lieutenant Governor, and members of the General Assembly, stating that "The Report compares all categories of ratepayers for all electric and gas public utilities *so that a reasonably accurate comparison of rates can be made* between similar ratepayers receiving services in different service areas of the Commonwealth." Moreover, each year's report states that "*To achieve an accurate comparison*, the Commission established ratepayer categories and monthly usage parameters."[12] The 2021 Report also stated that "The sections that follow present the rate tables for each utility, *so an accurate comparison between utilities can be made*."[13] Even the "disclaimer" presented by Mr. Adamo notes that the intended use of the Report was precisely the use to which I put them. The Reports state that they are to "facilitate an apples-to-apples comparison of rates and bill amounts *across all utilities for all years*." (UGI St. 11-R, at 22). Mr.

[11] Pennsylvania Public Utility Commission, Rate Comparison Report, prepared by the PUC Bureau of Technical Utility Services (August 25, 2021).

[12] Id., at 4. (emphasis added).

[13] Id., at 5. (emphasis added).

Adamo's argument that the data in the Rate Comparison Reports do not present accurate or meaningful information should be dismissed.

Finally, Mr. Adamo argues that my discussion "does not distinguish the factors contributing to [UGI's] bills." (Id., at 23). He argues that "this proceeding is focused exclusively on the Company's proposed adjustment to base rates." (Id., at 23). Mr. Adamo offers no explanation of why an examination of bill affordability should be limited to a *portion* of the customers' bills. Customers do not pay only a portion of their bill. Nor would customers avoid the disconnection of service if they paid only the distribution portion of their bill. Bill affordability is driven by the total bill, not exclusively by the portion or portions of the bill that are (or are not) "outside the Company's control."

Q. PLEASE RESPOND TO MR. ADAMO'S REBUTTAL TESTIMONY REGARDING YOUR BILL BURDEN ANALYSIS.

A. Mr. Adamo argues that my bill burden analysis is "misleading" because it does not "focus on what CAP provides for the Company's lowest income customers." (UGI St. 11-R, at 24). He argues that the CAP energy burdens for the lowest income customers are set at 2% and 6% of income for households with income less than 50% of Poverty. (Id., at 25). Mr. Adamo's argument, however, incorrectly equates "low-income" and "CAP participants." The affordability analysis I presented applies to UGI's total low-income customer population. I do not narrowly limit it to CAP participants. As I explain in detail above, and do not repeat the detail here, UGI's CAP enrolls only 13.7% of its estimated low-income customer population. Mr. Adamo's Rebuttal Testimony, in other words, ignores the impact of UGI's rates on 86% of the Company's low-income population (nearly 6-of-7 low-income customers).

Mr. Adamo seeks to dismiss potential reasons for non-participation in CAP as lacking "evidentiary support." (UGI St. 11-R, at 26). His argument appears to be:

- The 86% of UGI customers who are income-eligible for CAP, but who do not participate, do not participate only because they *choose* not to participate. (Id., at 26).

- There are no "information failures" that impede, if not completely prevent, some of UGI's low-income customers from enrolling in CAP (or recertifying for CAP when the need arises). All 86% of UGI customers who are income-eligible for CAP, but who do not participate, not only know about the existence of CAP, but know the exact eligibility requirements for CAP, and know how to enroll in CAP. (Id., at 26).

- Not one of the 86% of UGI's low-income customers who are income-eligible for CAP, but who do not participate, cannot negotiate the administrative processes to apply for the program. (Id., at 26). No-one has a disability that impedes their ability to enroll. No-one has a language access problem that impedes their ability to enroll. No-one who because of their age (e.g., either very young or very old) finds the application process daunting.

Mr. Adamo's testimony in this regard is not credible. If his testimony were accurate, there would be no reason for UGI to have (and for the Commission to require) a Customer Education and Outreach Plan (CEOP) as part of the Company's Universal Service and Energy Conservation Plan (USECP). There would be no reason for UGI to provide for customers who fail to timely re-enroll in CAP an opportunity to re-enroll late (since, after all, those who failed to timely recertify did so only because they *chose* not to recertify in a timely fashion). And there would have been no reason for the Commission to have opened the 2023 Review of All Jurisdictional Fixed Utilities' Universal Service Programs (Docket: M-2023-3038944) to facilitate improvements in the programs.

Q. PLEASE RESPOND TO MR. ADAMO'S REBUTTAL TESTIMONY REGARDING THE IMPACT OF AN INCREASED FIXED CUSTOMER CHARGE ON THE ABILITY OF LOW-INCOME CUSTOMERS TO REDUCE THEIR UGI BILLS BY REDUCING THEIR ENERGY CONSUMPTION.

A. Mr. Adamo offers two responses to my testimony regarding the ability of low-income customers to reduce their bills by reducing energy consumption. In offering his Rebuttal Testimony, Mr. Adamo completely ignores my detailed discussion about the efforts through which low-income customers try to reduce their consumption in harmful ways (not involving energy efficiency). First, Mr. Adamo cites the existence of the federal Inflation Reduction Act as reasons why UGI's increased customer charge will not impede the ability of low-income customers to reduce their bills by reducing their consumption. I addressed the fallacy of that argument in my testimony above (e.g., the definition of "low-income" in the federal act is substantially higher than the definition of "low-income" used in Pennsylvania). However, even given the Inflation Reduction Act, the dollars available are minor compared to the dollars that would be needed to treat UGI's low-income customers with energy efficiency investments.

In addition, Mr. Adamo relies on Mr. Taylor's rebuttal testimony as the basis for his argument that by increasing the proportion of a low-income customer's bill that is unavoidable (through a fixed customer charge), UGI will actually lower that low-income customer's bill. I will address that argument in my response to Mr. Taylor.

Q. PLEASE RESPOND TO MR. ADAMO'S REBUTTAL TESTIMONY REGARDING THE REMEDIES YOU PROPOSE TO MITIGATE THE HARMS OF THIS RATE CASE ON LOW-INCOME CUSTOMERS.

A. Mr. Adamo objects to my recommendation that one reasonable response to the harms created and/or exacerbated by UGI in this proceeding can be mitigated by increasing the LIURP budget. He spends considerable time advancing the proposition, which he asserts the Commission has adopted in prior proceedings, that increases in the LIURP budget should occur only in USECP proceedings. (UGI St. 11-R, at 28 – 31). A closer look at those prior PUC decisions, however, reveals that what the Commission found was that it was most appropriate to increase the LIURP budget only in a USECP proceeding *if* the increase was to respond to an unmet need. That unmet need is not the basis for my recommendation in this proceeding. My recommendation is that given: (1) the additional harms imposed on low-income customers by the rate increase *in this proceeding*; (2) the extent to which those additional harms *from this proceeding* impede, if not completely prevent, low-income customers from reducing their bills by reducing their consumption; and (3) the extent to which the Company's proposed increase in its fixed monthly residential customer charge has a disproportionately adverse effect on the ability of low-income customers to reduce their bills by pursuing energy efficiency investments on their own (without external assistance), there is a need for immediate remedial action.

Adopting Mr. Adamo's proposition, that LIURP budgets can only be reassessed once every five years irrespective of what the Company does in the meantime to make those budgets ineffective and insufficient, leaves low-income customers with a harm lacking a remedy. While even if it is appropriate for the Commission to hold that the overall low-income energy efficiency needs should be determined in a USECP proceeding, that policy should not be used to preclude the use of LIURP investments from responding to the harms that UGI, itself, is creating by its very own actions.

Next, Mr. Adamo engages in the same reasoning that I responded to above in discussing the Rebuttal Testimony of I&E witness Keller. Mr. Adamo questions why ratepayers should spend more money on LIURP given that Mr. Adamo asserts that UGI is maximizing its capacity to engage in LIURP investments as it is. (UGI St. 11-R, at 28 – 31). As I note with respect to Mr. Keller's similar argument, this additional spending will not occur, because of the manner in which LIURP is funded, if UGI finds that it both currently lacks the capacity, and is incapable of ramping up its capacity, to provide the LIURP services. LIURP spending is authorized up to a particular budget and is recovered from ratepayers through UGI's universal service surcharge only to the extent that it is actually spent. UGI's Rider C specifically provides that the Company shall, on an annual basis, recover actual revenues received through the Rider with "actual recoverable costs." The Rider then defines those costs as follows: "actual recoverable costs shall reflect. . .*actual* LIURP costs. . ." (UGI Electric Tariff, Rider C) (emphasis added). If UGI does not use the additional budget, those dollars will not be charged to ratepayers.

Mr. Adamo disputes my observation that increased spending on LIURP would not result in a dollar-for-dollar increase in rates to other ratepayers. He disputes that weatherization services delivered to low-income households will result in a corresponding reduction in arrears. (UGI St. 11-R, at 32). As the basis for this dispute, he cites the same long-term study of LIURP which Penn State University undertook for the PUC. He concedes that the PSU study found that "the average energy bill arrearage declines from the pre- to post-period." (Id., at 32). He then bases his opposition on language which he emphasized stating that:

> it is not possible to assess how much of this reduction LIURP is directly responsible for. This is because part of the LIURP process is to recommend to, and enroll eligible households in payment assistance plans whenever possible, and the variables collected as part of LIURP are not specific enough to separate the impact of weatherization measures from the impact of payment assistance on reduced arrearages.

(UGI St. 11-R, at 32). Based on this quote, Mr. Adamo states that he "caution[s] against relying on this study to increase LIURP spending because there are just too many other non-weatherization variables at play." (Id.)

Mr. Adamo's conclusion does not follow from his premise as even the quotation he includes in his Rebuttal Testimony indicates. First, the factors Mr. Adamo cites as "other non-weatherization factors" are not separate and apart from LIURP. As the Penn State study found, the weatherization provided in LIURP does not stand alone. However, the other "non-weatherization factors" are, according to Penn State, "*part of the LIURP process*." Second, the Penn State study did *not* find that the weatherization aspect of LIURP results in *no* impact on arrears. All it said, and this seems self-evident, was that given that LIURP offers a suite of services, it is not possible to "*separate* the impact of weatherization measures" from the total impact of the total suite of services. If UGI were not to pursue any combined services unless the impact of each separate service could be separately identified, one would never weatherize a CAP participant (unless the impacts of CAP and weatherization could be separately identified); would never offer LIHEAP to a LIURP recipient (unless the impacts of LIHEAP and LIURP could be *separately* identified). The Penn State study, in other words, does not support the "caution" that Mr. Adamo urges in his Rebuttal Testimony.

In any event, Mr. Adamo's argument that a reduction in bills would have *no* impact on reducing arrears should not be given weight. Consider the overall circumstances presented by this proceeding. As I discuss above, (1) while 23.3% of UGI's residential customers are in arrears, 52.3% of UGI's low-income customers are in arrears; and (2) while the median arrears of residential customers in arrears is $258, the median arrears of low-income customers in arrears is $513. Under Mr. Adamo's reasoning, UGI would not undertake any response unless the exact impact of that response can be *separately* identified. UGI would certainly not offer those low-income customers having payment difficulty a suite of services encouraging them to apply for LIHEAP, participate in CAP, and agree to have LIURP services installed, unless the impacts of each element of the suite of services could be "separately" identified. That conclusion flies in the face of Pennsylvania's entire universal service framework.

Finally, Mr. Adamo asserts that the Commission should not take into consideration the impact that LIURP has on reducing arrears unless there is "specific, credible, quantifiable evidence on the 'offset' of those costs." (UGI St. 11-R, at 34). This Rebuttal suffers from the flaw that Mr. Adamo does not identify *why* the Commission should not consider the known impacts of LIURP in reducing arrears. I do not propose a specific dollar amount of "offset" to my recommended LIURP spending. My testimony simply noted that Pennsylvania has long accepted that the LIURP program does not exclusively involve costs. Rather, LIURP is an ongoing, long-term investment, in improving affordability and helping low-income participants to reduce their arrears. While a LIURP investment is a one-time cost, that investment returns ongoing benefits year-upon-year. Irrespective of whether the long-term ongoing benefits of weatherization can be separately attributed to the specific separate components of LIURP, there is a positive policy significance to the long-term benefits flowing from the investments made in low-income homes through LIURP.

Q. PLEASE RESPOND TO MR. ADAMO'S REBUTTAL TESTIMONY REGARDING UGI LOW-INCOME CUSTOMER ARREARAGES.

A. Mr. Adamo disagrees with my Direct Testimony that "confirmed low-income customers are consistently in greater payment difficulty" than are residential customers as a whole by asserting that UGI residential customers as a whole have fewer dollars in arrears than do other Pennsylvania electric utilities. Moreover, he asserts that UGI's low-income arrears are "in line with the industry average." (UGI St. 11-R, at 35 – 36). These two observations do not conflict with, let alone rebut, my initial assertion that low-income customers have consistently greater payment problems than do residential customers as a whole. Even Mr. Adamo's testimony concedes that while average UGI residential arrears are $653.31 (Id., at 35), average UGI low-income arrears are $1,092.33 (Id., at 36), nearly 70% higher ($1,092.33 / $653.33 = 1.7). Mr. Adamo does not explain why he uses averages when my Direct Testimony referred to medians. [14]

Similarly, Mr. Adamo disputes my conclusion that median low-income arrears are twice as high as median residential arrears. He bases his disagreement on the observation that

[14] The fact that the average (i.e., mean) arrearage balances (cited by Mr. Adamo) are higher than the median arrearage balances (which I used in my Direct Testimony) indicates that more than half of UGI's accounts in arrears are higher than the average (i.e., the shape of the distribution is skewed to the right).

the average UGI low-income arrears is lower than the industry average. (UGI St. 11-R, at 35). This statement does not conflict with, let alone rebut, my observation that the data UGI, itself, provided indicated that the *median* UGI low-income residential arrears of $513 is two times higher than the median residential arrears of $258.

In sum, my Direct Testimony discussed how UGI's low-income customers were in greater payment difficulty than UGI's residential customers as a whole. The facts remain that, as I document in my Direct Testimony: (1) while 23.3% of UGI's residential customers are in arrears, 52.3% of UGI's low-income customers are in arrears; and (2) while the median arrearage of residential customers in arrears is $258, the median arrearage of low-income customers in arrears is $513. Mr. Adamo's Rebuttal Testimony does not rebut that data. When two times the percentage of low-income customers are in arrears, and when those customers in arrears have a median arrears twice as high as residential customers, the only conclusion that can be drawn is that low-income customers are consistently in greater payment difficulty, just as I testified.

Part 4. Response to UGI Rebuttal Witness John Taylor.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to the Rebuttal Testimony of UGI Witness John Taylor with respect to the impact of UGI's proposed increase to its residential customer charge on low-income customers.

Q. PLEASE SUMMARIZE THE REBUTTAL TESTIMONY OF MR. TAYLOR TO WHICH YOU RESPOND.

A. Mr. Taylor's Rebuttal Testimony asserts that "a common critique of increasing a customer charge is the supposition that an increase in the customer charge disproportionately impacts low-income customers, as they are typically low usage customers." (UGI St. 6-R, at 24). He asserts in "rebuttal" that "this is not a correct characterization of low-income customers who are indeed higher-use customers." (Id.)

Q. WHAT IS YOUR RESPONSE?

A. The first problem with Mr. Taylor's Rebuttal is that he is responding to an argument that I never advanced in my Direct Testimony. In other words, Mr. Taylor put forth a straw-man argument. Mr. Taylor asserts that the argument to which he responds is "one common critique," but does not (and could not) cite to any page or line number in my Direct Testimony where that "common critique" is asserted.

Mr. Taylor then presents an analysis of bills given average consumption for what he refers to as "low-income customers" and for CAP participants. (UGI St. 6-R, at 27). He does not acknowledge that those populations are nearly coterminous because, as I explain earlier in my testimony, the primary way UGI identifies its "low-income" customers is through their enrollment in CAP. Moreover, since a customer will not participate in CAP unless their usage is sufficiently high to have a bill burden which exceeds the PUC's thresholds of affordability, by definition, CAP participant usage will be higher than the average or typical bill. In essence, Mr. Taylor is taking 14% of UGI's highest usage customers and ascribing their average usage to all low-income customers, including the 86% of low-income customers who do not participate in CAP.

When one examines the usage of low-income customers generally, the overwhelming evidence is that low-income customers, typically and disproportionately, have low consumption. This is not to say that *every* low-income customer is a low usage customer. The conclusion that low-income customers are typically, and on average, low use customers, however, is accurate.

The U.S. Department of Energy/Energy Information Administration's (DOE/EIA) Residential Energy Consumption Survey (RECS) has made this unquestionable finding. According to the most recent RECS (2020), there is an unquestionable relationship between income and electricity consumption. As income declines, average electricity consumption declines as well.

Annual Household Electricity Use by Income (Northeast) (2020 RECS Table CE2.2)[15]			
2020 annual household income	**Housing Units (millions)**	**mmBtu**	**kWh**
Less than $5,000	0.66	25.0	7,320
$5,000 to $9,999	0.69	19.8	5,815
$10,000 to $19,999	1.77	20.5	6,002
$20,000 to $39,999	3.36	22.2	6,514
$40,000 to $59,999	3.04	24.1	7,054
$60,000 to $99,999	5.03	27.8	8,145
$100,000 to $149,999	3.29	30.6	8,962
$150,000 or more	4.09	35.5	10,395

Mr. Adamo dismisses the difference in data as "a matter of disagreement between OCA witness Colton and me." (UGI St. 6-R, at 24). It is not, however, simply a "matter of disagreement" between Mr. Adamo and myself. Every federal study that has considered

[15] https://www.eia.gov/consumption/residential/data/2020/c&e/pdf/ce2.2.pdf

the issue, when such a study, contrary to Mr. Adamo's, does not use a high use low-income population as the basis for conclusions, reaches a conclusion contrary to Mr. Adamo's. In addition to the U.S. Department of Energy research discussed above, consider research by the U.S. Department of Labor (DOL), the U.S. Department of Housing and Urban Development (HUD), and the U.S. Department of Health and Human Services (DHHS).

- When DOL examined the issue (using deciles of income rather than dollars of income), it reached the same conclusion as the U.S. Department of Energy did.[16]
- In its most recent LIHEAP Report to Congress, the DHHS found that consumption was as follows:[17] (1) All households (85.0 mmBtu); (2) Non-low-income households (91.0 mmBtu); and (3) Low-income households (73.8 mmBtu)
- In its most recent study of the nation as a whole,[18] as well as for Pennsylvania in particular,[19] HUD found the same relationship between electricity and income as did DOE/EIA, DOL, and DHHS.

[16] https://www.bls.gov/cex/tables/calendar-year/mean-item-share-average-standard-error/cu-income-deciles-before-taxes-2021.pdf

[17] https://www.acf.hhs.gov/sites/default/files/documents/ocs/RPT_LIHEAP_RTC01BodyTTAProjects_FY2017.pdf

[18] American Housing Survey (AHS) - AHS Table Creator (census.gov)

[19] American Housing Survey (AHS) - AHS Table Creator (census.gov)

Table 1. Electricity Costs by Income (electricity paid separately) American Housing Survey (U.S. Department of Housing and Urban Development)				
	United States		Pennsylvania	
	Median (dollars)	Mean (dollars)	Mean (dollars)	Median (dollars)
Less than $10,000	$66.0	$79.7	$66.0	$79.7
$10,000 to $19,999	$66.0	$85.1	$66.0	$85.1
$20,000 to $29,999	$70.0	$79.2	$70.0	$79.2
$30,000 to $39,999	$77.0	$87.6	$77.0	$87.6
$40,000 to $49,999	$84.0	$95.5	$84.0	$95.5
$50,000 to $59,999	$85.0	$95.4	$85.0	$95.4
$60,000 to $79,999	$105.0	$121.1	$105.0	$121.1
$80,000 to $99,999	$91.0	$118.9	$91.0	$118.9
$100,000 to $119,999	$142.0	$157.4	$142.0	$157.4
$120,000 or more	$145.0	$171.8	$145.0	$171.8

The significance of these study results is not merely that there is _*one*_ study that reaches a conclusion contrary to Mr. Adamo's, it is that _*every*_ study that does not rely on a flawed sample of inherently high use customers reaches a conclusion contrary to Mr. Adamo's conclusion.

Q. IS THERE ANY FINAL RESPONSE YOU MAKE TO MR. ADAMO AND TO MR. TAYLOR?

A. Yes. I note that neither Mr. Adamo nor Mr. Taylor respond to, let alone seek to rebut, my Direct Testimony regarding how increasing the unavoidable fixed monthly customer charges will both: (1) make it more difficult for low-income customers to justify energy efficiency investments given their frequent mobility and low levels of discretionary income; and (2) make low-income customers who seek to reduce their bills by reducing their consumption through unsafe and unhealthy strategies less effective.

Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

Appendix SR-1

CAO NAME AND ADDRESS

CASE IDENTIFICATION				
CO	RECORD NUMBER	CAT	CSLD	DIST
RECORD NAME				DATE

AUTHORIZATION FOR RELEASE OF INFORMATION

NAME	SOCIAL SECURITY NUMBER
ADDRESS	ZIP CODE

I hereby authorize and request the disclosure to the county assistance office any information concerning the age, residence, citizenship, employment, applications for employment, education and training activities, income, resources and any additional information involving eligibility for public assistance for myself and/or those individuals on whose behalf public assistance benefits are paid to me. It is understood that the information obtained will be used only for purposes directly related to the eligibility of individuals in the public assistance case.

SIGNATURE | DATE

SIGNATURE OF REPRESENTATIVE APPLYING ON BEHALF OF CLIENT(S) | LEGAL RELATIONSHIP OF REPRESENTATIVE TO CLIENT(S) | DATE

ORIGINAL CASE RECORD FILE

RECORD COPY FORM RETENTION PERIOD: ACTIVE CASE - RETAIN UNTIL NEW FORM IS SIGNED.
CLOSED CASE - RETAIN 4 YEARS FROM MONTH OF CASE CLOSURE

pennsylvania
DEPARTMENT OF HUMAN SERVICES

PA 4 (SG) 10/15

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2022-3037368
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement 4SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: June 7, 2023
*347163

Signature: ______________________
Roger D. Colton

Consultant Address: Fisher, Sheehan, & Colton
34 Warwick Road
Belmont, MA 02478

OCA STATEMENT NO. 5

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2022-3037368
	:	
UGI Utilities, Inc. – Electric Division	:	

DIRECT TESTIMONY
OF
MORGAN N. DEANGELO

ON BEHALF OF
THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

APRIL 25, 2023

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<u>Introduction</u>

Q. Please state your name, business address and occupation.

A. My name is Morgan N. DeAngelo. My business address is 555 Walnut Street, Forum Place, 5th Floor, Harrisburg, Pennsylvania 17101. I am currently employed as a Regulatory Analyst by the Pennsylvania Office of Consumer Advocate (OCA).

Q. Please describe your educational background and qualifications to provide testimony in this case.

A. I have a Master's Degree in Business Administration and a Bachelor of Business Administration Degree, with a concentration in Finance and a minor in Accounting from Wilkes University. My educational background and qualifications are further described in Appendix A.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the OCA.

Q. Have you previously testified before the Pennsylvania Public Utility Commission?

A. Yes. I have provided written testimony in rate cases concerning rate case normalization, cash working capital and operation and maintenance expenses, rate of return, the impact the COVID-19 Pandemic has had on consumers in Pennsylvania, acquisition adjustments, and various provisions to the utility's tariff, as well as petitions for a smaller utility to be acquired by a capable utility concerning adequate and reasonable service, and applications regarding the acquisition of municipal utilities under fair market value, concerning affirmative public benefits.

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to provide my response to the Pennsylvania Public Utility Commission (Commission) regarding UGI Utilities, Inc. – Electric Division's (UGI or the Company) battery storage project and testimonies heard at the public input hearing.

<u>Battery Storage Project</u>

Q. What is the battery storage project?

A. The battery storage project was first proposed in the 2021 Base Rate Case. The project was intended to be a pilot program, which included a 1.25MWh lithium-ion based battery, that would cost approximately $1.5 million.

Q. What was the intended purpose of the battery storage project?

A. The intended purpose of the battery storage project was to increase the reliability of service to the customers served off the Rucker Hill circuit. In his testimony in this case, UGI witness Mr. Sorber indicated "reliability issues (specifically the number of customer outages experienced) on this circuit were exacerbated by an elevated number of outages impacting the circuit for Rucker Hill, which is constructed in a tight corridor that features mountainous terrain with heavy vegetation, railroad tracks, and a river." (UGI Statement No. 4, p. 17-18, ln. 22-24, 1-2).

Q Did the Commission approve the battery storage project?

A. Yes. In the 2021 Base Rate Case, the Commission approved the Joint Petition for Settlement, which indicated "the Settlement reflects a carefully-crafted compromise of the parties' positions and is based on the small size of the battery and the unique circumstances of the Rucker Hill Road distribution circuit, including its voltage, its status as a worst performing circuit, the surrounding terrain, the nearby vegetation, and the load served by this circuit." (R-2021-3023618 Joint Petition for Settlement, p. 9, 50).

Q. In this case, did UGI address the status of the battery storage project pursuant to the 2021 Electric Rate Case at Docket No. R-2021-3023618 settlement?

A. Yes. In this case, in UGI Statement No. 4, Mr. Sorber discussed the status of the battery storage project. He indicated a status report was filed with the Commission on December 30, 2022, and that the Company faced challenges in implementing the battery storage project. (UGI Statement No. 4, p. 17, ln. 12-14). According to Mr. Sorber, "UGI Electric is not continuing to pursue the battery storage project at this time as contemplated in settlement of the 2021 Electric Rate Case." (UGI Statement No. 4, p. 19, ln. 3-4). He also indicated that "none of the options currently on the market were able to provide a cost-effective solution that met the intended design parameters necessary to move forward with project construction at this time." (UGI Statement No. 4, p. 18, ln. 12-14).

Q. Is there an alternative solution the Company will use since the battery storage project is not being pursued?

A. In response to OCA Interrogatories Set VI-1, UGI indicated the Company will continue to monitor the Rucker Hill circuit's performance while searching for cost-effective solutions that will improve long-term reliability to impacted customers. The response also indicated a second round of targeted danger tree removal took place in 2022.

Q. What is happening with the assumed $1.5 million cost of the battery storage project?

A. According to Mr. Sorber, "the Company redirected approximately $1.5 million of battery storage funding to other reliability projects." (UGI Statement No. 4, p.19, ln.8-9).

Q. On page 18 of his testimony, Mr. Sorber stated that UGI is continuing to explore a possible three-phase battery storage solution. If the funding is being redirected, how would it fund this?

A. In response to interrogatories set OCA-X-3, Mr. Sorber indicated "UGI Electric did not propose continued exploration of a three-phase battery storage solution. To the extent a commercially available battery becomes available to address the reliability challenges on Rucker Hill Road, UGI Electric would utilize funds budgeted for major system improvement projects to fund the program."

Q. Do you agree?

A. No. It is important that UGI continue to explore possible options in enhancing the Rucker Hill circuit reliability. However, by redirecting the budgeted $1.5 million, there would be no budget left for a similar project.

Q. Why is the battery storage project important?

A. There are approximately 67 customers that the battery storage project was intended to support due to the reliability issues on the circuit for Rucker Hill. Utilities are responsible for providing and maintaining adequate, efficient, safe, and reasonable service. When customers are experiencing repeated outages, the service becomes unreliable. I recommend the Company prioritizes its efforts in searching for a solution. I also recommend the Company be required to provide a status report at the end of the FPFTY including any information or developments it has made towards the battery storage project. Moreover, in the Company's Rebuttal testimony in this case there should be an explanation of where the $1.5 million for the battery project has been reallocated to as those dollars were earmarked in the 2021 rate case settlement to provide a reliability solution to the customers on the Rucker Hill circuit.

<u>Public Input Hearing Testimony</u>

Q. Were there any witnesses that expressed concern regarding the impacts of this rate increase?

A. Yes. Six witnesses testified at the public input hearings on April 11th to express concerns about the base rate case and rate impacts they will face. Many testified the increase will be a burden to themselves and the community, putting a strain on finances. Others identified they are middle income communities and the programs UGI offers are ineffective and inefficient, indicating they don't qualify for any assistance.

Witness Lisa Delaney testified she "went from full time to working two part time jobs and a third part time job just to make ends meet". She also indicated "we are well above where we can get any assistance from anybody." (4/11/23, 1pm, Public Input Hearing, Tr. 75).

Witness Bridget Gimbi testified she has "a condition which my body does not regulate my temperature. I need heat and air conditioning to survive". She also indicated she's "enrolled in what I can be enrolled in, and it's basically just a budget program", while also expressing that she has exhausted other resources. (4/11/23, 6pm, Public Input Hearing, Tr. 115-117).

Witness Melissa Pugh testified “I do oppose UGI’s rate increase because they aren’t doing anything beneficial for myself or the community with that proposed increase. We’re not going to receive better, superior, or different service. It’s all just going to remain the same.” Ms. Pugh indicated she currently rents her residence and “these rate hikes not only make saving for a home difficult, but looking to purchase one with UGI wanting to increase their rates would be even harder on my family’s budget.” She also stated that “the increase will be a financial burden for us and the entire community.” (4/11/23, 6pm, Public Input Hearing, Tr. 120-121).

Q. What can you conclude from the witnesses that testified in the Public Input Hearing?

A. In summary, it is clear that many of UGI’s customers are struggling to pay the already-high rates. As shown in the recent Rate Comparison Report issued by the Commission, UGI has the highest average monthly usage at 1,000 kWh and second highest average monthly bill at $190.43. Furthermore, when comparing similar monthly bill usage of 500 and 2,000 kWh between the utilities, the Report shows UGI is in the top 1/3.[1] Increasing rates at this time will only set these customers and communities further back, causing more of a struggle. The Commonwealth, and more specifically the cities and townships throughout UGI’s service territory in Luzerne and Wyoming counties have been faced with the lingering effects of the struggles of unemployment and financial burdens throughout the last three years due to the COVID-19 Pandemic. The most recent PA

[1] https://www.puc.pa.gov/media/2364/23_rate-comparison-report_final.pdf

County Work Stats Reports issued in April 2023 show that both Luzerne Country (5.3%) and Wyoming County (4.6%) have unemployment rates higher than Pennsylvania's overall unemployment rate (4.4%).[2] At this point, a rate increase at the magnitude proposed by UGI will only serve to deepen the financial struggles faced by UGI's customers, as discussed in OCA witness Colton's Direct Testimony, Statement No. 4, on pages 7-30.

Conclusion

Q. Please summarize your recommendations.

A. I recommend the following:

- The Company prioritizes its efforts in searching for a reliability solution for the Rucker Hill customers.
- The Company be required to provide a status report at the end of the FPFTY including any information or developments it has made toward the battery storage project.
- In its Rebuttal testimony in this case, the Company should be required to provide an explanation of where the $1.5 million for the battery project has been reallocated to.

The Commission should consider the specific facts described in my testimony and those of the other OCA witnesses when reaching its decision on a rate increase. It is important to recognize the interests of consumers and the continuing financial struggles they face, as evidenced by the Public Input Hearing testimonies.

[2] https://www.workstats.dli.pa.gov/Documents/County%20Profiles/Luzerne%20County.pdf, https://www.workstats.dli.pa.gov/Documents/County%20Profiles/Wyoming%20County.pdf

Q. Does that conclude your Direct Testimony?

A. Yes, it does. However, I reserve the right to modify or supplement my testimony if necessary.

Appendix A

QUALIFICATIONS OF

MORGAN N. DEANGELO

Education:

2020 M.B.A., Wilkes University

2018 B.B.A. concentration in Finance, minor in Accounting, Wilkes University

Positions:

June 2020 – Present	Regulatory Analyst, Pennsylvania Office of Consumer Advocate
2018 – 2020	Graduate Assistant, Office of Student Development, Wilkes University

Experience:

I am currently employed by the Pennsylvania Office of Attorney General, Office of Consumer Advocate (OCA) as a Regulatory Analyst. In this position, my responsibilities include reviewing utility company filings with the Pennsylvania Public Utility Commission (Commission) and analyzing the financial, economic, rate of return, and policy issues that are relevant to the filings. Additionally, I am tasked with preparing recommendations for the OCA's involvement in utility filings with the PA PUC, writing testimony and presenting oral testimony on behalf of the OCA.

Relevant Training:

IPU Regulatory Studies - Intermediate Course, August 2020
IPU Accounting and Ratemaking Course, February 2021

Previous Cases where testimony was submitted:

- Petition of Twin Lakes Utilities, Inc., P-2020-3020914
- Application of Pennsylvania American Water Company, A-2020-3019634
- PaPUC v. UGI Utilities, Inc. – Electric Division, R-2021-3023618
- PaPUC v. Pittsburgh Water and Sewer Authority, R-2021-3024773, R-2021,3024774, R-2021-3024779
- PaPUC v. Aqua Pennsylvania, Inc., Aqua Pennsylvania Wastewater, Inc., R-2021-3027285, R-2021-3027186
- PaPUC v. City of Lancaster – Water Department, R-2021-3026682
- Application of Aqua Pennsylvania Wastewater, Inc., A-2021-3027268
- PaPUC v. Borough of Ambler – Water, R-2022-3031704
- PaPUC v. Citizens' Electric Company of Lewisburg, PA, R-2022-3032369, C-2022-3032529
- PaPUC v. Valley Energy, R-2022-3032300, C-2022-3032533
- PaPUC v. Pennsylvania American Water Company, R-2022-3031672, C-2022-3032485, R-2022-3031673, C-2022-3032487
- PaPUC v. The York Water Company, R-2022-3031340, C-2022-3032868, C-2022-3032902, R-2022-3032806, C-2022-3032869, C-2022-3033016
- Application of Aqua Pennsylvania, Inc., A-2022-3034143

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2022-3037368
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Morgan N. DeAngelo, hereby state that the facts set forth in my Direct Testimony, OCA Statement 5, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 25, 2023
*344778

Signature: Morgan N. DeAngelo
Morgan N. DeAngelo

Consultant Address: Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923

OCA St. 5SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2022-3037368
	:	
UGI Utilities, Inc. – Electric Division	:	

SURREBUTTAL TESTIMONY
OF
MORGAN N. DEANGELO

ON BEHALF OF
THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JUNE 7, 2023

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Introduction

Q. Please state your name, business address and occupation.

A. My name is Ms. Morgan N. DeAngelo. My business address is 555 Walnut Street, Forum Place, 5th Floor, Harrisburg, Pennsylvania 17101. I am currently employed as a Regulatory Analyst by the Pennsylvania Office of Consumer Advocate (OCA).

Q. Have you previously provided testimony in this case?

A. Yes. I provided direct testimony in this case on April 25, 2023, in OCA Statement No. 5.

Q. What is the purpose of your surrebuttal testimony?

A. In my surrebuttal testimony, I will comment on the rebuttal testimony submitted by UGI Utilities, Inc. – Electric Division (UGI or the Company) witness Eric W. Sorber, Statement No. 4-R, which responds to issues discussed in my direct testimony.

Q. Did any of the rebuttal testimony you reviewed cause you to change your positions and recommendations as stated in your direct testimony?

A. Generally, no. In addition, to the extent I do not address a particular statement or position raised in the rebuttal testimonies filed in this case, it does not constitute my agreement with the same.

Response to UGI Rebuttal Testimony

Q. Please address UGI's response to your first recommendation.

A. The first recommendation I made in my direct testimony was that the Company prioritize its efforts in searching for a reliability solution for the Ruckle Hill Road customers. Mr. Sorber responded to my recommendation on pages 13-15 of his rebuttal testimony. He indicated "UGI Electric has continued to monitor the operational reliability of Ruckle

Hill Road and explore alternative solutions for the reliability challenges identified" (UGI Statement No. 4-R, p. 13-14, 23-24, 1). Mr. Sorber also stated, "In the interim, the Company has already undertaken additional targeted vegetation work that is expected to provide short-term relief and the Ruckle Hill Road customers have benefitted in part from the installation of a redundant primary distribution circuit across the Susquehanna River which provides a second source of supply to that segment of UGI Electric distribution system" (UGI Statement No. 4-R, p. 14, ln. 1-5).

Q. Does Mr. Sorber indicate if the Company is searching for a long-term solution?

A. Yes. Mr. Sorber stated "the Company is working to develop a long-term approach toward addressing reliability for this location. In order to address Mr. [sic] DeAngelo's concern related to reporting on solutions, the Company is willing to report on identified long-term approaches as part of its November 2024 Annual Asset Optimization Plan." (UGI Statement No. 4-R, p. 14, ln. 5-9)

Q. Do you have a response?

A. Yes. As stated in my direct testimony, utilities are responsible for providing and maintaining adequate, efficient, safe, and reasonable service. I appreciate that UGI is continuing to search for a long-term solution. However, there are approximately 67 customers that are still facing potential reliability issues on the circuit for Ruckle Hill Road. It has been nearly two years since the Settlement of the 2021 Base Rate Case where the battery storage project was approved. The reliability issues should have been addressed. However, they apparently continue to persist, and a long-term solution still hasn't been developed. Searching for a reliable solution is not the same as actively providing a reliable solution. The Company has an obligation under 1501 to provide safe, adequate and reliable service. I continue to recommend the Company prioritize its efforts in searching for a reliability solution for the Ruckle Hill customers. This is not a new and recent issue. I am additionally recommending the Company develops a plan identifying how it will proceed with its search process to keep it accountable in finding a long-term solution.

Q. Please address UGI's response to your second recommendation.

A. The second recommendation I made in my direct testimony was that the Company be required to provide a status report at the end of the FPFTY including any information or developments it has made toward the battery storage project. In his rebuttal testimony, Mr. Sorber indicated "the Company is willing to report on identified long-term approaches as part of its November 2024 Annual Asset Optimization Plan ("AAOP") filing (i.e., the first AAOP filing after the end of the FPFTY)" (UGI Statement No. 4-R, p. 14, ln. 7-9).

Q. Do you have anything additional to add?

A. I appreciate the Company is willing to provide a report on its long-term approaches in its November 2024 AAOP. Additionally, I recommend that every six months, the Company reports the status of its long-term approaches on a separate basis from the AAOP, to the Commission and all stakeholders in this docket. Specifically, reaching a solution to resolve the reliability issue is crucial. The Company should identify and discuss in detail the status of the project in its submission. Specifically, the Company should provide details as to the current state of reliability on the Ruckle Hill circuit considering the current vegetation management practices and also the additional primary distribution circuit. The status report should also identify whether a long-term solution has been developed and what the components of that plan are.

Q. Please address UGI's response to your third recommendation?

A. The third recommendation I made in my direct testimony was that in its rebuttal testimony in this case, the Company should be required to provide an explanation of where the $1.5 million for the battery storage project has been reallocated to. Mr. Sorber stated, "The $1.5 million planned for the battery storage project was absorbed into the Company's Distribution Replacement and Betterment budget and allocated to other capital projects focused on reliability and end of life replacements" (UGI Statement No. 4-R, p. 14, ln. 15-17). He also indicated should the Company identify an alternative solution to improve reliability on the Ruckle Hill circuit, "UGI Electric would treat a reliability solution for Ruckle Hill Road in a manner similar to other planned large scale reliability projects and build it into its budget planning process" (UGI Statement No. 4-R, p. 15, ln. 4-5).

Q. Do you have a response?

A. Yes. The approximate $1.5 million cost of the intended battery storage pilot program funding that was approved by the Commission in the 2021 Base Rate Case was meant specifically for the battery storage project to address the reliability problems for Ruckle Hill Road. The budget was not meant to be allocated elsewhere. Therefore, I recommend the Company be required to reallocate $1.5 million for a reliability solution specifically for Ruckle Hill Road and keep these funds separate from any other budget, as they should be used toward the battery storage project or an alternative solution to resolve the reliability issues. UGI has already collected these funds from ratepayers and they should not be required to pay for them again.

<u>Conclusion</u>

Q. Please summarize your conclusion regarding this proceeding.

A. As stated in my direct testimony, the Commission should consider the specific facts described in my testimony and those of the other OCA witnesses when reaching its decision on a rate increase. I encourage the Company to take action and recognize the interests of consumers and the impacts that are being faced.

Q Please summarize your recommendations including any changes you made in this surrebuttal.

A. My recommendations are as follows:

- The Company prioritizes its efforts in searching for a reliability solution for the Ruckle Hill customers.
- The Company develops a plan identifying how it will proceed in its search process, to keep it accountable in finding a long-term solution.
- The Company provides a thorough update in its 2024 AAOP as to the status of any plans/solutions for the Ruckle Hill reliability concerns.
- Every six months, the Company reports the status of its long-term approaches on a separate basis from the AAOP, as detailed herein.
- The Company should keep the $1.5 million budget for the battery storage project or alternative solution separate from any other budget as these funds were dedicated for a particular purpose.

Q. Does this conclude your surrebuttal testimony?

A. Yes. However, I reserve the right to modify my testimony if necessary.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2022-3037368
	:	
UGI Utilities, Inc. – Electric Division	:	

<u>VERIFICATION</u>

I, Morgan N. DeAngelo, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 5SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: June 7, 2023
*347166

Signature: Morgan N. DeAngelo
Morgan N. DeAngelo

Consultant Address: Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923

OSBA Hearing Exhibit 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2022-3037368**
UGI UTILITIES, INC. – ELECTRIC DIVISION	:	

<u>LIST OF EVIDENCE TO BE ADMITTED INTO THE EVIDENTIARY RECORD BY THE OFFICE OF SMALL BUSINESS ADVOCATE</u>

The Office of Small Business Advocate ("OSBA") intends to admit the following evidence into the evidentiary record in the above-captioned proceeding at the evidentiary hearings currently scheduled for June 13th & 14, 2023:

- <u>DIRECT TESTIMONY</u>: OSBA Statement No. 1 and Exhibits RDK-1 through RDK-4 : Direct Testimony of Robert D. Knecht, which contains 10 pages of testimony, Exhibit RDK-1 through RDK-4 and Mr. Knecht's signed Verification.

- <u>REBUTTAL TESTIMONY</u>: OSBA Statement No. 1-R and Exhibit RDK-1R: Rebuttal Testimony of Robert D. Knecht, which contains 7 pages of testimony, Exhibit RDK-1R and Mr. Knecht's signed Verification.

- <u>SURREBUTTAL TESTIMONY</u>: OSBA Statement No. 1-S: Surrebuttal Testimony of Robert D. Knecht, which contains 3 pages of testimony and Mr. Knecht's signed Verification.

The evidence listed is enclosed herein and included as part of **OSBA HEARING EXHIBIT 1.**

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Pennsylvania Office of Small Business Advocate
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(717) 783-2525
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sgray@pa.gov

Dated: June 8, 2023

COMMONWEALTH OF PENNSYLVANIA

April 25, 2023

The Honorable Christopher P. Pell
The Honorable Charece Z. Collins
Administrative Law Judge
Pennsylvania Public Utility Commission
801 Market Street, Suite 4063
Philadelphia, PA 19107

Re: Pennsylvania Public Utility Commission v. UGI Utilities, Inc. – Electric Division
Docket No. R-2022-3037368

Dear Judge Pell & Judge Collins:

Enclosed please find the Direct Testimony and Exhibits of Robert D. Knecht, labeled OSBA Statement No. 1, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

Enclosures
cc: PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Robert D. Knecht
Parties of Record

Office of Small Business Advocate
Forum Place 555 Walnut Street, 1st Floor | Harrisburg, PA 17101 717.783.2525 | Fax 717.783.2831 | www.osba.pa.gov

OSBA Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2022-3037368**
UGI UTILITIES, INC. – ELECTRIC DIVISION	:	

Direct Testimony and Exhibits of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation
Rate Design

Date Served: April 25, 2023

Date Submitted for the Record: ____________________________

DIRECT TESTIMONY OF ROBERT D. KNECHT

1. Witness Identification and Summary of Conclusions

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I am an independent consultant specializing in the economics and regulation of public utilities. For many years, I was a Principal of Industrial Economics, Incorporated ("IEc"), a consulting firm located at 2067 Massachusetts Avenue, Cambridge, MA 02140.

My consulting practice consists primarily of the preparation of analysis and expert testimony in the field of regulatory economics on a variety of topics. I obtained a B.S. degree in Economics from the Massachusetts Institute of Technology in 1978, and a M.S. degree in Management from the Sloan School of Management at M.I.T. in 1982, with concentrations in applied economics and finance.

I am appearing in this proceeding on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA"), pursuant to a contractual agreement between OSBA and IEc. My résumé and a listing of the expert testimony that I have filed in utility regulatory proceedings during the past five years are attached in Exhibit RDK-1.

I presented testimony on behalf of the OSBA in the last three base rates proceedings involving UGI Utilities Inc. – Electric Division ("UGI Electric" or "the Company") in 1996 at Docket No. R-00953534, in 2018 at Docket No. R-2017-2640058, and in 2021 at Docket No. R-2021-3023618.

Q. Please describe your assignment in this matter.

A. The OSBA requested that I review the Company's filing and interrogatory responses, to evaluate whether the rates proposed for small business customers are consistent with sound economics, regulatory principles and applicable Commission precedent from the Company's 2018 and 2021 base rates proceedings. My evaluation is generally limited to issues of cost allocation, revenue allocation, rate design for small and medium business customers.

Q. How is the balance of your testimony organized?

A. This testimony is organized as follows:

- Section 2 provides a brief overview of the rate classes under which small businesses take service.
- Section 3 presents my evaluation of the Company's Allocated Class Cost of Service Study ("ACOSS").
- Section 4 reviews the Company's proposed allocation of the rate increase among rate classes ("revenue allocation").
- Section 5 reviews the Company's proposed rate design for the rate classes under which small businesses take service (GS-1 and GS-4).

2. <u>General Service Rate Classes</u>

Q. Please describe the general service tariff categories at UGI Electric.

A. The two primary categories for service to small and medium business customers are Rates GS-1 and GS-4.

Rate GS-1 comprises the smallest non-residential customers, with a maximum billing demand of only 5 kW. The average customer consumes about 506 kWh per month, only a little more than half that of the average residential customer. A summary of GS-1 customers by 2-digit SIC code is shown in Exhibit RDK-4, copied from my direct testimony in the Company's 2018 rate case.[1] As shown, there is a wide array of entities served under Schedule GS-1. By count, the most common industry classifications are auto repair and parking (mostly parking), small warehouses, real estate services (which probably implies that the premises are leased to different types of businesses), broadcasting equipment and other communications (which are probably not separate businesses), and religious organizations. By load, the most common industries are religious organizations, real estate services, auto repair and parking, and small warehouses. It is thus likely that a

[1] The data shown in Exhibit RDK-4 must be viewed with a certain amount of caution, as it is unknown when the SIC code information was last verified.

significant number of GS-1 customers are not small businesses. The GS-1 tariff for distribution services consists of a monthly customer charge and a flat energy charge. The vast majority of Rate GS-1 load takes utility default service electric supply (93 percent of load).

Rate GS-4 service applies to customers with at least 5 kW in billing demand, generally up to the 100-kW minimum for Rate LP large power service. Service is generally 3-phase, although single phase service is provided to certain customers. A summary of GS-4 customers by 2-digit SIC code is also shown in Exhibit RDK-4. Like GS-1, there is a wide array of businesses served under Schedule GS-4. By count, the most common industries are real estate services (leasing to other businesses), restaurants and other eating places, miscellaneous retail, auto dealers/gas stations and health services. By load, the most common industries are restaurants (and other eating places), real estate services, food stores and miscellaneous retail. The GS-4 tariff for distribution services consists of a two-block demand charge (sharply declining), and a three-load-factor-block "Wright" energy tariff.[2] A significant share of GS-4 service load takes default service, although approximately 27 percent of the load is purchased from competitive electric generation suppliers ("EGSs").

In addition to the two major general service rate categories, the current UGI Electric tariff also includes the following tariff schedules that serve general service and/or business customers:

- Rate GS-5: Volunteer fire departments, non-profit senior centers, rescue squad and ambulance service, which are served at Residential rates. For cost and revenue allocation purposes, these customers are included in Rate GS-1.

- Rate FCP: A "flood control service," applicable only to seven municipalities for flood pumping stations, for emergency pumping operations. In this proceeding,

[2] A "Wright tariff" is one in which the energy charges are charged based on customer load factor, with the marginal energy rates declining as customer load factor increases.

pursuant to the settlement in the last base rates case, Rate FCP is treated as a separate class for cost allocation.

- Rate LP: Large power service, for customers with billing demand over 100 kW.

- Rate HTP: High tension power, for customers who take service at a voltage of 66 kV and minimum billing demand of 2,000 kW. The Company has no customers on this tariff.

3. <u>Cost Allocation</u>

Q. What is the purpose of a utility's allocated cost of service study ("ACOSS")?

A. The most important criterion for setting regulated utility rates is the cost incurred by the utility for providing the service.[3] To assign costs to specific customers, utilities aggregate customers into rate classes, within which the customers generally have similar load sizes, seasonal consumption, peak demand patterns, and other characteristics. An ACOSS is an analytical tool with which the utility's total cost (or "revenue requirement") is allocated among each of the rate classes. These allocated costs are then used as a key input in determining the total revenues that the utility plans to recover from each rate class through tariff rates.

In using the results from an ACOSS to develop class revenue requirements, utilities and regulatory authorities usually have a longer-term goal of moving the revenue recovered from each class as close as possible to the costs allocated to that class. Thus, rate classes whose revenues substantially exceed allocated costs are assigned either relatively low rate increases or rate decreases. Rate classes whose revenues are well below allocated costs are assigned relatively larger rate increases than those classes whose revenues are only slightly below allocated costs.

In addition to class revenue requirement issues, an ACOSS can provide useful cost information regarding the specific nature of utility tariff charges. In particular, an ACOSS

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[3] The Commonwealth Court affirmed this basic principle, referring to cost of service as the "polestar" criterion. <u>Lloyd v. Pennsylvania Public Utility Commission</u>, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006).

provides a cost basis for the relative magnitude of the various individual tariff charges, including the customer charge, demand charges and energy charges.

Q. How does an ACOSS assign costs to the various rate classes?

A. The underlying principle of an ACOSS is that costs are assigned to the rate classes that *cause* the utility to incur those costs. This principle of cost causation is both equitable and economically efficient. It is equitable because costs are borne by those customers who cause them. It is economically efficient because the price signal for consumption from a particular rate class is reasonably consistent with the cost incurred by the utility to provide the service. In that way, the consumer receives the correct price signal for determining whether he should purchase more or less of the utility service. In effect, the consumer balances the value that he receives from the purchase of that service against the utility's cost of providing the service.

Q. What is the Company's approach to cost allocation in this proceeding?

A. The Company's cost allocation methodology and the associated ACOSS are presented by Mr. John D. Taylor of Atrium Economics in UGI Electric Statement No. 6. The ACOSS model was submitted as Exhibit D, for the fully projected future test year ("FPFTY") ending September 30, 2024. A working electronic version of the model was subsequently provided in response to OSBA-I-1, and an updated version correcting for errors identified during the discovery process was provided in Attachment OSBA-II-1.2. I have relied on this last version as the Company's filed position for this proceeding.

Mr. Taylor also prepared the ACOSS for the Company in the 2018 and 2021 base rates cases, and he generally indicates that the methodology is similar in the current case, updated for new data.[4] The Company's cost allocation methodology was generally approved by the Commission in the 2018 rate case, citing to its consistency with

[4] OSBA-I-5.

Commission precedent and the dictates of the NARUC Electric Utility Cost Allocation Manual ("NARUC "Manual").[5,6]

Q. What are the key issues for an electric distribution company ("EDC") ACOSS?

A. The most contentious issue for EDC cost allocation is generally the "classification" of joint-use distribution plant, namely substations, poles, conductors and line transformers. Because individual components of this plant serve customers across multiple classes, it is not possible to directly assign plant costs to customer classes, and therefore an arithmetic allocation method is necessary. Because the distribution system must (a) be sized to meet geographically-specific peak system demands, and (b) must be extended to serve all customers, the cost for this plant is often segregated into sub-components that are causally related to peak demand and customer count.[7] This "classification" process is generally undertaken using "minimum system" or "zero-intercept" methodologies. In a minimum system approach, the "customer component" of costs is based on the cost of installing a system using the lowest capacity components currently in use, and the demand component reflects the cost of scaling that system up to meet the system capacity requirements. The "zero-intercept" approach adopts the same concept, except that the customer component is the cost of a zero-capacity system, derived mathematically from the statistical relationship between asset cost and its associated load-carrying capacity. In both this proceeding and the previous UGI Electric case, Mr. Taylor applies the minimum system methodology to both secondary and primary voltage systems.

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[5] Opinion and Order, Pennsylvania Public Utility Commission, Docket No. R-2017-2640058 at 160.

[6] "Electric Utility Cost Allocation Manual," National Association of Regulatory Utility Commissioners, January 1992.

[7] Some regulators and analysts conclude that there is no causal relationship between electric distribution system costs and customer count, and implicitly deem that there are no scale economies in the distribution system for serving larger customers relative to smaller customers. In addition, some analysts conclude that a portion of distribution system assets are causally related to energy use. The Commission has generally rejected these arguments.

In addition to the classification of distribution plant, the major cost allocation issues involve the allocation of meters and service drop costs, and the choice of demand allocators.

For meters and service line costs, EDCs may not have detailed accounting information of actual costs incurred by rate class, and thus estimates or proxy values (such as replacement cost) are used in place of direct assignment of costs. Because plant costs for meters and services are significant, alternative methods can have a material impact on cost allocation results.

For allocating demand-related cost, utility cost allocation experts use a variety of measures of peak demand. These measures vary primarily in how much load "diversity" is reflected in the allocator. The choice of demand allocator should depend on the asset's location within the distribution system and the nature of the load served by that asset. Moreover, because many EDCs do not have interval-metering in place for most of their customers, it is not possible to directly measure individual and class peak demands. Peak demands for customer classes are therefore often derived using sampled load research data, scaled up to the customer class level. In this proceeding, UGI Electric has opted to use a class non-coincident peak ("NCP") demand value derived from load research values for the past year. As I explain further below, the Company proposes to retain the single NCP approach that it adopted in its rebuttal testimony in the last proceeding.[8]

Q. Have you developed your own version of an ACOSS?

A. Yes. I began by developing an electronic spreadsheet ACOSS model that replicates the Company's results from the attachment to OSBA-II-1. This electronic model is attached as RDK WP1. I then modified that model to reflect two alternative simulations of this model reflecting the discussion in this testimony. These are attached as RDK WP2 and RDK WP3.

Q. Have you reviewed the Company's functionalization and classification calculations for distribution plant?

[8] OSBA-I-5.

A. I have. Because the Company's accounting system does not explicitly record assets into primary and secondary system sub-functions, the Company undertakes that analysis generally based on the type of equipment installed. The Company then develops a minimum system classification analysis for both the primary and secondary plant assets. The Company's calculations were provided in response to OSBA-II-18.

In the Company's last base rates case, I recommended that the Company make a number of changes to its sub-functionalization and classification calculations. In its rebuttal testimony in that proceeding, the Company generally adopted my recommendations. I have reviewed the Company's calculations in this proceeding, and I conclude that the changes are reasonably consistent with my recommendations in the prior case.

Q. Please describe the issues involved in the development of the peak demand allocation factor for the demand-related component of distribution costs.

A. Each component of the distribution system must be sized to meet the combined peak load for all of the customers served by that equipment. As such, the relevant peak demand measure varies considerably depending on the type of equipment and the nature of customers served. For example, distribution substations often serve a wide variety of customers in different rate classes. For that type of equipment, a peak demand measure that reflects the benefits of diversity across rate classes, such as a "coincident peak" ("CP") demand metric, is more appropriate. However, for substations that serve only a few large commercial and industrial locations, the appropriate demand metric is the peak demands for those customers. For equipment that is located closer to customers, such as line transformers, the equipment must be sized to meet the individual peaks of the (usually small number of) customers served by the equipment. For this equipment, a "sum of individual customer peaks" metric is most consistent with cost causation. For the in-between assets, the appropriate peak demand should reflect some benefits of the diversity of downstream load, but not as much diversity as a systemwide CP allocator. A common approach is to use class "non-coincident peak" ("NCP") demand, which represents the diversified peak demand within each rate class, but which excludes inter-class load diversity effects.[9]

Q. Please address the Company's calculations for the development of the peak demand allocation factor that applies to demand-related distribution plant costs.

A. The Company's description of its methodology is provided in OSBA-II-18, and the associated spreadsheet for that response shows some of the calculations used to derive the NCP allocators. Like many utilities, the Company relies entirely on NCP demand for allocating demand-related costs for all types of distribution equipment ranging from substations to line transformers, despite the cost causation differences within the distribution system. NCP demands are derived on both a primary system and secondary system basis. For customers served at primary voltage, the secondary system peak demand is zero.

In the Company's original filing in its last base rates case, it used its load research data to derive NCP allocators for each rate sub-class for each month of the year, and then averaged the 12 observations. In that proceeding, I explained why this "12 NCP" approach was not consistent with distribution cost causation, and recommended use of a single NCP approach. The Company adopted that recommendation in its rebuttal testimony, and it retains that approach in this proceeding.

Q. Why have you prepared two alternative ACOSS simulations in this proceeding?

A. In the Company's last two proceedings, I accepted the Company's approach to use the minimum system method for distribution cost classification, for both primary and secondary voltage systems. My primary reason for doing so was practical, namely that the Commission had accepted this approach in litigated proceedings involving both PPL Electric and UGI Electric.

For this proceeding, however, I am advised by counsel that the Commission has made it clear that it is willing to reconsider precedent in each successive rate case for any particular

[9] This review is presented in more detail in the NARUC Manual at 96-98.

utility, and that parties are free to rely on ACOSS methodologies that are not consistent with established precedent. Specifically, the Commission decided, as follows:

> We note that even in cases in which the revenue allocation methodology is litigated, a determination regarding which ACCOSS should be used should be determined on a case-by-case basis. We have observed that 'the inherent distinctions between utilities and rate cases may result in different methodologies to be reasonable for different reasons. In other words, the best-suited ACCOSS may depend on the circumstances of the situation on a case-by-case basis.'

PUC v. Columbia Gas of Pennsylvania, Inc. Docket No. R-2022-3031211 (Order entered December 8, 2022) at 107, footnote 30.

The conceptual idea behind the various methods in use for classifying distribution plant (poles, conductors, transformers) costs into demand-related and customer-related components is to reflect economies of scale associated with serving larger customers. These economies result from two economic factors. First, distribution equipment with higher capacity will cost less per unit of capacity. For example, a 50 kW transformer will cost less per kW than a 10 kW transformer. Second, the distribution system generally needs to be extended over a greater distance to serve smaller customers than to serve larger customers, thus increasing the per-kW cost of serving smaller customers.

Advocates for the use of the "100 percent demand" or "peak-and-average" approaches for distribution plant cost causation implicitly assume that there are no economies of scale, and that larger customers cost no less to serve per unit of demand than smaller customers.

I do not find the assumption that there are no scale economies to be credible for electric distribution systems. There are sound reasons to believe that serving 100 5-kW customers is more expensive than serving 1 500-kW customer. Except where the 100 customers are concentrated in an apartment building or an office building, the distribution system must generally require more poles, more conductor feet and more transformers than that needed to serve one customer, and the costs for all that equipment exhibit material economies of scale. Thus, there is a common-sense support for reflecting these economies in the cost allocation study.

The problem, of course, is that there is no perfect method for precisely determining the magnitude of these economies, or how they should be reflected in cost allocation. Thus, the debate regarding distribution plant cost classification continues to rage as it has for many decades, with a range of approaches being passionately supported by utilities, regulators, and other cost allocation practitioners. At one extreme lie the "no customer component" advocates, who deny the existence of scale economies. Then there are the "minimum system" advocates, who argue that customer-related costs should be based on the costs associated with hypothetical primary and secondary voltage electric distribution system consisting only of the smallest size equipment currently being installed, unadjusted for the load carrying capability of that minimum system.[10] In this proceeding, Mr. Taylor, with the support of Commission precedent, takes a position close to the unadjusted minimum system method, although he makes a small adjustment for the load-carrying capability of minimum-sized line transformers.

One approach for addressing this debate is to make the assumption that there are significant economies in the secondary voltage system, but less so in the primary voltage system. Thus, for example, where minimum sized capacity in the secondary voltage system may serve only a few small customers, the minimum sized capacity in the primary system may serve many customers. Thus, some analysts will apply a customer-demand classification approach for secondary voltage plant but use a 100 percent demand approach for primary voltage plant.[11]

Therefore, for the purpose of developing revenue allocation and rate design recommendations in this proceeding, I have considered the results of two simulations, one applying the minimum system approach to both primary and secondary voltage systems (as proposed by the Company and most recently approved by the Commission) which is

[10] Some advocates may take the position that the secondary voltage system, and possibly the primary voltage system, are causally related only to the number of customers.

[11] See, e.g., Duquesne Light Company, Docket No. R-2021-3024750, DLC Statement No. 15, pages 21-22.

provided in RDK WP2, and one in which all primary voltage system costs are classified as demand-related, shown in RDK WP3.

Q. Beyond these differences, have you made any other modifications to the Company's filed ACOSS?

A. I have made the following minor adjustments:

1. Based on a class-specific lead-lag analysis, it is apparent that the revenue lag for non-residential customers is only marginally longer than the lag in payments, implying that the non-residential classes contribute little to the need for working capital. I have modified the allocation accordingly.[12]

2. The Company appears to have a minor programming error with respect to the derivation of the INT_REV_REQ Pre-tax functionalization factor, which affects the allocation of non-supply gross receipts tax costs at current rates.[13] I have modified the allocation accordingly.

3. For the purpose of deriving customer-related costs, I classified all uncollectibles and universal service charges as demand-related, to exclude them from the cost basis for the customer charge. I also modified the allocator for non-residential customer premises to reflect that allocator's reliance on both demand-related and customer-related factors.[14] These changes have no effect on the magnitude of allocated costs among the classes, but they serve to reduce costs classified as customer-related for the purposes of non-residential rate design.

Q. What are the results of your ACOSS compared to the Company's filed version?

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[12] See development of the "WC" allocator in the "Allocators" worksheet in RDK WP2 and RDK WP3.

[13] See Attachment OSBA-II-1.2, Functionalization worksheet, cells H298 and I298. The INT_REV_REQ Pre-tax functionalization factor for the Distribution and PA PUC Direct Customer subfunctions are based on (a) total costs rather than functionalized costs, and (b) include electric supply costs although this factor and its associated allocator will apply to non-supply GRT.

[14] In Attachment OSBA-II-1.2, this allocator is denoted CPREMIS. In my simulations, it is CPREM.

A. Table RDK-1 below compares the ACOSS results using class rates of return at current rates and normalized revenue-cost ratios. My rationale for relying on revenue-cost ratios for revenue allocation purposes is presented in detail in Appendix A.

Table RDK-1 Comparative ACOSS Results						
	Class Rate of Return at Current Rates			Revenue-Cost Ratios Current Rates		
	UGI Electric*	RDK WP2	RDK WP3	UGI Electric*	RDK WP2	RDK WP3
Residential	-0.33%	-0.29%	1.11%	87.2%	86.9%	92.2%
GS-1	3.10%	3.20%	9.13%	94.5%	96.1%	119.4%
GS-4	16.58%	17.42%	9.09%	155.4%	157.7%	119.9%
FCP	4.40%	4.50%	-4.46%	96.7%	98.1%	56.9%
Large Power	28.87%	30.40%	10.73%	222.6%	226.3%	128.0%
Lighting	37.71%	40.39%	34.67%	246.2%	250.1%	227.5%
System	**3.77%**	**3.77%**	**3.77%**	**100.0%**	**100.0%**	**100.0%**
* Filed version, as updated in Attachment OSBA-II-1.2, and replicated in RDK WP1. Sources: RDK WP1, RDK WP2, RDK WP3						

As shown, the results from my WP2 simulation are very similar to the Company's filing, while the WP3 simulation shows much better revenue-cost performance by the Residential and GS-1 classes than under the Company's approach. Nevertheless, all three simulations suggest that revenues from the Residential class at current rates fall well short of allocated costs. Directionally, the difference is that in the RDK WP3 scenario, with primary distribution plant classified as 100 percent demand-related, the GS-1 class is over-recovering costs at present rates, as opposed to under-recovering costs in the Company's methodology.

4. <u>Revenue Allocation</u>

Q. What is revenue allocation?

A. Revenue allocation is the assignment of the dollar net increase or decrease to each of the Company's rate classes in a base rates proceeding. In contrast, rate design determines how the allocated revenue is recovered from individual ratepayers within each class. From a cost recovery standpoint, revenue allocation addresses *inter-class* cross-subsidization issues, while rate design addresses *intra-class* cross-subsidization issues.

Q. What are the primary economic and regulatory criteria for revenue allocation?

A. In general, allocated cost is the primary criterion used by regulators in the revenue allocation process. Most utilities and regulators adopt a policy in a base rates proceeding of attempting to move revenues more into line with allocated costs by varying the magnitude of the rate increases for the individual classes. However, regulators also subject the rate increases to other non-cost criteria of ratemaking. Of the traditional rate design criteria, the most common non-cost considerations in the revenue allocation process are:

- the *gradualism* principle (or avoidance of "rate shock"), in which large rate increases for individual customers or classes of customers are avoided; and
- the *value of service* principle, which is often used to mitigate rate increases for customers or customer classes with relatively elastic demand.[15]

Using these criteria, the utility will develop a proposal for assigning the increase in the revenue requirement among the classes that reflects both cost and non-cost considerations. To move rates more into line with allocated cost, the utility will generally propose above-average rate increases for classes that under-recover costs at present rates, and below-average increases for rate classes that over-recover costs. With this proposal, the ACOSS can be simulated at both present and proposed rates to evaluate the magnitude of "progress" has been made toward the policy of achieving cost-based rates.

Q. What metric is used to evaluate "progress" toward cost-based rates?

A. To my long-standing dismay, many analysts in Pennsylvania have traditionally relied on an "indexed rate of return" (also known as "relative rate of return") measure, including Mr.

[15] See, for example, Principles of Public Utility Rates, Second Edition, Bonbright, Danielsen, Kamerschen, 1988, pages 383 to 387. Note that the criteria in this text apply to the overall development of a utility rate structure. The criteria that I discuss in this testimony are those that apply to the revenue allocation portion of the process, which is only one aspect of the overall development of utility rates.

Taylor in this proceeding.[16] This metric is derived as the ratio of the class rate of return on rate base to the systemwide average return on rate base. Thus, for example, if a rate class is earning 2 percent on rate base at current rates and the system average is 5 percent, the indexed rate of return metric is 2.0/5.0 = 0.4. The metric correctly indicates that this class ***is*** under-recovering costs. As a measure of ***progress***, however, the indexed rate of return metric overstates progress toward cost-based rates, and it can show progress when none exists. For example, the indexed rate of return metric will show that an across-the-board rate increase results in progress toward cost-based rates, when in fact such an increase necessarily produces zero progress toward cost-based rates.[17] This problem is detailed at some length in Appendix A.

I have therefore relied on revenue-cost ratio metric at present and proposed rates in evaluating the progress toward cost-based rates for revenue allocation in this proceeding.

Q. Is the Company's proposed revenue allocation consistent with its own ACOSS?

A. The Company's proposed revenue allocation is directionally consistent with the results of is ACOSS. However, the Company's approach for moving rates into line with allocated costs appears to be materially more aggressive for the GS-1 customers than for the Residential customers.

Table RDK-2 below shows the Company's proposed revenue allocation, which involves substantial rate increases being assigned to the rate classes that under-recover costs (Residential, GS-1 and FCP) and near-zero increases to the classes which over-recover costs. Table RDK-2 also shows the percentage "progress" toward cost-based rates as measured by the revenue-cost ratio. While the Company's proposal is consistent with its ACOSS methodology and generally reasonable, it must be recognized that the actual progress toward cost-based rates is far lower than that claimed by the Company. Using the flawed indexed rate of return metric, the Company claims that residential rates move

[16] See Table 4 in UGI Statement No. 6.

[17] See RDK WP1 "Indexed RoR" worksheet for a numerical example demonstrating this result.

approximately 74 percent of the way to allocated cost.[18] In fact, the actual progress is 41 percent.

Table RDK-2 UGI Electric Revenue Allocation Summary					
	Increase ($000)	Increase (%)	R-C Ratio Current Rates	R-C Ratio Proposed Rates	Progress (%)
Residential	$10,706	27.5%	87.2%	92.5%	41%
GS-1	$714	26.3%	94.5%	99.9%	98%
GS-4	$0	0.0%	155.4%	132.1%	42%
FCP	$5	26.3%	96.7%	106.2%	287%
Large Power	$0	0.0%	222.6%	201.3%	17%
Lighting	$0	0.0%	246.2%	204.3%	29%
System	**$11,425**	**20.9%**	**100.0%**	**100.0%**	**--**

1. Revenue-cost ratios are based on revenues and costs excluding electric supply. The Company's ACOSS includes electric supply in its revenue-cost metrics.
2. Costs values are based on the Company's ACOSS method, replicated in RDK WP1.
3. Percentage increases are based on revenues associated with base distribution rates, DSIC, STAS and the EE&C charge.

Source: RDK WP1

Q. Is the Company's revenue allocation proposal consistent with the principles of rate gradualism?

A. Using a typical "rule-of-thumb" for rate gradualism, it is. For large overall rate increases such as that proposed by the Company, a 1.5-times or 2.0-times system average increase is often adopted as a limit on the maximum increase. In addition, regulators will often apply a rule against rate decreases for some classes when other classes face relatively large increases. This is with the Company's proposal. Specifically, the Company proposes to assign a zero increase to GS-4, LP and Lighting, and limits the largest increase (to the Residential class) to 1.31 times the system average.

[18] UGI Electric Statement No. 6 Table 4.

Q. If your proposed ACOSS in RDK WP2 is approved, what impact would it have on your proposed revenue allocation?

A. As I indicated earlier, my RDK WP2 ACOSS confirms the Company's conclusions that the Residential, GS-1, and FCP rate classes receive significant cross-subsidies from the other rate classes. Regarding rate gradualism, I agree with the Company's proposal to avoid rate decreases for the GS-4, LP and Lighting classes. With this constraint, the average percentage increase for the remaining classes is 27.4 percent.

The only modification that I propose to the Company's revenue allocation approach is to make the balance of progress toward cost-based rates more even across the rate classes. In particular, I propose modest reductions to the increases for the GS-1 and FCP classes, such that both of those classes exhibit 50 percent progress toward cost-based rates. These reductions are offset by a very small percentage increase to the Residential class.

Thus, based on those restrictions and my ACOSS, my revenue allocation recommendation is shown in Table RDK-3:

Table RDK-3
RDK Revenue Allocation Summary: RDK WP2 Simulation

	Increase ($000)	Increase (%)	R-C Ratio Current Rates	R-C Ratio Proposed Rates	Progress (%)
Residential	$10,827	27.8%	86.9%	92.4%	42%
GS-1	$595	21.9%	96.1%	98.0%	50%
GS-4	$0	0.0%	157.7%	134.0%	41%
FCP	$3	16.0%	98.1%	99.0%	50%
Large Power	$0	0.0%	226.3%	204.6%	17%
Lighting	$0	0.0%	250.1%	207.5%	28%
System	**$11,425**	**20.9%**	**100.0%**	**100.0%**	**--**

1. Revenue-cost ratios are based on revenues and costs excluding electric supply.
2. Costs values are based on the RDK WP2 method, very similar to the Company's approach.
3. Percentage increases are based on revenues associated with base distribution rates, DSIC, STAS and the EE&C charge.

Source: RDK WP2

As shown in Table RDK-3, this approach results in a modestly lower increases for the GS-1 and FCP classes than that proposed by the Company. Note also that the maximum increase for the Residential class is 1.26 times system average, well within the "rule-of-thumb" constraints for rate gradualism.

Q. What are the implications of your alternative ACOSS simulation as shown at RDK WP3?

A. Despite the fact that the RDK WP3 simulation results in fairly significant cost shifts, it has only a relatively modest impact on my proposed revenue allocation. While the Residential class exhibits a materially higher revenue-cost ratio at current rates, the revenues remain well below allocated costs. Similarly, for the LP class, the revenue-cost ratio at current rates is well below that in the Company's ACOSS, but revenues remain well above allocated costs. Thus, the revenue allocation for those classes is little changed from RDK WP2. The primary effect of this alternative ACOSS methodology is to imply a shift in required revenues from the small commercial class (GS-1) to the medium commercial class (GS-4). It also has the effect of implying a much larger percentage rate increase for the FCP class, although the dollar implications are small. My proposed revenue allocation is shown in Table RDK-4 below. It is based on the goal of moving both the GS-1 and GS-4 rate classes about 50 percent to the way toward allocated costs. As shown, this alternative implies a shift of about $400,000 from GS-1 to GS-4 revenues, compared to the Company's proposal, as well as a large percentage increase for the FCP class. The impact on the Residential class compared to the Company's proposal is *de minimis.*

Table RDK-4 RDK Revenue Allocation Summary: RDK WP3 Simulation					
	Increase ($000)	**Increase (%)**	**R-C Ratio Current Rates**	**R-C Ratio Proposed Rates**	**Progress (%)**
Residential	$10,755	27.6%	92.2%	97.9%	73%
GS-1	$264	9.7%	119.4%	109.7%	50%
GS-4	$400	7.9%	119.9%	109.9%	50%
FCP	$6	31.3%	56.9%	65.0%	19%
Large Power	$0	0.0%	128.0%	115.8%	44%
Lighting	$0	0.0%	227.5%	188.8%	30%
System	**$11,425**	**20.9%**	**100.0%**	**100.0%**	**--**

1. Revenue-cost ratios are based on revenues and costs excluding electric supply.
2. Costs values are based on the RDK WP3 method, with primary distribution assets classified as 100% demand-related.
3. Percentage increases are based on revenues associated with base distribution rates, DSIC, STAS and the EE&C charge.

Source: RDK WP3

5. <u>Rate Design Issues</u>

Q. Please describe the Company's GS-1 tariff.

A. Like most other Pennsylvania electric distribution utilities, UGI Electric's tariff charges for the smallest general service customers consist of a flat monthly customer charge and a per-kWh energy charge. A comparison of the Company's current and proposed tariff charges with those of other Pennsylvania EDCs is shown in Table RDK-5 below.

Table RDK-5 Pennsylvania EDC Tariff Rates for Small General Service Customers			
	Rate	**Customer Charge ($/month)**	**Energy Charge (cents/kWh)**
UGI Electric Current	GS-1	$ 13.00	5.237
UGI Electric Proposed	GS-1	$14.00	7.615
PPL Electric	GS-1*	$22.00	2.337
Metropolitan Edison	GS-Small	$21.88	4.069
Pennsylvania Electric	GS-Small	$18.33	3.624
Penn Power	GS-Small	$24.89	3.623
West Penn Power	Rate 20 GS	$9.52	3.529
PECO	GS**	$18.99	5.149

* PPL Electric applies a $4.361 per kW demand charge, as all customers have smart meters. Energy charge estimated from base rate proof of revenue analysis.

** Single-phase service without demand measurement; most PECO GS customers have demand meters.

Source: Utility tariff schedules on-line, reviewed April 22, 2023.

As shown, the major Pennsylvania EDCs generally have monthly customer charges well in excess of the UGI Electric proposed charge, and most have lower energy charges.

Moreover, for UGI Electric, my simulations of the ACOSS model imply a customer component of costs for GS-1 of $42.86 under RDK WP2 and $26.96 under RDK WP3.

Finally, as I indicated earlier, it is likely that there are a significant number of small GS-1 customers that are not small businesses. Each of these customers is attracting customer costs to the class of at least $27 per month in the ACOSS but providing only a small fraction of that amount in the monthly customer charge.

Despite this evidence, the Company proposes only a minimal increase in the customer charge for Rate GS-1, and an enormous increase (45.4 percent) to the GS-1 commodity charge. When the effects of the DSIC are recognized, the current customer charge is effectively $13.65, to which the Company would apply an increase of 2.6 percent.

I disagree with this proposal. Given the substantial under-recovery of customer costs, a larger percentage increase should apply to the customer charge. At the Company's proposed class increase for the class is 26.1 percent, an increase in the customer charge to $17.00 is cost justified and is not out of line with the practices of other Pennsylvania EDCs. The impact of this change is shown in Table RDK-6 below.

Table RDK-6 GS-1 Class Rate Design: UGI Electric Proposed Class Increase			
	Current	**Proposed**	**Percent**
UGI Proposal			
Customer Charge ($/month)	$13.00	$14.00	7.7%
Energy Charge (cents/kWh)	5.237	7.615	45.4%
RDK Alternative			
Customer Charge ($/month)	$13.00	$17.00	38.5%
Energy Charge (cents/kWh)	5.237	6.8241	30.3%

If the increase to the GS-1 rate class is scaled back due to a reduction in the overall proposed rate increase or do to changes in the revenue allocation, I recommend that the increases proposed in Table RDK-6 be scaled back proportionately.

Q. Please provide your assessment of the Company's proposed GS-4 tariff.

A. The Company's GS-4 tariff consists of three components. First, the tariff has a $15.00 per month customer charge. Second, the tariff includes a two-block demand charge above and below monthly demand of 20 kW, with a wide rate spread ($3.59 to $2.20 per kW) between the block charges. The third component is a Wright energy tariff with three blocks, at the first 200 kWh/kW, the next 300 kWh/kW and over 500 kWh/kW. The decline in the energy charges across the blocks is currently relatively modest, from 2.88 to 1.51 cents per kWh, implying that this tariff structure functions primarily as an energy charge.[19]

[19] A Wright tariff consists of blocked energy charges that vary based on the load factor of the customer. The blocks are typically based on the number of kWh of energy consumed per unit of billing demand. As that ratio rises, the block energy charges decline. Thus, a low load factor customer will typically face charges that are primarily based on the highest first block rate, while higher load factor customers are more subject to the lower block charges.

The Company's use of a declining block demand charge is presumably an effort to reflect the relatively low magnitude of the monthly service charge, such that the rate premium in the first demand block is designed to recover customer-related costs from smaller customers. This is not necessarily an unreasonable approach. However, for the smallest customers in the class, with billing demand averaging around 5 kW, the current customer charge plus the excess in the first block demand charge would only recover about $21 per month, well below allocated customer cost for Rate GS-4 ($48.41 in RDK WP2 and $32.37 in RDK WP3).

Turning to the demand and load-factor energy charges, it is important to recognize that electric distribution costs are generally customer-related or demand-related. Using broad-based energy charges to recover distribution costs will necessarily result in intra-class cross-subsidization. Energy charges for distribution service therefore tend to be used when demand-metering is not available, for customer acceptance reasons (e.g., residential service), or to recognize that very low load factor customers probably do not contribute proportionately to distribution system peaks, particularly primary voltage systems. In my experience, the larger Pennsylvania EDCs have generally moved away from energy charges for medium general service customers.

Q. What, then, do you recommend regarding Rate GS-4 tariff design?

A. Because the Company proposes a zero increase for this rate class, it proposes only minimal changes to the Rate GS-4 tariff design. Specifically, the Company proposes to shift the revenues currently recovered in the DSIC to the three energy blocks of the Wright tariff. The net effect of the Company's proposal, relative to the current tariff and recognizing the effect of the DSIC, is to reduce the customer component of rates, reduce the demand component of rates, and effectively increase the effect of the energy charge.

Therefore, the Wright tariff tends to function like a combination of demand and energy charges, with protection for extremely low load factor customers. The relative importance of the demand effect and the energy effect depends on the steepness of the decline in energy charges. Thus, for example, when energy charge rates decline sharply from first block to tail block, the Wright tariff functions more like a demand charge. When there is little difference in the charges, the tariff behaves more like an energy charge.

Given the advantages of rate stability and recognizing that the Company has not attempted to develop a longer-term plan regarding the evolution of the GS-4 tariff, I generally accept the Company's proposal, with some minor adjustments. First, I suggest that the customer charge for the GS-4 class be increased commensurate to the increase in the GS-1 customer charge, to $18.00 per customer per month. Second, I suggest that the demand charges be increased by 3.5 percent, which will have the effect of retaining some of the increase in the demand charge that is currently reflected in the DSIC. With those changes, the net zero rate increase would be achieved by applying a 3.8 percent increase to the Wright blocked energy charges. Overall, this proposal would modestly increase revenues from the customer charge, with small rate decreases to the effective demand and energy charges, compared to current rates (with DSIC).[20]

A summary of the GS-4 rate design proposals is shown in Table RDK-7 below.

[20] The detailed analysis supporting the GS-4 rate design is provided at RDK WP2, in the GS-4 Proposed RDK worksheet.

Table RDK-7 GS-4 Class Rate Design: UGI Electric Proposed Class Increase			
	Current*	**Proposed**	**Percent**
UGI Proposal			
Customer Charge ($/month)	$15.00	$15.00	0.0%
First 200 kWh/kW (cts/kWh)	2.882	3.126	8.5%
Next 300 kWh/kW (cts/kWh)	1.816	1.968	8.4%
Over 500 kWh/kW (cts/kWh)	1.513	1.640	8.4%
First 20 kW Demand ($/kW)	$3.59	$3.59	0.0%
Over 20 kW Demand ($/kW)	$2.20	$2.20	0.0%
RDK Alternative			
Customer Charge ($/month)	$15.00	$18.00	20.0%
First 200 kWh/kW (cts/kWh)	2.882	2.992	3.8%
Next 300 kWh/kW (cts/kWh)	1.816	1.885	3.8%
Over 500 kWh/kW (cts/kWh)	1.513	1.571	3.8%
First 20 kW Demand ($/kW)	$3.59	3.72	3.6%
Over 20 kW Demand ($/kW)	$2.20	2.28	3.6%
Customer Charge ($/month)	$15.00	6.8241	30.3%
* Excludes effect of DSIC			

At some point, the Company should evaluate whether it wishes to retain the complex combination of declining load factor block energy charges, declining block demand charges, and a customer charge, or whether a simpler tariff would be more consistent with cost causation and better understood by customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

APPENDIX A

MEASURES OF PROGRESS TOWARD COST BASED RATES

PENNSYLVANIA UTILITY COST AND REVENUE ALLOCATION

Introduction

The Pennsylvania Commonwealth Court held that cost of service is "the polestar" criterion for assigning a utility rate increase among the various rate classes.[21] Parties to Pennsylvania base rates proceedings generally agree that this criterion implies that the revenues for each class at the rates approved by the Commission should be closer to allocated costs than the rates in place when the rate case is filed. Thus, parties to the proceeding will typically compare some metric for cost recovery under "proposed rates" with that same metric for cost recovery under "current rates." This comparison can show (a) *whether* the proposed rates result in class revenues that are closer to allocated costs, and (b) *how much* progress the proposed rates make toward moving class revenues toward allocated costs.

While different metrics are used for this analysis, the most common metric in Pennsylvania is the "indexed rate of return" metric (also called the "relative rate of return" or "unitized rate of return" metric). This appendix demonstrates why the indexed rate of return is not a reliable metric for identifying whether proposed rates are closer to allocate costs than current rates, and that even where the indexed rate of return correctly implies that there is progress toward cost-based rates, it is not a reliable indicator of the amount of progress that is achieved.[22] This appendix also compares the indexed rate of return to three other metrics for evaluating progress toward cost-based rates, namely the dollar subsidy, the rate of return differential, and revenue-cost ratio metrics.

[21] Lloyd v. Pennsylvania Public Utility Commission, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006).

[22] This problem with the indexed rate of return metric was identified in OSBA-sponsored testimony at least as early as 1994. This critique has been presented in expert testimony many times since. No credible rebuttal to these basic conclusions has been submitted, but the widespread use of this flawed metric continues.

The Structure of the Cost Allocation Study

The indexed rate of return metric is derived from the method that is most often used for utility cost allocation in Pennsylvania. When a utility or regulator develops a revenue requirement for a test year, it simply sums all of the individual cost items for that year, including operating and maintenance ("O&M"), administrative and general ("A&G"), depreciation, taxes other than income, income taxes and allowed return on rate base. Thus, the objective of a cost allocation study should be to simply allocate each of these cost elements to the various rate classes. Because the allowed return and associated income tax are derived from rate base, the cost allocation study allocates all net plant and other rate base items to the various rate classes, and the return and income taxes can then be allocated in proportion to rate base.

Cost allocation studies in Pennsylvania, however, are most often conducted on a class rate of return basis. That is, the cost allocation study calculates a class rate of return by taking revenues, deducting the allocated O&M, A&G, depreciation and taxes other than income, to produce a pre-tax class net income. Income taxes are then most often allocated based on the calculated pre-tax class income, and a net income by class value is derived by difference. The allocated pre-tax and net income figures are thus not a cost of capital, but represent the implied return provided by each class under the revenues (current or proposed) used in the cost allocation study. These net income values are then divided by the allocated rate base, to produce percentage class rates of return.[23] Thus, with this approach to cost allocation, there is a desire by utilities and regulators to develop a metric for evaluating progress toward cost-based rates that is based on the class rates of return produced by the cost allocation study.

Defining Progress Toward Cost-Based Rates

It is not necessarily obvious what it means to "move rates more into line with allocated cost" between current and proposed rates. At the simplest level, one could argue that if the current rate revenues for a particular class are below the allocated cost for that class at the full proposed

[23] Some Pennsylvania utilities also calculate cost of service using a "levelized rate of return" method, in which return and income tax costs are allocated such that each class produces the system average rate of return. This approach is arithmetically equivalent to allocating return and income tax costs in proportion to rate base, as described above.

revenue requirement, any increase in rates will move that class's revenues closer to allocated cost. However, the objective of this exercise is to measure the progress toward cost-based rates for each rate class compared to that for all of the other classes. Thus, a revenue allocation proposal must be evaluated for its impact on all of the rate classes.

Also at the simplest level, of course, a proposed revenue allocation will by definition move rates more into line with allocated cost if each class's revenues are moved exactly to the full proposed allocated cost of service. Or, equivalently, rates are exactly cost-based when each class's revenues are set such that the class produces the system average rate of return. Therefore, there is no question that moving a class exactly to an indexed rate of return of unity (1.0) is necessarily consistent with making rates more cost-based.

In many base rate proceedings, however, moving rates fully into line with allocated costs cannot be achieved due to consideration of other rate design factors, most notably "rate gradualism," which serves to limit the increase for any particular class of customers in any rate proceeding, and has the aim of gradually moving rates into line with allocated cost.

Thus, in terms of determining whether a particular rate proposal moves rates into line with allocated cost, this appendix takes the position that there is progress toward cost-based rates if the proposed relative rate increases across the various classes, when followed for a number of base rates proceedings (in which there is no change in the relative cost structure), will eventually result in cost-based rates. Thus, for any particular metric, it is important to consider not only the difference between the metric and current rates and proposed rates in one base rates case, but also what that metric will imply going into the next base rates case.

As shown further in the numerical example below, this standard for defining progress implies that for classes with revenues below allocated cost at current rates (or, equivalently, with a class rate of return below system average), progress can only be achieved by assigning that class a rate increase above the system average increase. This, of course, is just plain common sense. If a class is under-recovering costs, it should be assigned an above average increase. As shown below, however, the indexed rate of return metric fails at common sense.

The Numerical Example

This appendix takes the approach of defining a specific numerical example, and showing the implications of various different metrics on different rate increase scenario. The calculations associated with this example are also provided in MS Excel electronic format (RDK WP4), and parties are able to simulate alternative examples to evaluate the rigor of this analysis.

The example attached to this appendix shows the arithmetic impacts of a single two-class utility example under four different rate increase proposals. Each page shows the implications of a different revenue-cost metric, namely the indexed rate of return, dollar subsidy, differential rate of return, the revenue-cost ratio and the normalized revenue-cost ratio.

The example involves two rate classes, A and B, in which each generates the same revenue at current rates, but in which Class A has a moderately higher cost to serve. The four rate increase scenarios are (I) an across-the-board increase in which both classes get the same percentage increase, (II) a scenario with a moderately higher percentage increase for Class B, and (III) a slightly higher percentage increase for Class A, and (IV) a moderately higher percentage increase for Class B.

The common-sense answer is that the across-the-board scenario (I) should show no progress toward cost-based rates, Scenario II should indicate that revenues are moving farther away from costs, and Scenarios III and IV should show that revenues are moving slightly and modestly closer to allocated costs. The discussion of each metric below highlights where the metric produces results that are at odds with these expectations.

To evaluate the question as to whether there is consistent progress toward cost-based rates, the metrics are evaluated at both proposed rates in the "current" base rates proceeding, and for what the values would imply going into the next base rates case after a uniform increase in costs.

The Indexed Rate of Return Metric

The indexed rate of return metric is measured as the class rate of return divided by the system average rate of return, at current and proposed rates. If revenues are fully in line with allocated costs, the class indexed rate of return is unity (1.0). Thus, if a class has an indexed rate of return at present rates that is higher than system average, it is deemed to be over-recovering costs, and conversely, where the indexed rate of is below unity, the class is under-recovering allocated costs.

As a standalone measure for relative cost performance, there is nothing wrong with the indexed rate of return metric – for any particular system average rate of return scenario, the farther a class's indexed rate of return is from unity, the farther it is from allocated costs.

Moreover, since an indexed rate of return of unity represents cost-based rates, it is conceptually appealing to conclude that if the indexed rate of return moves closer to unity, there is progress toward cost-based rates. Moreover, it is similarly appealing to conclude that progress toward cost-based rates could be measured by how much closer the index gets toward unity between current and proposed rates. Unfortunately, this intuitive approach fails in the actual arithmetic.

Utilities have used this argument for decades in Pennsylvania. While it is not clear why alternative methods have not been adopted, it may be that the metric is attractive to both utilities and regulators in that it tends to show significant progress toward cost-based rates when in fact there is little such progress. This then allows utilities to claim that they are following the cost standard without having to make politically unpopular decisions regarding differentiating rate increases among the various rate classes.

When applied in an actual example, the indexed rate of return fails even the simplest test. In the example shown, the current rates class rates of return are 2.50% and 5.71% for Classes A and B respectively, producing indexed rates of return of 0.625 and 1.429 relative to the system average return of 4.00%. When a 30% increase is applied to both classes, the system average rate of return rises to 8.00%, and the class returns rise to 6.25% and 10.00% respectively, yielding indexed rates of return of 0.781 and 1.250.

Thus, despite the fact that both classes get the same percentage increase and common sense says that there should be no progress toward cost-based rates, the indexed rate of return metric not only implies that there is progress, but that there is significant progress. The Class A indexed rate of return moves from 0.625 to 0.781, which appears to imply that the class has moved 42 percent of the way to cost-based rates.[24]

The fallacy of this logic is shown in the implications for the next rate case. When costs increase, the system average rate of return falls back to its lower level and the indexed rate of return metrics all shift farther away from unity. Thus, as shown, an across-the-board increase in the current rate case followed by an across-the-board cost increase for the next case will demonstrate that, in fact, there is no progress toward cost-based rates and the indexed rates of return are right back where they started.

The other revenue increase scenarios show similar problems with the indexed rate of return metric. In Scenario II, despite a smaller percentage increase for the higher-cost Class A, the indexed rate of return again implies that there is progress toward cost-based rates, which is obviously nonsense. This is again demonstrated by the implications for the next base rates case, which understandably show that rates are farther out of line than they were going into the current rate case. It is simply unreasonable to believe that assigning larger percentage increases to the rate class that is already over-recovering costs will somehow reduce inter-class subsidies. And yet that is the implication of the indexed rate of return metric.

In Scenarios III and IV, the indexed rate of return does produce the correct directional answer, namely that rates are moving more into line with allocated cost. But the indexed rate of return metric implies that both scenarios result in enormous progress toward cost-based rates, when in fact there is relatively little progress, particularly in Scenario III. As shown in the example, despite a small differential in the rate increases, the indexed rate of return implies that revenues have moved 50 percent of the way toward allocated cost. Realistically, however, as shown in the implications for the next base rates case, the actual progress is much lower.

Thus, the indexed rate of return metric is a wholly unreliable guide for evaluating progress toward cost-based rates in a utility rate proceeding, because it (a) may show progress toward cost-

[24] "Progress" is measured by how much the metric has moved divided by how far it needs to move to become fully cost-based. Thus, in the residential class example, the index moves from 0.625 to 0.781, a difference of 0.156, compared to moving fully to cost-based rates, which would require the index to move from 0.625 to 1.000, a difference of 0.375. Progress is measured as 0.156/0.375, or 42 percent.

based rates when in fact revenues are moving farther away from costs, and (b) will overstate the magnitude of progress toward cost-based rates when progress is occurring.

<u>The Dollar Subsidy Method</u>

While the indexed rate of return metric is the most common approach used by Pennsylvania utilities, the Commission has also supported the use of the dollar subsidy metric. In an order involving the City of Bethlehem – Water Department, the Commission concluded:

> "As noted by the OSBA, the proper yardstick for measuring the degree of movement toward cost of service is the change in the absolute level of class subsidies at present and proposed rates."[25]

In the dollar subsidy method, the total cost to provide service is calculated using the method described above, in which each component to cost, including return and income taxes, is allocated to each cost. The difference between current rate revenues and the allocated cost is the dollar subsidy.[26]

In allocating the return and income tax costs under the "current rates" evaluation, the values used represent only the return that the utility would achieve and the income taxes that it would incur if it were assigned no rate increase. These values therefore do not represent the utility cost of capital, but simply residual values of what is left from current rate revenues after O&M, A&G, depreciation and other taxes are deducted.

When the dollar subsidy metric is applied to the four alternative revenue allocation proposals in the attached example, it implies the following:

- For the across-the-board increase, the dollar subsidy metric indicates that the dollar value of the revenue-cost difference increases under proposed rates, implying that rates

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[25] *Pennsylvania Public Utility Commission v. City of Bethlehem -- Water Department*, Docket No. R-2020-3020256, Order entered April 15, 2021, at 36.

[26] This appendix uses the term "subsidy" as the difference between revenues and fully allocated cost in a utility cost allocation study. Theoretical economics generally defines subsidy based on incremental cost concepts, rather than fully allocated cost.

are moving farther away from costs. In dollar terms, that conclusion is correct, although in percentage terms the subsidies remain the same.

- When a larger increase is assigned to Class B, the dollar subsidy metric indicates correctly that rates are moving farther away from allocated cost, and that the problem will be worse with the next base rates proceeding.

- When a modestly larger increase is assigned to Class A, the dollar subsidy metric implies that there is no progress toward cost-based rates in the current rate proceeding, and that the situation will be worse in the next base rates case. In effect, even though the slightly higher rate increase for Class A will (eventually) lead to cost-based rates, the dollar subsidy method implies that there is no progress.

- When a materially larger increase is assigned to Class A, the dollar subsidy metric correctly indicates that there is progress toward cost-based rates.

Thus, overall, the dollar subsidy metric will tend to slightly understate progress toward cost-based rates, but the distortion is far smaller (and in the opposite direction) of that of the indexed rate of return metric.

<u>The Differential Rate of Return</u>

The differential rate of return metric is similar to the indexed rate of return metric, in that both approaches calculate class rates of return and current and proposed rates, and compares each class's return to the system average. However, where the indexed rate of calculates the *ratio* of class to average return, the differential rate of return calculates the *difference* between class and average rates of return. In the indexed rate of return, cost-based rates are achieved with an indexed rate of return of unity (1.0); for the differential rate of return, cost-based rates are achieved with a differential rate of return of zero.

When applied to the four revenue allocation scenarios in the example, the differential rate of return produces results that are nearly the same as the dollar subsidy method. That is, the differential rate of return calculation will slightly understate progress toward cost-based rates, but the results are much less distorted than those from the indexed rate of return metric.

Revenue-Cost Ratio

The revenue cost ratio is similar to the dollar subsidy metric, except rather than taking the difference between revenues and allocated costs, it takes the ratio of revenues to allocated cost. Like the indexed rate of return, cost-based rates are achieved at a revenue-cost ratio of unity (1.0 or 100 percent).

Unlike the indexed rate of return metric, however, the revenue-cost ratio generally does not distort the implications of a revenue allocation proposal. As shown in the example, in all four revenue allocation proposals, the revenue-cost ratio correctly indicates when there is progress toward cost-based rates and when there is not.

The only downside to this unadjusted revenue-cost ratio approach is that the progress toward cost-based rates in the current case is not the same as that going into the next base rates case. This results because the mix of operating costs allocated to each class is different from the mix of rate base costs. This minor distortion is addressed in the final metric below.

Normalized Revenue-Cost Ratio

The normalized revenue-cost ratio makes a technical correction to the revenue-cost ratio metric to reduce the distortion associated with using a non-cost parameter, namely the residual return and income tax costs, as a measure of cost at current rates. This metric uses fully allocated costs including the utility's allowed return on capital as the cost metric at both current and proposed rates. In this metric, however, the revenues at current rates are "normalized" by applying the system average rate increase to each class. Thus, in this metric, the current rates revenue-cost ratio is the revenues that would be earned from each class if an across-the-board rate increase were applied divided by the fully allocated class revenue requirement. This is then compared to the revenue-cost ratio that results from the actual proposed revenue allocation.

As shown in the attached example, this metric correctly shows the progress toward cost-based rates in each of the scenarios, and it also correctly predicts what each class' revenue-cost performance will be going into the next base rates case if there is no change in the underlying cost structure.

Summary

The indexed rate of return is a metric that has intuitive appeal, in that cost-based rates are achieved when the index is at unity (1.0), and that it would seem therefore that moving the index closer to 1.0 would represent progress toward cost-based rates.

Alas, it is not that simple. As shown in the examples attached, and as evidenced in hundreds of utility rate proceedings in Pennsylvania, the indexed rate of return is not a reliable metric for gauging progress toward cost-based rates for any particular revenue allocation proposal. It may give a directionally correct answer, and it may not. And even when it does correctly show progress, it implies that there is much more progress toward cost-based rates than actually exists.

Of the five metrics evaluated in this review, the indexed rate of return is the only metric to fail the test and imply that there is progress toward cost-based rates when there is none, and even when rates are moving substantially away from allocated cost.

All the other metrics evaluated in this review are superior to the indexed rate of return approach. The dollar subsidy and differential rate of return have a modest disadvantage in that they may imply that there is no progress toward cost-based rates when in fact some small progress is occurring. This is a relatively modest disadvantage since the distortion is much smaller than that in the indexed rate of return, and moreso because it will encourage Pennsylvania utilities and regulators to adopt revenue allocation proposals that are more aggressive in moving revenues into line with allocated cost, consistent with the legal standard that cost of service be the polestar criterion.

Overall, however, the revenue-cost metric, particularly the normalized revenue-cost metric, does not suffer from the distortions of any of the other methods, and is the most reliable of the methods on offer.

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EXHIBIT RDK-1

RÉSUMÉ AND EXPERT TESTIMONY LIST

FOR

ROBERT D. KNECHT

Overview

Mr. Knecht has more than 40 years of economic consulting experience, focusing on the energy, utility, metals and mining industries. For the past 30 years, Mr. Knecht's practice has primarily involved providing analysis, consulting support and expert testimony in regulatory matters, primarily involving electric and natural gas utilities. Mr. Knecht's work includes many aspects of utility regulation, including industry restructuring, cost unbundling, cost allocation, rate design, rate of return, customer contributions, energy efficiency programs, smart metering programs, treatment of stranded costs and utility revenue requirement issues. He has consulted to state advocacy agencies, industrial customer groups, law firms, regulatory agencies, government agencies and utilities, in both the United States and Canada. He has provided expert testimony in more than one hundred separate utility proceedings.

In addition to his work with regulated utilities, Mr. Knecht has consulted on international industry restructuring studies, prepared economic policy analyses, participated in a variety of litigation matters involving economic damages, and developed energy industry forecasting models.

Mr. Knecht served as a Principal of IEc for 33 years, and as its Treasurer for 15 years. He is currently an independent consultant who remains affiliated with IEc.

Education

Master of Science, Management (Applied Economics and Finance), Sloan School of Management, M.I.T.

Bachelor of Science, Economics, Massachusetts Institute of Technology

Select Project Experience

For more than 25 years, Mr. Knecht has provided consulting services, analysis and expert testimony before the Pennsylvania Public Utility Commission on all manner of regulatory proceedings to the **PENNSYLVANIA OFFICE OF SMALL BUSINESS ADVOCATE**. In addition to expert testimony, Mr. Knecht has assisted OSBA with the development of public policy positions, litigation strategy, and longer term strategy.

For the **ATTORNEY GENERAL OF THE STATE OF RHODE ISLAND**, Mr. Knecht provided consulting and expert witness services in an acquisition proceeding involving PPL Corporation's proposed acquisition of Narragansett Electric from National Grid. Mr. Knecht's testimony addressed financial, economic, environmental, tax, operating cost and rate implications.

For the **NEW BRUNSWICK PUBLIC INTERVENER,** Mr. Knecht provides consulting and expert witness services in a variety of regulatory proceeding before the New Brunswick Energy and Utilities Board involving New Brunswick Power, Enbridge Gas New Brunswick, and petroleum products. Mr. Knecht has addressed issues of load forecasting, costs forecasting, cost of capital, allocation of corporate overhead costs, utility cost allocation, revenue allocation, market-based rate design, cost-based rate design, and rate decoupling.

For **L'ASSOCIATION QUÉBÉCOISE DES CONSOMMATEURS INDUSTRIELS D'ÉLECTRICITÉ (AQCIE) AND LE CONSEIL DE L'INDUSTRIE FORESTIÈRE DU QUÉBEC (CIFQ)**, Mr. Knecht provided analysis, consulting advice and expert testimony before the Régie de l'énergie in regulatory matters involving Hydro Québec Distribution and TransÉnergie. This work includes revenue requirement, power purchasing, cost allocation, treatment of cross-subsidies, and rate design.

For the **INDEPENDENT POWER PRODUCERS SOCIETY OF ALBERTA**, Mr. Knecht provided consulting advice, analysis and expert testimony before the Alberta Energy and Utilities Board in a series of proceedings involving the restructuring of the electric utility industry, the unbundling of rates, and the development of transmission rates.

EXHIBIT RDK-2

REFERENCED INTERROGATORY RESPONSES

OSBA-I-1

OSBA-I-5

OSBA-II-1

OSBA-II-19

OSBA-I-1

Request:

Reference Exhibit D:

a. In “live” MS Excel electronic format with formulae intact, please provide Exhibit D, Allocated Cost of Service Study (“ACOSS”).

Response:

Please refer to Attachment OSBA-I-1 for Exhibit D, ACOSS in electronic format with all formulas intact.

Prepared by or under the supervision of: John D. Taylor

OSBA-I-5

Request:

Reference UGI Statement No. 6 at pages 10-11, and Exhibit D, NCP allocator:

a. Please reconcile the use of a 12 NCP average allocator with the Company's rebuttal Statement No. 6-R at Docket No. R-2021-3023618 page 25: "I . . . have updated the primary and secondary NCP allocation factors in the rebuttal ACOSS model presented below to reflect a single NCP peak, rather than the average of the monthly NCPs." Has the Company retained the 1 NCP approach or reverted to the 12 NCP approach? Please provide your rationale.

b. Please explain why the Company uses a class-wide NCP allocator for secondary system distribution costs, when only a relatively few customers are served by each line transformer. Does UGI Electric reflect class-wide demand diversity in constructing its secondary distribution system?

c. To the extent available, please provide a sum of individual customer peaks allocation factor for each rate class, with supporting workpapers.

d. Please indicate whether the footage values in Exhibit D Schedule 2 for conductors (overhead and underground, primary and secondary) are circuit feet or conductor feet.

e. Please indicate whether UGI Electric has or has not adopted the other changes it made to its filed ACOSS model in rebuttal testimony at Docket No. R-2021-3023618. Please explain your rationale.

Response:

a. UGI Statement No. 6 inadvertently uses the term 'average'. The NCP allocation factor used to allocate demand related distribution costs is the maximum NCP peak for each rate class. As such, the Company has retained the 1 NCP approach and has not reverted to the 12 NCP approach.

b. UGI Electric builds a particular section of its secondary distribution system to connect and serve the local demands placed on that section, which relates to the customers served on that particular section. The Company's ACOSS allocates all secondary distribution costs, not each individual circuit, and does so by allocating

OSBA-I-5 (Continued)

only the minimum portion of the Company's secondary system on customers and the remaining demand related portion on the maximum NCP peak for each rate class.

c. Please see the response to OSBA-I-7.

d. Conductor feet.

e. The ACOSS model filed as Exhibit D in this proceeding reflects the methods employed in the rebuttal filing from Docket No. R-2021-3023618. The specific equipment sizes and unit costs used in the minimum system studies are different than the rebuttal filing from Docket No. R-2021-3023618. These differences reflect current cost information and minimum sizes.

Prepared by or under the supervision of: John D. Taylor

OSBA-II-1

Request:

Reference demand allocators for Rate LP, Exhibit D, Schedule 3, page 1 and tariff page 66. Rate LP character of service is defined as 3-phase primary voltage service with one transformation using equipment supplied by the Company, metered on the primary side of the transformer.

a. Please explain how the Rate LP service criteria are reflected in the demand allocators used for secondary system poles, conductors and conduit, as well as for line transformers.

b. Please provide an explanation for what "NCPs @ Secondary" represent for this class, if demand is metered at primary voltage (or metered at secondary and grossed up for billing).

c. Please provide an explanation for the change in how secondary system demands are developed for this class as compared to the Company's last base rates case.

d. Please explain the difference between LP customers categorized as using the primary voltage system (PRI_CUST) and customers using the secondary voltage (SEC_CUST).

Response:

a. The NCPs @ Secondary include the demand requirements of those LP customers that are served at secondary voltage. The NCPs @ Primary includes the demand requirements of all LP customers, those served at the secondary voltage and at the primary voltage. Further, the allocation of the customer component of distribution facilities also utilizes different customer counts. The secondary system's customer related costs are allocated only to those LP customers served at secondary and the primary system's customer related costs are allocated to all LP customers. This differentiation of allocation factors at voltage levels reflects the Rate LP service criteria through a reflection of the character of service at different voltage levels.

b. Upon preparation of this response, the Company reviewed the development of the NCPS @ Secondary and found cell reference errors in the External Allocators. The NCPs @ Secondary inadvertently referenced the total metered NCPs rather

OSBA-II-1 (Continued)

than the NCPs @ Secondary. Attachment OSBA-II-1.1.xlsx provides the updated external allocator workbook with the correct cell reference for NCPs @ Secondary. This decreases the allocation of secondary demand-related costs (through the allocator NCPs @ Secondary) from 20.82% to 8.16%. The result of this changed allocation factor on the class cost of service study is provided as Attachment OSBA-II-1.2.xlsx. There is a decrease in the revenue requirement for the LP class of $532k. This does not impact the Company's proposed revenue apportionment.

c. With the correction noted in part b of this response, the method employed is the same as the Company's last base rate case.

d. The customers are categorized based on the voltage level they are taking service, distinguished between secondary voltage and primary voltage. Please see the description of the allocators in part a of this response.

Prepared by or under the supervision of: John D. Taylor

OSBA-II-19

Request:

Reference response to OSBA-I-7, load research: Please explain why allocation factors are based on stratum per-customer maximum demands from the load research rather than stratum load factors from the load research.

Response:

The allocation factors were developed using the stratum per-customer maximum demands from the load research as the load research is based on a subset of customers and develops an average for this subset (i.e., the sample meters). The stratum per-customer maximum demands are multiplied by the customer count to estimate the total class peak demands. If the stratum load factors were used without multiplying by the customer count, they would not account for the relative customer accounts across the rate classes.

Prepared by or under the supervision of: John D. Taylor

EXHIBIT RDK-3

ELECTRONIC WORKPAPERS

RDK WP1: Replication of UGI Electric Proposed ACOSS

RDK WP2: RDK Proposed ACOSS

RDK WP3: RDK Alternative ACOSS

RDK WP4: Revenue Allocation Metrics

***** Workpapers will be served electronically in excel format simultaneous to email service of Direct Testimony*****

EXHIBIT RDK-4

SUMMARY COMPOSITION OF RATES GS-1 AND GS-4

BY SIC CODE

(Exhibit IEc-3 at Docket No. R-2017-2640058)

Exhibit IEc-3
Summary of General Service Customers and Load by SIC Code

RATE GS-1: Sorted by Cutomer Count

SIC Code	Count	Cumulative Count%	Usage	Average Use	SIC Description
75	833	16%	2,139,290	214	Automotive Repair, Services and Parking
42	616	28%	1,718,710	233	Motor Freight Transportation
65	574	39%	2,841,563	413	Real Estate
36	406	47%	1,793,512	368	Electronic & Other Electrical Equipment & Components
86	259	52%	3,236,038	1,041	Membership Organizations
72	177	56%	850,412	400	Personal Services
11	158	59%	628,793	332	Metal Mining
23	148	62%	343,935	194	Apparel, Finished Products from Fabrics & Similar Materials
49	131	64%	558,262	355	Electric, Gas and Sanitary Services
79	115	67%	462,823	335	Amusement and Recreation Services
59	114	69%	649,837	475	Miscellaneous Retail
50	112	71%	601,869	448	Wholesale Trade - Durable Goods
55	108	73%	584,758	451	Automotive Dealers and Gasoline Service Stations
58	101	75%	762,242	629	Eating and Drinking Places
80	89	77%	692,237	648	Health Services
15	87	78%	307,521	295	Construction - General Contractors & Operative Builders
48	81	80%	736,411	758	Communications
73	74	81%	226,188	255	Business Services
1	73	83%	204,380	233	Agricultural Production - Crops
35	64	84%	186,450	243	Industrial and Commercial Machinery and Computer Equipment
70	59	85%	306,516	433	Hotels, Rooming Houses, Camps, and Other Lodging Places
54	58	86%	342,928	493	Food Stores
44	56	87%	91,215	136	Water Transportation
99	40	88%	187,817	391	Nonclassifiable Establishments
17	34	89%	154,224	378	Construction - Special Trade Contractors
57	34	90%	267,757	656	Home Furniture, Furnishings and Equipment Stores
76	32	90%	168,395	439	Miscellaneous Repair Services
52	31	91%	187,768	505	Building Materials, Hardware, Garden Supplies & Mobile Homes
87	27	91%	224,589	693	Engineering, Accounting, Research, and Management Services
91	26	92%	141,577	454	Executive, Legislative & General Government, Except Finance
92	25	92%	230,988	770	Justice, Public Order and Safety
82	23	93%	98,890	358	Educational Services
16	21	93%	133,031	528	Heamy Construction, Except Building Construction, Contractor
2	20	94%	105,742	441	Agricultural Production - Livestock and Animal Specialties
24	18	94%	70,665	327	Lumber and Wood Products, Except Furniture
64	18	94%	123,376	571	Insurance Agents, Brokers and Service
7	17	95%	164,652	807	Agricultural Services
51	17	95%	74,177	364	Wholesale Trade - Nondurable Goods
56	16	95%	83,561	435	Apparel and Accessory Stores
93	16	96%	41,560	216	Public Finance, Taxation and Monetary Policy
34	15	96%	114,068	634	Fabricated Metal Products
95	15	96%	71,684	398	Administration of Environmental Quality and Housing Programs
27	13	96%	67,221	431	Printing, Publishing and Allied Industries
81	13	97%	87,531	561	Legal Services
83	13	97%	135,932	871	Social Services
Other	161		833,683	432	Other
Grand Total	**5,138**		**24,034,778**	**390**	

Exhibit IEc-3
Summary of General Service Customers and Load by SIC Code

RATE GS-1: Sorted by Load

SIC Code	Count	Usage	Cum. Usage %	Average Use	SIC Description
86	259	3,236,038	13%	1,041	Membership Organizations
65	574	2,841,563	25%	413	Real Estate
75	833	2,139,290	34%	214	Automotive Repair, Services and Parking
36	406	1,793,512	42%	368	Electronic & Other Electrical Equipment & Components
42	616	1,718,710	49%	233	Motor Freight Transportation
72	177	850,412	52%	400	Personal Services
58	101	762,242	56%	629	Eating and Drinking Places
48	81	736,411	59%	758	Communications
80	89	692,237	61%	648	Health Services
59	114	649,837	64%	475	Miscellaneous Retail
11	158	628,793	67%	332	Metal Mining
50	112	601,869	69%	448	Wholesale Trade - Durable Goods
55	108	584,758	72%	451	Automotive Dealers and Gasoline Service Stations
49	131	558,262	74%	355	Electric, Gas and Sanitary Services
79	115	462,823	76%	335	Amusement and Recreation Services
23	148	343,935	77%	194	Apparel, Finished Products from Fabrics & Similar Materials
54	58	342,928	79%	493	Food Stores
15	87	307,521	80%	295	Construction - General Contractors & Operative Builders
70	59	306,516	81%	433	Hotels, Rooming Houses, Camps, and Other Lodging Places
57	34	267,757	82%	656	Home Furniture, Furnishings and Equipment Stores
92	25	230,988	83%	770	Justice, Public Order and Safety
73	74	226,188	84%	255	Business Services
87	27	224,589	85%	693	Engineering, Accounting, Research, and Management Services
1	73	204,380	86%	233	Agricultural Production - Crops
99	40	187,817	87%	391	Nonclassifiable Establishments
52	31	187,768	88%	505	Building Materials, Hardware, Garden Supplies & Mobile Homes
35	64	186,450	89%	243	Industrial and Commercial Machinery and Computer Equipment
76	32	168,395	89%	439	Miscellaneous Repair Services
7	17	164,652	90%	807	Agricultural Services
17	34	154,224	91%	378	Construction - Special Trade Contractors
91	26	141,577	91%	454	Executive, Legislative & General Government, Except Finance
83	13	135,932	92%	871	Social Services
16	21	133,031	92%	528	Heamy Construction, Except Building Construction, Contractor
64	18	123,376	93%	571	Insurance Agents, Brokers and Service
34	15	114,068	93%	634	Fabricated Metal Products
2	20	105,742	94%	441	Agricultural Production - Livestock and Animal Specialties
82	23	98,890	94%	358	Educational Services
44	56	91,215	94%	136	Water Transportation
81	13	87,531	95%	561	Legal Services
56	16	83,561	95%	435	Apparel and Accessory Stores
51	17	74,177	95%	364	Wholesale Trade - Nondurable Goods
95	15	71,684	96%	398	Administration of Environmental Quality and Housing Programs
24	18	70,665	96%	327	Lumber and Wood Products, Except Furniture
47	6	67,701	96%	940	Transportation Services
27	13	67,221	97%	431	Printing, Publishing and Allied Industries
Other	171	807,542		394	Other
Grand Total	**5,138**	**24,034,778**		**390**	

Exhibit IEc-3
Summary of General Service Customers and Load by SIC Code

RATE GS-4: Sorted by Cutomer Count

SIC Code	Count	Cum. Count%	Usage	Average Use	SIC Description
65	254	11%	10,429,843	3,422	Real Estate
58	236	22%	15,591,784	5,506	Eating and Drinking Places
59	129	27%	6,801,535	4,394	Miscellaneous Retail
55	112	32%	6,458,600	4,806	Automotive Dealers and Gasoline Service Stations
80	108	37%	4,851,878	3,744	Health Services
54	95	41%	7,409,985	6,500	Food Stores
49	90	45%	4,895,443	4,533	Electric, Gas and Sanitary Services
75	81	49%	2,134,962	2,196	Automotive Repair, Services and Parking
48	80	53%	4,779,167	4,978	Communications
42	73	56%	2,779,942	3,173	Motor Freight Transportation
72	58	58%	1,500,938	2,157	Personal Services
50	57	61%	2,824,057	4,129	Wholesale Trade - Durable Goods
79	56	63%	2,556,420	3,804	Amusement and Recreation Services
70	47	66%	2,970,150	5,266	Hotels, Rooming Houses, Camps, and Other Lodging Places
60	46	68%	2,853,853	5,170	Depository Institutions
86	41	69%	2,590,417	5,265	Membership Organizations
73	40	71%	1,552,776	3,235	Business Services
11	39	73%	1,150,437	2,458	Metal Mining
15	38	75%	1,044,300	2,290	Construction - General Contractors & Operative Builders
99	32	76%	1,683,705	4,385	Nonclassifiable Establishments
82	28	77%	2,377,469	7,076	Educational Services
51	28	79%	1,177,446	3,504	Wholesale Trade - Nondurable Goods
56	27	80%	1,189,633	3,672	Apparel and Accessory Stores
52	27	81%	888,381	2,742	Building Materials, Hardware, Garden Supplies & Mobile Homes
57	26	82%	831,524	2,665	Home Furniture, Furnishings and Equipment Stores
53	23	83%	1,828,156	6,624	General Merchandise Stores
95	21	84%	2,018,923	8,012	Administration of Environmental Quality and Housing Programs
92	19	85%	1,560,295	6,843	Justice, Public Order and Safety
35	18	86%	706,561	3,271	Industrial and Commercial Machinery and Computer Equipment
87	17	86%	1,558,189	7,638	Engineering, Accounting, Research, and Management Services
20	17	87%	1,189,487	5,831	Food and Kindred Products
17	17	88%	835,798	4,097	Construction - Special Trade Contractors
91	17	89%	778,284	3,815	Executive, Legislative & General Government, Except Finance
83	16	89%	570,220	2,970	Social Services
78	15	90%	328,669	1,826	Motion Pictures
36	14	91%	829,860	4,940	Electronic & Other Electrical Equipment & Components
34	14	91%	631,565	3,759	Fabricated Metal Products
25	13	92%	1,279,023	8,199	Furniture and Fixtures
76	13	92%	413,253	2,649	Miscellaneous Repair Services
7	13	93%	381,174	2,443	Agricultural Services
1	13	94%	350,303	2,246	Agricultural Production - Crops
64	12	94%	348,628	2,421	Insurance Agents, Brokers and Service
32	11	95%	524,493	3,973	Stone, Clay, Glass, and Concrete Products
24	10	95%	733,156	6,110	Lumber and Wood Products, Except Furniture
43	10	96%	467,896	3,899	United States Postal Service
Other	101		5,855,550	4,831	
Total	**2,252**		**116,514,128**	**4,312**	

Exhibit IEc-3
Summary of General Service Customers and Load by SIC Code

RATE GS-4: Sorted by Load

SIC Code	Count	Usage	Cum. Usage %	Average Use	SIC Description
58	236	15,591,784	13%	5,506	Eating and Drinking Places
65	254	10,429,843	22%	3,422	Real Estate
54	95	7,409,985	29%	6,500	Food Stores
59	129	6,801,535	35%	4,394	Miscellaneous Retail
55	112	6,458,600	40%	4,806	Automotive Dealers and Gasoline Service Stations
49	90	4,895,443	44%	4,533	Electric, Gas and Sanitary Services
80	108	4,851,878	48%	3,744	Health Services
48	80	4,779,167	53%	4,978	Communications
70	47	2,970,150	55%	5,266	Hotels, Rooming Houses, Camps, and Other Lodging Places
60	46	2,853,853	58%	5,170	Depository Institutions
50	57	2,824,057	60%	4,129	Wholesale Trade - Durable Goods
42	73	2,779,942	62%	3,173	Motor Freight Transportation
86	41	2,590,417	65%	5,265	Membership Organizations
79	56	2,556,420	67%	3,804	Amusement and Recreation Services
82	28	2,377,469	69%	7,076	Educational Services
75	81	2,134,962	71%	2,196	Automotive Repair, Services and Parking
95	21	2,018,923	72%	8,012	Administration of Environmental Quality and Housing Programs
53	23	1,828,156	74%	6,624	General Merchandise Stores
99	32	1,683,705	75%	4,385	Nonclassifiable Establishments
92	19	1,560,295	77%	6,843	Justice, Public Order and Safety
87	17	1,558,189	78%	7,638	Engineering, Accounting, Research, and Management Services
73	40	1,552,776	79%	3,235	Business Services
72	58	1,500,938	81%	2,157	Personal Services
25	13	1,279,023	82%	8,199	Furniture and Fixtures
56	27	1,189,633	83%	3,672	Apparel and Accessory Stores
20	17	1,189,487	84%	5,831	Food and Kindred Products
51	28	1,177,446	85%	3,504	Wholesale Trade - Nondurable Goods
11	39	1,150,437	86%	2,458	Metal Mining
15	38	1,044,300	87%	2,290	Construction - General Contractors & Operative Builders
26	2	1,015,794	88%	42,325	Paper and Allied Products
52	27	888,381	88%	2,742	Building Materials, Hardware, Garden Supplies & Mobile Homes
17	17	835,798	89%	4,097	Construction - Special Trade Contractors
57	26	831,524	90%	2,665	Home Furniture, Furnishings and Equipment Stores
36	14	829,860	90%	4,940	Electronic & Other Electrical Equipment & Components
81	7	807,252	91%	9,610	Legal Services
91	17	778,284	92%	3,815	Executive, Legislative & General Government, Except Finance
24	10	733,156	92%	6,110	Lumber and Wood Products, Except Furniture
35	18	706,561	93%	3,271	Industrial and Commercial Machinery and Computer Equipment
34	14	631,565	94%	3,759	Fabricated Metal Products
16	9	621,391	94%	5,754	Heamy Construction, Except Building Construction, Contractor
83	16	570,220	95%	2,970	Social Services
27	8	569,012	95%	5,927	Printing, Publishing and Allied Industries
32	11	524,493	96%	3,973	Stone, Clay, Glass, and Concrete Products
43	10	467,896	96%	3,899	United States Postal Service
76	13	413,253	96%	2,649	Miscellaneous Repair Services
Other	128	4,250,875		2,767	Other
Total	**2,252**	**116,514,128**		**4,312**	

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2022-3037368**
UGI UTILITIES, INC. – ELECTRIC DIVISION	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Direct Testimony labelled OSBA Statement No. 1 and associated Exhibits RDK-1 through RDK-4 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: April 25, 2023

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2022-3037368**
	:	
UGI Utilities, Inc. – Electric Division	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless otherwise noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

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DATE: April 25, 2023

/s/ Steven C. Gray

____

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

COMMONWEALTH OF PENNSYLVANIA

May 25, 2023

The Honorable Christopher P. Pell
The Honorable Charece Z. Collins
Administrative Law Judge
Pennsylvania Public Utility Commission
801 Market Street, Suite 4063
Philadelphia, PA 19107

Re: Pennsylvania Public Utility Commission v. UGI Utilities, Inc. – Electric Division
Docket No. R-2022-3037368

Dear Judge Pell & Judge Collins:

Enclosed please find the Rebuttal Testimony and Exhibit of Robert D. Knecht, labeled OSBA Statement No. 1-R, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

Enclosures
cc: PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Robert D. Knecht
Parties of Record

Office of Small Business Advocate
Forum Place 555 Walnut Street, 1st Floor | Harrisburg, PA 17101 717.783.2525 | Fax 717.783.2831 | www.osba.pa.gov

OSBA Statement No. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2022-3037368**
UGI UTILITIES, INC. – ELECTRIC DIVISION	:	

Rebuttal Testimony and Exhibits of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation

Date Served: May 25, 2023

Date Submitted for the Record: ____________________________

REBUTTAL TESTIMONY OF ROBERT D. KNECHT

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I submitted direct testimony and associated exhibits earlier in this proceeding, and my qualifications were presented therein.

Q. Please state the purpose of this rebuttal testimony.

A. The Pennsylvania Office of Small Business Advocate ("OSBA") requested that I review the cost allocation and revenue allocation recommendations of Dr. Karl Richard Pavlovic representing the Pennsylvania Office of Consumer Advocate ("OCA").

The acronyms, abbreviations and initialisms defined in my direct testimony apply also to this rebuttal testimony.

Q. Please state the cost allocation issues in Dr. Pavlovic's testimony to which you respond.

A. Dr. Pavlovic accepts the Company's allocated cost of service study ("ACOSS") as filed, with the exception of the "classification" of joint-use distribution plant assets.

As I explained in my direct testimony, the Company's ACOSS sub-functionalizes joint-use distribution plant (poles, conductors and transformers in FERC accounts 364-368) into primary voltage and secondary voltage system categories, and then it classifies each cost item into a "demand-related" and a "customer-related" component using a modified "minimum system" approach. Demand-related costs are allocated based on each class's non-coincident peak ("NCP") demand, and customer-related costs are allocated based on number of customers.

Dr. Pavlovic does not contest the sub-functionalization of these costs, but concludes that the cost items should be classified as 100 percent demand-related.

Q. What is Dr. Pavlovic's rationale for his position?

A. In short, Dr. Pavlovic concludes:

- Utilities are moving away from the traditional practice of classifying a portion of joint-use distribution plant costs into customer components;
- The widely used Bonbright text indicates that classification of electric distribution system costs with a customer component is incorrect;
- UGI Electric's planning documents indicate that the Company relies only on peak demand requirements for sizing its distribution system, and they do not cite to number of customers as a planning criterion.

Q. Do you agree with Dr. Pavlovic's view that other utilities are moving away from the inclusion of a customer component to joint-use distribution plant costs?

A. I have not attempted to verify this assertion, nor does Dr. Pavlovic offer evidence of any trend. However, I do not believe that the practices of other regulators are relevant to this issue in this proceeding. If regulatory precedent is to be a criterion, the most obvious criterion would be to rely on the Commission's most recent decisions for UGI Electric, and failing that, its decisions for other Pennsylvania electric distribution company ACOSSs. And if that precedent is used, the Commission has specifically endorsed the Company's method both for UGI Electric (Docket No. R-2017-2640058), and other Pennsylvania EDCs (see, in particular, PPL Electric at Docket Nos. R-2010-2161694 and R-2012-2200597).

Moreover, for issues involving distribution system assets, reliance on the practices of other jurisdictions may be more reflective of a lack of representation for small and medium general service customers than a careful regulatory evaluation of allocated costs.

Nevertheless, as Dr. Pavlovic recognizes at page 9, the classification of costs in this proceeding should reflect how this specific utility designs its distribution system and incurs costs. As I indicated in my direct testimony, the Commission has made it clear that costs should be evaluated on a case-by-case basis, and that even recent Commission precedent has limited relevance for any particular proceeding.

Q. Are Dr. Pavlovic's citations to <u>Principles of Public Utility Rates</u> relevant to this proceeding?

A. The beauty of Professor Bonbright's text is that it can be used to justify a wide range of positions in regulatory proceedings. The good professor's observations cited by Dr. Pavlovic do generally appear to conclude that classifying costs as customer-related do not reflect cost causation, apparently based on the results of a single statistical study for which there is no supporting data conducted more than 40 years ago. However, the Bonbright text also indicates, *"The most obvious examples of these customer costs are the expenses associated with local connection facilities, metering equipment and meter reading, billing and accounting, and a portion of the distribution system."* Even Dr. Pavlovic's citation to the text indicates that customer-related costs include "minimum service" costs, which can reasonably be interpreted to include joint-use distribution costs in close proximity to individual customers, particularly secondary voltage system costs. Moreover, the Bonbright citations have been presented to the Commission in numerous past EDC cost allocation proceedings, and they have yet to convince the Commission that the classification of distribution plant into demand and customer components is incorrect.

Q. What does Dr. Pavlovic rely upon to conclude that UGI Electric does not consider customer count in designing its distribution system?

A. As I understand the testimony, Dr. Pavlovic bases his conclusion on the fact that the Company's "Planning Principles and Practices" document does not specifically refer to customers in its planning criteria for system expansion and load growth, and that it refers only to the need to meet the size of forecasted loads.

Q. Is this reasonable evidence to conclude that the Company's planning does not recognize customers?

A. Of course not. The planning document does not say that the system must be expanded to meet new customers because it is simply too obvious to mention. If new customers are attached, even if there is no overall increase in system load, the distribution system must necessarily be expanded.

In addition, while it is correct that any component of the distribution system must be sized to meet the peak demands of customers served by that equipment, that does not imply that serving many smaller customers has the same cost per unit of peak demand as serving a small number of larger customers. Thus, the cost for ten 25 kVA line transformers to serve, say, 100 residential customers will likely be much higher than the cost of a single 250 kVA transformer serving a few medium-sized business customers. Moreover, the cost of extending the poles and conductors to serve the geographically distributed smaller customers will substantially exceed the costs incurred for a few larger customers.

Q. How do your observations regarding the Company's planning document apply to the issue of economies of scale discussed in your direct testimony?

A. The planning document implicitly recognizes both types of scale economies associated with serving larger customers compared to smaller customers.

First, it recognizes as obvious that the distribution system must be extended further to interconnect many small customers than a few larger customers.

Second, it reflects that the demands of the specific customers "downstream" of a particular asset must be met. However, it does not state the obvious, namely that the cost per kW of load for serving many smaller customers with many poles, more conductor feet, and more smaller line transformers is likely to be higher than that needed to serve a few larger customers.

Q. Is there evidence of these economies in the Company's cost statistics?

A. Yes. The simplest example is for line transformers, which are detailed in the Company's response to OSBA-II-18, which I have attached as RDK WPR2 with supplementary calculations. As shown in that analysis, the average cost for a 25 kVA overhead transformer is $122 per kVA, while the average cost for a 250 kVA overhead transformer is $55 per kVA, less than half the unit cost. Similarly, for underground transformer, a 25 kVA transformer costs $209 per kVA, while a 300 kVA transformer costs $96 per kVA.

In Dr. Pavlovic's cost framework, the cost per unit of demand is the same regardless of the size of the transformer. In practice, however, there are substantial economies of scale that make serving larger customers less costly than serving smaller customers.

Q. What, then, do you recommend regarding Dr. Pavlovic's cost allocation proposal?

A. I respectfully disagree with Dr. Pavlovic that there are zero economies for serving larger customers. In my direct testimony, I present what I believe to be a reasonable range for estimating the magnitude of these economies, with two alternative approaches. Dr. Pavlovic's proposal lies well outside that range, and I recommend against its adoption.

Q. Turning to the issue of revenue allocation, is Dr. Pavlovic's proposed revenue allocation consistent with the results of the OCA ACOSS methodology?

A. It is not.

To evaluate Dr. Pavlovic's proposal, I relied on my working version of the Company's ACOSS model, which is based on the updated version rather than the version Dr. Pavlovic relied upon. I simulated that model with a zero customer component for all joint-use distribution plant in accounts 364-368. This produced resulted in class rates of return very similar to those presented in Dr. Pavlovic's testimony. This simulation is attached to this testimony in working electronic format as RDK WPR1.

As I explained in my direct testimony, relying on the "indexed rate of return" metric for evaluating progress toward cost-based rates is an exercise in innumeracy. Dr. Pavlovic's proposed revenue allocation is based on that metric, and his results show clearly the flaws in that method. Consider the results of my simulation of Dr. Pavlovic's ACOSS method and revenue allocation for the Residential and GS-4 rate classes shown in Table RDK-R1 below:

Table RDK-R1
OCA ACOSS and Revenue Allocation Proposal: Residential and GS-1 Only

	Current Rates RoR	**Base Rate Increase**	**Proposed Rates RoR**
Residential	1.5%	19.8%	6.3%
GS-4	5.2%	29.5%	9.1%
System	**3.8%**	**21.3%**	**8.2%**

Note: Base rate increase reflects base rates, DSIC and STAT only, excluding electric supply costs and other charges that distort the percentage changes.
Source: RDK WPR1

So consider this proposal. Dr. Pavlovic's ACOSS indicates that the Residential class is substantially under-recovering costs at present rates, with a class rate of return of 1.5 percent compared to system average of 3.8 percent. Yet Dr. Pavlovic proposes to assign a rate increase to this class which is *below* system average. Common sense (and good arithmetic) indicate, for a rate class that is under-recovering costs, it is necessary to assign an above-average increase to improve that class's cost recovery. And yet, Dr. Pavlovic's analysis appears to produce the magical result that it is possible to move the Residential class revenues more into line with allocated costs by assigning below-average rate increases. This is, of course, nonsense.

The GS-4 class, by contrast, is modestly *over-recovering* allocated costs in Dr. Pavlovic's ACOSS, with a 5.2 percent return compared to system average 3.8 percent. And yet, Dr. Pavlovic assigns that class a rate increase far in excess of system average, at 29.5 percent compared to 21.3 percent. Common sense, of course, would indicate that if we assign a much higher than system average increase to that class, its over-recovery of costs should get worse. But, by using the flawed indexed rate of return metric, that class is purportedly producing revenues much closer to allocated cost.

Q. What are the implications of Dr. Pavlovic's revenue allocation and ACOSS proposals using the revenue-cost ratio metric you advocate in your direct testimony?

A. The revenue-cost ratio metric produces much more logical results, and it shows that Dr. Pavlovic's revenue allocation proposal will generally serve to move revenues farther away from allocated costs, even when Dr. Pavlovic's cost allocation method is adopted. The revenue-cost ratio results are shown in Table RDK-R2 below, and detailed in RDK WPR1.

Table RDK-R2 OCA ACOSS and Revenue Allocation Implications				
	Current Rates R-C Ratio	OCA Proposed Base Rate Increase	Proposed Rates R-C Ratio	R-C Ratio "Progress"
Residential	94.6%	19.8%	93.4%	-23%
GS-1	135.2%	16.6%	130.0%	15%
GS-4	100.8%	29.5%	107.5%	-872%
FCP	57.0%	16.6%	54.7%	-5%
Large Power	115.5%	27.9%	121.8%	-40%
Lighting	210.2%	15.6%	200.2%	9%
System	**100.0%**	**21.3%**	**100.0%**	--
Source: RDK WPR1				

The R-C ratio metric produces more intuitive results. The Residential class is assigned an increase slightly below system average, so its R-C ratio drops from 94.6 to 93.4 precent. Similarly, the enormous percentage increases to the GS-4 and LP classes proposed by Dr. Pavlovic serve only to increase the over-recovery of costs at current rates. The only classes that exhibit any progress toward cost-based rates are the GS-1 and Lighting classes, and those classes exhibit only small progress.

In short, Dr. Pavlovic's revenue allocation proposal is wholly inconsistent with the results of the ACOSS model presented in his testimony. As such, even if the OCA ACOSS method is adopted, Dr. Pavlovic's revenue allocation proposal should be rejected.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT RDK-1R

ELECTRONIC WORKPAPERS

RDK WPR1: UGI Electric COSS with Zero Customer Component and OCA Revenue Allocation

RDK WPR2: UGI Electric Sub-Functionalization and Classification Workpapers

***** Electronic Workpapers in excel format will be served via email simultaneous to service of Rebuttal Testimony*****

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2022-3037368**
UGI UTILITIES, INC. – ELECTRIC DIVISION	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Rebuttal Testimony labelled OSBA Statement No. 1-R and associated Exhibit RDK-1R are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: May 25, 2023

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
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DATE: May 25, 2023

/s/ Steven C. Gray

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Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

COMMONWEALTH OF PENNSYLVANIA

June 7, 2023

The Honorable Christopher P. Pell
The Honorable Charece Z. Collins
Administrative Law Judge
Pennsylvania Public Utility Commission
801 Market Street, Suite 4063
Philadelphia, PA 19107

Re: Pennsylvania Public Utility Commission v. UGI Utilities, Inc. – Electric Division
Docket No. R-2022-3037368

Dear Judge Pell & Judge Collins:

Enclosed please find the Surrebuttal Testimony of Robert D. Knecht, labeled OSBA Statement No. 1-S, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

Enclosures
cc: PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Robert D. Knecht
Parties of Record

OSBA Statement No. 1-S

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2022-3037368**
UGI UTILITIES, INC. – ELECTRIC DIVISION	:	

Surrebuttal Testimony of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation

Date Served: Jun 7, 2023

Date Submitted for the Record: ____________________________

SURREBUTTAL TESTIMONY OF ROBERT D. KNECHT

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I submitted direct testimony, rebuttal testimony, and associated exhibits earlier in this proceeding, and my qualifications were presented therein.

Q. Please state the purpose of this rebuttal testimony.

A. The Pennsylvania Office of Small Business Advocate ("OSBA") requested that I review the rebuttal testimony of Mr. John D. Taylor representing UGI Electric and Dr. Karl Richard Pavlovic representing the Pennsylvania Office of Consumer Advocate ("OCA").

The acronyms, abbreviations and initialisms defined in my direct testimony apply also to this rebuttal testimony.

Q. Please respond to Mr. Taylor's rebuttal testimony.

A. For most of Mr. Taylor's rebuttal, I have either no disagreement or I agree that the issue is not quantitatively material to this proceeding. I have a two brief observations:

At pages 16-17, Mr. Taylor indicates that UGI Electric counsel take the position that Commission decisions must be consistent with prior decisions except where there are new facts introduced. On advice of counsel, if that is the position of UGI Electric counsel, they are purposefully ignoring Footnote 30 of the Commission's Columbia Gas Order at Docket No. R-2022-3031211, at page 107.

At page 18, Mr. Taylor indicates that an evaluation of working capital requirements by class was not completed. In fact, the Company did prepare an evaluation of payment lag by class, and cost lag is invariant by class. My development of working capital allocators from that information was provided in RDK WP2 and RDK WP3.

Q. Please respond to Dr. Pavlovic's complaints about your reliance on economies of scale for justifying the classification of distribution plant into both customer and demand components.

A. Dr. Pavlovic acknowledges that economies of scale exist for different types of electricity distribution equipment, but he disagrees that this implies that smaller customers are more expensive to serve per unit of demand.

One would think that simple observation would verify that extending the distribution system to serve more geographically diverse residential customers would confirm that economies of scale exist for serving larger customers in more concentrated commercial areas. While it may not be easy to identify the exact magnitude of those scale economies, it is not reasonable to pretend that they do not exist. Moreover, Dr. Pavlovic greatly oversimplifies distribution system planning when he concludes that it designs the system based on aggregate demand. The distribution system must be developed to interconnect all of the customers, and each component of the distribution system must be sized to meet the maximum load served by that component. There are no components of UGI Electric's distribution system that are sized to meet aggregate system demand.

Moreover, Dr. Pavlovic implicitly concludes that smaller, less cost-efficient equipment (per unit of demand), is used equally for small and large customers. This, of course, makes no sense. It is simply not possible, for example, for UGI Electric's 25 kVA line transformers to serve 50 kW commercial customers. The utility necessarily uses the equipment with lower capacity to serve smaller customers. Because this equipment is more costly per unit of demand, it must necessarily follow that smaller customers are more costly to serve per unit of demand. Thus, once Dr. Pavlovic concedes that there are scale economies in the equipment, those scale economies are more applicable to larger customers who disproportionately rely on the larger equipment.

Q. Please respond to Dr. Pavlovic's concern that your proposed revenue allocation does not represent a reasonable apportionment of the rate increase, whereas the OCA proposed method results in a reasonable balance.

A. As I explained at some length in both my direct and rebuttal testimony, the metric upon which Dr. Pavlovic relies (indexed rate of return) is not reasonable for demonstrating progress toward cost-based rates. In fact, the indexed rate of return metric implies that Dr.

Pavlovic's revenue allocation would result in progress toward cost-based rates, when in fact Dr. Pavlovic's proposal moves rates farther away from allocated cost.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2022-3037368**
UGI UTILITIES, INC. – ELECTRIC DIVISION	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Surrebuttal Testimony labelled OSBA Statement No. 1-S are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: June 6, 2023

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2022-3037368**
	:	
UGI Utilities, Inc. – Electric Division	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless otherwise noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

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DATE: June 7, 2023

/s/ Steven C. Gray

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COMMISSON ON ECONOMIC OPPORTUNITY

CEO Statement No. 1

Direct Testimony of Jennifer Warabak

In Re: UGI Utilities, Inc. – Electric Division
Request for a Rate Increase

Docket Number: R-2022-3037368

Q. Please state your full name and business address.

A. Jennifer Warabak, 165 Amber Lane, PO Box 1127, Wilkes-Barre, Pennsylvania 18703-1127.

Q. By whom are you employed and in what capacity?

A. I am employed by the Commission on Economic Opportunity (CEO) as Executive Director.

Q. What are the interests of the CEO in this rate case?

A. The Commission on Economic Opportunity is a non-profit organization serving the low income and elderly in Luzerne County, PA. In a typical year, the Commission serves more than 20,000 Luzerne County residents, of which 98% are at or below 150% of the poverty level. It is part of our responsibility to our constituency to advocate for their interests in regulatory proceedings and this proposed request will certainly have an impact upon those low-income ratepayers. In addition to the affordability of transmission and distribution rates, CEO is particularly interested in the adequacy and operation of a company's universal service program.

Q. What background and experience in energy issues qualify you to submit testimony in this case?

A. I was appointed as the acting Executive Director of the Commission on Economic Opportunity in October 2022. I have been employed at CEO for over 20 years and during my tenure I have been involved in numerous energy related programs that CEO operates. From 2004 to 2016, I was CEO's Energy Services Coordinator where I supervised CEO's energy programs. During that time, I managed eight hardship utility programs and managed the LIHEAP Crisis program for Luzerne County on behalf of the Pennsylvania Department of Human Services as well as other utility customer assistance programs for a number of utility companies. In 2016 I became CEO's Program and Planning Coordinator where I evaluated program effectiveness and recommended modifications and/or improvements across the spectrum of programs offered by CEO, in the areas of energy, housing, job training etc.

During my tenure in those positions, CEO's experience and the expertise of its staff in energy programs has been recognized on state and national levels. CEO's energy related programs have been acknowledged by receipt of a Superior Achievement Award from the United States Department of Energy. CEO has weatherized more than 26,000 homes under the U.S. Department of Energy Weatherization Assistance Program. CEO also serves as a subcontractor for universal programs operated by a number of Pennsylvania gas and electric utility companies. CEO is also the PA Department of Public Welfare's contracted operator of the crisis component of the Low-Income Home Energy Assistance Program (LIHEAP) in Luzerne and Wyoming Counties. CEO was also a major contractor for PPL in the Low-Income Renewable Energy Pilot, and secured funding and installed several solar thermal water heating systems for the former PG Energy and UGI Gas Division.

Q. Before addressing the specifics of your testimony, does CEO take a position on whether the Company's rate increase should be granted?

A. Our main focus is on the funding and availability of universal service programs and opposing rate designs that discourage conservation. In this case, we do not necessarily oppose a rate increase, but do oppose <u>any</u> rate increase unless it is accompanied by measures that would provide additional relief to the Company's customers, particularly low-income customers, from the effects of a rate increase.

Q. Please describe the other areas of your testimony.

A. My testimony will address the Company's proposal to increase the fixed monthly charge for residential customers as well as proposals to help low-income customers deal with any resulting rate increase.

In its request for a rate increase the Company does not propose any additional increase in funding or measures that would help low-income customers deal with the proposed rate increase. Further, an increase in the fixed monthly charge, as requested by the Company, would negatively impact a customer's motive and ability to conserve energy. The company's proposal if granted would increase rates, discourage conservation and leave a customer with less ability to conserve energy and less ability to reduce their bills. Despite the impact of its proposal on residential customers, and in particular low-income customers, the Company's proposal offers nothing in the way of changes or increases in funding to its low-income programs, programs that would help mitigate the negative impact of the Company's proposals especially considering these difficult economic times.

Despite these difficult financial times for all, including ratepayers, the Company is requesting an increase in annual distribution revenues of $11.4 million. A residential customer using an average 1000kWh per month would see an increase from $192.73 to $209.96 per month, an increase of nearly 9%. In this case, the Company requests a rate increase and offers nothing additional to help low-income customers

Q. What rate design issue would you like to address?

A. In this case the Company is proposing to increase its fixed monthly charge for residential customers from $9.50 to $13.50 an increase of over 40%. Other than a proposed increase of $1 for General Service customers, the Company is not proposing any increases to the monthly customer charges for any of its four other classes. I am concerned about this proposal to increase its fixed monthly charge for residential customers and CEO opposes any increase to the fixed monthly customer charge.

Part of the proposed increase to residential customer's rates will be due to this increase in the fixed monthly customer charge. This increase in the monthly fixed charge concerns me, as it has the Commission, because it discourages conservation and impacts a customer's ability to save money through conservation; as the Company moves towards charging customers based upon the Company's fixed costs and away from a customer's consumption there is less incentive, and ability, to conserve. One of the only defenses a family, particularly a poor family, has against the sharp increases in energy costs is to conserve – lower the thermostat, seal air leaks, change filters regularly, add more insulation, get a more efficient heating unit, etc. The Company's proposal to increase the fixed costs greatly impacts a customer's motive to conserve and the ability to lessen the impact of any rate increase. The combined effect of an increase in rates and an increase in fixed monthly charges, without any changes to universal service funding or other measures to help low-income customers, not only results in higher rates but also lessens the ability of customers to deal with those increases. In particular, the negative impact would be particularly harsh on the Company's low-income customers and the Company's proposed request ignores the interests of its low-income customers.

Q. How does the effect of the Company's requests impact upon your testimony in this case?

A. I believe that should a rate increase be granted there should be relief offered in the form of increases to universal funding programs and other relief that would help low-income customers deal with any increase granted. For a typical residential customer, a 9% increase is substantial, but for a low-income customer, the effects can be dramatic, especially in this economic climate. High utility costs are not the only challenge for a poor person. CEO has been helping low-income people for years and knows firsthand that they face financial challenges on many fronts -- housing, energy costs, food and health care -- and a dramatic increase in any of those areas can have a devastating impact.

It is for these reasons that if an increase is granted it should be conditioned upon an increase in funding and relief to the Company's low-income customers.

Q. Should a request for a rate increase be granted what type of measures would you suggest be implemented for low-income customers?

A. In discovery responses in this case the Company indicated as of February 2023 it had 5,636 confirmed low-income customers who had an average annual income of $14,607. There are 21,726 estimated low-income customers. As a result of this proceeding rates are likely to increase, a customer's ability to conserve will decrease (if the fixed monthly charge is increased) yet no additional relief is being provided to customers that would allow them to increase their conservation of energy and decrease their monthly bills.

Q. Turning now to universal service programs what issues would you like to address?

A. I want to address the Company's low-income usage reduction program (LIURP). Annual funding for LIURP for each of the years 2023, 2024 and 2025 is set at $298,379. The Company expects to serve 66 ratepayers in LIURP.

CEO is proposing increased funding for LIURP because of the number of estimated and confirmed low-income customers in its territory, the flat LIURP funding and the limited number of people it serves and what is expected to be a rate increase resulting from this case.

Q: Do you have any recommendations regarding the funding level for LIURP?

A: Yes. CEO is recommending that annual LIURP funding be increased at least by the commensurate percentage increase in rates to residential customers that result form this proceeding.

Q: Do you have any other recommendations regarding the LIURP program?

A: Yes. CEO recommends that the Company continue to partner with the community-based organizations it has traditionally employed to provide LIURP services to its customers.

Q. Are there any other universal service topics that you want to address?

A. Yes. CEO recommends that the Company's contribution to its hardship fund be increased commensurate with the percentage increase in rates to the residential class that results from this proceeding. Although modest in comparison to other universal service funding, the proposal will help customers deal with a rate increase in these difficult economic times.

I also recommend that hardship funding be distributed in accordance with the percentage of low-income customers in the counties served by the Company.

Q. Can you please summarize your recommendations?

A. Yes. The CEO is recommending the following:

1. That the Company's request to increase its fixed residential monthly customer charge be denied;

3. That annual funding for LIURP be increased commensurate with the percentage increase in residential rates that result from this proceeding;

4. That the Company continue to partner with the community-based organizations it has traditionally employed to provide LIURP services to its customers;

5. That the Company's contribution to its Hardship fund be increased commensurate with the percentage increase in residential rates that result from this proceeding;

6. That Hardship funds be distributed in accordance with the percentage of

low-income customers in the counties served by the Company.

Q. Does this conclude your testimony?

A. Yes

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	
	:	
V.	:	R-2022-3037368
	:	
UGI UTILIITES, INC. – ELECTRIC DIVISION	:	

CERTIFICATE OF SERVICE

The undersigned certified that he served a copy of the foregoing CEO Statement No. 1 – Direct Testimony of Jennifer Warabak upon the following participants by electronic mail on the 25th day of April, 2023:

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VERIFICATION

I, **Jennifer Warabak,** hereby state and verify the following:

1. I am the Executive Director of the Commission on Economic Opportunity.

2. I have submitted in this proceeding, through counsel, written direct testimony, CEO Statement No. 1.

3. In lieu of my appearance at hearing in this matter, I am offering CEO Statement No. I into evidence at hearing through the statements set forth in this Verification.

4. If I were called to testify at hearing, the answers to the questions I gave in CEO Statement No. I would be the answers given by me at hearing in response to those same questions.

5. The facts set forth in my answers contained in CEO Statement No. I are true and correct and represent my answers to those questions.

6. There are no additions, corrections or deletions I would propose to CEO Statement No. I.

Jennifer Warabak

DATE: June 12, 2023