BOOK IV

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS STATEMENT NO. 6 – VICKY A. SCHAPPELL
UGI GAS STATEMENT NO. 7 – PAUL R. MOUL
UGI GAS STATEMENT NO. 8 – PAUL R. HERBERT
UGI GAS STATEMENT NO. 9 – JOHN F. WIEDMAYER
UGI GAS STATEMENT NO. 10 – NICOLE M. MCKINNEY

UGI UTILITIES, INC. – GAS DIVISION – PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 6

DOCKET NO. R-2019-3015162

Issued: January 28, 2020 **Effective: March 28, 2020**

UGI GAS STATEMENT NO. 6 – VICKY A. SCHAPPELL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2019-3015162

UGI Utilities, Inc. – Gas Division

Statement No. 6

Direct Testimony of
Vicky A. Schappell

Topics Addressed: **Capital Planning**

Dated: January 28, 2020

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 a 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") and the Gas Division ("UGI Gas" or the "Company"), 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 Gas Exhibit VAS-1 to my testimony.

Q. What are your responsibilities as Principal Analyst?

A. As Principal Analyst, I supervise a team of Analysts in preparing the annual capital budgets for UGI Gas and UGI Electric. I am responsible for obtaining budget inputs from various departments including Engineering, Operations, Corrosion, Marketing, Information Services, and the Building and Grounds Departments. I collaborate with the Vice President of Engineering and Operations Support, the Vice President of Operations, the Director of Engineering, the Director of Marketing Programs and Strategies, the Director of Pipeline System Planning and Optimization, the Financial Planning and Analysis Lead and Senior Engineering Managers to monitor annual capital budget performance and develop strategies to limit variances in capital installations and spending. I also work closely with the Chief Operations Officer in developing the overall capital spend strategy. I have prepared schedules and discovery requests for past rate cases. Additionally, I had an integral role in developing an expanded capital spending monitoring process (as a result of the Company's recent accelerated capital investments programs).

Q. Have you previously presented testimony in proceedings before a regulatory agency?

A. No, I have not.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Gas. In my testimony, I will address the Company's capital planning process for this proceeding.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, in addition to UGI Gas Exhibit VAS-1, I am sponsoring UGI Gas Exhibit VAS-2. I am also sponsoring certain responses to the Commission's standard filing requirements as indicated on the master list accompanying this filing.

II. CAPITAL PLANNING

Q. Please describe the categories of projects included in the capital budget for UGI Gas.

A. The principal categories for which UGI Gas develops capital budgets are: (1) replacement and betterment infrastructure; (2) new business; (3) information services; (4) other capital spend; and (5) removal and salvage. The budgeting process is further described in the direct testimony of Stephen F. Anzaldo (UGI Gas St. No. 2).

Q. What are replacement and betterment projects?

A. Replacement and betterment ("R&B") projects improve or replace existing infrastructure and include, but are not limited to, leak remediation, pipe relocations, material upgrades, service renewals, reliability improvements and metering and regulation upgrades.

Q. How does UGI Gas determine which R&B projects are included in the capital budget for a given year?

A. UGI Gas enters R&B projects into its capital budget according to a risk-based prioritization process.

Q. Please describe this risk-based prioritization process.

A. This process prioritizes the replacement of cast iron and bare steel pipe, which are more susceptible to failure from corrosion, cracks and leakage (as compared to other pipe materials). Risk evaluations for mains are based on numerous factors, including condition, age, coating, type of ground cover, geographical proximity to structures and prior leak and/or break history. UGI Gas reviews these factors annually to identify the highest risk pipe segments and prioritize them for replacement.[1] Specifically, commercial risk evaluation software is used in concert with a team of Subject Matter Experts to evaluate, prioritize, and bundle replacement projects. Furthermore, UGI Gas's Distribution Integrity Management Plan ("DIMP") and Transmission Integrity Management Program ("TIMP") provide a detailed listing of factors considered in the risk based evaluation, which may cause specific projects to be reprioritized for replacement on a more accelerated basis. This hybrid approach targets the highest risk mains first, while also balancing the need to maximize the efficient deployment of capital and resources.

UGI Gas's prioritization of projects for its capital budgets also is consistent with its Long-Term Infrastructure Improvement Plan ("LTIIP"), which is described in more detail in the direct testimony of UGI Gas witness, Kelly A. Beaver (UGI Gas St. No. 4). LTIIP replacement investments are in turn identified and prioritized on a risk basis in accordance with UGI Gas's DIMP.

Q. What are new business projects?

A. New Business projects provide new or upgraded gas service to customers and may involve the installation of new gas mains and services or conversions to natural gas service (from other heating sources).

[1] When replacing mains, the Company also replaces associated distribution equipment, including service lines, as well as installing or replacing safety and monitoring devices (excess flow valves), meters, risers, and meter bars. In some cases, indoor meters are relocated to an outside location. Similarly, regulator stations and service regulators are reviewed and prioritized for replacement based on nearby main replacement projects or required upgrades due to the updated equipment installed as part of the main replacement program.

Q. Please describe how the new business infrastructure projects are selected for inclusion in the capital budget.

A. These projects are selected for inclusion in the capital budget according to forecasts of new business opportunities, projections of customer conversions and plans for new construction and development projects. New business main extensions under the Company's Growth Extension Tariff ("GET") are planned, prioritized and included in the budget based on the guidelines outlined in the Company's Tariff and projections of customer demand (as measured by new service inquiry responses).

Q. What are information services projects?

A. Information services projects enhance the Company's information technology ("IT") systems. These projects improve the Company's methods (including computerized systems and hardware/software applications) for managing capital projects in a safe and reliable manner. Further, these projects facilitate the Company's ability to enter, store, retrieve and send data/information related to such projects.

Q. Please describe the prioritization process used to evaluate information services projects.

A. IT projects are prioritized (for inclusion in the budget) based on the need for new systems and hardware to continue performing capital projects in a safe and reliable fashion. Budget determinations are prioritized by the Company's IT Prioritization Committee, based on overall business impact, availability of system support, and resource availability.

Q. What are other capital projects?

A. Other capital projects include building-related projects, corrosion control projects, capital tool purchases, and fleet purchases. Building-related projects consist of building and land purchases, building improvements/renovations, and the purchase of furniture. Corrosion control projects include upgrades and replacements of cathodic protection systems for mains. Capital tool projects encompass new tool purchases for field use during capital projects. These tools include tapping and stopping equipment, safety tools, and leak detection equipment. Fleet purchases are needed to maintain a reliable mode of transportation for field employees to perform their daily functions. These acquisitions include SUVs, pickup trucks, cargo vans, service body trucks, compressor crew trucks, vacuum trucks, aerial lift trucks, dump trucks, backhoes, excavators, forklifts and equipment trailers for backhoes and excavators.

Q. Please describe the prioritization process used to evaluate other capital projects.

A. Building-related projects are prioritized (for budget inclusion) based on safety/security, regulatory, or financial and strategic needs. Regulatory driven projects originate from audit observations. Physical security audits may prompt the installation of fencing, gates and access controls. Corrosion control projects (involving coated steel main replacements) are prioritized (for budget inclusion) according to requirements set forth in the Federal Gas Safety Regulations (49 C.F.R. Part 192).[2] Corrosion control projects also may depend on unrepairable leakages or emerging main issues. Capital tool projects are

[2] Transmission lines may be replaced due to corrosion that affects wall thickness pursuant to 49 C.F.R. § 192.485. Additionally, portions of transmission lines (with localized corrosion pitting) may be replaced pursuant to 49 C.F.R. § 192.485. Similarly, distribution lines with corrosion (or portions thereof with localized pitting corrosion) may be replaced pursuant to 49 C.F.R. 192.487. Lines also may need to be replaced if they lack cathodic protection systems, as detailed in 49 C.F.R. § 192.463.

prioritized (for budget inclusion) according to the useful life of the existing assets. Fleet purchases are prioritized (for budget inclusion) based on age, condition, maintenance costs and mileage of the existing asset.

Q. What are removal and salvage projects?

A. Removal and salvage projects include main and service retirements where assets are not replaced. Additionally, this category of spend includes the environmental projects performed at UGI Gas (including mercury regulator remediation and waste disposal).

Q. Please describe the prioritization process used to evaluate removal and salvage projects.

A. These projects are identified and prioritized (for budget inclusion) through the same risk-based prioritization process used for the R&B projects. Environmental projects are entered into the budget as they are identified in the field. These kinds of capital projects are budgeted on a project level and are rolled up to the Electric and Gas Divisions (as appropriate). Capital projects of general application to UGI are budgeted by UGI and costs are allocated to the divisions in accordance with the Modified Wisconsin Formula ("MWF").

Q. How have UGI Gas's actual capital additions compared to budgeted capital additions (in relation to the above-described categories)?

A. Over the past three years, the Company's total budgeted capital additions (including all of the above-described categories) was $956.829 million, while the total actual additions was $978.859 million; there was a $22.030 million variance. More specifically, during this period, the Company's plant additions were 102.3% of its budget. (See UGI Gas Exhibit VAS-2). This close correlation between budgeted and actual plant placed in service over the past three years further supports the Company's claimed level of plant in service in this case, and is discussed in the testimony of UGI Gas witness Vivian K. Ressler (UGI Gas St. No. 3).

III. UNITE PHASE III-ENTERPRISE PERFORMANCE MANAGEMENT ("EPM")

Q. Please describe the Capital Planning, Forecasting and Budgeting tool that will be implemented in UNITE Phase III-EPM.

A. UNITE Phase III-EPM is an IT advancement that will allow the Company to improve its capital budgeting and forecasting processes. It will cost the Company $15,000,000 to replace its existing capital planning system with a more modern application. Based on the MWF, $14,118,000 (of the total $15,000,000 amount) is being included in the gas capital budget for the future test year ("FTY") in this case.

UGI currently uses a home-grown database (*i.e.*, 4CAP) for capital planning. However, the Company plans to replace the 4CAP system because it has run its useful life and lacks the capability to capture necessary project details (e.g., approval history, expected returns on investment, and planned labor spend). Because 4CAP lacks this capability, separate systems or manual processes are used currently to maintain this level of project detail.

Accordingly, the Company intends to replace the current 4CAP capital budgeting tool (in the FTY) with the PowerPlan Capital Budgeting and Forecasting application ("PowerPlan"). The PowerPlan Capital budgeting functionality will allow the Company to manage costs during the entire lifecycle of a project. It also will integrate project management and downstream accounting activities. PowerPlan is the leading software provider for plant accounting/capital planning in the utility industry and its application will allow the Company to efficiently integrate its capital budgeting and forecasting data with our existing PowerPlan plant accounting software for actuals.

IV. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS EXHIBIT VAS-1

Vicky A. Schappell

Senior Analyst – Capital Planning

Work Experience

2020-Present	Principal Analyst-Capital Planning UGI Utilities., Reading PA
2018-2020	Senior Analyst – Capital Planning UGI Utilities, Inc., Reading PA
2014-2018	Senior Supervisor Plant Accounting UGI Utilities, Inc., Reading PA
2011-2014	Senior Analyst – General Ledger UGI Utilities, Inc., Reading PA
2008-2011	Analyst II – General Ledger UGI Utilities, Inc. Reading PA
2007-2008	Accounting Supervisor Teleflex Medical, Reading PA
2003-2007	Senior Accountant – Financial Reporting Arrow International, Inc., Reading PA
1999-2003	Staff Accountant – Financial Reporting Arrow International, Inc., Reading PA
1997-1999	Auditor Heffler, Radetich & Saitta LLP, Philadelphia, PA

Education

B.S. in Accounting from Shippensburg University, 1997

UGI GAS EXHIBIT VAS-2

UGI UTILITIES, INC. - GAS DIVISION
Plant Placed in Service compared to Budget
$ amounts in '000s

	2017		2018		2019		3 Year Total	
	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual
Total Additions	$ 275,370	$ 295,932	$ 284,181	$ 309,879	$ 397,278	$ 373,049	$ 956,829	$ 978,859
							(1)	**(2)**

Capital Spend as % of Budget **(2) / (1)** **102.3%**

UGI GAS STATEMENT NO. 7 – PAUL R. MOUL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2019-3015162

UGI Utilities, Inc. – Gas Division

Statement No. 7

Direct Testimony of
Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

Topics Addressed:	**Capital Structure** **Rate of Return**

Dated: January 28, 2020

<u>UGI Utilities, Inc. - Gas Division</u>

Direct Testimony of Paul R. Moul

Table of Contents

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
CCR	Corporate Credit Rating
CE	Comparable Earnings
DCF	Discounted Cash Flow
FERC	Federal Energy Regulatory Commission
g	Growth rate
IGF	Internally Generated Funds
IRPA	Interest Rate Protection Agreement
LDC	local distribution companies
Lev	Leverage modification
LT	Long Term
OCI	Other Comprehensive Income
P-E	Price-earnings
PUC	Public Utility Commission
r	represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Return on the market
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
UGI Gas	UGI Utilities, Inc. – Gas Division
UGI	UGI Corporation
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value
ytm	Yield to maturity

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 Appendix A, 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 determining the revenues UGI Utilities, Inc. – Gas Division ("UGI Gas" 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 Exhibit B, which is a multi-page document divided into fourteen (14) schedules.

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 7.95% overall rate of return, which includes a 10.95% rate of return on common equity. My 10.95% rate of return on common equity includes recognition of the exemplary performance of the Company’s management, and 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 which 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
Total Debt	46.70%	4.51%	2.11%
Common Equity	53.30%	10.95%	5.84%
Total	100.00%		7.95%

This overall rate of return is applicable to the September 30, 2021, fully projected future test year ("FPFTY") and the initial period that the Company's proposed rates will be effective.

Q. What factors have you considered in the determination of the Company's cost of equity in this proceeding?

A. UGI Gas is a division of UGI Utilities, Inc. ("UGI Utilities"), a wholly-owned subsidiary of UGI Corporation ("UGI" or the "Parent Company"). The Company provides natural gas distribution service to more than 640,000 customers in forty-five Pennsylvania counties. The Company's service territory contains several production centers for basic industries involved in steel and aluminum manufacturing and fabrication chemicals, and food processing. Throughput to on-system customers in fiscal 2019 was represented by approximately 21% to sales customers and approximately 79% to transportation customers. The significant portion of the Company's throughput to industrial customers makes the Company a much higher risk utility as compared to the Gas Group. The Company obtains its natural gas supplies from producers and marketers and has transportation arrangements through connections to six interstate pipelines. The Company has storage arrangements for natural gas inventory. UGI Utilities also provides electric delivery service, through its Electric Division, to more than 62,000 customers in portions of Luzerne and Wyoming Counties.

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 a natural gas 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 10.95% represents a reasonable cost of equity, which is consistent with well recognized principles for determining a fair rate of return.

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 nine (9) natural gas companies. I began with all of the gas utilities contained in The Value Line Investment Survey, which consists of ten companies. Value Line is an investment advisory service that is a widely used source in public utility rate cases. I eliminated one company from the Value Line group. UGI Corp. was removed due to its diversified businesses consisting of six reportable segments, including propane, two international LPG segments, natural gas utility, energy services and midstream, and electric generation. I will refer to the nine companies as the "Gas Group" throughout my testimony. The companies are identified on page 2 of Schedule 3. These are the same companies that were used to apply the cost of equity models in the recent Quarterly Earnings Report approved by the Commission on November 14, 2019.

Q. How have you performed your cost of equity analysis with the market data for the Gas Group?

A. I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not measured separately the cost of

[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).

equity for the individual companies within the Gas Group, because the determination of the cost of equity for an individual company has become increasingly problematic. The use of average data for a portfolio of companies reduces the effect that anomalous results for an individual company may have on the rate of return determination. 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.

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. 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.

	Gas Group
DCF	11.81%
Risk Premium	10.25%
CAPM	11.01%
Comparable Earnings	12.25%

From these measures, I recommend a cost of equity of 10.95%. My recommendation is on the conservative side for UGI Gas because it is based on the Gas Group that does not have the Company's high-risk attributes related to its high level of industrial throughput. It does provide recognition of the performance of the Company's management. Mr. Brown's testimony in UGI Gas Statement No. 1 demonstrates that the Company ranks high in customer service and management effectiveness. In recognition of its outstanding performance, the Company should be granted an opportunity to earn a 10.95% rate of return on common equity. My 10.95% cost of equity recommendation includes 20 basis points or 0.20% recognition for the exemplary performance of the Company's management. 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. Along these lines, the Company is spending considerable amounts of new capital that are large by historical standards, which will put a strain on financial performance in the short run. In recognition of its performance, the Company should be granted an opportunity to earn a 10.95% rate of return on common equity.

NATURAL GAS RISK FACTORS

Q. What factors currently affect the business risk of the natural gas utilities?

A. Gas utilities face risks arising from competition, economic regulation, the business cycle, and customer usage patterns. Today, they operate in a more complex environment with time frames for decision-making considerably shortened. Their business profile is influenced by market-oriented pricing for the commodity distributed to customers and open access for the transportation of natural gas for customers.

Natural gas utilities have focused increased attention on safety and reliability and on conservation and energy efficiency. In order to address these issues and to comply with new and pending pipeline safety regulations, natural gas companies are now allocating more of their resources to addressing aging infrastructure issues and extension and expansion requests, which have led to increased external capital requirements.

Q. Does the Company face competition in its natural gas business?

A. Yes. The Company's service territory is within or in close proximity to the Marcellus Shale production area, which provides additional risk for UGI Gas compared to the companies in the Gas Group. Natural gas generally faces significant competition from alternative energy sources. The Company faces direct competition from electricity, fuel oil, and propane in its service territory. Propane and fuel oil have an advantage because they are not inhibited by regulatory constraints when conducting marketing and pricing their services. This situation is unlike that of UGI Gas, where specific thresholds must be satisfied for system expansions, where promotional activities are constrained and prices are regulated. The Company also faces the risk associated with throughput to interruptible customers whose deliveries are influenced by global oil prices. Further, the Company has identified eighteen (18) customers that could potentially bypass its system.

Q. Are there specific factors influencing the Company's risk profile?

A. Yes. The Company's risk profile is strongly influenced by throughput delivered to large competitive market customers. Large competitive market customers represent over 50% of throughput, but these customers represent about one-half of one percent of total customers. Moreover, the Company's top ten customers represent 185.8 million Mcf of total throughput or about 63%. Electric generation, manufacturing, cement, chemicals, and food processing are among these customers. Steel and aluminum manufacturing and fabrication face a number of challenges including international competition, increased costs, and fluctuating demand for their products. Industrial sales are generally higher in risk than sales to other classes of customers. Success in this segment of the Company's market is subject to the business cycle and the price of alternative energy sources. Moreover, external factors can also influence the Company's sales to these customers which face competitive pressures on their own operations from other facilities outside the Company's service territory.

Q. Please indicate how the Company's risk profile is affected by its construction program.

A. With customer demand for the Company's service at high levels, the Company is faced with the requirement to invest in new facilities to meet growth and to maintain and upgrade existing facilities in its service territory. To maintain safe and reliable service to existing customers, the Company must invest to upgrade existing facilities. The Company has approximately 1,310 miles of its distribution mains constructed of unprotected steel and cast iron pipe as of year-end 2018. The Company also has 36,303 of its services constructed of unprotected steel. The Company is also under a regulatory mandate to relocate all of its meters outside, with certain exceptions, by September 13, 2034. The continuing costs for upgrading the Company's pipe system will elevate the level of construction expenditures. In the situation where additional capital investment is required to replace existing facilities and also to serve new customers, supportive regulation is a necessary prerequisite for the Company to actually achieve a fair rate of return and attract new capital on reasonable terms.

For the future, the Company estimates that its construction expenditures will be:

Year	Capital Expenditures
2020	$ 394,098,000
2021	$ 398,921,000
2022	$ 452,494,000
2023	$ 479,053,000
Total	$ 1,724,566,000

During the 2020-2023 period, gross construction expenditures will represent an approximate 61% increase ($1,724,566,000 ÷ $2,808,340,000) in net utility plant, including construction work in progress, from the level at September 30, 2019.

Q. Is the Company's risk also affected by the substantial decline in usage per customer?

A. Yes. Despite adding new customers, usage per residential heating customer continues to decline over time as discussed in the testimony of Mr. Brown (UGI Gas Statement No. 1). Company analysis indicates that this decline will continue, particularly with the implementation of its successful energy efficiency and conservation plan. This plan will provide many benefits to customers and to the public, but can be expected to further reduce customer usage and consequently company revenues and return.

Q. Are you aware that there is a DSIC available to natural gas utilities in Pennsylvania, and does the DSIC affect the Company's cost of capital?

A. I am aware that the Company has utilized the Distribution System Improvement Charge ("DSIC") in the past. The cost of capital for UGI Gas, however, is not affected by the DSIC. I say this because most of the proxy group companies (i.e., eight of nine companies) whose data has been used to develop the cost of equity for UGI Gas in this proceeding have a DSIC or similar infrastructure rehabilitation mechanisms. Indeed, Atmos Energy, Chesapeake, New Jersey Resources, NiSource, Northwest Natural Gas, South Jersey Industries, Southwest Gas, and Spire make use of a DSIC or similar infrastructure rehabilitation mechanisms. Hence, whatever the benefit of a DSIC, or other regulatory mechanisms, that impact is already reflected in the market evidence of the cost of equity for the proxy group.

Q. How should the Commission respond to the issues facing the natural gas business and in particular UGI Gas?

A. The Commission should recognize the issues listed above when deciding the rate of return issue in this case. In particular, the Company has higher risks associated with its large throughput to industrial customers. Another risk is declining usage per customer discussed in the testimony of Company witness Mr. Christopher Brown (UGI Gas Statement No. 1). Moreover, the Company requires regulatory support at a time of increased infrastructure spending now underway for the Company.

FUNDAMENTAL RISK ANALYSIS

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 UGI Gas to the S&P Public Utilities, an industry-wide proxy consisting of all types of public utility endeavors, and to the Gas Group.

Q. What are the components of the S&P Public Utilities?

A. The S&P Public Utilities is a widely recognized index consisting 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 Gas Group?

A. As discussed above, my Gas Group consists of the following companies: Atmos Energy Corp., Chesapeake Utilities Corporation, New Jersey Resources Corp., NiSource, Inc., Northwest Natural Holding Co., ONE Gas, Inc., South Jersey Industries, Inc., Southwest Gas Holdings, and Spire, Inc.

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 Gas Group, and the S&P Public Utilities?

A. Presently, the Company's Long Term (“LT”) issuer rating is A2 from Moody's and A- from Fitch. 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 Gas Group, which has an average A2 and A-credit rating from Moody's and S&P, respectively. For the S&P Public Utilities, the average composite credit rating is 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.

Q. How do the financial data compare for UGI Utilities, the Gas Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3 and 4. The data cover the five-year period 2014-2018. I will highlight the important categories of relative risk, which may be summarized as follows:

Size. In terms of capitalization, UGI Utilities is smaller than the average size of the Gas Group. The S&P Public Utilities is very much larger than all the gas companies that I have considered. 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 UGI Utilities and the Gas Group.

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]

[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).

Since UGI Utilities' stock is not traded, there are no market ratios for the Company. The five-year average price-earnings multiple was similar for the Gas Group and the S&P Public Utilities. The five-year average dividend yield was lower for the Gas Group as compared to the S&P Public Utilities. The five-year average market-to-book ratio was somewhat higher for the Gas Group as compared to 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 high common equity ratio has low financial risk, while a firm with a low common equity ratio has high financial risk. The five-year average common equity ratios, based on permanent capital, based on book value, were 57.9% for UGI Utilities, 53.2% for the Gas Group, and 43.0% for the S&P Public Utilities. The historical common equity ratio for UGI Utilities was higher than the Gas Group average, although the ratio in this case of 53.30% is clearly with the range of common equity ratios for the Gas Group.

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 of variation, the greater degree of variability. During the five-year period, the coefficients of variation were 0.146 (1.9% ÷ 13.0%) for UGI Utilities, 0.086 (0.8% ÷ 9.3%) for the Gas Group, and 0.050 (0.5% ÷ 10.0%) for the S&P Public Utilities. The variability of the Company's rates of return was considerably higher than the Gas Group and the S&P Public Utilities, thereby signifying higher risk for the Company.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation and taxes other than income). The five-year average operating ratios were 76.5% for UGI Utilities, 84.7% for the Gas Group, and 79.0% for the S&P Public Utilities. The lower average operating ratio for UGI Utilities suggests somewhat lower 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 AFUDC) was 5.77 times for UGI Utilities, 4.41 times for the Gas Group, and 3.32 times for the S&P Public Utilities. The higher interest coverage for UGI Utilities suggests slightly lower credit risk.

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 UGI Utilities and the Gas Group. The effective income tax rate has declined, as revealed by the 2018 rate, and quality of earnings will suffer.

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 79.1% for UGI Utilities, 66.6% for the Gas Group, and 78.6% for the S&P Public Utilities. The Company's levels of IGF will be under pressure in future years as its construction expenditures will increase.

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. Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market.[3] A comparison of market risk is shown by the Value Line betas of .66 as the average for the Gas Group provided on page 2 of Schedule 3 and .62 as the average for the S&P Public Utilities provided on page 3 of Schedule 4.

Q. Please summarize your risk evaluation of UGI Utilities and the Gas Group.

A. The investment risk of UGI Utilities parallels that of the Gas Group in certain respects. In certain regards, principally related to its small size, large throughput to industrial customers, and more variable earned returns, UGI Utilities has somewhat higher risk traits. UGI Utilities has lower risk as shown by its historic higher common equity ratio but that is declining, with its lower operating ratio and higher interest coverages. The Company's credit rating is comparable to the Gas Group.

[3] 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.

RECOMMENDED CAPITAL STRUCTURE RATIOS

Q. Please explain the selection of capital structure ratios for UGI Utilities 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 UGI Utilities, 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. Since UGI Gas does not obtain its capital independently, I have employed the consolidated capital structure ratios of UGI Utilities to calculate the rate of return for this case. The circumstances of UGI Utilities indicate that the capital structure ratios of UGI Utilities should be used for rate of return purposes for both its utility divisions.

Q. Does Schedule 5 provide the capitalization and capital structure ratios you have considered?

A. Yes. Schedule 5 presents UGI Utilities' capitalization and related capital structure at September 30, 2019, the end of the historic test year ("HTY"). Also shown on Schedule 5 is the UGI Utilities' capital structure estimated at September 30, 2020, the end of the future test year ("FTY"), and at September 30, 2021, the end of the fully projected future test year ("FPFTY"). The changes in UGI Utilities' capital structure consist of: (i) quarterly principal payments of $6.250 million on the variable-rate term-loan in both the FTY and FPFTY (ii) the issuance of two $150 million debt issues in both the FTY and FPFTY, and (iii) the Company's projection of retained earnings at the end of the FTY and FPFTY.

Q. Have you made adjustments to the Company's capitalization for ratesetting 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 ratesetting purposes, the Company includes its total lease obligations as operating leases. That is to say, the total amount of lease payments, including the capital component, is reflected in the Company's operating expenses.

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 MLP 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. 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 which will exist during the period of time the proposed rates are to be effective. I will adopt the UGI Utilities' capital structure ratios at the end of the FPFTY, which consists of 46.70% long-term debt and 53.30% common equity, on a rounded basis. These ratios are with the ranges indicated for the Gas Group. 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.

Q. Have you included short-term debt as a component of the Company's capital structure in the case?

A. No. I have considered the issue of short-term debt, but I have rejected its use here. As a preliminary matter, the Company does not employ short-term debt as a permanent source of financing for its rate base. The Company uses short-term debt as bridge financing until it accumulates to a size that makes a permanent financing economical. That is to say, short-term debt represents interim financing that will be replaced with long-term debt and common equity on a periodic basis. Moreover, the Company uses short-term debt to finance non-rate base items. In reaching this conclusion, I have analyzed the 12-month average balances of short-term debt for the HTY, 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. Moreover, the Company has other assets on its balance sheet that require short-term financing such as its unrecovered environmental expenditures that are regulatory assets. The unrecovered balance of the environmental remediation costs is expected to be $5.202 million, as the twelve month average during the FPFTY. It is reasonable to assume that short-term debt represents the source of funds used to finance these costs that are not in the rate base. As a consequence, no amount of short-term debt can be assumed to finance the rate base in this case. In the FPFTY, the combined amount of CWIP balance and the unrecovered environmental expenditures regulatory asset essentially equals the average amount of short-term debt, e.g., there remains a very minimal amount of average short-term debt that represents only 0.01% of the Company's FPFTY capital structure. Therefore, all short-term debt is removed from the capital structure in the FTY.

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 UGI Utilities must be used for developing a fair rate of return for the Company. 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 UGI Utilities 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, 2019. On page 2 of Schedule 6, I have shown the estimated embedded cost rate of long-term debt at September 30, 2020. And on page 3 of Schedule 6, the embedded cost of long-term debt is shown for the FPFTY. 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 4.51% forecast embedded long-term debt cost rate at September 30, 2021, 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 46.70% long-term debt ratio.

Q. What cost rate have you assigned to the Company's variable-rate debt and the new issues of debt scheduled for the FTY and FPFTY?

A. UGI Utilities issued $150 million of Senior Notes on October 31, 2019, at a stated interest rate of 3.70%. The effective cost rate is 3.73% for this issue. The Company also previously entered into an interest rate swap agreement to fix the rate on the variable-rate term-loan. That rate is fixed at 2.988% and will be effective through July 2022. For the new issue of debt in the FPFTY, I have used a nominal (i.e., coupon) rate of 3.73% for the issue planned on October 31, 2021. The issuance in October 2021 reflects an estimated interest rate that is nearly the same as the recent issue.

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 Utilities, the Gas 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 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 Gas Group and arrived at a cost of equity of 10.95% for UGI Gas, which includes recognition of strong management performance.

DISCOUNTED CASH FLOW ANALYSIS

Q. Please describe the Discounted Cash Flow 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 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 and assumes 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.[4] My DCF results are provided on page 2 of Schedule 1 for the Gas Group. The DCF return is 11.81% for the Gas Group.

Among other 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.

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 dividend receipts. It is measured by the dividends 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 October 2019, the monthly dividend yields are shown on Schedule 7 and reflect an adjustment to the month-end prices to reflect the

[4] Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950's, J. B. Williams exposited the DCF model in its present form nearly two decades earlier.

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 2019 the average dividend yield was 2.60% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six-month period were 2.54% and 2.55%, respectively, for each group. I have used, for the purpose of the DCF model, the six-month average dividend yield of 2.54% for the Gas 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. This adjustment adds ten basis points to the six-month average historical yield, thus producing the 2.64% adjusted dividend yield for the Gas 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 earnings per share growth represent the DCF model's primary focus because under the constant price-earnings multiple assumption of the model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth, including: earnings, dividends, book value, and cash flow stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors. A fundamental growth rate analysis is sometimes represented by the internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. To be complete, the internal growth rate should be modified to account for sales of new common stock -- this is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of 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 where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" phase, 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 stabilizes 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, which are those used by investors when pricing common stocks.

Q. What investor-expected growth rate is appropriate in a DCF calculation?

A. 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. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner.

Q. How did you determine 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 using a variety of techniques must be evaluated when formulating a judgment of investor-expected growth.

Q. What data for the Gas Group have you considered in your growth rate analysis?

A. I have considered the growth in the financial variables shown on Schedules 8 and 9. In this regard, I have considered both historical and projected growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. While analysts will review all measures of growth as I have done, it is earnings per share growth that influences directly the expectations of investors for utility stocks. Forecasts of earnings growth are required within the context of the DCF because the model is a forward-looking concept, and with a constant price-earnings multiple and payout ratio, all other measures of growth will mirror earnings growth. So, with the assumptions underlying the DCF, all forward-looking projections should be similar with a constant price-earnings multiple, earned return, and payout ratio. The historical growth rates were taken from the Value Line publication that provides this data. As to the issue of historical data, investors cannot purchase past earnings of a utility, rather they are only entitled to future earnings. In addition, when significant weight is assigned to historical performance results, the historical data is double counted. While history cannot be ignored, it is already factored into the analysts' forecasts of earnings growth. In developing a forecast of future earnings growth, an analyst would first apprise himself/herself of the historical performance of a company. Hence, there is no need to count historical growth rates a second time, because historical performance is already reflected in analysts' forecasts which reflect an assessment of how the future will diverge from historical performance. The historical growth of earnings per share is shown on Schedule 8.

Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the traditional DCF model?

A. Yes. The constant form of the DCF assumes an infinite stream of cash flows, but 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 investor expected return. The growth in the price per share will equal the growth in earnings per share absent any change in price-earnings ("P-E") multiple -- a necessary assumption of the DCF. 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 the actual total return expectation of investors. Moreover, academic research focuses on five-year growth rates as they influence stock prices. Indeed, if investors really required forecasts which extended beyond five years in order to properly value common stocks, then I am sure that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of investors. The absence of such a publication suggests that there is no market for this information because investors do not require infinite forecasts in order to purchase and sell stocks in the marketplace.

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, Morningstar, and Value Line. IBES/First Call, Zacks and Morningstar, represent reliable authorities of projected growth upon which investors rely. The IBES/First Call and Zacks growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Zacks and Morningstar estimates are obtained from the Internet and are widely available to investors. First Call probably is quoted most frequently in the financial press when reporting on earnings forecasts. 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, Zacks and Morningstar, 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 have also been included on Schedule 9 for the Gas Group.

Q. What are the projected growth rates published by the sources you discussed?

A. As to the five-year forecast growth rates, Schedule 9 indicates that the projected earnings per share growth rates for the Gas Group are 5.41% by IBES/First Call, 6.63% by Zacks, 8.05% by Morningstar and 10.28% by Value Line. As noted earlier, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate rather than lower rates of growth in dividends per share and book value per share, thus producing the capital gains yield expected by investors.

Q. What other factors did you consider in developing a growth rate?

A. A variety of factors should be examined to reach a conclusion on the DCF growth rate. However, certain growth rate variables should be emphasized when reaching a conclusion on an appropriate growth rate. From the various alternative measures of growth identified above, earnings per share should receive greatest emphasis. Earnings per share growth are the primary determinant of investors' expectations regarding their total returns in the stock market. This is because 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). 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 this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is a forecast of earnings per share growth.[5] Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, Morningstar, and Value Line, represent a reasonable assessment of investor expectations.

Q. What growth rate do you use in your DCF model?

A. The forecasts of earnings per share growth, as shown on Schedule 9, provide a range of average growth rates of 5.41% to 10.28% for the Gas Group. Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 7.50% is a reasonable estimate of investor expected growth for the Gas Group and is within

[5] Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

the array of earnings per share growth rates shown by the analysts' forecasts. Indeed, my 7.50% growth rate is obtained from the analysts' growth forecasts that cover a five-year period, which are the growth rates that investors employ for DCF purposes. Continued gas utility infrastructure spending argues for a DCF growth rate near the high end of the range.

Q. Are the dividend yield and growth components of the DCF adequate to explain the rate of return on common equity when it is used in the calculation of the weighted average cost of capital?

A. Only if the capital structure ratios are measured with the market value of debt and equity. In the case of the Gas Group, those average capital structure ratios are 32.24% long-term debt, 0.00% preferred stock, and 67.76% 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. Where a firm's capitalization as measured by its stock price diverges from its book value capitalization, the potential exists for a financial risk difference, because the capitalization of a utility measured at its market value contains more equity, less debt and therefore less risk than the capitalization measured at its book value. A leverage adjustment accounts for this difference 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 than indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market capitalization of a firm. If the rate setting 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 rate setting process uses a different set of ratios calculated from the book value capitalization, then further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the 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,” provides a return of 8.35% 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 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 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 indeed 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 that 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. The adjustment that I label as 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), in the context of a return that applies to the capital structure used in ratemaking, which is computed with book value weights rather than market value weights, in order to arrive at the utility's total cost of equity. I specify a separate factor, which I call the leverage adjustment, but there is no need to do so other than providing identification for this factor. If I expressed my return solely in the context of the book value weights that we use to calculate the weighted average cost of capital and ignore the familiar D/P + g expression entirely, then there would be no separate element to reflect the financial leverage change from market value to 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 8.35%, which is the return for the Gas Group applicable to its equity with no debt in its capital structure (i.e., the cost of capital is equal to the cost of equity with a 100% equity ratio) plus 3.46% compensation for having a 47.93% debt ratio, plus 0.00% for having a 0.00% preferred stock ratio. The sum of the parts is 11.81% (8.35% + 3.46% + 0.00%) 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 summed the 2.64% dividend yield, the 7.50% growth rate, and the 1.67% for the leverage adjustment in order to arrive at the same 11.81% (2.64% + 7.50% + 1.67%) return. I know of no means to mathematically solve for the 1.67%

leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 1.67% adjustment is merely a convenient way to compare the 11.81% return computed directly with the Modigliani & Miller formulas to the 10.14% return generated by the DCF model (i.e., D_1/P_0 + g, or the traditional form of the DCF -- see page 1 of Schedule 7) based on a market value capital structure. A 10.14% 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 ratesetting process rather than the market value equity ratio related to the price of stock. The resulting DCF cost rate is:

	D_1/P_0	+	g	+	$lev.$	=	k
Gas Group	2.64%	+	7.50%	+	1.67%	=	11.81%

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 price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market, because price-earnings multiples do not remain constant. This is one of the constraints of this model that makes it important to consider other model results 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 page 2 of Schedule 1. That result is 10.25%.

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 3.75% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

Q. What historical data is 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 page 1 of Schedule 11. For the twelve months ended October 2019, the average monthly yield on Moody's index of A-rated public utility bonds was 3.94%. For the six and three-month periods ended October 2019, the yields were 3.59% and 3.35%, respectively. During the twelve-months ended October 2019, the range of the yields on A-rated public utility bonds was

3.29% to 4.52%. 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 1.20% on a twelve-month average basis, 1.19% on a six-month average basis, and 1.19% on a three-month average basis. From these averages, 1.25% represents a reasonable 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. The 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, 2019, and a yield spread of 1.25%, 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:

		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2019	Fourth	3.1%	4.0%	2.1%	1.25%	3.35%
2020	First	3.1%	4.0%	2.2%	1.25%	3.45%
2020	Second	3.2%	4.1%	2.2%	1.25%	3.45%
2020	Third	3.3%	4.2%	2.3%	1.25%	3.55%
2020	Fourth	3.4%	4.3%	2.4%	1.25%	3.65%
2021	First	3.4%	4.4%	2.5%	1.25%	3.75%

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 December 1, 2019 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
2021-2025	4.2%	5.2%	3.2%
2026-2030	4.7%	5.6%	3.7%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. A 3.75% yield on A-rated public utility bonds represents a reasonable benchmark for measuring the cost of equity in this case. In reaching my conclusion as to a prospective yield on A-rated public utility debt, I have considered the data relied upon by investors.

Q. What equity risk premium have you determined for public utilities?

A. To develop an appropriate equity risk premium, I analyzed the results from 2017 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 page 1 of Schedule 12.

Common Equity Risk Premiums	
Low Interest Rates	6.90%
Average Across All Interest Rates	5.63%
High Interest Rates	4.34%

Based on my analysis of the historical data, the equity risk premium was 6.90% when the marginal cost of long-term government bonds was low (i.e., 2.92%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.15% on average during periods of high interest rates) the spread narrowed to 4.34%. Over the entire spectrum of interest rates, the equity risk premium was 5.63% when the average government bond yield was 5.02%. I have utilized a 6.50% equity risk premium. The equity risk premium of 6.50% that I employed is somewhat above the midpoint 6.27% (6.90% + 5.63% = 12.53% ÷ 2) for the low and average risk premiums shown above. I have taken this approach in recognition of the low interest rates that have prevailed during recent periods and the fact that long-term forecasts published by Blue Chip show a trend toward higher rates in the future. The risk premium that I established provides a balance to both factors. I rounded up to the next one-half percentage point owing to the fact that long-term government bond yields today are lower than 2.92%. This equity risk premium is between the 6.90% premium related to periods of low interest rates and the 5.63% premium related to average interest rates across all levels.

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:

	i	+	*RP*	=	*k*
Gas Group and Subgroup	3.75%	+	6.50%	=	10.25%

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 11.01% for the Gas Group. 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 0.66 for the Gas 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 betas must be reflective of the financial risk associated with the rate setting 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. 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,[6] as follows:

$$\beta l = \beta u\ [1 + (1 - t)\ D/E + P/E]$$

where 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 0.48 for the Gas 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 0.83 for the book value capital structure of the Gas Group.

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 2019, the average yield on 30-year Treasury bonds was 2.74%. For the six- and three-months ended

[6] 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, December 27-29, 1971. (May 1972), pp. 435-452.

October 2019, the yields on 30-year Treasury bonds were 2.41% and 2.16%, respectively. During the twelve-months ended October 2019, the range of the yields on 30-year Treasury bonds was 2.12% to 3.36%. The low yields that existed during recent periods can be traced to the financial crisis and its aftermath commonly referred to as the Great Recession. The resulting decline in the yields on Treasury obligations was attributed to a number of factors, including: the sovereign debt crisis in the euro zone, concern over a possible double dip recession, the potential for deflation, and the Federal Reserve's large balance sheet that was expanded through the purchase of Treasury obligations and mortgage-backed securities (also known as QEI, QEII, and QEIII), and the reinvestment of the proceeds from maturing obligations and the lengthening of the maturity of the Fed's bond portfolio through the sale of short-term Treasuries and the purchase of long-term Treasury obligations (also known as "operation twist"). As noted previously, low interest rates were the product of the policy of the Federal Open Market Committee ("FOMC") in its attempt to deal with stagnant job growth, which is part of its dual mandate. The FOMC ended its bond purchasing program at its policy meeting on October 29, 2014. At its December 16, 2015 meeting, the FOMC increased the federal funds rate range by 0.25 percentage points. On December 14, 2016, the FOMC acted again by raising the federal funds rate by one-quarter percentage point. The FOMC also used this occasion to express a more aggressive approach to future increases in interest rates. In addition, the Fed has indicated that it will reduce the size of its balance sheet. FOMC increased the federal funds rate on three occasions in 2017 (i.e., March 15, 2017, June 14, 2017 and December 13, 2017) by one-quarter percentage point each. At its policy meetings on March 21, 2018, June

13, 2018, September 26, 2018, and December 19, 2018, the FOMC acted again to increase the federal funds rate by one-quarter percentage point in each instance. There have been nine (9) one-quarter percentage point increases in the Fed Funds rate since the FOMC began to normalize interest rates following the financial crisis and the Great Recession. Recently, the FOMC has reversed course attributed to low measures of inflation and has begun to reduce the Fed Funds rate (i.e., one-quarter percentage point reductions on July 31, 2019, September 18, 2019, and October 30, 2019), in response to a perceived weakening of the global economy due in part to the trade war with China. The FOMC has specifically noted weakness in business fixed investment and exports. Neither of these factors has an impact on the investment risk of UGI Utilities. Resolution of the trade dispute with China, when it takes place, will reduce the pressure on global economic growth. The influence of Presidential politics during the election year of 2020 may impact the trend of interest rates.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on November 1, 2018 indicate that the yields on long-term Treasury bonds are expected to be in the range of 2.1% to 2.5% during the next six quarters. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 3.2% from 2021 through 2025 and 3.7% from 2026 to 2030. 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 2.50% risk-free rate of return for CAPM purposes, which considers the Blue Chip forecasts.

Q. What market premium have you used in the CAPM?

A. As shown in the lower panel of data presented on page 2 of Schedule 13, 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 page 1 of Schedule 12. On that schedule, the market return was 11.74% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 2.92% when interest rates were low. As I describe above, interest rates are forecast to trend upward in the long-term according to Blue Chip. To recognize that trend, I have given weight to the average returns and yields that existed across all interest rate levels. As such, I carried over to page 2 of Schedule 13 the average large common stock returns of 11.81% (11.74% + 11.88% = 23.62% ÷ 2) and the average yield on long-term government bonds of 3.97% (2.92% + 5.02% = 7.94% ÷ 2). These financial returns rest between those experienced during periods of low interest rates and those experienced across all levels of interest rates. The resulting market premium is 7.84% (11.81% - 3.97%) based on historical data, as shown on page 2 of Schedule 13. As also shown on page 2 of Schedule 13, I calculated the forecast returns, which show a 13.78% total market return from the Value Line data and a DCF return of 11.65% for the S&P 500. With the average forecast return of 12.72% (13.78% + 11.65% = 25.43% ÷ 2), I calculated a market premium of 10.22% (12.72% - 2.50%) using forecast data. The market premium applicable to the CAPM derived from these sources equals 9.03% (10.22% + 7.84% = 18.06% ÷ 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 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 understate the cost of equity significantly 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. In this regard, the Gas Group has a market-based average equity capitalization of $4,587 million. For my CAPM analysis, I have adopted a mid-cap adjustment of 1.02%, as shown on page 3 of Schedule 13.

Q. What does your CAPM analysis show?

A. Using the 2.50% risk-free rate of return, the leverage adjusted beta of 0.83 for the Gas Group, the 9.03% market premium, and the 1.02% size adjustment, the following result is indicated.

	Rf	***+***	***ß***	***x (***	***Rm-Rf***	***) +***	***size***	***=***	***k***
Gas Group	2.50%	+	0.83	x (	9.03%	) +	1.02%	=	11.01%

<u>COMPARABLE EARNINGS APPROACH</u>

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 risks 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 vs. 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 Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas 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 page 3 of Schedule 14. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on page 1 of Schedule 14.

Value Line data was relied upon 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 page 2 of Schedule 14, 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 11.5% using only the returns that were less than 20%, as shown on page 2 of Schedule 14. The average forecasted rate of return as published by Value Line is 13.0% also using values less than 20%, as provided on page 2 of Schedule 14. Using the average of these data my Comparable Earnings result is 12.25%, as shown on page 2 of Schedule 1.

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 10.95% for UGI Gas, which includes 20 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 greater risk characteristics relative to the barometer 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 a 10.95% 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 the 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.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

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-one 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.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

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 GAS STATEMENT NO. 8 – PAUL R. HERBERT

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2019-3015162

UGI Utilities, Inc. – Gas Division

Statement No. 8

Direct Testimony of
Paul R. Herbert

Topics Addressed: Cost of Service Allocation

Date: January 28, 2020

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Paul R. Herbert. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. By whom are you employed?

A. I am employed by Gannett Fleming Valuation and Rate Consultants, LLC.

Q. Please describe your position with Gannett Fleming Valuation and Rate Consultants, LLC., and briefly state your general duties and responsibilities.

A. I am a Senior Consultant. My duties and responsibilities include the preparation of accounting and financial data for revenue requirements, the allocation of cost of service to customer classifications, and the design of customer rates in support of public utility rate filings.

Q. Have you presented testimony in rate proceedings before a regulatory agency?

A. Yes. I have testified before the Pennsylvania Public Utility Commission, the New Jersey Board of Public Utilities, the Public Utilities Commission of Ohio, the Public Service Commission of West Virginia, the Kentucky Public Service Commission, the Iowa State Utilities Board, the Virginia State Corporation Commission, the Illinois Commerce Commission, the Tennessee Regulatory Authority, the California Public Utilities Commission, New Mexico Public Regulation Commission, the Delaware Public Service Commission, Arizona Corporate Commission, the Connecticut Department of Public Utility Control, the Idaho Public Utilities Commission, the

Hawaii Public Utilities Commission, the New York State Public Service Commission, and the Missouri Public Service Commission concerning revenue requirements, cost of service allocation, rate design and cash working capital claims. A list of the cases in which I have testified is provided at the end of my direct testimony.

Q. What is your educational background?

A. I have a Bachelor of Science Degree in Finance from the Pennsylvania State University, University Park, Pennsylvania.

Q. Would you please describe your professional affiliations?

A. I am a member of the American Water Works Association and served as a member of the Management Committee for the Pennsylvania Section. I am also a member of the Pennsylvania Municipal Authorities Association. In 1998, I became a member of the National Association of Water Companies as well as a member of its Rates and Revenue Committee.

Q. Briefly describe your work experience.

A. I joined the Valuation Division of Gannett Fleming Corddry and Carpenter, Inc., predecessor to Gannett Fleming Valuation and Rate Consultants, LLC, in September 1977, as a Junior Rate Analyst. Since then, I have advanced through several positions and was assigned the position of Manager of Rate Studies on July 1, 1990. On June 1, 1994, I was promoted to Vice President and on November 1, 2003, I was promoted to Senior Vice President. On July 1, 2007, I was promoted to the position as President and served in that capacity until December 31, 2018. My current position is Senior Consultant.

While attending Penn State, I was employed during the summers of 1972, 1973 and 1974 by the United Telephone System - Eastern Group in its accounting department. Upon graduation from college in 1975, I was employed by Herbert Associates, Inc., Consulting Engineers (now Herbert Rowland and Grubic, Inc.), as a field office manager until September 1977.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company"). I will explain the cost of service allocation study, which is included with the filing as UGI Gas Exhibit D.

II. COST OF SERVICE ALLOCATION STUDY

Q. What is the purpose of the cost of service allocation study?

A. The purpose of the study is to allocate the total cost of service to the appropriate service classifications.

Q. Have you prepared cost of service studies for UGI Gas in prior cases?

A. Yes. I prepared the cost of service study in the former UGI Penn Natural Gas, Inc. rate cases at Docket Nos. R-2016-2580030 and R-2008-2079660 and the former UGI Central Penn Gas, Inc. rate case at Docket No. R-2010-2214415. I also prepared the cost of service study for UGI Utilities, Inc. - Gas Division at Docket Nos. R-2015-2518438 and R-2018-3006814.

Q. What method of cost allocation was used in the studies?

A. I used the Average and Extra Demand Method (Average/Excess), which is described in UGI Gas Exhibit D and in the text, "Gas Rate Fundamentals", published by the American Gas Association's Rate Committee.

Q. Please describe UGI Gas Exhibit D.

A. UGI Gas Exhibit D titled, "Cost of Service Allocation Study as of September 30, 2021," is the cost of service allocation study prepared for UGI Gas in support of its claims in this proceeding. It sets forth the results of the study based on the projected costs and conditions for the fully projected future test year for the twelve months ending September 30, 2021 (“FPFTY”). The data in the exhibit include a description of the methods and procedures used in the study, the allocations of cost of service and measure of value, the factors on which the allocations were based and an analysis of customer costs.

Q. Please outline the procedure that you followed in the first cost allocation study.

A. The detailed allocation of costs to cost functions and service classifications is presented in Schedule E, pages 10 through 13, of UGI Gas Exhibit D. Gas costs are excluded from the amounts in Schedule E in order to develop costs by function and classification related to the delivery of gas.

In the detailed allocation, the items of cost, which include operating expenses, depreciation expense, taxes, and income available for return, are identified in column 1 of Schedule E. The cost of each item, shown in column 3, is allocated to the appropriate service classifications: Residential (R and RT), Non-Residential (N and NT), Delivery Service (DS), Large Firm Delivery Service (LFD), Extended Large Firm Delivery Service (XD-Firm), and Interruptible Service (IS).

The allocation factor codes entered in column 2 enable one to determine the specific basis for the allocation of each item. The factor codes refer to the information presented in Schedule F, beginning on page 14, of the exhibit.

Q. Please explain the allocation of some of the large cost items in the study.

A. Referring to some of the larger delivery cost items, the costs associated with natural gas production expenses were allocated based on PGC volumes for Rate R and Rate N customers.

The costs related to distribution mains were first directly assigned to Rate XD-Firm and XD-I (a portion of IS-interruptible) customers based on an analysis of the mains and the proportion thereof serving each individual Rate XD customer. The methods and procedures used to determine the portion of mains directly assigned to Rate XD customers were provided by Company personnel. The remaining cost of mains was separated into small mains (2-inch and smaller) and large mains (over 2-inch). The allocation of small and large distribution mains is determined using Factor 4 and allocated to the Rate R, N, DS, and LFD classes based on the average and extra capacity demand for each classification, and only the average day demand for the Interruptible (IS) class (excluding the XD-I customers).

Customers under Rate XD-Firm and XD-I were excluded from the allocation of small and large distribution mains since Rate XD customers were directly assigned the cost of mains serving them, as explained above. Interruptible volumes were removed from the extra capacity calculations as these volumes can be curtailed during periods of peak demand.

Q. How did you weight the average and excess portions for Allocation Factor 4?

A. The weighting of the factors was based on the system-wide load factor for firm service. This results in 39.6% allocated based on average daily usage and 60.4% on excess above average day usage. See Factor 3 for the calculation of the firm service load factor.

Q. Please explain the allocation of meters and service line costs.

A. Costs related to service lines in Account 380 were allocated to classes, based on an analysis of service line investment by size and Rate Class as presented in the response to Standard Data Request SDR-COS-6. Costs related to meters in Accounts 381 and 385 were allocated to the classes based on an analysis of meter investment by size and Rate Class as presented in response to Standard Data Request SDR-COS-7.

Q. Please explain the allocation of uncollectible accounts and customer assistance expenses.

A. Uncollectible accounts associated with the gas cost portion are allocated consistent with the recovery of such costs through the Merchant Function Charge (Rider D) for Rates R and N. The remaining uncollectible account cost is recovered based on an analysis of write-offs. Costs associated with customer assistance programs are allocated directly to the residential class.

Q. Please describe the allocation of customer accounting costs and the remaining cost of service elements.

A. Customer accounting costs were allocated to service classifications on the basis of the number of customers. Administrative and general costs were allocated on the basis of the allocated direct operation and maintenance costs, excluding gas production expenses.

Annual depreciation accruals were allocated on the basis of the function of the facilities represented by the depreciation expense for each depreciable plant account. Similarly, certain taxes other than income taxes, income taxes, and income available for return were allocated on the basis of allocated rate base, including the original cost less accrued depreciation of utility plant in service and other rate base elements.

Q. What are the results of the cost of service allocation study?

A. The results of the cost of service allocation set forth in Schedule E are brought forward and summarized in Schedule D. The total cost of service by classification in Schedule

D is then brought forward to Schedule A (without gas costs), columns 2 and 3, where these results are compared to the *pro forma* revenues under present rates (columns 4 and 5) and proposed rates (columns 6 and 7). The proposed change in revenue under proposed rates and the percent change are shown in columns 8 and 9 of Schedule A. Please refer to the direct testimony of Christopher R. Brown (UGI Gas Statement No. 1) for an explanation of the proposed rate design and revenue distribution.

Q. Did you prepare a schedule showing the rate of return by classification?

A. Yes. Schedule B sets forth the rate of return by classification under present rates, and Schedule C shows the rate of return by classification under proposed rates.

Q. Did you prepare an analysis of customer costs?

A. Yes. I prepared a fully allocated customer cost analysis and a direct customer cost analysis. Both analyses of customer costs are presented in Schedule G of UGI Gas Exhibit D.

Q. Please explain the analysis of customer costs as set forth in UGI Gas Exhibit D.

A. In UGI Gas Exhibit D, all costs are first allocated to either volumetric costs or customer costs, as shown in Schedule E. The customer costs are allocated to the classes based on an analysis of meter and service line costs and the number of customers. The customer costs were further allocated to the R, N, DS, LFD, XD, and Interruptible Service classifications in the same schedule. The factors that were the bases for the allocation to cost functions and the allocation of customer costs to classifications are presented in Schedule F. A summary of the customer costs and the development of the costs per customer per month are presented in Schedule G.

Q. Did you prepare an analysis of costs related to the demand charge for Rate LFD and Rate XD-Firm Service?

A. Yes. The analysis of costs related to the demand charges for Rate LFD and Rate XD Service is presented in Schedule H of UGI Gas Exhibit D.

Q. Please explain the analysis of the Rate LFD and Rate XD Service costs related to demand charges as set forth in UGI Gas Exhibit D.

A. The costs related to Rate LFD and Rate XD Service demand charges were determined by the allocation of certain fixed costs, depreciation, taxes and return to these classifications. The allocation was performed in Schedule E. A summary of the allocated costs and the development of the unit demand costs are presented in Schedule H.

Q. Does that conclude your direct testimony?

A. Yes, it does.

PAUL R. HERBERT – LIST OF CASES TESTIFIED

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
1.	1983	Pa. PUC	R-832399	T. W. Phillips Gas and Oil Co.	Pro Forma Revenues
2.	1989	Pa. PUC	R-891208	Pennsylvania-American Water Company	Bill Analysis and Rate Application
3.	1991	WV PSC	91-106-W-MA	Clarksburg Water Board	Revenue Requirements (Rule 42)
4.	1992	Pa. PUC	R-922276	North Penn Gas Company	Cash Working Capital
5.	1992	NJ BPU	WR92050532J	The Atlantic City Sewerage Company	Cost Allocation and Rate Design
6.	1994	Pa. PUC	R-943053	The York Water Company	Cost Allocation and Rate Design
7.	1994	Pa. PUC	R-943124	City of Bethlehem	Revenue Requirements, Cost Allocation, Rate Design and Cash Working Capital
8.	1994	Pa. PUC	R-943177	Roaring Creek Water Company	Cash Working Capital
9.	1994	Pa. PUC	R-943245	North Penn Gas Company	Cash Working Capital
10.	1994	NJ BPU	WR94070325	The Atlantic City Sewerage Company	Cost Allocation and Rate Design
11.	1995	Pa. PUC	R-953300	Citizens Utilities Water Company of Pennsylvania	Cost Allocation and Rate Design
12.	1995	Pa. PUC	R-953378	Apollo Gas Company	Rev. Requirements and Rate Design
13.	1995	Pa. PUC	R-953379	Carnegie Natural Gas Company	Rev. Requirements and Rate Design
14.	1996	Pa. PUC	R-963619	The York Water Company	Cost Allocation and Rate Design
15.	1997	Pa. PUC	R-973972	Consumers Pennsylvania Water Company Shenango Valley Division	Cash Working Capital
16.	1998	Ohio PUC	98-178-WS-AIR	Citizens Utilities Company of Ohio	Water and Wastewater Cost Allocation and Rate Design
17.	1998	Pa. PUC	R-984375	City of Bethlehem - Bureau of Water	Revenue Requirement, Cost Allocation and Rate Design
18.	1999	Pa. PUC	R-994605	The York Water Company	Cost Allocation and Rate Design
19.	1999	Pa. PUC	R-994868	Philadelphia Suburban Water Company	Cost Allocation and Rate Design
20.	1999	WV PSC	99-1570-W-MA	Clarksburg Water Board	Revenue Requirements (Rule 42), Cost Allocation and Rate Design
21.	2000	Ky. PSC	2000-120	Kentucky-American Water Company	Cost Allocation and Rate Design
22.	2000	Pa. PUC	R-00005277	PPL Gas Utilities	Cash Working Capital
23.	2000	NJ BPU	WR00080575	Atlantic City Sewerage Company	Cost Allocation and Rate Design
24.	2001	Ia. St Util Bd	RPU-01-4	Iowa-American Water Company	Cost Allocation and Rate Design
25.	2001	Va. St. CC	PUE010312	Virginia-American Water Company	Cost Allocation and Rate Design
26.	2001	WV PSC	01-0326-W-42T	West-Virginia American Water Company	Cost Allocation And Rate Design
27.	2001	Pa. PUC	R-016114	City of Lancaster	Tapping Fee Study
28.	2001	Pa. PUC	R-016236	The York Water Company	Cost Allocation and Rate Design
29.	2001	Pa. PUC	R-016339	Pennsylvania-American Water Company	Cost Allocation and Rate Design
30.	2001	Pa. PUC	R-016750	Philadelphia Suburban Water Company	Cost Allocation and Rate Design
31.	2002	Va.St.CC	PUE-2002-0375	Virginia-American Water Company	Cost Allocation and Rate Design
32.	2003	Pa. PUC	R-027975	The York Water Company	Cost Allocation and Rate Design
33.	2003	Tn Reg Auth	03-	Tennessee-American Water Company	Cost Allocation and Rate Design
34.	2003	Pa. PUC	R-038304	Pennsylvania-American Water Company	Cost Allocation and Rate Design
35.	2003	NJ BPU	WR03070511	New Jersey-American Water Company	Cost Allocation and Rate Design
36.	2003	Mo. PSC	WR-2003-0500	Missouri-American Water Company	Cost Allocation and Rate Design
37.	2004	Va.St.CC	PUE-200 -	Virginia-American Water Company	Cost Allocation and Rate Design
38.	2004	Pa. PUC	R-038805	Pennsylvania Suburban Water Company	Cost Allocation and Rate Design
39.	2004	Pa. PUC	R-049165	The York Water Company	Cost Allocation and Rate Design
40.	2004	NJ BPU	WRO4091064	The Atlantic City Sewerage Company	Cost Allocation and Rate Design
41.	2005	WV PSC	04-1024-S-MA	Morgantown Utility Board	Cost Allocation and Rate Design
42.	2005	WV PSC	04-1025-W-MA	Morgantown Utility Board	Cost Allocation and Rate Design
43.	2005	Pa. PUC	R-051030	Aqua Pennsylvania, Inc.	Cost Allocation and Rate Design
44.	2006	Pa. PUC	R-051178	T. W. Phillips Gas and Oil Co.	Cost Allocation and Rate Design
45.	2006	Pa. PUC	R-061322	The York Water Company	Cost Allocation and Rate Design
46.	2006	NJ BPU	WR-06030257	New Jersey American Water Company	Cost Allocation and Rate Design
47.	2006	Pa. PUC	R-061398	PPL Gas Utilities, Inc.	Cost Allocation and Rate Design
48.	2006	NM PRC	06-00208-UT	New Mexico American Water Company	Cost Allocation and Rate Design
49.	2006	Tn Reg Auth	06-00290	Tennessee American Water Company	Cost Allocation and Rate Design
50.	2007	Ca. PUC	U-339-W	Suburban Water Systems	Water Conservation Rate Design
51.	2007	Ca. PUC	U-168-W	San Jose Water Company	Water Conservation Rate Design
52.	2007	Pa. PUC	R-00072229	Pennsylvania American Water Company	Cost Allocation and Rate Design
53.	2007	Ky. PSC	2007-00143	Kentucky American Water Company	Cost Allocation and Rate Design
54.	2007	Mo. PSC	WR-2007-0216	Missouri American Water Company	Cost Allocation and Rate Design

PAUL R. HERBERT – LIST OF CASES TESTIFIED

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
55.	2007	Oh. PUC	07-1112-WS-IR	Ohio American Water Company	Cost Allocation and Rate Design
56.	2007	Il. CC	07-0507	Illinois American Water Company	Customer Class Demand Study
57.	2007	Pa. PUC	R-00072711	Aqua Pennsylvania, Inc.	Cost Allocation and Rate Design
58.	2007	NJ BPU	WR07110866	The Atlantic City Sewerage Company	Cost Allocation and Rate Design
59.	2007	Pa. PUC	R-00072492	City of Bethlehem – Bureau of Water	Revenue Reqmts, Cost Alloc.
60.	2007	WV PSC	07-0541-W-MA	Clarksburg Water Board	Cost Allocation and Rate Design
61.	2007	WV PSC	07-0998-W-42T	West Virginia American Water Company	Cost Allocation and Rate Design
62.	2008	NJ BPU	WR08010020	New Jersey American Water Company	Cost Allocation and Rate Design
63.	2008	Va St CC	PUE-2008-0009	Virginia American Water Company	Cost Allocation and Rate Design
64.	2008	Tn.Reg.Auth.	08-00039	Tennessee American Water Company	Cost Allocation and Rate Design
65.	2008	Mo PSC	WR-2008-0311	Missouri American Water Company	Cost Allocation and Rate Design
66.	2008	De PSC	08-96	Artesian Water Company, Inc.	Cost Allocation and Rate Design
67.	2008	Pa PUC	R-2008-2032689	Penna. American Water Co. – Coatesville Wastewater	Cost Allocation and Rate Design
68.	2008	AZ CC.	W-01303A-08-0227 SW-01303A-08-0227	Arizona American Water Co. - Water - Wastewater	Cost Allocation and Rate Design
69.	2008	Pa PUC	R-2008-2023067	The York Water Company	Cost Allocation and Rate Design
70.	2008	WV PSC	08-0900-W-42T	West Virginia American Water Company	Cost Allocation and Rate Design
71.	2008	Ky PSC	2008-00250	Frankfort Electric and Water Plant Board	Cost Allocation and Rate Design
72.	2008	Ky PSC	2008-00427	Kentucky American Water Company	Cost Allocation and Rate Design
73.	2009	Pa PUC	2008-2079660	UGI – Penn Natural Gas	Cost of Service Allocation
74.	2009	Pa PUC	2008-2079675	UGI – Central Penn Gas	Cost of Service Allocation
75.	2009	Pa PUC	2009-2097323	Pennsylvania American Water Co.	Cost Allocation and Rate Design
76.	2009	Ia St Util Bd	RPU-09-	Iowa-American Water Company	Cost Allocation and Rate Design
77.	2009	Il CC	09-0319	Illinois-American Water Company	Cost Allocation and Rate Design
78.	2009	Oh PUC	09-391-WS-AIR	Ohio-American Water Company	Cost Allocation and Rate Design
79.	2009	Pa PUC	R-2009-2132019	Aqua Pennsylvania, Inc.	Cost Allocation and Rate Design
80.	2009	Va St CC	PUE-2009-0059	Aqua Virginia, Inc.	Cost Allocation (only)
81.	2009	Mo PSC	WR-2010-0131	Missouri American Water Company	Cost Allocation and Rate Design
82.	2010	VaSt CorpCom	PUE-2010-00001	Virginia American Water Company	Cost Allocation and Rate Design
83.	2010	Ky PSC	2010-00036	Kentucky American Water Company	Cost Allocation and Rate Design
84.	2010	NJ BPU	WR10040260	New Jersey American Water Company	Cost Allocation and Rate Design
85.	2010	Pa PUC	2010-2167797	T.W. Phillips Gas and Oil Co.	Cost Allocation and Rate Design
86.	2010	Pa PUC	2010-2166212	Pennsylvania American Water Co. - Wastewater	Cost Allocation and Rate Design
87.	2010	Pa PUC	R-2010-2157140	The York Water Company	Cost Allocation and Rate Design
88.	2010	Ky PSC	2010-00094	Northern Kentucky Water District	Cost Allocation and Rate Design
89.	2010	WV PSC	10-0920-W-42T	West Virginia American Water Co.	Cost Allocation and Rate Design
90.	2010	Tn Reg Auth	10-00189	Tennessee American Water Company	Cost Allocation and Rate Design
91.	2010	Ct PU RgAth	10-09-08	United Water Connecticut	Cost Allocation and Rate Design
92.	2010	Pa PUC	R-2010-2179103	City of Lancaster-Bureau of Water	Rev Rqmts, Cst Alloc/Rate Design
93.	2011	Pa PUC	R-2010-2214415	UGI Central Penn Gas, Inc.	Cost Allocation
94.	2011	Pa PUC	R-2011-2232359	The Newtown Artesian Water Co.	Revenue Requirement
95.	2011	Pa PUC	R-2011-2232243	Pennsylvania-American Water Co.	Cost Allocation and Rate Design
96.	2011	Pa PUC	R-2011-2232985	United Water Pennsylvania Inc.	Demand Study, COS/Rate Design
97.	2011	Pa PUC	R-2011-2244756	City of Bethlehem-Bureau of Water	Rev. Rqmts/COS/Rate Design
98.	2011	Mo PSC	WR-2011-0337-338	Missouri American Water Company	Cost Allocation and Rate Design
99.	2011	Oh PUC	11-4161-WS-AIR	Ohio American Water Company	Cost Allocation and Rate Design
100.	2011	NJ BPU	WR11070460	New Jersey American Water Company	Cost Allocation and Rate Design
101.	2011	Id PUC	UWI-W-11-02	United Water Idaho Inc.	Cost Allocation and Rate Design
102	2011	Il CC	11-0767	Illinois-American Water Company	Cost Allocation and Rate Design
103.	2011	Pa PUC	R-2011-2267958	Aqua Pennsylvania, Inc.	Cost Allocation and Rate Design
104.	2011	VaStCom	2011-00099	Aqua Virginia, Inc.	Cost Allocation
105.	2011	VaStCom	2011-00127	Virginia American Water Company	Cost Allocation and Rate Design
106.	2012	TnRegAuth	12-00049	Tennessee American Water Company	Cost Allocation and Rate Design
107.	2012	Ky PSC	2012-00072	Northern Kentucky Water District	Cost Allocation and Rate Design
108.	2012	Pa PUC	R-2012-2310366	Lancaster, City of – Sewer Fund	Cost Allocation and Rate Design
109.	2012	Ky PSC	2012-00520	Kentucky American Water Co.	Cost Allocation and Rate Design
110.	2013	WV PSC	12-1649-W-42T	West Virginia American Water Co.	Cost Allocation and Rate Design
111.	2013	Ia St Util Bd	RPU-2013-000_	Iowa American Water Company	Cost Allocation and Rate Design
112.	2013	Pa PUC	R-2013-2355276	Pennsylvania American Water Co.	Cost Allocation and Rate Design

PAUL R. HERBERT – LIST OF CASES TESTIFIED

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
113.	2013	Pa PUC	R-2012-2336379	The York Water Company	Cost Allocation and Rate Design
114.	2013	Pa PUC	R-2013-2350509	City of DuBois – Bureau of Water	Cost Allocation and Rate Design
115.	2013	Pa PUC	R-2013-2390244	City of Bethlehem – Bureau of Water	Cost Allocation and Rate Design
116.	2014	Pa PUC	R-2014-2418872	City of Lancaster – Bureau of Water	Cost Allocation and Rate Design
117.	2014	Pa PUC	R-2014-2428304	Borough of Hanover	Cost Allocation and Rate Design
118.	2014	VAStCom	2014-00045	Aqua Virginia, Inc.	Cost Allocation
119.	2015	NJ BPU	WR15010035	New Jersey American Water Company	Cost Allocation and Rate Design
120.	2015	Pa PUC	R-2015-2462723	United Water PA	Cost Allocation and Rate Design
121.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Cost Allocation and Rate Design
122.	2015	Id PUC	UWI-W-15-01	United Water Idaho Inc.	Pro Forma Revenues
123.	2015	Mo PSC	WR-2015-0301	Missouri American Water Company	Cost Allocation and Rate Design
124.	2015	Va St Com	PUE-2015-00097	Virginia American Water Company	Cost Allocation and Rate Design
125.	2015	Hi PSC	2015-0350	HOH Utilities, Inc.	Cost Allocation and Rate Design
126.	2016	Ky PSC	2015-00418	Kentucky American Water Company	Cost Allocation and Rate Design
127.	2016	Pa PUC	R-2015-2518438	UGI Utilities, Inc. - Gas Division	Cost Allocation
128.	2016	Il CC	16-0093	Illinois American Water Company	Cost Alloc/Rate Dsgn/Demand Sty
129.	2016	NY PSC	16-W-0130	SUEZ Water New York Inc.	Cost Allocation and Rate Design
130.	2016	Oh PUC	16-0907-WW-AIR	Aqua Ohio, Inc.	Cost Allocation and Rate Design
131.	2016	Ia St Util Bd	RPU-2016-0002	Iowa American Water Company	Cost Allocation and Rate Design
132.	2016	NJ BPU	WR16100957	Atlantic City Sewerage Company	Cost Allocation and Rate Design
133.	2017	Pa PUC	R-2016-2580030	UGI Penn Natural Gas, Inc.	Cost Allocation and Rate Design
134.	2017	Pa PUC	R-2017-2595853	Pennsylvania American Water Co.	Cost Allocation and Rate Design
135.	2017	IL CC	17-0259	Aqua Illinois, Inc.	Cost Allocation and Rate Design
136.	2017	NY PSC	17-W-0528	SUEZ Water Owego-Nichols, Inc.	Cost Allocation and Rate Design
137.	2017	NJ BPU	WR17090985	New Jersey American Water Company	Cost Allocation and Rate Design
138.	2017	Ca PUC	A.18-01-004	San Jose Water Company	Rate Design
139.	2018	PaPUC	R-2018-3000834	SUEZ Water Pennsylvania Inc.	Cost Allocation and Rate Design
140.	2018	PaPUC	R-2018-3000019	The York Water Company	Cost Allocation and Rate Design
141.	2018	NJ BPU	WR18050593	SUEZ Water New Jersey, Inc.	Cost Allocation and Rate Design
142.	2018	Pa PUC	R-2018-3001306	Hidden Valley Utility Services, L.P. – Water	Revenue Requirements
143.	2018	Pa PUC	R-2018-3001307	Hidden Valley Utility Services, L.P. - Wastewater	Revenue Requirements
144.	2018	Pa PUC	R-2018-3003558	Aqua Pennsylvania, Inc.	Cost Allocation and Rate Design
145.	2018	Pa PUC	R-2018-3003566	Aqua Pennsylvania Wastewater, Inc.	Cost Allocation and Rate Design
146.	2019	Pa PUC	R-2018-3006814	UGI Utilities, Inc. – Gas Division	Cost of Service Allocation Studies
147.	2019	NYPSC	19-W-0168	SUEZ Water New York, Inc.	Cost Allocation and Rate Design

UGI GAS STATEMENT NO. 9 – JOHN F. WIEDMAYER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2019-3015162

UGI Utilities, Inc. – Gas Division

Statement No. 9

Direct Testimony of
John F. Wiedmayer C.D.P.

Topics Addressed: **Depreciation**

Date: January 28, 2020

TABLE OF CONTENTS

Page

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 degree in Engineering 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 33 years of depreciation experience, which includes expert testimony in numerous cases before 14 regulatory commissions, including this 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 my present position as 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 my employment with Gannett Fleming I have assisted in the preparation of numerous depreciation studies for utility companies in various industries. I assisted in the preparation of depreciation studies for the following telephone companies: Alberta Government Telephone, Commonwealth Telephone

Company, Telus, United Telephone Company of New Jersey and United Telephone of Pennsylvania. I assisted in the preparation of depreciation studies for the following companies in the railroad industry: CSX Transportation, Union Pacific Railroad, Burlington Northern Railroad, Burlington Northern Santa Fe Railway, Amtrak, Kansas City Southern Railroad, Norfolk & Western, Southern Railway, and Norfolk Southern Corporation.

I assisted in the preparation of depreciation studies for the following organizations in the electric industry: AmerenUE, Arizona Public Service Company, UGI Utilities, Inc. - Electric Division, Penelec, Metropolitan Edison, the City of Red Deer, Nova Scotia Power, Newfoundland Power, Owen Electric Cooperative, Bangor Hydro Electric Company, Maine Public Service Company, Michigan Electric Transmission Company, PECO, Jackson Electric Cooperative Corporation, Houston Lighting and Power, TXU, Maritime Electric, Nolin Rural Electric Cooperative, AmerenCIPS, AmerenCILCO, AmerenIP, and the City of Calgary - Electric System.

I assisted in the preparation of depreciation studies for the following gas companies: BGE, PECO, UGI Utilities, Inc., North Penn Gas, PFG Gas, UGI Central Penn Gas, Inc., Equitable Gas, Centra Gas Alberta, Questar Gas, Orange and Rockland, Con Edison, Dominion East Ohio, AmerenUE, AmerenCILCO, AmerenCIPS, and AmerenIP.

In each of the above studies, 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 Jersey Board of Public Utilities, the New York Public Service Commission, the Connecticut Public Utilities Regulatory Authority and the Pennsylvania Public Utility Commission.

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 2000, 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 Imbalances and True-Up" and "Data Requirements for a Depreciation Study."

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 consolidated Pennsylvania gas plant of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company"). I have been retained by the Company as a depreciation consultant. UGI Gas retained me to determine the book depreciation reserve as of September 30, 2021, 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.

The Company is proceeding with a consolidated base rate case filing for its gas operations in Pennsylvania related to its customers served by the now consolidated UGI Gas, which service territory results from the merger of the former Gas Division of UGI Utilities, Inc., the former UGI Central Penn Gas, Inc. ("CPG"), and the former UGI Penn Natural Gas, Inc. ("PNG") service territories. Effective October 1, 2018, UGI Utilities, Inc., CPG, and PNG merged and the regulated gas operations became the Gas Division of UGI Utilities, Inc.

I am also a sponsoring witness for UGI Gas's depreciated original cost of gas 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, 2021.

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 Gas Exhibit I:

Item No.	Subject
I-A-3	Description of Depreciation Methods and Factors Considered in Arriving at Estimates of Service Life and Dispersion by Account
I-A-4	Survivor Curves and Surviving Original Cost Including Related Annual and Accrued Depreciation
I-A-5	Comparison of Calculated Reserve vs. Book Reserve
I-A-6	Survivor Curves and Annual Accrual Rates
I-A-7	Cumulative Depreciated Original Cost by Vintage Year
l-A-17	Net Salvage

Q. Have you previously prepared comparable studies for UGI Gas?

A. Yes. I provided testimony on depreciation matters for the Company in the prior two PNG base rate cases at Docket No. R-2016-2580030 and Docket No. R-2008-2079660, the prior two CPG base rate cases at Docket No. R-2010-2214415 and Docket No. R-2008-2079675 and the two most recent base rate cases for UGI Utilities, Inc. – Gas Division at Docket No. R-2015-2518438 and Docket No. R-2018-3006814. Prior to those rate filings, I prepared exhibits for the depreciation study in UGI Gas's base rate case filed in 1995 at Docket No. R-00953297.

III. OUTLINE OF EXHIBITS C (FULLY PROJECTED), 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 Gas Exhibit C (Fully Projected), UGI Gas Exhibit C (Future) and UGI Gas Exhibit C (Historic). UGI Gas Exhibit C (Fully Projected) presents the summarized depreciation calculations and supporting tables related to the fully projected future test year ending September 30, 2021 ("FPFTY") for the consolidated gas company inclusive of the plant attributable to the former UGI PNG, former UGI CPG and pre-merger UGI Gas. UGI Gas Exhibit C (Future) presents similar summarized depreciation calculations and supporting charts and tables related to the depreciation study for the future test year ending September 30, 2020 ("FTY"). UGI Gas Exhibit C (Historic) presents the summarized depreciation calculations and supporting tables related to the historic test year ended September 30, 2019 ("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 Gas Exhibit C (Future) contains additional information including the supporting charts and life tables related to the service life estimates.

Q. Does UGI Gas Exhibit C (Fully Projected) accurately portray the results of your depreciation study as of September 30, 2021?

A. Yes.

Q. In preparing the depreciation study, did you follow generally accepted practices in the field of depreciation?

A. Yes.

Q. Please describe the contents of the depreciation study report, UGI Gas Exhibit C (Future) and UGI Gas Exhibit C (Fully Projected).

A. The depreciation study report in UGI Gas Exhibit C (Future) consists of eight parts including charts and tables filed in the Company's most recent service life study report submitted in 2019. 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 procedures used for calculating annual and accrued depreciation; and (2) an explanation of the way 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, 2020. 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, Detailed Depreciation Calculations sets forth the detailed depreciation calculations related to surviving original cost as of September 30, 2020. 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 years 2016 through 2020.

UGI Gas Exhibit C (Fully Projected) 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, 2021. The descriptions and explanations presented in UGI Gas Exhibit C (Future) are also applicable to the depreciation calculations presented in UGI Gas Exhibit C (Fully Projected). The graphs and tables related to service life presented in UGI Gas Exhibit C (Future) also support the service life estimates used in UGI Gas Exhibit C (Fully Projected), inasmuch as the estimates are the same for all three test years, i.e., Historic, Future and Fully Projected. The service life estimates set forth in UGI Gas Exhibit C (Historic) are the same estimates as those approved in the Company's Annual Depreciation Report submitted to the PUC in March 2019.

The results of the study are set forth in Part II in UGI Gas Exhibit C (Fully Projected). Table 1, pages II-3 through II-4 of UGI Gas Exhibit C (Fully Projected), presents the estimated survivor curve, the original cost and depreciation reserve at September 30, 2021, and the calculated annual depreciation rate and amount for each account or subaccount of Gas Plant in Service. Table 2, pages II-5 through II-6 of UGI Gas Exhibit C (Fully Projected), presents the bring-forward to September 30, 2021, of the depreciation reserve as of September 30, 2019. Table 3, pages II-7 through II-8 of UGI Gas Exhibit C (Fully Projected), presents the calculation of the book depreciation amounts for the FPFTY. Table 4, pages II-9 through II-10 of UGI

Gas Exhibit C (Fully Projected), presents the experienced and estimated net salvage for fiscal years 2017 through 2021. The amortization of net salvage is based on experienced and estimated net salvage during the period October 1, 2016 through September 30, 2021. The summary tables and detailed depreciation calculations set forth in UGI Gas Exhibit C (Fully Projected) as of September 30, 2021, are organized and presented in the same manner as those presented in UGI Gas Exhibit C (Future) as of September 30, 2020.

Q. Please outline the contents of Exhibit C (Historic).

A. UGI Gas Exhibit C (Historic) is organized similar to UGI Gas Exhibit C (Fully Projected). UGI Gas 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, 2019. The service life estimates used in the historic test year period were based on the survivor curve estimates set forth in the Annual Depreciation Report (ADR) submitted to the PUC in March 2019. The survivor curve estimates based on the consolidated service life study which includes data through 2017 was used in each of the three respective test year periods. The summary tables and detailed depreciation calculations as of September 30, 2019, are organized and presented in the same manner as those as of September 30, 2021 with two exceptions. Tables 2 and 3 presented in UGI Gas Exhibit C (Fully Projected) are not necessary and, therefore, are not presented in UGI Gas 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 Class A and Class B Natural Gas Companies. "Depreciation" refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas 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, requirements of public authorities and the exhaustion of natural resources.

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 the most recent Annual Depreciation Report filed for UGI Gas in March 2019?

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 over thirty years. The depreciation methods and procedures are described further in Part II of UGI Gas 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 gas plant to be included in rate base in this proceeding?

A. As of September 30, 2021, the original cost of gas plant in service is $4,324,363,850 as shown in column 4 of Table 1 on pages II-3 through II-5 of UGI Gas Exhibit C (Fully Projected). This amount includes $4,051,158,639 of Gas Plant and $273,205,211 of Other Utility Plant allocated to Gas Division. 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 between the Gas and Electric Divisions of UGI Utilities, Inc. The costs related to Common Plant and IS are allocated to Gas Division at 88.43 percent and 94.12 percent, respectively. In addition, the building that houses most of the IS assets, *i.e.*, the Reading Office and Service Center located on 225 Morgantown Road, is included in Account 390.1, Structures and Improvements in Gas Division. Since a portion of the building relates to IS, a portion of the cost attributable to the electric utility divisions was deducted from the Reading Office and Service Building. Also, the full cost of the buildings at the Empire Service Center in Wilkes Barre, PA were included in Gas Division. However, electric division personnel share portions of the buildings at that location and therefore a portion of the cost related to Empire was deducted from Gas Division and allocated to Electric Division.

VI. THE ACCRUED DEPRECIATION CLAIM

Q. Have you determined UGI Gas's accrued depreciation for ratemaking purposes as of September 30, 2021?

A. Yes. I have determined the allocated book depreciation reserve as of September 30, 2021, to be $1,160,182,946.

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 set forth in the Company's financial statements and approved annually in connection with the Company's submission of its annual depreciation report each March to the Commission.

Q. How did you determine UGI Gas's allocated book depreciation reserve as of September 30, 2019?

A. The book depreciation reserve attributable to Gas Division as of September 30, 2020, is set forth in column 5 of Table 1 of UGI Gas Exhibit C (Future). Table 2 of UGI Gas Exhibit C (Future) is an annual bring-forward of the book depreciation reserve as of September 30, 2019, using estimated accruals, retirements, salvage and cost of removal for the twelve months October 2019 through September 2020. The table sets forth, by plant account, the beginning book reserve balance as of September 30, 2019, the estimated reserve activity, and the ending reserve balance as of September 30, 2020. 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 Gas 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, 2019, by plant account, shown in column 2 of Table 2 was obtained from UGI Gas's books and records and are the same amounts set forth in Table 1 of Exhibit C (Historic).

Q. Please explain the way you projected the depreciation accruals for the twelve months ended September 30, 2020.

A. The depreciation accruals for the twelve months ended September 30, 2020, by plant account, were estimated by applying the annual depreciation accrual rates calculated as of September 30, 2019, to the projected average 2020 plant balance. The average balance for the twelve months ended September 30, 2020, is computed in columns 2 through 6 of Table 3 and is based on the projected additions, retirements and transfers in columns 3 through 5.

Q. With reference to Table 2, column 4, please explain what you mean by "the amortization of net salvage" and explain the way 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, 2014 through September 30, 2019.

Q. Please explain the way 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, for the five years 2015 through 2019, to FTY and FPFTY 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, expressed as a percent of retirement amounts, for the five years 2015 through 2019, to the projected retirement amounts.

Q. Was the book reserve at September 30, 2021, estimated using the same methodology?

A. Yes, it was essentially the same methodology with one minor exception. The book depreciation accruals calculated for fiscal year 2021 were based on applying the depreciation rate to average monthly plant balances for purposes of calculating the book reserve as of September 30, 2021.

VII. THE ANNUAL DEPRECIATION EXPENSE CLAIM

Q. Have you determined UGI Gas'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 $119,677,327 and consists of $111,825,887 of annual accruals to recover original cost and $7,851,440 of net salvage amortization. These amounts are set forth in column 8 of Table 1 in UGI Gas Exhibit C (Fully Projected).

Q. How did you determine the annual accruals of $119,677,327?

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 way 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 Gas's gas plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from engineering management and operating personnel concerning UGI Gas'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 for the purpose of estimating the service life characteristics of UGI Gas's gas plant?

A. The data consisted of the entries made by UGI Gas to record gas plant transactions during the period 1951 through 2017. 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 survivor curve and were not used.

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 in these interpretations. The results of the retirement rate analyses are presented in Part VI of UGI Gas Exhibit C (Future).

Q. Please explain briefly what an "Iowa type survivor curve" is and how you use 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 35-R2 curve indicates an average service life of thirty-five years; a Right-skewed, or R, type curve (the mode or highest frequency of retirements occurs after average life for right modal curves); and a relatively low height, 2, 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 Pennsylvania Public Utility Commission ("PA PUC") every five years, at minimum. UGI Gas's most recent service life study report was performed in 2018 and submitted in 2019 in connection with the 2019 base rate case filing at Docket No. R-2018-3006814, Exhibit C (Future), submitted in January 2019. Facilities visited during field trips, generally include representative city gate stations, district regulating stations, service centers, etc. The most recent field trip was conducted over 2 days in August 2018. 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 were incorporated in the interpretation and extrapolation of the statistical analyses.

Q. Please describe the second phase of the process that you used in order 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 on Table 1 of UGI Gas Exhibit C (Historic), UGI Gas Exhibit C (Future) and UGI Gas Exhibit C (Fully Projected). The detailed tabulations of the depreciation calculations are presented in Part III of UGI Gas Exhibit C (Historic) and UGI Gas Exhibit C (Fully Projected) and Part VII of UGI Gas 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.

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 very small percent of depreciable gas 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. All units are retired per books when the age of the vintage reaches the amortization period.

VIII. ILLUSTRATION OF DEPRECIATION STUDY PROCEDURE

Q. Please illustrate the procedure followed in your depreciation study and the way it is presented in UGI Gas Exhibit C (Future) using an account as an example.

A. I will use Account 376.1, Mains – Primarily Steel, to illustrate the way the study was conducted. Account 376.1 represents 16.5 percent of the total depreciable gas plant. As the initial step of the service life study phase, aged plant accounting data were compiled for the years 1951 through 2017. These data have been coded in the course of UGI Gas's normal recordkeeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the gas 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 primarily cathodically-protected, steel mains, although some bare steel mains are still in service. The Iowa 73-R2.5 survivor curve was judged most appropriate for this account and is the survivor curve used for this filing. The original life table and chart for the 1951-2017 experience band is set forth on pages VI-40 through VI-46.

The calculation of annual depreciation, the second phase, for the original cost of steel mains in service at September 30, 2020, is presented by vintage in Part VII on pages VII-55 through VII-63 of UGI Gas Exhibit C (Future) for Gas Plant in Service. The detailed depreciation calculations at September 30, 2021 are presented in Part III of Exhibit C (Fully Projected). 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). 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 73-R2.5 survivor curve. In the calculation, the surviving cost in each vintage was further subdivided, using a computer program, into depreciable groups according to the expected service lives as defined by the Iowa 73-R2.5 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 73-R2.5 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-63 of UGI Gas 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 in order to calculate the annual depreciation accrual rate in column 6. A similar process was used for the FPFTY.

Q. Is the procedure you described for Account 376.1 typical of that followed for most of the plant investment?

A. Yes, it is, inasmuch as 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 way it is presented in UGI Gas 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, 2020, is presented by vintage in Part VII on pages VII-161 and VII-162 of UGI Gas 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-162 of UGI Gas Exhibit C (Future) was brought forward to column 8 of Table 1 on page V-5 of UGI Gas Exhibit C (Future). A similar process was performed for UGI Gas Exhibit C (Fully Projected) and UGI Gas 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, 2021, is presented by vintage on pages III-161 and III-162 of UGI Gas Exhibit C (Fully Projected) and summarized in Table 1 on page II-4.

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 Gas Exhibit C (Historic) and UGI Gas Exhibit C (Fully Projected) and in Part VII of UGI Gas 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 CPG (formerly PPL Gas Utilities Corporation's ("PPL Gas")) 2006 rate filing (Docket No. R-00061398). This procedure is consistent with how other Pennsylvania public utilities, including UGI, 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 Gas's annual depreciation expense consists, in part, of $7,851,440 of net salvage amortization. How did you determine that amount?

A. The $7,851,440 is the result of determining the five-year average of net salvage experienced and estimated during the period of October 1, 2016 through September 30, 2021. Net salvage is defined in the Uniform System of Accounts as gross salvage less cost of removal. For most gas utilities, including UGI Gas, 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 Gas Exhibit C (Future) and Part IV of UGI Gas Exhibit C (Fully Projected).

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 I-A-5, I-A-6, and I-A-7. In general, these responses are self-explanatory. The response to I-A-5 is a comparison of the actual and projected book depreciation reserve with the calculated accrued depreciation as of the end of the historic, future and fully projected future test years, respectively. The response to l-A-6 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. The response to l-A-7 is the cumulative depreciated original cost by installation year as of the end of the test years. The amounts requested in response to I-A-7 are set forth in UGI Gas Exhibit C (Historic) and UGI Gas Exhibit C (Future) in the section titled "Cumulative Depreciated Original Cost".

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS STATEMENT NO. 10 – NICOLE M. MCKINNEY

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2019-3015162

UGI Utilities, Inc. – Gas Division

Statement No. 10

Direct Testimony of
Nicole M. McKinney

Topics Addressed: **Taxes and Tax Adjustments**

Dated: January 28, 2020

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Nicole M. McKinney. 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 Utilities, Inc. ("UGI") as Manager of Tax and Regulatory Accounting. UGI is a subsidiary of UGI Corporation ("UGI Corp."). UGI's Gas Division ("UGI Gas") and Electric Division ("UGI Electric") are regulated by the Pennsylvania Public Utility Commission ("Commission" or "PA PUC").

Q. What are your principal duties and responsibilities as Manager of Tax and Regulatory Accounting?

A. My primary duties as Manager of Tax and Regulatory Accounting include the preparation of tax data to be reported in UGI'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. Additionally, I manage the reporting of the Company's various tax and accounting filings with the PUC and the Federal Energy Regulatory Commission, as well as maintain the accounting for our regulatory asset and liability accounts.

Q. Please describe your educational background and professional experience.

A. They are set forth in my resume attached as UGI Gas Exhibit NMM-1.

Q. Please describe the purpose of your testimony.

A. I am providing testimony on behalf of UGI Gas. 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, 2021 ("FPFTY"). I will also explain the tax adjustments made to the results of UGI Gas's historic test year ended September 30, 2019 ("HTY") and future test year ending September 30, 2020 ("FTY").

Q. Ms. McKinney, are you sponsoring any exhibits in this proceeding?

A. Yes. Together with other Company witnesses, I am sponsoring portions of UGI Gas Exhibit A (Fully Projected), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic) that pertain to tax-related issues. These exhibits comprise UGI'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. <u>TAX ADJUSTMENTS</u>

Q. Please provide an overview of UGI Gas's principal accounting exhibits relative to the proposed tax adjustments.

A. As explained in the direct testimony of Mr. Stephen F. Anzaldo (UGI Gas St. 2), UGI's principal accounting exhibit is UGI Gas Exhibit A (Fully Projected), which includes a presentation for the FPFTY ending September 30, 2021. Section D of UGI Gas 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's *pro forma* income at present and proposed rates as set forth in Schedule A-1 of the same exhibit.

UGI Gas Exhibit A (Historic) and UGI Gas Exhibit A (Future) follow the format of UGI Gas Exhibit A (Fully Projected), but reflect data for the HTY ended September 30, 2019, and the FTY ending September 30, 2020. This information is provided to comply with the Commission's filing requirements and provides a basis for comparing UGI's FPFTY claims with actual book results from the HTY and adjusted FTY results. Section D to UGI Gas Exhibit A (Historic), Schedule D-31, and UGI Gas Exhibit A (Future), Schedule D-31 include adjustments that share the same methodology as used in Schedule D-31 of UGI Gas 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 amounts were based on the plan year budget, as adjusted for reasonably known and measurable changes to various payroll taxes as supported by the direct testimony of Mr. Stephen F. Anzaldo (UGI Gas St. 2). These adjustments are shown on UGI Gas Exhibit A (Fully Projected), Schedule D-31. The net adjustment of $212,000 is brought forward to Schedule D-3, page 2.

B. TAX CUTS AND JOBS ACT

Q. What is the Tax Cuts and Jobs Act of 2017?

A. The Tax Cuts and Jobs Act of 2017 ("TCJA") was tax reform legislation signed into law on December 22, 2017. Most pertinent for this proceeding, the TCJA:

- Reduced the corporate federal income tax rate from 35 percent to 21 percent, effective January 1, 2018; and
- Modified tax depreciation rules.

Q. Has UGI Gas reflected the impact of the TCJA in this proceeding?

A. Yes, the Company has reflected the impact of the TCJA in how it has calculated Schedules C-6, D-33 and D-34. I will describe how the Company has reflected the TCJA in greater detail in Section D.

C. 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 Gas 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. Consistent with established ratemaking practices, UGI Gas has normalized the tax repairs expense deduction for federal tax purposes. For state tax purposes, UGI Gas proposes to flow-through the repairs tax benefit over the tax useful 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 Gas Exhibit A (Fully Projected), Schedule D-1.

Q. Please describe the claim for income taxes shown on Schedule D-1, lines 19 and 20.

A. The calculation of federal and state income taxes can be found on Schedule D-33. Schedule D-33 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 using the rate base claim from Schedule C-1, with the cost of debt and the debt component of UGI's capital structure recommended in the direct testimony of Paul R. Moul (UGI Gas St. 7) 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 (9.99%) was then applied 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 Gas?

A. As shown on Schedule D-33 at line 31, the pro forma tax expense at present rates is $28.4 million and the pro forma tax expense at proposed rates for the FPFTY is $49.6 million. As explained below in Section G, this figure is not reduced by a consolidated income tax adjustment.

D. 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, 2021. 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 has been further reduced by the state regulatory liability associated with our 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. Was the calculation of ADIT impacted by the TCJA?

A. Yes. Beginning after September 30, 2018, the TCJA repealed "bonus depreciation" rules which would have permitted UGI to depreciate certain investments on a more accelerated basis than the regular Modified Accelerated Cost Recovery System ("MACRS"). The loss of bonus depreciation as a tax deduction significantly reduces UGI Gas's cash flow. The loss of this cash tax benefit will cause ADIT to grow at a slower pace than before. Further, the amount of such capital investments that must be financed by alternative means is likely to increase due to the loss of the cash tax benefit from bonus depreciation.

The enactment of the TCJA also created Excess Deferred Federal Income Taxes ("EDFIT"). Up through December 21, 2017, the Company's plant related ADIT was measured at 35% because that was the expected federal tax rate for when the temporary differences would reverse. As a result of the TCJA, the federal tax rate became 21%.

Thus, future temporary differences are now expected to reverse at 21%. Due to the change in the federal tax rate, ADIT was re-measured such that ending ADIT balances for GAAP purposes were at the new 21% federal tax rate. The difference in the ADIT balance from when it was at a 35% tax rate to its new 21% tax is EDFIT. The EDFIT represents that taxes are no longer due at the 35% federal tax rate; rather, they are due at the new 21% tax rate. The Company has reduced its rate base by EDFIT which is incorporated in the ADIT balance on Line 8 of Schedule C-6.

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 6 of Schedule A-1, the ADIT offset is $605.13 million, which includes an amount related to EDFIT.

Q. Has the Company reflected the amortization of the EDFIT on its income tax claim?

A. Yes, the Company has calculated the amount of the EDFIT that would 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 $3.64 million, calculated using the Average Rate Assumption Method ("ARAM") as required by tax normalization rules.

Q. Has the Company's ADIT rate base deduction been calculated 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 be in compliance with IRS normalization requirements. The pro-rationing concept requires that utilities pro-rate their rate base ADIT deduction to account for the time during the fully projected future test year that the ADIT for plant additions will be accrued by the company. This pro-rata calculation is required by the IRS in order for a utility company to be permitted to use accelerated depreciation and not have a normalization violation. As such, the Company reflects a pro-rationing of the ADIT associated with its FPFTY plant additions. This method is consistent with the Company's past ratemaking practice and has been accepted by the Commission in the Company's past base rate proceedings. The amount of the adjustment, $17.6 million, is reflected on Schedule C-6, line 7. Please see Attachment NMM-2 for the details of the calculation.

E. REPAIRS TAX METHOD

Q. Please explain UGI Gas's accounting treatment of the Repairs Tax Method.

A. As has been accepted in past cases, UGI Gas has chosen to calculate its federal income tax expense claim, inclusive of the repairs tax deduction, consistent with normalization.

As a result, the difference between using 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 Gas has chosen 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.

F. CONSOLIDATED TAX BENEFITS

Q. Has the Company calculated a consolidated tax expense adjustment?

A. Yes, but not for the purpose of flowing through as a ratemaking deduction to federal income tax expense. It is my understanding that Act 40 of 2016, which added 66 Pa. C.S § 1301.1 to the Public Utility Code, prohibits the use of a consolidated tax adjustment for ratemaking purposes. However, Section 1301.1(b) requires a public utility seeking to change rates 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, 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 Attachment II-A-26. This attachment indicates that, on a consolidated basis, UGI Gas had negative taxable income. As such, a consolidated tax adjustment for ratemaking purposes would have been $0. Company witness Mr. Stephen F. Anzaldo (UGI Gas St. 2) discusses how this demonstrates the Company has satisfied the requirements of Act 40.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS EXHIBIT NMM-1

Nicole M. McKinney, CPA

79 Landis Drive
Lancaster, PA 17602

(717) 330-9138
nrispress@gmail.com

PROFESSIONAL EXPERIENCE:

UGI Utilities, Inc. Reading, PA
Manager. March 2015 – Present

- Supervise 2 direct reports
- Manage the accounting for income taxes in accordance with ASC 740 and regulated operations under ASC 980
- Provide technical accounting guidance and expertise on regulatory accounting and compliance and income tax matters
- Manage the preparation of various regulatory and income tax related filings

DENTSPLY International. York, PA
Manager. August 2012 –April 2014

- Supervised staff of 3
- Responsible for identifying deficiencies and areas of improvement for current tax and accounting processes
- Managed completion of domestic federal tax returns and income tax provision
- Performed periodic presentations to senior management regarding tax implications of various business transactions and changes in tax law
- Supervised special tax projects such as research & development tax credit study, domestic production activities deduction, and accounting method changes

ParenteBeard, LLC. Lancaster, PA
Manager. December 2010 – July 2012.

- Supervised staff of 5
- Managed client relationships for middle-market businesses to ensure satisfaction of tax and accounting needs
- Assisted in the standardization of accounting processes and working papers
- Served as the liaison between external auditors and clients to achieve efficiency and successful results in year- end audits
- Reviewed complex individual, partnership, corporate, and international federal and state tax returns
- Served as manager on the strategic tax initiative team

WTAS, LLC. Philadelphia, PA
Manager. August 2006 – November 2010.

- Supervised staff of 3+
- Managed successful consulting engagements resulting in substantial cash savings
- Developed various complex financial models for client budgetary and forecasting needs
- Prepared and reviewed various international, domestic, and state corporate and partnership tax returns

EDUCATION:

Villanova University, Villanova, PA
Master of Accountancy - May 2007
Bachelor of Science - International Business/Management & Accounting - May 2006
Summa cum Laude
Bartley Medallion of Honor

UGI GAS EXHIBIT NMM-2

UGI Utilities, Inc. - Gas Division
Calculation of Pro-Rata Accumulated Deferred Income Tax
(In Thousands)

Month	A Increase to Deferred Taxes	B # of Days	C = B/365 Pro-Rata %	D = C*A Pro-Rata Incr to Deferred Taxes	Per Treas. Reg.1.167(l)-1(h)(6)(ii) Accumulated Deferred Income Tax Balance
9/30/2020					$ 594,319
10/31/2020	1,093	335	91.78%	1,003	595,322
11/30/2020	1,799	305	83.56%	1,503	596,825
12/31/2020	2,773	274	75.07%	2,082	598,907
1/31/2021	3,143	243	66.58%	2,092	600,999
2/28/2021	1,690	215	58.90%	996	601,995
3/31/2021	2,478	184	50.41%	1,249	603,244
4/30/2021	1,180	154	42.19%	498	603,742
5/31/2021	1,622	123	33.70%	547	604,288
6/30/2021	1,570	93	25.48%	400	604,688
7/31/2021	1,561	62	16.99%	265	604,953
8/31/2021	1,830	31	8.49%	155	605,109
9/30/2021	7,680	1	0.27%	21	**$ 605,130**