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 – PAUL R. MOUL
UGI GAS STATEMENT NO. 7 – NICOLE M. MCKINNEY
UGI GAS STATEMENT NO. 8 – SHERRY A. EPLER
UGI GAS STATEMENT NO. 9 – TIMOTHY J. ANGSTADT
UGI GAS STATEMENT NO. 10 – CONSTANCE E. HEPPENSTALL
UGI GAS STATEMENT NO. 11 – JOHN D. TAYLOR

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

DOCKET NO. R-2021-3030218

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UGI GAS STATEMENT NO. 6

PAUL R. MOUL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3030218

UGI Utilities, Inc. – Gas Division

Statement No. 6

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

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

Dated: January 28, 2022

UGI Utilities, Inc. - Gas Division
Direct Testimony of Paul R. Moul
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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 determining the revenues UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company") should be authorized to recover 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 consisting of Schedules one (1) through fourteen (14).

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 7.96% overall rate of return, which includes an 11.20% rate of return on common equity. My 11.20% 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.

DIRECT TESTIMONY OF PAUL R. MOUL

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	44.88%	3.98%	1.79%
Common Equity	55.12%	11.20%	6.17%
Total	100.00%		7.96%

This overall rate of return is applicable to the September 30, 2023, fully projected future test year ("FPFTY") and the initial period that the Company's proposed rates will be effective.

Q. Is the market impact of the COVID-19 Pandemic reflected in your analysis of the cost of equity for the Company?

A. Yes. My cost of equity analysis reflects the impact of the COVID-19 Pandemic ("Pandemic"). These events have had a significant impact on the stock and bond markets beginning in the February-March 2020 time frame. During this period, we saw abrupt reaction to the Pandemic. These events led to the end of the record-setting 128-month economic expansion. As we entered a recession in February 2020, extraordinary actions were taken by the Federal Open Market Committee

("FOMC") to address these disruptions. Over the course of the Pandemic, stock prices have rebounded and have reached new highs. Economic growth has rebounded and has produced renewed inflation to levels not seen in three (3) decades. Supply shortages have also significantly impacted the consumer sector of the economy. Energy prices have increased as well, with the commodity cost of natural gas spiking upward. While short-term interest rates remain at historically low levels, longer term interest rates began to rise in February 2021. At this point, short-term interest rates are poised to increase when the FOMC ends its bond buying program. The FOMC has indicated that several increases in the Fed Funds rate will likely occur in 2022. Stock market performance has reacted to renewed economic growth by reaching new highs. I have considered these events as they impact the inputs that I used in the various models of the cost of equity.

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 672,000 customers in forty-five (45) eastern and central 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 year 2020 was represented by approximately 19% to sales customers and approximately 81% to transportation customers. The significant portion of the Company's throughput to industrial customers (68% of total throughput) 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 several interstate pipelines and storage facilities. The Company has storage arrangements for natural gas inventory. UGI Utilities also provides electric delivery service, through UGI Electric, to more than 62,500 customers in portions of Luzerne and Wyoming Counties.

Q. How have you determined the cost of common equity in this 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 UGI Gas. In this regard, I have considered four (4) well-recognized models. These methods include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach. The results of a variety of approaches indicate that the Company's rate of return on common equity is 11.20%, including 0.20% in recognition of the Company's exemplary management performance.

Q. In your opinion, what factors should the Commission consider when determining the Company's cost of capital in this proceeding?

A. The Commission's rate of return allowance must be set 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. How have you measured 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 from a group of companies engaged in the distribution of natural gas. I will refer to these companies as the "Gas Group" throughout my testimony. I began with all of the gas utilities contained in The Value Line Investment Survey, which consists of ten (10) companies. Value Line is an investment advisory service that is a widely used source in public utility rate cases. However, I eliminated one (1) company from the Value Line group. UGI Corporation was removed due to its diversified businesses consisting of six (6) reportable segments, including propane, two (2) international LPG segments, natural gas utility, energy services, and electric generation. The remaining nine (9) companies in the Gas Group 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 October 9, 2021.

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

A. I have applied the methods/models for estimating the cost of equity using the average data for the Gas Group. I have not measured separately the cost of equity for the individual companies within the Gas Group, because the determination of

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[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).

the cost of equity for an individual company can be problematic. The use of group average data will reduce the effect of potentially anomalous results for an individual company if a company-by-company approach were utilized.

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. 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.

DCF	11.21%
Risk Premium	10.50%
CAPM	13.55%
Comparable Earnings	12.70%

From these measures, I recommend a cost of equity of 11.00%, to which 0.20% should be added in recognition of the Company's exemplary management performance. 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. My determination of the cost of equity focuses on the DCF and Risk Premium approaches that provide a return of 10.86% (11.21% + 10.50% = 21.71% ÷ 2 = 10.86%) and on all of the market-based models, i.e., DCF, Risk Premium and CAPM, that provide a return of 11.75% (11.21% + 10.50% + 13.55% = 35.26% ÷ 3 = 11.75%). My 11.20% cost of equity recommendation includes 20 basis points or 0.20% recognition for the exemplary performance of the Company's management and falls within the range of 10.86% to 11.75% indicated above. Mr. Brown's testimony in UGI Gas Statement No. 1 demonstrates that the Company ranks high in customer service and management effectiveness. To obtain new capital to support an expanded construction program and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements. Along these lines, the Company is spending considerable amounts of new capital, which 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 an 11.20% rate of return on common equity.

NATURAL GAS RISK FACTORS

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

A. Natural gas utilities face risks arising from competition, economic regulation, the business cycle, and customer usage patterns. Today, they operate in a 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. The gas distribution industry also faces the risk associated with increased availability of renewable energy sources, expanded emphasis on energy efficiency, and potential initiatives directed toward decarbonization as a national energy policy.

Natural gas utilities have focused increased attention on safety and reliability issues and on conservation. 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. The testimony of Company witnesses discusses the investments that the Company has made and will continue to make to address these issues 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 it compared to many companies in the Gas Group. Natural gas utilities generally face significant competition from alternative energy sources. The Company faces direct competition from electricity, fuel oil, and propane in its service territory, and there is now an increased emphasis on electricity as an energy source. 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 seventeen (17) customers that could potentially bypass its system.

Q. What are the risks associated with the Company's large volume customers?

A. The Company's risk profile is strongly influenced by throughput delivered to large competitive market customers. Industrial customers represent 68% of throughput, but these customers represent about one-half of one percent of total customers. Moreover, the Company's top ten (10) customers represent 185.8 million Mcf of total throughput or about 64% of the total. Electric generation, manufacturing, 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 detail the regulatory risks faced by the Company?

A. Among other factors, regulatory risks faced by the Company are elevated when it comes to permits and approvals necessary for the siting of projects that assure reliable supply of natural gas. Obtaining these permits and approvals has become a time consuming and increasingly risky process that adds delay and costs to the projects that will assure adequate gas supply for the Company.

Q. Please discuss some of the operational risks faced by the Company?

A. Risks that affect the Company's operations relate to adequate delivery capability, counterparty risk, and risks related to cyber-security. The Company is also faced with counterparty risk should suppliers fail to perform their obligations, especially with regard to hedging obligations. In addition, the handling of natural gas is inherently risky. Finally, cyber-security has created increased risk when systems that deliver gas to customers are vulnerable to attack from foreign enemies and domestic terrorists.

Q. What risks are associated with the Company's infrastructure?

A. The Company's infrastructure is aging and is in the process of rehabilitation and replacement. Investments that address these issues cause costs to increase without any corresponding increase in throughput that would add to revenues.

This places pressure on the price paid by customers that may prompt them to seek alternative energy sources.

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 its existing facilities. The Company had 1,070 miles of its distribution mains constructed of unprotected steel and cast iron pipe as of year-end 2020. The Company also has 26,744 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 total construction expenditures will be:

Year	Capital Expenditures
2022	$ 475,000,000
2023	$ 499,000,000
2024	$ 493,000,000
2025	$ 493,484,000
Total	$ 1,960,484,000

Of these amounts, $1,862,535,675 are attributed to the Gas Division. During the 2022-2025 period, gross construction expenditures will represent an approximate 59% increase ($1,960,484,000 ÷ $3,331,998,000) in net utility plant, including construction work in progress, from the level at September 30, 2021.

Q. Are there other features of the Company's business that should be considered when assessing the Company's risk?

A. Yes. Most of the Company's residential and commercial customers use natural gas for space heating purposes. Therefore, a large proportion of the Company's residential and commercial customers present a low load factor profile and their energy demands are significantly influenced by temperature conditions, over which the Company has absolutely no control. To help deal with this issue, UGI Gas is proposing a weather normalization adjustment ("WNA") mechanism as part of its tariff.

Q. Does your cost of equity analysis and recommendation take into account the revenue decoupling mechanism?

A. Yes. The Company is proposing a weather normalization mechanism in this case as described in the prefiled direct testimony of Company witness Mr. John D. Taylor (UGI Gas Statement No. 9). This is intended to reconcile actual weather-adjusted sales margins with those approved in the Company's most recent rate case. My cost of equity analysis takes into account the Company's WNA mechanism.

Q. How have you addressed this issue?

A. My analysis reflects the impact of the WNA on investor expectations through the use of market-determined models. All of the companies in my Gas Group have some form of WNA mechanism that is intended to accomplish the same result as the Company's proposal in this case. As a group, the market prices of these companies' common equity reflect the expectations of investors that the companies' revenues are stabilized to some extent by a WNA. Therefore, my analysis reflects the impacts of decoupling on investor expectations through the use of market-determined models.

As such, the market prices of these companies' common stocks reflect the expectations of investors related to a regulatory mechanism that adjusts revenues for conservation, abnormal weather, and other items. The trend in the industry is to stabilize the recovery of fixed costs, which are unaffected by usage. Indeed, there has been a proliferation of these mechanisms in the LDC business. Because the Gas Group that I use to measure the cost of equity has the risk attributes related to the revenue decoupling mechanism "baked in" to their stock prices, the absence of the benefit of the WNA would increase the cost of equity as determined by the models that are applied with the Gas Group data.

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 is shown in UGI Gas Exhibit SAE-3 and discussed in the testimony of Ms. Sherry Epler (UGI Gas Statement No. 8).

Company analysis indicates that this decline will continue, particularly with the implementation of its successful energy efficiency and conservation plan. This plan provides 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 (8) of nine (9) 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 Ms. Sherry Epler

(UGI Gas Statement No. 8). 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 a determination of a utility's cost of equity?

A. Yes, it is. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors that bear upon Company risk have already been discussed. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and their required returns were described above. For this purpose, I compared the Company to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, 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 that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4.

Q. What companies comprise the Gas Group?

A. 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 important 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 shown directly 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 compensation to recognize the higher risk of an equity investment compared to debt.

Q. How do the credit quality ratings compare for the Company, the Gas Group, and the S&P Public Utilities?

A. Presently, the Company's Long Term ("LT") issuer credit quality rating is A2 from Moody's Investors Service ("Moody's") and A- from Fitch. The rating represents the LT issuer rating by Moody's, which focuses upon the credit quality of the issuer of the debt rather than upon the debt obligation itself. For the Gas Group, the average LT issuer rating is A3 by Moody's and A- by Standard & Poor's, as displayed on page 2 of Schedule 3. For the S&P Public Utilities, the average credit quality rating is A3 by Moody's and BBB+ by Standard & Poor's, as displayed on page 3 of Schedule 4. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. How do the financial data compare for the Company, 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 2016-2020. The important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, the Company is smaller than the average size of the Gas Group, and smaller still than the average size of the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity. This is the case for UGI Gas as compared to the Gas Group and the S&P Public Utilities.

Market Ratios. Market-based financial ratios, such as earnings/price ratios 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 that exhibit greater 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]

There are no market ratios available for the Company because its stock is owned by UGI Corporation. The five-year average price-earnings multiple was somewhat higher for the Gas Group compared to 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 slightly lower 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

[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).

equity ratios (the complement of the ratio of debt and other senior capital). A firm with a higher common equity ratio has lower financial risk, while a firm with a lower common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 56.6% for UGI Gas, 51.5% for the Gas Group, and 41.3% for the S&P Public Utilities. The Company's common equity ratio was higher than the Gas Group, thereby indicating somewhat lower financial risk. However, for the purpose of this case, the Company's common equity ratio is within the range of other gas distribution utilities.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater 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 coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.120 (1.4% ÷ 11.7%) for the Company, 0.079 (0.7% ÷ 8.9%) for the Gas Group, and 0.039 (0.4% ÷ 10.3%) 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).[3] The five-year average operating ratios were 76.7% for the Company, 83.6% for the Gas Group, and 78.8% for the S&P Public Utilities. The Company's operating ratios were somewhat lower than the Gas Group, thereby indicating slightly lower risk.

[3]The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

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. Excluding Allowance for Funds Used During Construction ("AFUDC"), the five-year average pre-tax interest coverage was 5.07 times for the Company, 4.05 times for the Gas Group, and 3.02 times for the S&P Public Utilities. The interest coverages were higher for the Company as compared to the Gas Group, thereby indicating lower credit risk.

Quality of Earnings. Measures of earnings quality usually are 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 because poor quality of earnings would not generate high levels of cash flow. During the Pandemic, there was further pressure on cash flows due to the suspension of collection activities and the moratorium against shut off service due to nonpayment. Moreover, the Company has created a regulatory asset consisting of Pandemic related costs that the Commission has allowed to be deferred, such as excess uncollectible accounts expense and costs for an approved Emergency Relief Program. Such actions have a negative impact on the Company's cash flow. Quality of earnings has not been a significant concern for the Company, the Gas Group, and the S&P Public Utilities.

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 capital expenditures was 72.4% for the Company, 56.0% for the Gas Group, and 69.5% for the S&P Public Utilities. The Company's IGF to construction expenditures dropped in 2019 and 2020 after the reduction in the provision for deferred taxes due to the elimination of bonus depreciation.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[4] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of 0.88 as the average for the Gas Group (see page 2 of Schedule 3) and 0.91 as the average for the S&P Public Utilities (see page 3 of Schedule 4). The systematic risk for the Gas Group as measured by the Value Line beta is fairly similar to the S&P Public Utilities.

Q. Please summarize your risk evaluation.

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, its lower operating ratio, and higher interest

[4]Beta is a relative measure of the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index. The ''Beta coefficient'' is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. The betas are adjusted for their long-term tendency to converge toward 1.00. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

coverages. On balance, the cost of equity measured with the Gas Group data will provide a reasonable, albeit conservative, representation of the Company's cost of equity.

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. I have employed the consolidated capital structure ratios of UGI Utilities to calculate the rate of return for this case because it finances all its operations on a consolidated basis. The circumstances of UGI Gas 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, 2021, the end of the historic test year ("HTY"). Also shown on Schedule 5 is the UGI Utilities' capital structure estimated at September 30, 2022, the end of the future test year ("FTY"), and at September 30, 2023, the end of the FPFTY. The changes in UGI Utilities' capital structure consist of: (i) debt maturities and principal payments of $107.813 million in both the FTY and FPFTY, (ii) the issuance in three (3) series of $300 million debt issues in both the FTY and FPFTY,

(iii) the receipt of $35 million of capital contributions in the FTY, and (iv) 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 rate-setting purposes?

A. Yes. I have removed accumulated other comprehensive income ("OCI") from the Company's common equity account.

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 derivative instruments. 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 related to the portion attributable to employees of UGI Corporation and non-utility subsidiaries. That is to say, the accumulated OCI associated with MPL is not related to utility operations.

Q. What capital structure ratios do you recommend be adopted for rate of return purposes in this proceeding?

A. I will adopt the UGI Utilities' capital structure ratios at the end of the FPFTY, which consists of 44.88% long-term debt and 55.12% common equity, on a rounded basis. These ratios are within 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. 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 ("Allowance of Funds Used During Construction 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. That is to say, the use of short-term debt for AFUDC decreases the overall cost of construction that ultimately goes into rate base so ratepayers ultimately receive the benefit for this lower cost capital. 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 environment remediation costs is expected to be $3.796 million at the end of 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 CWIP balance exceeds the average amount of short-term debt. Hence, all short-term debt is excluded from the capital structure in the FPFTY.

COST OF SENIOR CAPITAL

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 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, 2021. On page 2 of Schedule 6, I have shown the estimated embedded cost rate of long-term debt at September 30, 2022. 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.

The interest rates for the three (3) new issues of debt in the FTY and FPFTY are 3.687% for the 30-year issue in May 2022, 1.410% for the 5-year issue in July 2022, and 3.791% for the 30-year issue in October 2022. With these rates, I calculate a 3.98% forecast embedded long-term debt cost rate at September 30, 2023, 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 44.88% long-term debt ratio.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe how you determined the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among UGI Gas, 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 11.20%, including a provision for recognition of exemplary management performance.

DISCOUNTED CASH FLOW

Q. Please describe the DCF model.

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF-determined return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model, which assumes that future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: P = D/(k-g), where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: k= D/P + g. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model.[5] My DCF results are provided on Schedule 1, page 2, for the Gas Group. The DCF return is 11.21% with the leverage adjustment and 10.26% without the leverage adjustment for the Gas Group. The leverage adjustment is discussed more fully below.

Among the limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility. Other limitations of the DCF include the constant price-earnings multiple assertion that does not conform with actual stock market performance. And,

[5] 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.

indeed, the FERC has moved to using multiple methods for measuring the cost of equity close due to the limitations of the DCF.

Q. What is the dividend yield component of a DCF analysis?

A. The dividend yield reveals the portion of investors' cash flow that is generated by the return provided by the dividends an investor receives. It is measured by the dividends 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 (12) months ended September 2021, the monthly dividend yields are shown on Schedule 7. The month-end prices were adjusted to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two (2) to three (3) weeks prior to the actual payment).

For the twelve (12) months ended September 2021, the average dividend yield was 3.49% 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 and three-month periods were 3.39% and 3.51%, respectively. For applying the DCF model, I have used the six-month average dividend yield of 3.39% 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 (3) different, but generally accepted, manners and used the average of the three (3) adjusted values as calculated in the lower panel of data presented on Schedule 7. This adjustment adds twelve (12) basis points to the six-month average historical yield, thus producing the 3.51% 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 growth in earnings per share is the DCF model's primary focus because, under the model's assumption that the price-earnings multiple remains constant, the price per share of stock will grow at the same rate as earnings per share. A growth rate analysis considers a variety of variables to reach a consensus of prospective growth, including historical data and widely available analysts' forecasts of earnings, dividends, book value, and cash flow (all stated on a per-share basis). A fundamental growth rate analysis is frequently based upon internal growth ("b x r"), where "r" is the expected rate of return on common equity and "b" is the retention rate (a fraction representing the proportion of earnings not paid out as dividends). To be complete, the internal growth rate should be modified to account for sales of new common stock (external growth), which is represented by the formula s x v, where "s" is the number of new common shares the firm expects to issue and "v" is the value that accrues to existing shareholders from selling stock at a price above book value. Fundamental growth, which combines internal and external growth, encompasses the factors that cause book value per share to grow over time.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage 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" stage, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilize at levels where they remain for the life of a firm. The three (3) stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three (3) 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 (3) 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. 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 should be evaluated using a variety of techniques 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 considered the growth in the financial variables shown on Schedules 8 and 9, which reflect historical (Schedule 8) and projected (Schedule 9) rates of growth in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. While analysts will review all measures of growth, as I have done, earnings per share growth directly influences the expectations of investors for the future performance of utility stocks. Forecasts of earnings growth are required because the DCF model is forward-looking, and, with the constant price-earnings multiple and constant payout ratio that the DCF model assumes, all other measures of growth will mirror earnings growth. The historical growth rates were obtained from the Value Line publication that provides this data. While historical data cannot be ignored, it is much less significant in applying the DCF model than projections of future growth. Investors cannot purchase the past earnings of a utility. To the contrary, they are only entitled to future earnings, which are the focus of growth projections. Furthermore, if significant weight is assigned to historical performance, the historical data are double counted because they are already factored into analysts' forecasts of earnings growth.

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

A. Yes, it is. Although the constant form of the DCF model assumes an infinite stream of cash flows, investors do not expect to hold an investment indefinitely. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investors' expected return. The growth in the price per share will equal the growth in earnings per share if, as the DCF model assumes, there is no change in the price-earnings ("P-E") multiple. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, conforms with the type of analysis that influences investors' expectations of their actual total return. Moreover, academic research focuses also on five-year growth rates specifically because market outcomes occurring over that investment horizon are what influence stock prices. Indeed, if investors required forecasts beyond five (5) years in order to properly value common stocks, then it would be reasonable to expect that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of the marketplace. The absence of such a publication suggests that there is no market for this information because investors do not require forecasts for an infinite series of future data points in order to make informed decisions to purchase and sell stocks.

Q. What are the analysts' forecasts of future growth that you considered?

A. Schedule 9 provides projected earnings per share growth rates taken from analysts' five-year forecasts compiled by IBES/First Call, Zacks, and <u>Value Line</u>. These are all reliable authorities of projected growth that investors use to make buy, sell, and hold decisions. The IBES/First Call and Zacks estimates are obtained from the Internet and are widely available to investors. The growth rates reported by IBES/First Call and Zacks are consensus forecasts taken from a survey of analysts that make growth projections for these companies. Notably, First Call's earnings forecasts are frequently quoted in the financial press. The Value Line forecasts also are widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries. The IBES/First Call and Zacks forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share for the Gas Group are also included on Schedule 9.

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

A. Schedule 9 shows the prospective five-year earnings per share growth rates projected for the Gas Group by IBES/First Call (5.41%), Zacks (5.88%), and Value Line (7.61%).

Q. Are certain growth rate forecasts entitled to greater weight in developing a growth rate for use in the DCF model?

A. Yes. While a variety of factors should be examined to reach a reasonable conclusion on the DCF growth rate, growth in earnings per share should receive the greatest emphasis. Growth in earnings per share is the primary determinant of investors' expectations of the total returns they will obtain from stocks because the capital gains yield (i.e., price appreciation) will track earnings growth if the P-E multiple remains constant, as the DCF model assumes. Moreover, earnings per share (derived from net income) are the source of dividend payments and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In fact, Professor Myron Gordon, the foremost proponent of the use of the DCF model in setting utility rates, concluded that the best measure of growth for use in the DCF model is a forecast of earnings per-share growth.[6] Consistent with Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, and Value Line, provide the best indication of investor expectations.

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

A. The forecasts shown on Schedule 9 for the Gas Group exhibit a range of average earnings per share growth rates from 5.41% to 7.61%. DCF growth rates should not be established by mathematical formulation, and I have not done so. In my opinion, a growth rate of 6.75% is a reasonable estimate of investor-expected growth for the Gas Group. This value is within the array of analysts' forecasts of five-year earnings per share growth rates and is below the midpoint of that data set. The reasonableness of this growth rate is also supported by the expected continuation of gas utility infrastructure spending.

Q. Are the dividend yield and growth components of the DCF adequate to accurately depict the rate of return on common equity when it is used to calculate a utility's weighted average overall cost of capital?

A. The components of the DCF model are adequate for that purpose only if the capital structure ratios are measured by the market value of debt and equity. In the case of the Gas Group, average capital structure ratios are 43.49% long-term debt, 0.46% preferred stock, and 56.06% common equity, as shown on Schedule 10. If

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

book values are used to compute the capital structure ratios, then a leverage adjustment is required.

Q. What is a leverage adjustment?

A. If a firm's capitalization, as measured by its stock price, diverges from its capitalization, measured at book value, the potential exists for a financial risk difference. Such a risk difference arises because a market-valued capitalization contains more equity and less debt than a book-value capitalization and, therefore, has less risk than the book-value capitalization. A leverage adjustment properly accounts for the risk differential between market-value and book-value capital structures.

Q. Why is a leverage adjustment necessary?

A. In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes), the market-derived cost rate must be adjusted to account for this difference in financial risk. The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different from the capital structure indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market-valued capitalization of a firm. If the ratemaking process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the ratemaking process uses ratios calculated from a firm's book value capitalization, further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the firm's equity. This adjustment is developed through precise mathematical calculations, using well recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. The calculations presented in the lower panel of data shown on Schedule 10, under the heading "M&M,"[7] provides a return of 7.52% 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

[7] Franco Modigliani and Merton H. Miller, The Cost of Capital, Corporation Finance, and the Theory of Investments, American Economic Review, June 1958, at 261-297. Franco Modigliani and Merton H. Miller, Taxes and the Cost of Capital: A Correction, American Economic Review, June 1963, at 433-443.

that contains 100% equity) plus the additional return required for introducing debt and/or preferred stock leverage into the capital structure.

Further, as noted previously, the relatively high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on the book value of equity that differs from their cost of equity determined from stock market prices. Stock prices above book value are common for utility stocks, and indeed the stock prices of non-regulated companies exceed book values by even greater margins. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of their cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they actually existed.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true: when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

Q. Is the leverage adjustment that you propose designed to transform the market return into one that is designed to produce a particular market-to-book ratio?

A. No, it is not. What I label a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g) when the DCF return applies to a capital structure used for ratemaking that is computed with book-value weighting rather than market-value weighting. Although I specify a separate factor, which I call the leverage adjustment, there is no need to do so other than to identify this factor. If I expressed my return solely in the context of the book value weighting that we use to calculate the weighted average cost of capital and ignore the familiar D/P + g expression entirely, then a separate element in the DCF cost of equity determination would not be needed to reflect the differential in financial leverage between a market-value and book-value capitalization. As shown in the bottom panel of data on Schedule 10, the equity return applicable to the book value common equity ratio is equal to 7.52%, which is the return for the Gas Group appropriate for a capital structure with no debt (i.e., a 100% equity ratio) plus 3.67% to compensate investors for the risk of a 51.07% debt ratio and 0.02% for a 0.54% preferred stock ratio. These are the book-value ratios that differ markedly from the market-value based ratios I discussed previously. Under this approach, the parts sum to 11.21% (7.52% + 3.67% + 0.02%), 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 3.51% dividend yield, the 6.75% growth rate, and 0.95% for the leverage adjustment in order to arrive at the same 11.21% (3.51% + 6.75% + 0.95%) return. I know of no means to mathematically solve for the 0.95% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.95% adjustment is merely a convenient way to compare the 11.21% return computed using the Modigliani & Miller formulas to the 10.26% return generated by the DCF model (i.e., $D_1/P_0 + g$, or the traditional form of the DCF shown on Schedule 7, page 1) based on a market-value capital structure. An 11.21% return assigned to anything other than the market value of equity cannot equate to a reasonable return on book value that has higher financial risk. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

Q. Please provide the DCF return based upon your preceding discussion of dividend yield, growth, and leverage.

A. As explained previously, I have utilized a six-month average dividend yield (D_1/P_0) adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate (g) previously developed. The DCF also includes the leverage modification (lev.) required when the book value equity ratio is used in determining the weighted average cost of capital in the ratemaking process rather than the market value equity ratio related to the price of stock. The resulting DCF cost rate is 11.21%, computed as follows:

	D_1/P_0	+	g	+	*lev.*	=	k
Gas Group	3.51%	+	6.75%	+	0.95%	=	11.21%

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 the results of other models when determining a company's cost of equity.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the Risk Premium approach to determine the cost of equity.

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on Schedule 1, page 2. That result is 10.50%.

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 are shown by the Moody's data?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on Schedule 11, page 1. For the twelve (12) months ended September 2021, the average monthly yield on Moody's index of A-rated public utility bonds was 3.06%. For the six- and three-month periods ended December 2020, the yields were 3.11% and 2.95%, respectively. During the twelve (12) months ended September 2021, the range of the yields on A-rated public utility bonds was 2.77% to 3.44%. 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 1.09% on a twelve-month average basis, 1.01% on a six-month average basis, and 1.02% on a three-month average basis. Giving greater emphasis to the six-month average spread, 1.00% 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. 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 October 1, 2021, and a yield spread of 1.00%, derived from historical data.

Q. How have you used these data to project the yield on A-rated public utility bonds for the purpose of your Risk Premium analyses?

A. Shown below is my calculation of the prospective yield on A-rated public utility bonds using the building blocks discussed above, i.e., the Blue Chip forecast of Treasury bond yields and the public utility bond yield spread. For comparative purposes, I also have shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2021	Fourth	2.9%	3.6%	2.2%	1.25%	3.45%
2022	First	3.0%	3.8%	2.3%	1.25%	3.55%
2022	Second	3.1%	4.0%	2.4%	1.25%	3.65%
2022	Third	3.2%	4.1%	2.5%	1.25%	3.75%
2022	Fourth	3.3%	4.2%	2.6%	1.25%	3.85%
2023	First	3.4%	4.3%	2.7%	1.25%	3.95%

Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its June 1, 2021 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2023-2027	4.3%	5.3%	3.5%
2028-2032	4.8%	5.8%	3.9%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. A 3.75% yield on A-rated public utility bonds represents a reasonable benchmark for measuring the cost of equity in this case. All the data I used to formulate my conclusion as to a prospective yield on A-rated public utility debt are available to investors, who regularly rely upon such data to make investment decisions. Later FOMC pronouncements have moved the forecasts of interest rates to higher levels.

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

A. To develop an appropriate equity risk premium, I analyzed the results from 2021 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 Attachment 12, page 1.

Common Equity Risk Premiums	
Low Interest Rates	6.63%
Average Across All Interest Rates	5.67%
High Interest Rates	4.69%

Based on my analysis of the historical data, the equity risk premium was 6.63% when the marginal cost of long-term government bonds was low (i.e., 2.85%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.09% on average during periods of high interest rates), the spread narrowed to 4.69%. Over the entire spectrum of interest rates, the equity risk premium was 5.67% when the average government bond yield was 4.95%. I have utilized a 6.75% equity risk premium. The equity risk premium of 6.75% that I employed is near the risk premiums associated with low interest rates.

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	3.75%	+	6.75%	=	10.50%

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 13.55% for the Gas Group with the leverage adjustment. Without the leverage adjustment, the CAPM result is 12.38% (13.55% - (0.12 x 9.78%)). To compute the cost of equity with the CAPM, three (3) components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 2 of Schedule 3, the average beta is 0.88 for the 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 ratemaking capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. 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,[8] as follows:

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

ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.54 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 1.00 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 (12) months ended September 2021, the average yield on 30-year Treasury bonds was 1.97%. For the six- and three-months ended September 2021, the yields on 30-year Treasury bonds were 2.10% and 1.93%, respectively. During the twelve (12) months ended September 2021, the range of the yields on 30-year Treasury bonds was 1.57% to 2.34%. The low yields that existed during recent periods can be traced to weakness in business fixed investment and exports due in part to the trade dispute between the United States

[8] 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.

and China. Thereafter, extraordinary events associated with the Pandemic induced significant turmoil that jolted the capital markets in the February-May 2020 time frame. During this period, we saw abrupt reaction to the Pandemic. These events led to the end of the record-setting 128-month economic expansion. As the recession unfolded in February 2020, the FOMC acted to address these disruptions. The FOMC continues to support the money and capital markets during the recovery from the COVID-19 Pandemic. Presently, the Fed Funds rate is near zero. It is expected that a transition in FOMC policy will prospectively produce higher interest rates as the Pandemic nears its end. A forward-looking assessment of the capital markets is especially relevant now because the Company's rates will be based on financial conditions in 2022 and beyond. Higher inflation expectations are a contributing factor that points to higher interest rates. Indeed, higher inflation today is revealed by a 5.9% increase in social security payments announced on October 13, 2021, which is the largest one-year increase in nearly four (4) decades. FOMC has signaled that it plans to taper its bond buying program (i.e., quantitative easing) in November 2021 and to end it completely by March 2022. The Fed Funds rate is also likely to increase from very low levels that existed during the Pandemic. Higher interest rates clearly point to higher capital costs prospectively. I will describe the forecasts of interest below, including the end of quantitative easing by the FOMC and indications prospectively of several increases in the Fed Funds rate in 2022.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on October 1, 2021indicate that the yields on long-term Treasury bonds are expected to be in the range of 2.2% to 2.7% during the next six (6) quarters. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 3.5% from 2023 through 2027 and 3.9% from 2028 to 2032. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a 2.75% 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 Schedule 13, page 2, the market premium is derived from historical data and the forecast returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on Schedule 12, page 1. On that schedule, the market return was 12.06% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 2.85% when interest rates were low. As such, I carried over to Schedule 13, page 2, the average large common stock returns of 12.06% and the average yield on long-term government bonds of 2.85%. The resulting market premium is 9.21% (12.06% - 2.85%) based on historical data, as shown on Schedule 13, page 2. As also shown on Schedule 13, page 2, I calculated the forecast returns, which show a 13.10% total market return. With this forecast, I calculated a market premium of 10.35% (13.10% - 2.75%) using forecast data. The resulting market premium applicable to the CAPM derived from these sources equals 9.78% (10.35% + 9.21% = 19.56% ÷ 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. As noted previously, UGI Gas is relatively smaller than the Gas Group. To recognize this fact, I used the mid-cap adjustment of 1.02%, as revealed on page 3 of Schedule 13, for the CAPM calculation.

Q. What does your CAPM analysis show?

A. Using the 2.75% risk-free rate of return, the leverage adjusted beta of 1.00 for the Gas Group, the 9.78% market premium, and the 1.02% size adjustment, the following result is indicated.

	Rf	**+**	***ß***	***x (***	***Rm-Rf***	***) +***	***size***	***=***	***k***
Gas Group	2.75%	+	1.00	x (	9.78%	) +	1.02%	=	13.55%

COMPARABLE EARNINGS APPROACH

Q. What is the Comparable Earnings approach?

A. The Comparable Earnings approach estimates a fair return on equity by comparing returns realized by non-regulated companies to returns that a public utility with similar 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 (2) 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 (6) 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 Schedule 14, page 3. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on Schedule 14, page 1.

I relied upon Value Line data because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on Schedule 14, page 2, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities.

Q. What data did you consider in your Comparable Earnings analysis?

A. I used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (five (5) historical years and five (5) projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 12.5% using only the returns that were less than 20%, as shown on Schedule 14, page 2. The average forecasted rate of return as published by Value Line is 12.9% also using values less than 20%, as provided on Schedule 14, page 2. Using the average of these data, my Comparable Earnings result is 12.70%, as shown on Schedule 1, page 2.

CONCLUSION ON COST OF EQUITY

Q. What is your conclusion regarding the Company's cost of common equity?

A. Based upon the application of a variety of methods and models described previously, it is my opinion that a reasonable rate of return on common equity is 11.20% 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 an 11.20% rate of return on common equity so that it can compete in the capital markets, attain reasonable credit quality, sustain its cash flow in the context of its high levels of capital expenditures, and receive recognition of the significant accomplishments that management has achieved.

Q. Does this complete your direct testimony?

A. Yes. However, I reserve the right to supplement my testimony, if necessary, and to respond to witnesses presented by other parties.

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 Commission 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. 7

NICOLE M. MCKINNEY

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3030218

UGI Utilities, Inc. – Gas Division

Statement No. 7

Direct Testimony of
Nicole M. McKinney

Topics Addressed: **Taxes and Tax Adjustments**
Employee Retention Credit ("ERC")

Dated: January 28, 2022

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. Through December 6, 2021, I was employed by UGI Utilities, Inc. ("UGI") as Senior Manager Natural Gas Tax Accounting. UGI is a subsidiary of UGI Corporation ("UGI Corp."). UGI's Gas Division ("UGI Gas" or the "Company") and Electric Division ("UGI Electric") are regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC"). On December 6, 2021, I transitioned to the role of Director of Financial Planning and Analysis at UGI Corp. For purposes of this rate case proceeding, I continued my former duties as Senior Manager Natural Gas Tax Accounting.

Q. What were your principal duties and responsibilities as Senior Manager of Natural Gas Tax Accounting?

A. My primary duties as Senior Manager Natural Gas Tax Accounting included 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 maintained the current and deferred income tax accruals and expense accounts, performed tax research, and assisted UGI with tax matters as they arose. Additionally, I managed the reporting of the Company's various tax filings with its local, state, and federal jurisdictions.

Q. What are your current principal duties and responsibilities as Director of Financial Planning and Analysis?

A. In this role, I provide strategic and operational direction for UGI's processes and functions related to financial planning and analysis. My budget supervision responsibilities include the: 1) coordination and review of financial inputs from various departments; 2) development of financial forecasts; and 3) preparation and distribution of this information to UGI executive management, investor relations, and the UGI Board of Directors. Additionally, I oversee capital investment processes, manage corporate finance projects, and report directly to the Chief Finance Officer.

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, 2023 ("FPFTY"). I will also explain the tax adjustments made to the results of UGI Gas's historic test year ended September 30, 2021 ("HTY") and future test year ending September 30, 2022 ("FTY").

Q. Have you testified previously before this Commission?

A. Yes. UGI Gas Exhibit NMM-1 contains a list of those proceedings.

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

A. Yes. I am sponsoring the UGI Gas Exhibits: NMM-1, NMM-2, NMM-3 and NMM-4. 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 Gas'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 Ms. Tracy A. Hazenstab (UGI Gas Statement No. 2), UGI Gas's principal accounting exhibit is UGI Gas Exhibit A (Fully Projected), which includes a presentation for the FPFTY ending September 30, 2023. 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 Gas'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, 2021 and the FTY ending September 30, 2022. This information is provided to comply with the Commission's filing requirements and provides a basis for comparing UGI Gas'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 consists of the Pennsylvania Utility Realty Tax ("PURTA"), Pennsylvania and Local Property taxes, Social Security taxes, Federal Unemployment tax ("FUTA"), State Unemployment tax ("SUTA") and the Company's assessed contribution to the Commission, Office of Consumer Advocate and Office of Small Business Advocate. TOTI amounts were based on the plan year budget, as adjusted for reasonably known and measurable changes to various payroll taxes as supported by the direct testimony of Ms. Tracy A. Hazenstab (UGI Gas Statement No. 2). These adjustments are shown on UGI Gas Exhibit A (Fully Projected), Schedule D-31. The net adjustment of $298,000 is brought forward to Schedule D-3, page 2.

B. INCOME TAXES

Q. Please discuss the Company's claim for income taxes.

A. Income tax expense for the FPFTY at present and proposed rates is set forth in UGI 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. UGI Gas is continuing its practice of normalizing the tax repairs expense deduction for federal tax purposes. For state tax purposes, UGI Gas continues 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, lines 13 and 19. Schedule D-33 shows the calculation of *pro forma* income taxes for the FPFTY at present and proposed rates. Line 1 shows revenue at present and proposed rates, while line 2 shows 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 Gas's capital structure recommended in the direct testimony of Paul R. Moul (UGI Gas Statement No. 6) 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 $39.8 million and the *pro forma* tax expense at proposed rates for the FPFTY is $63.3 million. As explained below in Section G, this figure is not reduced by a consolidated income tax adjustment.

Q. Has the Company reflected the amortization of Excess Deferred Federal Income Taxes ("EDFIT"), as a result of the 2017 Tax Cuts and Jobs Act ("TCJA"), on its income tax expense 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 $4.3 million, calculated using the Average Rate Assumption Method ("ARAM") as required by tax normalization rules.

C. ACCUMULATED DEFERRED INCOME TAXES

Q. How are Accumulated Deferred Income Taxes ("ADIT") calculated?

A. Schedule C-6 shows the FPFTY ending balance for federal ADIT as of September 30, 2023. This amount is deducted from rate base. The total shown on line 8 reflects the difference in income tax expense for book and tax purposes attributable to the difference between the accelerated tax depreciation and straight-line book depreciation on test year plant balances, net of offsets associated with contributions in aid of construction. Rate base was further reduced by the state regulatory liability associated with UGI Gas's repairs tax method shown on line 6. As the state tax consequence of accelerated depreciation is flowed through, there is no associated state ADIT balance.

Q. What is the amount of the ADIT offset to rate base?

A. As shown on line 8 of Schedule C-6 and on line 6 of Schedule A-1, the ADIT offset is $628.5 million, which includes the amount related to EDFIT.

Q. Does the Company's reduction to rate base include EDFIT?

A. Yes, the Company has reduced its rate base by the unamortized EDFIT, which is incorporated in the ADIT balance on Line 8 of Schedule C-6.

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 comply with IRS normalization requirements. To qualify for normalization, the IRS requires utilities to pro-rate rate base deductions for ADIT to account for the fact that the Company accrues ADIT for plant additions throughout the year. See UGI Gas Exhibit NMM-2 for the calculation of the pro-rata adjustment.

D. REPAIRS TAX METHOD

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

A. In its tax return for the year ended September 30, 2009, UGI Gas adopted a tax accounting method to expense as repairs certain items capitalized for book purposes in accordance with federal tax regulations. As it did in the Company's previous base rate case at Docket No. R-2019-3015162, UGI Gas has chosen to normalize its federal income tax expense claim, inclusive of the repairs tax deduction. The difference between accelerated tax depreciation versus book depreciation in the calculation of federal tax expense creates ADIT. For state income tax purposes, solely with respect to the repairs tax deduction, UGI 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.

E. CONSOLIDATED TAX BENEFITS

Q. Does the Company's proposed revenue requirement reflect a federal consolidated tax expense adjustment?

A. No. The Company's revenue requirement is established based on its stand-alone federal income tax attributes. It is my understanding that Act 40 of 2016, which added 66 Pa. C.S § 1301.1 to the Public Utility Code, eliminates the need to show a consolidated tax adjustment for ratemaking purposes. However, Section 1301.1(b) requires a public utility to demonstrate that it shall use at least 50 percent of what would have been a consolidated tax expense adjustment under the law prior to Act 40 for reliability or infrastructure related capital investment and the other 50 percent shall be used for general corporate purposes.

A calculation of the consolidated tax adjustment for that purpose, using the modified effective tax rate methodology traditionally used by the Commission prior to the enactment of Act 40, is included in the Company's filing as Attachment II-A-26 and UGI Gas Exhibit NMM-3. Company witness Ms. Tracy A. Hazenstab (UGI Gas Statement No. 2) discusses how the Company has satisfied the requirements of Act 40.

F. EMPLOYEE RETENTION CREDIT

Q. Are you familiar with the settlement of the Company's last Natural Gas Base Rate Case at Docket No. R-2019-3015162, et al. and its requirement that UGI Gas report tax credits related to the Coronavirus Aid, Relief, and Economic Security ("CARES") Act?

A. Yes. Ordering Paragraph 32 in the Commission's Order approving the Settlement (entered October 8, 2020) stated:

That the Company shall provide a report as part of the Company's next base rate case detailing: (1) its efforts to maximize its utilization of and track any government benefits, whether direct grant, tax credits, or other, to minimize costs to be deferred; (2) any amounts obtained as part of these efforts and their intended use; and, (3) if denied, the reason for such denial.

Q. Did UGI Gas receive any tax credit as a result the CARES Act?

A. Yes. Pursuant to Section 2301 of the CARES Act, UGI Gas received approximately $1.5 million in Employee Retention Credits ("ERC"), which it applied against the payroll tax deferral allowed under Section 2302 of the CARES Act. See UGI Gas Exhibit NMM-4 for a report containing further details on all tax benefits obtained from the CARES Act and other initiatives the Company pursued per Ordering Paragraph 32 in the settlement of the 2019 UGI Gas Base Rate Case at Docket No. R-2019-3015162.

Q Does the Company intend to return any of the ERC tax benefits to customers?

A. No. The Company does not intend to return the ERC tax benefits to customers since the tax credits relate to costs, primarily payroll, that were incurred outside of the test year periods. Specifically, the ERC relates to payroll costs incurred after March 12, 2020 and before January 1, 2021.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT NMM-1

Nicole M. McKinney, CPA

460 N. Gulph Road
King of Prussia, PA 19406

mckinneyn@ugicorp.com
(484) 877-7601

PROFESSIONAL EXPERIENCE:

UGI Corporation. King of Prussia, PA
Director – FP&A. December 2021 – Present

- Supervise 2 reports
- Manage the monthly forecast cycle and annual budget cycle
- Monitor and review various management financial reports
- Support analysis of business development opportunities
- Oversee UGI's investment policy

UGI Utilities, Inc. Denver, PA
Sr. Manager of Natural Gas Tax Accounting. March 2015 – Present

- Supervise 2 reports
- Manage the accounting for income taxes in accordance with ASC 740 for Natural Gas business segment
- Provide technical accounting guidance and expertise on tax accounting, planning and compliance matters
- Oversee and review the preparation of various 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

Previous Testimony:

UGI Electric Base Rate Case	Docket No. R-2021-3023618
UGI Gas Base Rate Case:	Docket No. R-2019-3015162
UGI Gas Base Rate Case:	Docket No. R-2018-3006814
UGI Electric Base Rate Case:	Docket No. R-2017-2640058
UGI Penn Natural Gas, Inc. Rate Case:	Docket No. R-2016-2580030
UGI Utilities, Inc. – Gas Division Rate Case:	Docket No. R-2015-2518438

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
9/30/2022					$ 620,598
10/31/2022	829	335	91.78%	761	621,359
11/30/2022	1,244	305	83.56%	1,039	622,399
12/31/2022	2,281	274	75.07%	1,712	624,111
1/31/2023	2,073	243	66.58%	1,380	625,491
2/28/2023	1,037	215	58.90%	611	626,101
3/31/2023	1,037	184	50.41%	523	626,624
4/30/2023	1,244	154	42.19%	525	627,149
5/31/2023	1,244	123	33.70%	419	627,568
6/30/2023	1,244	93	25.48%	317	627,885
7/31/2023	2,073	62	16.99%	352	628,237
8/31/2023	3,110	31	8.49%	264	628,501
9/30/2023	3,317	1	0.27%	9	**$ 628,510**

UGI GAS

EXHIBIT NMM-3

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

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

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

Notes:

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

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

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

Explanations of Adjustments:

(1) UGI Corporation adjustment relates to bonus depreciation taken on non-utility fixed assets for a one-time acquistion.

(2) AmeriGas adjustment relates to one-time adjustment for entity restructuring.

(3) UGI Development adjustment relates to one-time sale of non-utility fixed assets and partnership interest.

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

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

UGI GAS

EXHIBIT NMM-4

Report of Amounts Obtained from Government Benefits per Ordering Paragraph 32 in the Commission's Order on the Settlement of the 2019 UGI Gas Base Rate Case at Docket No. R-2019-3015162

1. **Employee Retention Credit ("ERC")**
   Section 2301 of the CARES Act allowed qualifying employers to claim a credit against the employer portion of applicable employment taxes for wages paid after March 12, 2020 and before January 1, 2021 for each calendar quarter in an amount equal to 50-percent of qualified wages, including allocable qualified health expenses, with respect to each employee. For the time period claimed by the Company, the ERC could not exceed $5,000 per employee. UGI Gas claimed an approximate ERC tax benefit of $1.5 million. The Company utilized an outside accounting firm to assist it in determining its eligibility for the tax credit as well as in reviewing its process and calculation for quantifying the credit. UGI Gas worked with its third-party payroll processor to file the applicable IRS forms (i.e. 941 and 941X) to claim the ERC tax benefits.

2. **Payroll Tax Deferral**
   Section 2302 of the CARES Act allowed employers to defer the deposit and payment of the employer's portion of Social Security taxes and certain railroad retirement taxes for the period March 27, 2020 through December 31, 2020. The Company chose to defer the payments allowed under the CARES Act. The first payment of 50% of the total deferred amount was due by December 31, 2021, and the Company timely made this payment. The other 50% payment is due by December 31, 2022. UGI Gas is working with its third-party payroll processor to quantify and remit the deferred amounts. Further, in discussions with its payroll processor, the Company was advised that the IRS would apply any ERC benefit claimed against the deferred amounts.

3. **Families First Coronavirus Response Act ("FFCRA")**
   The FFCRA provided small and midsize employers refundable tax credits which reimbursed them, dollar-for-dollar, for the cost of providing paid sick and family leave wages to employees for leave related to COVID-19. Only employers with fewer than 500 employees were eligible for these tax credits. Due to exceeding the allowable number of employees, UGI Gas did not qualify for these tax credits. As such, the Company did not claim any FFCRA tax credits.

UGI GAS STATEMENT NO. 8

SHERRY A. EPLER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3030218

UGI Utilities, Inc. – Gas Division

Statement No. 8

Direct Testimony of
Sherry A. Epler

Topics Addressed:	**Test Year Sales and Revenues** **Revenue Allocation and Rate Design** **Tariff Changes**

Dated: January 28, 2022

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Sherry A. Epler. My business address is 1 UGI Drive, Denver, PA 17517.

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

A. I am employed as Senior Manager, Tariff & Supplier Administration, by UGI Utilities, Inc. ("UGI"). UGI has both a Gas Division ("UGI Gas"), which is a certificated natural gas distribution company ("NGDC"), and an Electric Division ("UGI Electric"), a certificated electric distribution company ("EDC").

Q. What are your responsibilities as Senior Manager, Tariff & Supplier Administration with respect to UGI Gas?

A. My current responsibilities related to UGI Gas include: (1) all aspects of tariff and rate administration for UGI Gas, including interactions with natural gas suppliers under UGI Gas's supplier tariff; and (2) revenue analysis.

Q. Please provide your educational background.

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

Q. Please provide your professional experience.

A. I have worked for UGI since 1986, supporting the Accounting and Rates groups in varying capacities. Please see my resume, UGI Gas Exhibit SAE-1, for my full employment history.

Q. Please describe the purpose of your testimony.

A. I will address: (1) the development of sales and revenue for the historic test year ended September 30, 2021 ("HTY"), future test year ending September 30, 2022 ("FTY"), and fully projected future test year ending September 30, 2023 ("FPFTY"); (2) revenue allocation and rate design; and (3) certain proposed tariff modifications.

Q. Are any other witnesses providing testimony on the areas you identified above?

A. Yes. Company witness Constance E. Heppenstall, who is employed as Senior Project Manager, Rate Studies by Gannett Fleming Valuation and Rate Consultants, LLC (UGI Gas Statement No. 10), is sponsoring UGI Gas Exhibit D – Cost of Service, from which revenue allocations were derived. Ms. Heppenstall also utilizes the projected sales and revenue figures discussed in my testimony.

Q. Are you sponsoring any exhibits or filing requirements in this proceeding?

A. Yes, I am sponsoring the following Exhibits: UGI Gas Exhibit SAE-1 (Resume), UGI Gas Exhibit SAE-2 (15 year Normal Heating Degree Days), UGI Gas Exhibit SAE-3 (Normalized Multi-Year and 12-Month Ending Trends of Use Per Customer for Residential and Commercial Heating), UGI Gas Exhibit SAE-4 (Fully Projected Future Test Year Sales and Revenue Adjustments), UGI Gas Exhibit SAE-5 (Future Test Year Sales and Revenue Adjustments), UGI Gas Exhibit SAE-6 (Historic Test Year Sales and Revenue Adjustments), UGI Gas Exhibit SAE-7 (Fully Projected Future Test Year Usage Per Customer Detail by Class), UGI Gas Exhibit SAE-8 (No Notice Service (NNS) Rate Calculation), UGI Gas Exhibit SAE-9 (Monthly Balancing Service (MBS) Rate Calculation), UGI Gas Exhibit SAE-10 (Rider D-Merchant Function Charge (MFC)

Calculation), certain portions of UGI Gas Exhibit F (Proposed Tariff), and UGI Gas Exhibit E (Proof of Revenue). I am also sponsoring certain responses to the Commission's standard filing requirements, as indicated on the mater list accompanying this filing, that were prepared by me or under my direction.

II. TEST YEAR SALES AND REVENUE

Q. Please explain the process for developing the Company's Fiscal Year 2023 sales and revenue budgets.

A. The sales and revenue budgets were a joint effort of the marketing and financial planning and analysis ("FP&A") departments, with the marketing department providing customer growth and attrition information by customer class along with specific large commercial and industrial sales and revenue budget projections. The FP&A department developed projections for budgeted usage per customer for core customer classes, total calculated sales and total calculated revenues. In developing sales and revenues, the Vice President, Marketing and Customer Relations, with input and assistance from other marketing employees, budgets the number of customers by class. Various factors are considered in developing customer budgets, including: (1) projected conversions to and from other energy sources; (2) the level of applications and inquiries for service; (3) other customer attritions; (4) new construction activity; (5) current and projected economic factors; and (6) the costs of competing fuels. The usage per customer reflected in the 2023 budget was the same as that used for the 2022 budget and specifically does not incorporate use per customer conservation trends related to the Company's core residential and commercial class customers. Budget use per customer values were developed based on a simple regression of 24 months of actual use per customer data and then normalized based on normal heating degree days. Planned budgeted numbers of customers and usage per customer for these customer classes are then combined to produce planned budgeted sales. Sales are allocated by month, and appropriate rates are applied to derive budgeted revenues. Sales and revenues related to large contract customer classes are developed by the marketing department on a customer specific basis using customer input where appropriate. As discussed in the testimony of Tracy A. Hazenstab (UGI Gas Statement No. 2), the derivation of the 2023 planned budget reflects a forecast that will subsequently be updated during calendar year 2022 as part of the normal annual budget process. This process is conducted several months prior to the start of the new fiscal year and finalized prior to the beginning of the new fiscal year.

Q. Please explain how the Company's FPFTY sales and revenues were developed.

A. FPFTY sales and revenues were developed by annualizing and normalizing the Company's 2023 fiscal year planned sales and revenue budgets. Where similar adjustments are made across rate class groups, the methodology applied to develop normalized use per customer adjustments (for the FPFTY, FTY, and HTY) to budget values is the same for all three periods in order to present sales and revenue on a ratemaking basis. A summary of projected use per customer by class group for the FPFTY, FTY, and HTY are included in UGI Gas Exhibit SAE-7. The projected Residential Heating use per customer was established for Rate R/RT-Heating per the UGI Gas model detailed in SDR-RR-11. Since, over time, switching occurs on a regular basis between Rates R (retail service) and RT (transportation service), the regression analysis was performed on a total Rate R/RT basis in order to eliminate potential switching impacts which could distort use per customer analyses. More detail on this regression analysis is provided below as part of the discussion related to the Company's "Adjustment for Normalized & Annualized Use/Customer." Weather normalized sales for Rate RT-Heating customers for the 12 months ended September 30, 2021, were then utilized to derive the separate Rate RT-Heating and Rate R-Heating use per customer values (from the combined Rate R/RT-Heating use per customer value).

Actual sales were normalized for Rate R-General and Rate RT-General, in total, to reflect the 12 months ended September 30, 2021. These data were used to project combined Rate R/RT-General use per customer in total. Weather normalized sales for Rate RT-General customers for the 12 months ended September 30, 2021, were then utilized to derive the separate Rate RT-General and Rate R-General customer values (from the combined Rate R/RT-General use per customer value).

The projected Commercial Heating use per customer was established on a combined total basis for Rates N/NT/DS-Heating per the UGI Gas model regression techniques detailed in SDR-RR-11. Given that, over time, switching occurs on a regular basis between Rates N (retail service), NT (transportation service) and DS (transportation service), the regression analysis was performed on a total Rates N/NT/DS basis in order to eliminate potential switching impacts that could distort use per customer analyses. More detail on this regression analysis is provided below as part of the discussion related to the Company's "Adjustment for Normalized & Annualized Use/Customer." In order to then separate the combined Rate N/NT/DS – Commercial Heating value into respective Rate N, Rate NT and Rate DS values, Rate NT – Commercial Heating use per customer was established on the basis of weather normalized sales for Rate NT-Commercial Heating customers, for the 12 months ended September 30, 2021 as this class in much smaller in number than the Rate N – Commercial Heating class. Rate DS – Commercial Heating use per customer was then established based on budgeted 2023 sales for Rate DS-Commercial Heating, as Rate DS budgeting was performed on a detailed per-customer level. These Rate NT and Rate DS commercial heating values were then utilized to mathematically derive the Rate N-Commercial Heating use per customer values (from the combined Rates N/NT/DS-Commercial Heating use per customer value).

Actual sales were normalized for Rate N-Commercial General, Rate NT-Commercial General and Rate DS-Commercial General, in total, to reflect the 12 months ended September 30, 2021, in order to project combined Rates N/NT/DS-Commercial General use per customer in total. In order to then separate the combined Rate N/NT/DS – Commercial General value into respective Rate N, Rate NT and Rate DS values, Rate NT – Commercial General was based on weather normalized sales for Rate NT-Commercial General, for the 12 months ended September 30, 2021, and Rate DS – Commercial General was based on budgeted 2023 sales for Rate DS-Commercial General, which were done on a per-customer level. These Rate NT and Rate DS values, were then utilized to mathematically derive the Rate N-Commercial General use per customer values (from the combined Rates N/NT/DS-Commercial General use per customer value).

Actual sales were normalized for Rate N-Industrial, Rate NT-Industrial, and Rate DS-Industrial to reflect the 12 months ended September 30, 2021, in order to project combined Rates N/NT/DS-Industrial use per customer in total. In order to then separate the combined Rate N/NT/DS – Industrial value into respective Rate N, Rate NT and Rate DS values, Rate NT – Industrial was based on weather normalized sales for Rate NT-Industrial for the 12 months ended September 30, 2021. Rate DS – Industrial was based on budgeted 2023 sales for Rate DS-Industrial, which were done on a per-customer level. These Rate NT and Rate DS values were then utilized to mathematically derive the Rate

N-Industrial use per customer value (from the combined Rates N/NT/DS-Industrial use per customer value).

Q. How was temperature accounted for in developing sales and revenue forecasts?

A. The Company's FPFTY sales and revenue forecasts reflect annual normal heating degree days of 5,568. This annual normal heating degree day calculation is derived from a composite sales weighted value (by system demand) of each of the Company's four delivery regions, and the respective normal heating degree values. Normal heating degree days are defined based upon an average over a 15-year period and are updated every five years; the most recent update was for the 15-year period ending December 31, 2019. UGI Gas Exhibit SAE-2 provides supporting detail by year for the 15-year normal heating degree days.

Q. Is the use of average temperature data for a 15-year period consistent with the methodology used for calculating normal heating degree days in previous UGI Gas base rate cases?

A. Yes. The Company has consistently used a 15-year period methodology in the past seven gas base rate cases that the Company or its former subsidiaries have filed (as listed below).

- UGI Central Penn Gas ("CPG") 2009 Base Rate Case, Docket No. R-2008-2079675
- UGI Penn Natural Gas ("PNG") 2009 Base Rate Case, Docket No. R-2008-2079660
- UGI CPG 2011 Base Rate Case, Docket No. R-2010-2214415
- UGI Gas 2016 Base Rate Case, Docket No. R-2015-2518438
- UGI PNG 2017 Base Rate Case, Docket R-2016-2580030
- UGI Gas 2019 Base Rate Case, Docket No. R-2018-3006814
- UGI Gas 2020 Base Rate Case, Docket No. R-2019-3015162

Q. Please describe the adjustments made to the budget for the 12 months ending September 30, 2023, to develop FPFTY sales and revenues.

A. A summary of all adjustments made to the 2023 budget in order to develop FPFTY sales and revenue is shown on UGI Gas Exhibit SAE-4(a). Detail for each of these adjustments is provided on subsequent worksheets labeled 4(b) through 4(m). In total, these adjustments reflect a decrease to sales of 1,781 MMcf and an increase to revenue of $65.690 million, inclusive of Purchased Gas Cost ("PGC") revenues.

Q. Please explain the "Adjustment for Customer/Contract Changes" shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for Customer/Contract Changes" annualizes customer counts to anticipated end-of-test-year levels based on the Company's most recent forecast for the FPFTY; it is inclusive of any large transportation contract customer changes related to customers served under Rates LFD, XD, and IS. In particular, among other adjustments, this adjustment includes a net increase of 411 residential heating customers (Rate R) from budgeted levels to anticipated end-of-test-year levels and a net decrease of 28 commercial heating customers (Rate N) from budgeted levels to anticipated end-of-FPFTY levels on September 30, 2023.

Q. How were these adjustments calculated?

A. UGI Gas Exhibit SAE-4(b) provides the calculation of the associated sales and revenue adjustments for the stated customer counts. In total, this adjustment decreases sales by 194 MMcf and increases projected revenues by $0.278 million, inclusive of PGC revenues. Additional detail for column (9) of UGI Gas Exhibit SAE-4(b) can be found on UGI Gas

Exhibit SAE-4(b)(1), which provides a breakout of customer data for large transportation customer classes.

Q. Please explain the adjustment titled "Adjustment for Customer/Contract Changes – Large Transport and Interruptible Detail" as shown on UGI Gas Exhibit SAE-4(b)(1).

A. The adjustments for large transportation customers were developed by UGI Gas's marketing personnel following their review of individual large customer accounts and market segments. It reflects annualizing anticipated increases or reductions from original fiscal adjustments and includes the addition of $308,000 in anticipated revenue related to the Auburn Capacity Lease, as discussed in the direct testimony of Christopher R. Brown (UGI Gas Statement No. 1).

Q. Please explain your next adjustment, "Adjustment for Normalized & Annualized Use/Customer" shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for Normalized & Annualized Use/Customer" normalizes and annualizes usage per customer to projected end-of-test-year levels. Specifically, in developing usage per customer projections for the Company's core Residential Heating rate groups (Rates R and RT), the Company utilized an econometric regression model that incorporates four independent variables: (1) use per customer; (2) heating degree days; (3) lagged heating degree days; and (4) weighted time trend. While use per customer, heating degree days, and lagged heating degree days capture weather related usage factors, which can then be used to project normalized and annualized customer usage under normal weather conditions, the weighted time trend variable of this regression captures non-weather trends that underlie changes in usage per customer over time (*e.g.*, conservation). These trends can vary, but as a comprehensive variable, "trend" will capture the impacts of conservation, including but not limited to: (1) regular appliance replacements; (2) accelerated appliance replacements; (3) high-efficiency appliance installations; (4) setback thermostat installations; (5) modifications to new and existing buildings that are designed to decrease energy consumption; and (6) changes in consumer usage behavior due to other economic influences. Given the number of variables that can influence customer usage over time, and the difficulty in identifying, quantifying, and tracking all variables over time, a trend variable is used to provide a comprehensive indicator of usage trends, which can then be used to forecast for a future period. Additionally, the trend variable is weighted by heating degree days to reflect a "weighted trend," which more accurately reflects that the impacts of these trends are directly related to usage during heating time periods.

For the Residential Heating groups of Rates R and RT, the multi-year period regression methodology is the same base method that the Company has utilized in prior rate cases, updated for the use of a common data set period of October 2003 through September 2021. October 2003 is the earliest common data set available for the entire service territory, given the timing and data availability of historic service and former rate district level details for UGI Gas and its former subsidiaries, UGI PNG and UGI CPG.

For the Company's core Commercial Heating rate groups (inclusive of Rates N, NT, and DS), the Company utilized the same regression method as presented in UGI Gas's 2019 and 2020 Gas Rate Cases. Specifically, to forecast the Commercial Heating rate group use per customer, the Company utilized three variables: (1) use per customer; (2) heating degree days; and (3) lagged heating degree days. For the Commercial Heating group, the Company used the period of October 2012 through September 2021 for regression modeling, or the period during which common non-residential rate structures existed for UGI Gas and its former subsidiaries.

The forecasts for end-of-FPFTY use per customer are generated using the regression results along with a projection of regression variable inputs including normal annual heating degree days and, where applicable, a weighted trend variable. The results are presented in summary on UGI Gas Exhibit SAE-4(a) and in detail on UGI Gas Exhibit SAE-4(c). In total, the result is a net sales decrease, from the fiscal 2023 budget, of 1,348 MMcf, and a net revenue decrease, from the fiscal 2023 budget, of $15.863 million, inclusive of PGC revenues.

Q. Why did UGI Gas utilize a multi-year regression period?

A. The Company decided to use the multi-year period because it provides a larger sample set of data to smooth out short-term variations and capture the underlying long-term use per customer trends to more accurately project usage per customer during the period rates are likely to be in effect. This methodology is consistent with that utilized in the last seven base rate cases of UGI Gas and its predecessor entities.

Q. Has UGI Gas compared the results of the multi-year regression method to develop normalized usage for Residential Heating and Commercial Heating customer groups with any other normalization method?

A. Yes. Please see UGI Gas Exhibits SAE-3(a) and SAE-3(b), which contain use per customer graphs that illustrate both the results of the multi-year normalized regression method I have explained above ("Normalized Multi-year") and a short-term normalized ("Normalized 12 Months ended") value for the same groups of Residential Heating and Commercial Heating customers. The short-term normalized values are computed via a simple determination of temperature sensitive load each month. As can be seen from these graphs, short-term trend fluctuations of the "Normalized 12 months ended" line occur in certain periods, but consistently revert to the long-term "Normalized Multi-year" trend which has been used to forecast FPFTY use per customer values, demonstrating the ongoing base trend in declining use per customer.

Q. Please explain the "Adjustment for PGC" shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for PGC" shown in summary on UGI Gas Exhibit SAE-4(a) annualizes FPFTY PGC revenues using the PGC rate in effect as of December 1, 2021. UGI Gas Exhibit SAE-4(d) provides the calculations for these adjustments. This adjustment increases PGC revenues for the FPFTY by $49.4 million.

Q. Please explain the following three adjustments shown in summary on UGI Gas Exhibit SAE-4(a): "Adjustment for MFC," "Adjustment for USP," and "Adjustment for GPC."

A. The Adjustment for MFC annualizes the Company's Merchant Function Charge ("MFC") revenues for the FPFTY based on the MFC surcharge rates in effect as of December 1, 2021. The MFC Adjustment increases projected revenues by $0.814 million.

The Adjustment for USP annualizes the Company's Universal Service Program ("USP") surcharge revenues for the FPFTY based on the USP Rider rate in effect as of December 1, 2021. The Adjustment for USP also updates the sales volume for Customer Assistance Program ("CAP") customers in the USP Revenue calculation with end of Fiscal Year 2021 data in comparison to the budgeted sales volume for CAP customers, which was calculated using end of Fiscal Year 2020 data. The USP adjustment increases revenues by $1.119 million.

The Adjustment for GPC annualizes the Gas Procurement Cost ("GPC") revenues to reflect the impact of all volume adjustments to the original Fiscal Year 2023 planned budget. The GPC adjustment decreases revenues by $0.111 million. Additional details for these three adjustments are provided on UGI Gas Exhibit SAE-4(e), UGI Gas Exhibit SAE-4(f), and UGI Gas Exhibit SAE-4(g), respectively.

Q. Please explain "Adjustment for Excess Take Revenues" as shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for Excess Take" detailed in UGI Gas Exhibit SAE-4(h) reflects the assumption that large transportation customers will evaluate new service elections and will make the necessary adjustments to avoid Excess Take penalties in the FPFTY. The Excess Take adjustment reduces revenue by $1.7 million.

Q. Please explain the "Adjustment for EEC Rider" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for EEC Rider" annualizes the revenue from the Energy Efficiency and Conservation ("EE&C") Rider ("EEC Rider") for the FPFTY based on the EEC Rider rate in effect as of December 1, 2021. This adjustment increases revenues by $3.809 million and is shown on UGI Exhibit SAE-4(i).

Q. Please explain the "Adjustment for EEC Conservation Impact" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for EEC Conservation Impact" annualizes the impact to revenues from

UGI Gas's ongoing EE&C programs and associated reduced energy consumption as a result of measures implemented as part of the EE&C programs. This adjustment decreases FPFTY sales by 239 MMcf and decreases revenues by $2.405 million and can be seen on UGI Gas Exhibit SAE-4(j).

Q. Please explain the "Adjustment for GET Gas" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for GET Gas" annualizes GET Gas residential revenues to reflect end of year conditions. The revised residential revenues were developed by annualizing the projected GET Gas surcharge payments at the end of the FPFTY. The adjustment also adds anticipated GET Gas revenues related to commercial customers, which were inadvertently omitted from the original FPFTY budget. In total this adjustment decreases revenues by $0.016 million, as shown on UGI Gas Exhibit SAE-4(k).

Q. Please explain the "Adjustment for GDE" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for GDE" annualizes Gas Delivery Enhancement ("GDE") Rider revenue based on the current rate as of December 1, 2021. This adjustment increases revenues by $0.020 million and is shown on UGI Gas Exhibit SAE-4(l).

Q. Please explain the "Adjustment for DSIC" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for DSIC" annualizes Distribution System Improvement Charge ("DSIC") revenue based on the application of the 5% DSIC charge cap to FPFTY revenues. The FPFTY budget incorrectly excluded the projected DSIC rate revenues. This adjustment continues applying the 5% DSIC rate, projected at the end of the FTY, to the end of the FPFTY period. This allows the Company to properly quantify DSIC revenues, which will be rolled into the new base rates established in this proceeding as a result of re-setting the DSIC rate to zero. This adjustment increases revenues by $30.327 million and is shown on UGI Gas Exhibit SAE-4(m).

Q. Do the adjusted FPFTY revenues exclude revenues related to off-system sales and non-jurisdictional revenue?

A. Yes.

III. DEVELOPMENT OF SALES AND REVENUE FOR THE FTY AND HTY

Q. How were normalized and annualized sales and revenue determined for the FTY?

A. Budgeted sales and revenues serve as the starting point for the development of the normalized and annualized FTY sales and revenues, as shown in UGI Gas Exhibit SAE-5. All of the adjustments that were made in the development of the FPFTY sales and revenues were also made in the development of the FTY sales and revenues, with the exception of the adjustments for the EEC Conservation Impact and DSIC that are contained in the FPFTY, but not the FTY.

Q. How were normalized and annualized sales and revenue determined for the HTY?

A. Historic sales and revenues serve as the starting point for the development of the normalized and annualized HTY sales and revenues shown in UGI Gas Exhibit SAE-6. All of the adjustments that were made in the development of the FPFTY were also made in the development of the HTY, with the exception of the adjustments for the EEC Conservation Impact, GDE Rider, and DSIC.

IV. REVENUE ALLOCATION AND RATE DESIGN

Q. What is UGI Gas's ratemaking philosophy for revenue allocation and rate design?

A. The Company's ratemaking goal is to implement reasonable rates that recover its cost of doing business. Revenue allocation and rate design are generally developed to reflect reasonable movement toward class cost of service and to be competitive with prices of alternate energy sources, including bypass options. UGI Gas's rates and rate design seek to promote and achieve efficient utilization of the Company's facilities and natural gas supplies.

Q. What factors has the Company considered in establishing its proposed rate structure?

A. The Company considered class cost of service, rate of return and relative rate of return compared to the system average rate of return as the primary factors in determining revenue allocation and rate design. In measuring cost of service, the Company relied on the cost of service study prepared by Company witness Constance E. Heppenstall (UGI Gas Statement No. 10).

Q. What is the Company's proposed revenue allocation in this case?

A. Below is a summary of the proposed allocation of the $82.7 million increase proposed in this case, shown by rate class:

Rates R/RT	$68.1 million
Rates N/NT	$14.4 million
Rate DS	$0.7 million
Rate LFD	$1.5 million
Rate XD	($1.0 million)
Rate IS	($1.0 million)

Q. What were the Company's goals in deriving its proposed revenue allocation?

A. The Company's goals for revenue allocation were two-fold. First, the Company wanted to materially move all classes towards the system average rate of return. Second, the Company wanted to complete the unification of the DS and N/NT rate classes for the former North and South/Central Rate Districts.

UGI Gas's proposed revenue allocation accomplishes both of these two goals. The revenue allocation moves all customer classes toward system average rate of return, while also completing the unification of the Rate DS and N/NT classes.

Q. How does the Company's proposed revenue allocation move all customer classes toward system average rate of return?

A. Table 1 below shows the percentage increase in distribution revenue, excluding gas costs, and summarizes the changes in relative rates of return by rate class. The percentage movement towards the system average rate of return is also included in the table data.

Table 1. – Percent Increase, Relative Rate of Return ("ROR") and Change in Relative ROR

Rate	Percent increase (without gas costs)	Relative ROR-present rates	Relative ROR-proposed rates	Change in relative ROR	Percent movement in relative ROR toward unity ROR
R/RT	18.1%	0.70	0.87	0.17	56%
N/NT	10.4%	1.18	1.08	0.10	-56%
DS	1.9%	1.40	1.10	0.30	-75%
LFD	3.4%	1.54	1.24	0.30	-56%
XD	-2.6%	2.28	1.64	0.64	-50%
IS	-4.4%	2.19	1.54	0.65	-55%
Total	12.4%	1.0	1.0	1.0	

Q. Could you please explain how you developed the proposed revenue allocation and achieved rate uniformity for both the Rates N/NT and Rate DS customer classes?

A. For Rate R/RT, Rate N/NT, and Rate LFD, UGI Gas allocated a portion of the total proposed increase to those classes by determining an amount that moves each class by an equivalent percentage towards the system average rate of return. Moving an equivalent percentage toward the system average rate of return achieves a just and reasonable revenue allocation. As part of this process, the Company also unified the former North Rate District's Rate N/NT class rates with the former South and Central Rate Districts' Rate N/NT class rates as a rate design element.

In addition, the Company looked at unifying the Rate DS classes in the former North Rate District with those from the former South and Central Rate Districts. Since the Company first began moving its customers to uniform rates in 2019, the resulting impact to the Rate DS class in the former North Rate District has served as a limiting factor for consideration for the overall revenue allocation. Completing unification in this case is reasonable in terms of the level of impact to these customers. As the total system average increase in distribution rates (non-gas costs rates) proposed in this case is 12.4%, the increase to this Rate DS group was limited to two times (2x) the system average increase, or 24.8%. Limiting the increase by a maximum of two times the overall increase in distribution rates is consistent with the methodology utilized in the Company's proposals in past rate cases in order to limit the overall impact to any one particular customer group affected by the overall rate increase.

Furthermore, the distribution rates for the former South and Central Rate DS class were adjusted in order to achieve uniformity across the entire Rate DS class. This resulted in an overall decrease to the former South and Central Rate DS class of 4.1% and an overall

Rate DS class increase of 1.9% (in terms of non-gas cost rates). These collective changes to Rate DS resulted in a total revenue allocation of $653,946 of the total requested $82.7 million increase.[1]

Additionally, UGI Gas recognized that its competitive negotiated rate classes of Rate XD and Rate IS (Interruptible) have relative rates of return at present rates that are all well above system average (more than 2x system average). As such, the Company is proposing no incremental revenue allocation to these rate classes. These classes are subject to competitive limitations on an ongoing basis, and rates charged are routinely reviewed and established on a competitive alternative basis to assure overall benefits to all customers are maximized.

Q. Please describe the impacts related to revenue allocation and rate design for the residential Rate R customer group.

A. As evidenced by the cost of service study presented by Ms. Heppenstall, under present rates, the residential Rate R customer group (Rates R and RT) is producing a return of 4.33%, as compared to a system average return of 6.14%. This translates to a relative rate of return of 0.70 compared to the system average. In allocating revenues, the Company proposes to allocate $68.1 million of the revenue increase to the Rate R customer group in order to move it closer toward cost of service. This increase will result in an overall return

[1] Moreover, it should be noted that the Company has considered gradualism in the context of the increase to the former North Rate District Rate DS class. Despite the Company's proposal to unify Rate DS rates for all customers in the 2019 and 2020 Gas Rate Cases, only modest movement has been achieved in settlement. Thus, former North Rate District Rate DS customers have now continued to pay below system average Rate DS rates for a period of three years. These lower rates have accrued benefits over the three-year period to the former North Rate District Rate DS customers and further support the movement to the full proposed rates in this proceeding, which, as explained above, were limited to an increase equal to two times the system average. Based on these reasonableness checks for gradualism, the Company believes uniform rates for Rate DS are an appropriate outcome of this proceeding.

of 6.94% for the Rate R customer group, compared to the proposed system average of 7.97%, and a relative rate of return of 0.87; thus, moving the Rate R customer group more than halfway toward system average rate of return.

As to rate design, the Company is proposing a Rate R customer charge of $19.95 per month, as compared to the current charge of $14.60 per month, to better reflect the direct customer costs per bill of $27.47, as identified within the cost of service study presented in UGI Gas Exhibit D. This partial movement toward the direct customer cost per bill reflects the Company's application of the ratemaking principle of gradualism.

Q. Please describe the impacts related to revenue allocation and rate design for the small commercial Rate N customer group.

A. For the small commercial Rate N customer group (Rates N and NT), current rates are producing a return of 7.28% with a relative rate of return 1.18. UGI Gas proposes to allocate $14.4 million of the revenue increase to the Rate N customer group. This increase will result in an overall return of 8.62% or a relative rate of return of 1.08; thus, moving the Rate N customer group more than halfway toward system average rate of return.

As to rate design, the Company is proposing a Rate N customer group customer charge of $30.00 per month, as compared to the current charge of $23.50 per month, to better reflect the direct customer costs per bill of $45.87 as identified within the cost of service study presented in UGI Gas Exhibit D. This partial movement toward the direct customer cost per bill reflects the Company's application of the ratemaking principle of gradualism.

Q. Please describe the impact of the revenue allocation and rate design for Rate DS.

A. For Rate DS, current rates are producing a return of 8.61%, with a relative rate of return of

1.40. The Company proposes to allocate $653,946 of the revenue increase to the Rate DS customers in order to increase their rates in the former North Rate District and decrease rates for the former South and Central Rate District customers to achieve unity in this customer group. These adjustments in rates will result in an overall class return of 8.79% or a relative rate of return of 1.10.

As to rate design, the Company is proposing to maintain the current Rate DS customer charge of $260.00 per month. The $260.00 per month charge is fully supported by the direct customer costs per bill for Rate DS of $370.12 as identified within the cost of service study presented in UGI Gas Exhibit D.

Q. Is the Company proposing any change to the rate assessed under Rate NNS (No Notice Service)?

A. Yes. Rate NNS is a daily balancing service offered by the Company. It provides an alternate election of a daily balancing tolerance for transportation customers, allowing a customer to optionally elect a balancing tolerance greater than the standard basic balancing provided by the Company. A customer is able to make an election under Rate NNS up to its DFR (Daily Firm Requirement) contract demand level and pay only for the level chosen. The Company is proposing to update the tariffed NNS rate to reflect current cost elements, using the methodology from the Company's 2019 Gas Rate Case.

Q. How was the proposed NNS rate developed?

A. The charge for providing service under Rate NNS is a monthly charge established using the Company's cost of interstate storage that can be utilized for balancing excess or shortfall requirements on the Company system. UGI Gas Exhibit SAE-8 shows the calculation of the Rate NNS charge. This charge was developed based on the same methodology used in the Company's 2019 Gas Rate Case. As seen on UGI Gas Exhibit SAE-8, the proposed NNS rate is $0.1860 per Mcf/d of an elected daily no notice allowance ("NNA") tolerance quantity. This compares to a current NNS rate of $0.4880 per Mcf/d of elected NNA, which was established in the Company's 2020 Gas Rate Case (See Ordering Paragraph 22 in the Commission's Order issued on October 8, 2020 at Docket Nos. R-2019-3015162, *et al.*).

Q. Will the Company continue to credit the revenues received from Rate NNS to PGC Rates?

A. Yes, revenues from Rate NNS will continue to be credited to the PGC Rates as part of the Company's annual 1307(f) proceeding.

Q. Please describe Rate MBS (Monthly Balancing Service).

A. Rate MBS is a monthly balancing service offered by the Company. Service under Rate MBS allows transportation imbalances of up to 10% for the month to be carried forward in the customer's MBS account for delivery of excess volumes, or receipt of shortfalls, in subsequent months.

Q. Has the Company proposed any changes to the Rate MBS rates?

A. Yes. UGI Gas Exhibit SAE-9 provides the basis for the MBS rate calculation. As a result of the settlement in the Company's 2019 Gas Rate Case, storage demand charges were included in the calculation of Rate MBS on a 100% load factor basis and the Company is continuing that inclusion in the proposed rates presented. The MBS rate is updated annually on December 1st each year, using 12 months of data ending in September, for the average monthly imbalance utilized in development of the rate. The MBS rates most recently updated for December 1, 2021, are: $0.0277/Mcf for Rates DS and IS; $0.0160/Mcf for Rate LFD; and $0.0165/Mcf for Rate XD. As seen on UGI Gas Exhibit SAE-9, the proposed, MBS rates will be: $0.0437/Mcf for Rates DS and IS; $0.0263/Mcf for Rate LFD; and $0.0221/Mcf for Rate XD; in particular, these Rate MBS increases are principally driven by recent increases to the Company's applicable storage demand charges.

Q. Will the Company continue to credit the revenues received from Rate MBS to PGC Rates?

A. Yes, revenues from Rate MBS will continue to be credited to the PGC as part of the Company's annual 1307(f) proceeding.

Q. Please describe the GPC.

A. The GPC recovers costs associated with gas procurement that were unbundled from base rates.

Q. Is the Company proposing to update its GPC in this proceeding?

A. No. The Company proposes to continue the $0.0660/Mcf blended rate that was approved in the Company's 2020 Gas Rate Case (see Joint Petition for Approval of Unopposed Settlement of All Issues, Appx. A, p. 12, filed on August 3, 2020, at Docket Nos. R-2019-3015162, *et al.*, which was approved by the Commission's Opinion and Order entered on October 8, 2020, in that proceeding).

Q. Please describe the MFC.

A. The MFC is equal to the fixed percentage of purchased gas costs that are expected to be uncollectible.

Q. Is the Company proposing to update its MFC in this proceeding?

A. Yes. The Company is updating the percentages for the MFC rates to reflect the actual uncollectible expense for the last three years. Based on this updated data, the residential MFC will be 2.27%, and the MFC for the commercial class will be 0.44%. Please see UGI Gas Exhibit SAE-10 for additional details.

Q. Please describe the USP Rider.

A. The USP Rider recovers those costs associated with the provision of universal service offerings approved by the Commission in the Company's Universal Service and Energy Conservation Plan.

Q. Is the Company proposing any changes to the USP Rider?

A. Yes. The Company is proposing changes to the annual reconciliation provisions of Rider F – Universal Service Program "USP" to update the threshold number of customers enrolled in the Customer Assistance Program ("CAP") that is used in the calculation of the offset applied to recoverable CAP costs. This offset reduces the Company's recovery of CAP spending above projected enrollment to account for write-offs of bad debt that would arguably have occurred if not for CAP. The Company proposes to set the CAP enrollee threshold equal to the number of CAP participants as of September 30, 2022, to provide an enrollee figure that reflect the actual ongoing impacts on CAP enrollment. This proposal is consistent with the establishment of the CAP enrollee figure in the last UGI Gas 2020 Rate Case at Docket No. R-2019-3015162.

V. TARIFF CHANGES

Q. What tariff changes are being proposed in this case?

A. The Company is revising references to the Supplement number, Notice language, Issue and Effective dates, and page numbers as necessary per this case. Apart from the proposed rate schedule changes, a complete list of tariff modifications can be found in the List of Changes Made by the Supplement section in UGI Gas Exhibit F – Proposed Supplement No. 32 to UGI Gas Tariff No. 7 and Proposed Supplement No. 32 to UGI Gas Tariff No. 7S. As previously stated, the Company is proposing to complete the unification of the DS and N/NT rate classes for the former North and South/Central Rate Districts. To that end, UGI Gas is proposing to fully consolidate the listings of counties served in the Description of Territories Served, which are currently apportioned by the three former Rate Districts. More significant proposed changes to the tariffs include:

- Rider C - The current Extended Tax Cuts and Job Act (“TCJA”) Temporary Surcharge Rider C has been removed as the surcharge has ended. In replacement, the Company proposes to add a new Rider C, Weather Normalization Adjustment (“WNA”) Rider C, which is detailed in the direct testimony of John D. Taylor (UGI Gas Statement No. 11).
- References to the expired Rider C, TCJA Temporary Surcharge have been deleted from the following rate schedules: Rate R, RT, GL, N, NT, DS, LFD, XD, R/S, and IS.

- The State Tax Adjustment Surcharge, Rider A, has been rolled into rates and reset to 0.00%.
- The reference to Rate Gas Beyond the Main (“GBM”) in Rider A has been removed, as that rate has now been eliminated.
- Rider D - MFC has been set to 2.27% for PGC Residential Customers and 0.44% for Non-Residential PGC Customers, as described above.
- Section 15. Price to Compare (“PTC”) has been updated to reflect changes to the MFC.
- Rider F – Universal Service Program has been revised so that the CAP credit bad debt offset will be associated with the participants in excess of the number of CAP enrollees as of September 30, 2022, in place of the existing September 30, 2020 date.
- Rider I – DSIC has been reset to 0.00% in accordance with 66 Pa. C.S. § 1358(b).
- Rate NNS – The existing NNS election volumetric option, specific to the former rate districts for customers not having daily metering, have been removed, as the Company now has daily metering on all applicable customers.
- Rate NNS and MBS have been revised to remove outdated language that was applicable for service prior to November 1, 2020.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT SAE-1

Sherry Epler

Senior Manager, Tariff & Supplier Administration

Work Experience

UGI Utilities, Inc., Denver, PA

November 2019 – Present	Senior Manager, Tariff & Supplier Administration
2018 – November 2019	Manager, Revenue/Sales & Choice Administration

UGI Utilities, Inc., Reading, PA

2000 – 2018	Rates Analyst – I/II/Sr/Principal (Progressive Positions)
1997 – 2000	Data and Expense Analyst – Residential Marketing
1990 – 1997	Staff Accountant – Supply Accounting
1989 – 1990	Accounting Assistant, Supply – Accounting
1988 – 1989	Accounting Assistant, Rates & Budgets – Accounting
1986 - 1988	Accounting Assistant B – Accounting

Education

Bachelor of Science, Accounting, Albright College, 1995

Associate of Science, Business Administration, Pennsylvania State University, 1986

Previous testimony provided before the Pennsylvania Public Utility Commission:

Docket No. R-2021-3023618   UGI Electric Base Rate Case

UGI GAS

EXHIBIT SAE-2

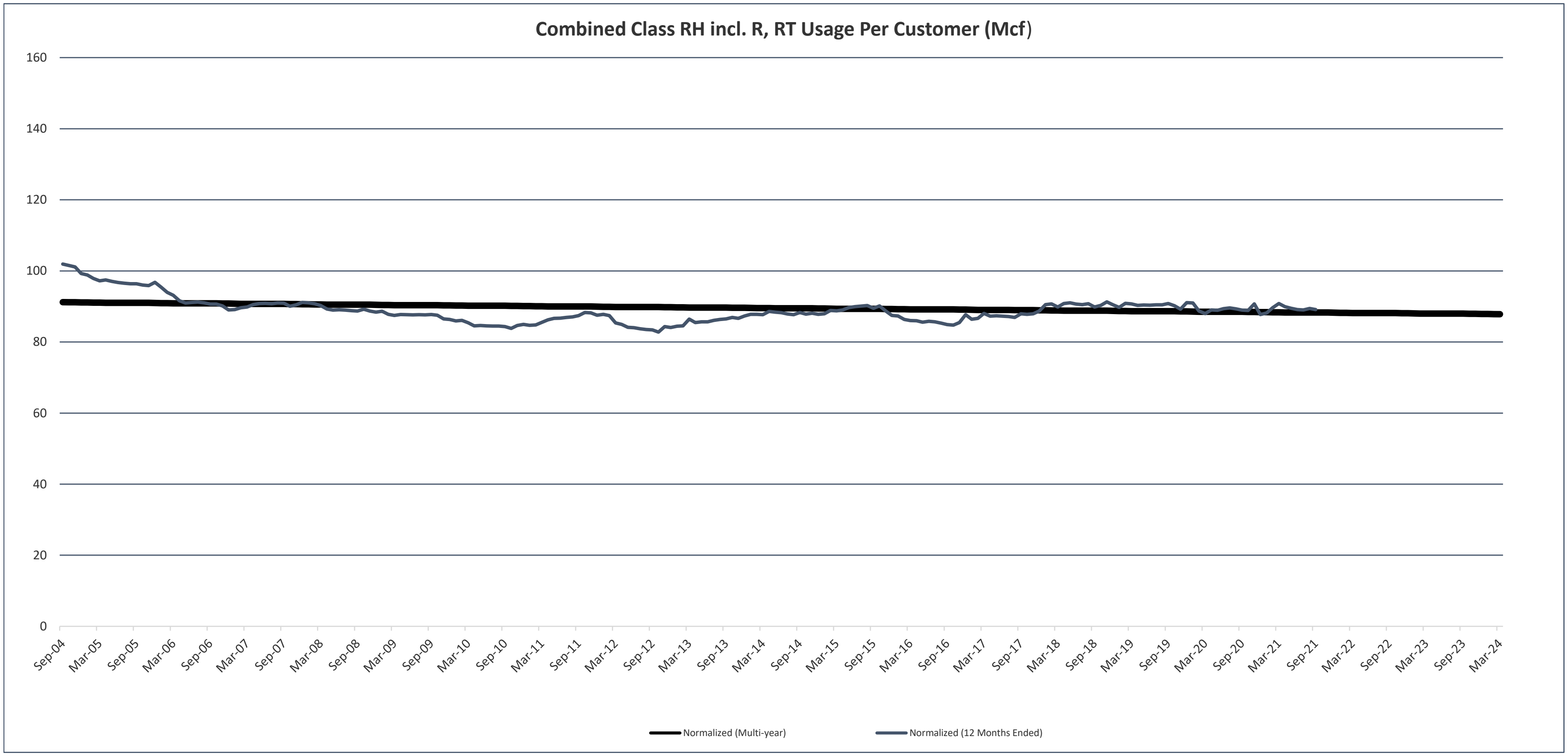
UGI Utilities, Inc. - Gas Divison
15 Year Normal Heating Degree Days (2005-2019)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	15 Year Average *
Jan	1,195	891	996	1,053	1,292	1,154	1,251	999	1,042	1,313	1,236	1,132	956	1,150	1,140	1,120
Feb	943	953	1,178	977	931	1,018	947	813	975	1,114	1,282	915	714	769	900	962
Mar	950	774	816	823	777	627	834	484	882	974	961	578	865	904	826	805
Apr	391	391	550	373	425	327	414	431	424	464	409	464	261	567	318	414
May	282	198	144	279	180	154	126	70	175	153	88	221	206	62	119	164
Jun	21	46	27	26	43	25	20	37	21	15	36	24	32	30	27	30
Jul	4	4	20	7	20	5	1	1	5	14	6	3	3	3	1	0
Aug	5	11	24	23	19	9	11	8	15	16	11	2	20	2	7	16
Sep	47	129	79	85	116	68	75	110	140	100	47	53	90	58	34	83
Oct	357	431	227	467	436	383	399	336	330	305	385	319	230	365	272	350
Nov	613	555	741	724	569	670	559	782	774	764	516	586	687	771	769	672
Dec	1,121	814	1,008	1,016	1,052	1,162	841	844	1,009	916	631	974	1,086	883	926	952
Totals	5,929	5,197	5,810	5,853	5,860	5,602	5,478	4,915	5,792	6,148	5,608	5,271	5,150	5,564	5,339	5,568

*Average adjusted for rounding of 15 year calculation and normal representation of Heating Degree Days falling consecutively through normal year.

UGI GAS

EXHIBIT SAE-3(a)


Combined Class RH incl. R, RT Usage Per Customer (Mcf)
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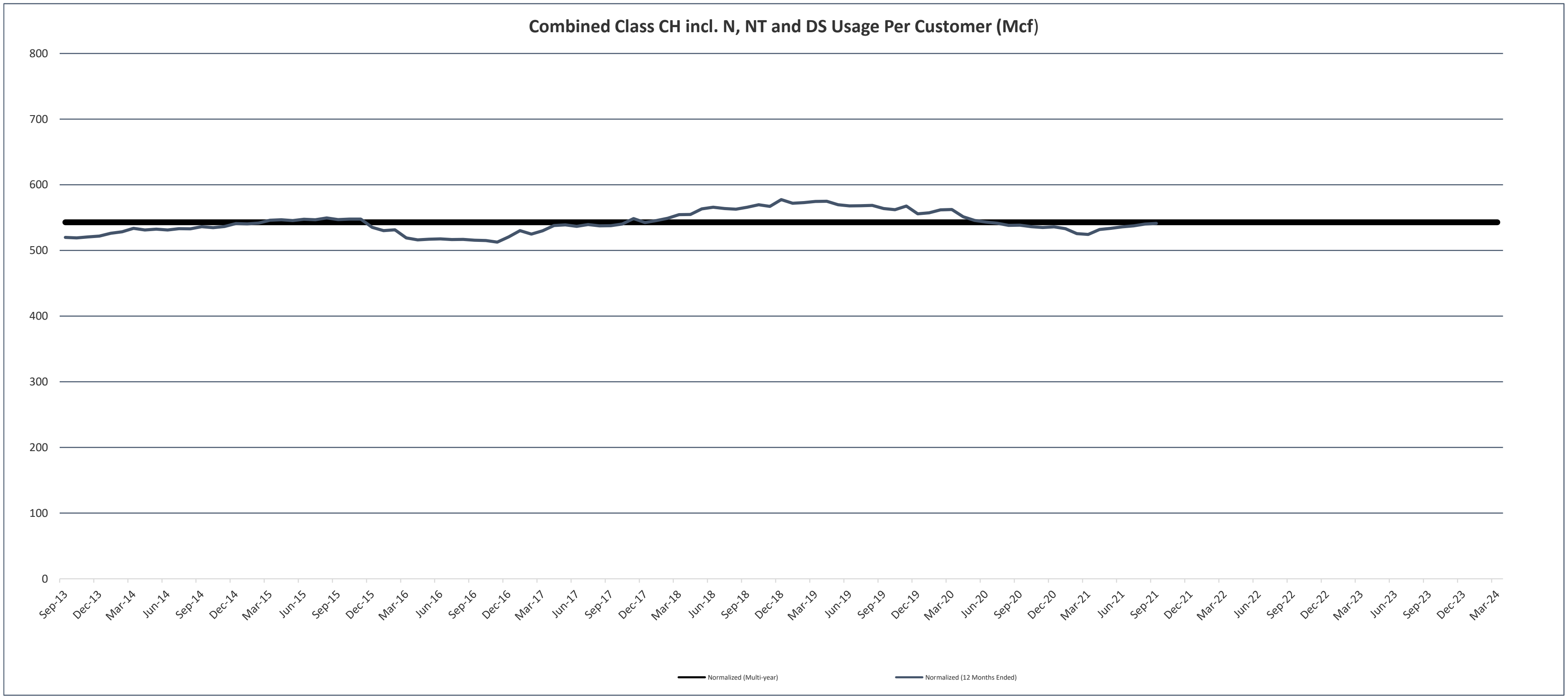
Sep-21
Mar-22
Sep-22
Mar-23
Sep-23
Mar-24
Normalized (Multi-year)
Normalized (12 Months Ended)

UGI GAS

EXHIBIT SAE-3(b)


Combined Class CH incl. N, NT and DS Usage Per Customer (Mcf)
800
700
600
500
400
300
200
100
0
Sep-13
Dec-13
Mar-14
Jun-14
Sep-14
Dec-14
Mar-15
Jun-15
Sep-15
Dec-15
Mar-16
Jun-16
Sep-16
Dec-16
Mar-17
Jun-17
Sep-17
Dec-17
Mar-18
Jun-18
Sep-18
Dec-18
Mar-19
Jun-19
Sep-19
Dec-19
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Jun-20
Sep-20
Dec-20
Mar-21
Jun-21
Sep-21
Dec-21
Mar-22
Jun-22
Sep-22
Dec-22
Mar-23
Jun-23
Sep-23
Dec-23
Mar-24
Normalized (Multi-year)
Normalized (12 Months Ended)

UGI GAS

EXHIBIT SAE-4(a) – (m)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year 2023 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Budget 2023	342,178	986,747	602,316	
Adjustment for Customer/Contract Changes	(194)	278	158	UGI Utilities, Inc.- Gas Division-Exhibit SAE-4(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	(1,348)	(15,863)	(5,673)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-4(c)
Adjustment for PGC		49,419	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(d)
Adjustment for MFC		814	814	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(e)
Adjustment for USP		1,119	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(f)
Adjustment for GPC		(111)	(111)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(g)
Adjustment for Excess Take		(1,700)	(1,700)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(h)
Adjustment for EEC Rider		3,809	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(i)
Adjustment for EEC Conservation Impact	(239)	(2,405)	(1,032)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(j)
Adjustment for Get Gas		(16)	(16)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(k)
Adjustment for GDE		20	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(l)
Adjustment for DISC		30,327	30,327	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(m)
Fully Projected Future Test Year 2023	340,397	1,052,437	625,083	

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for Customer/Contract Changes

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total *	[9] Rates LFD, XD, IS Transport-Other **	[10] Grand Total
1	FPFTY Revenues (Unadjusted)	$ 7,774	$ 569,371	$ 44,272	$ 7,709	$ 162,770	$ 7,711	$ 52,182	$ 32,197	$ 102,761	$ 986,747
2	FPFTY PGC Revenues	$ (2,181)	$ (279,118)	$ (3,110)	$ (4,081)	$ (90,242)	$ (4,518)	$ 32	(642)	(571)	(384,431)
3	FPFTY Revenues net of PGC - Margin (Unadjusted)	$ 5,593	$ 290,254	$ 41,162	$ 3,628	$ 72,528	$ 3,193	$ 52,213	$ 31,555	$ 102,191	$ 602,316
4	FPFTY Average Effective Customers (Unadjusted)	23,011	512,710	80,279	3,289	47,586	660	18,617	1,392	1,021	688,565
5	FPFTY Average Annual Margin Per Customer (L3 / L4 or Weighted Value by District)	$ 0.243	$ 0.566	$ 0.513	$ 0.974	$ 0.851	$ 4.890	$ 2.805	$ 22.669	$ 100.089	$ 0.875
6	FPFTY Customers (Fully Adjusted)	22,732	513,121	80,279	3,295	47,558	655	18,617	1,392	1,021	688,670
7	Change in Customers during FPFTY (L6 - L4)	(279)	411	-	6	(28)	(5)	-	-	-	105
8	Annualization of Margin (L5 * L7)	$ (68)	$ 233	$ -	$ 6	$ (24)	$ (22)	$ -	$ -	$ 34	$ 158
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4 or Weighted Value by District)	$ 0.338	$ 1.111	$ 0.551	$ 2.212	$ 2.757	$ 11.742	$ 2.803	$ 23.130	$ 100.648	$ 1.433
10	Annualization of Total FPFTY Revenue (L7 * L9)	$ (94)	$ 456	$ -	$ 13	$ (78)	$ (53)	$ -	$ -	$ 34	$ 278
11	Annualization Adjustment for FPFTY PGC Revenues (L10 - L8)	$ (26)	$ 224	$ -	$ 7	$ (54)	$ (31)	$ -	$ -	$ -	$ 119
12	Total FPFTY UPC (Unadjusted) - MCF	15.80	90.90	82.10	225.10	343.90	1,242.50	708.00	6,905.50		
13	Annualization Adjustment for FPFTY Sales - MMCF (L7 * L12)/1000	(4)	37	-	1	(10)	(6)	-	-	(213)	(194)

Notes:
* Adjustments for Rates DS are by customer and not in aggregate
** Column [9] further detailed on UGI Gas Exhibit SAE-4(b)(1)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for Customer/Contract Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] IS	[5] TOTAL
1	FPFTY Revenues (Unadjusted)	$ 44,333	$ 35,427	$ 1,887	$ 21,115	$ 102,761
2	FPFTY PGC Revenues	(571)	-	-	-	(571)
3	FPFTY Revenues net of PGC - Margin (Unadjusted)	$ 43,762	$ 35,427	$ 1,887	$ 21,115	$ 102,191
4	FPFTY Average Effective Customers (Unadjusted)	602	56	57	306	1,021
5	FPFTY Average Annual Margin Per Customer (L3 / L4)	$ 72.694	$ 632.627	$ 33.107	$ 69.002	$ 100.089
6	FPFTY Customers (Fully Adjusted)	604	56	57	304	1,021
7	Change in Customers during FPFTY (L6 - L4)	2	-	-	(2)	(0)
8	Annualization of Margin	$ (236)	$ 309	$ -	$ (39)	$ 34
9	Average Annual Revenue Per Customer (L1 / L4)	$ 73.642	$ 632.627	$ 33.107	$ 69.002	$ 100.648
10	Annualization of Total FPFTY Revenue	$ (236)	$ 309	$ -	$ (39)	$ 34
11	Annualization of FPFTY PGC Revenues (L10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total FPFTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for FPFTY Sales - MMCF	(136)	-	-	(77)	(213)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other	[10] Reconciliation Adj. *	[11] Total
1	FPFTY (Unadjusted) Use/Customer ("UPC") - MCF	15.80	90.90	82.10	225.10	343.90	1,242.50	708.00	6,905.50			
2	FPFTY UPC (Fully Adjusted) - MCF	16.30	88.00	82.90	215.10	346.00	1,109.50	712.50	6,905.50			
3	Change in UPC - MCF (L2 - L1)	0.50	(2.90)	0.80	(10.00)	2.10	(133.00)	4.50	0.00			
4	FPFTY Customers (Fully Adjusted)	22,732	513,121	80,279	3,295	47,558	655	18,617	1,392	1,021	-	688,670
5	Annualization Adjustment for Sales - MMCF (L3 * L4)/1000)	11	(1,488)	64	(33)	100	(87)	85	-	-	-	(1,348)
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	$ 129	$ (16,856)	$ 315	$ (331)	$ 1,001	$ (878)	$ 281	$ -	$ -	$ 477	$ (15,863)
7	Total Unit Revenue Adjustment (L6 / L5)	$ 11.3277	$ 11.3277	$ 4.9080	$ 10.0595	$ 10.0246	$ 10.0836	$ 3.3271	$ -	$ -		
8	Distribution Margin Adjustment (L5 * L9)	$ 47	$ (6,116)	$ 264	$ (117)	$ 353	$ (312)	$ 266	$ -	$ -		$ (5,617)
9	Distribution Unit Rate (Rate N/NT Weighted Value by District)	$ 4.1104	$ 4.1104	$ 4.1104	$ 3.5647	$ 3.5314	$ 3.5877	$ 3.1483	$ -	$ -		
10	PGC Revenue (L5 * L11)	$ 71	$ (9,340)	$ -	$ (207)	$ 627	$ (547)	$ -	$ -	$ -	$ 1	$ (9,395)
11	PGC Unit Rate	$ 6.2767	$ 6.2767		$ 6.2767	$ 6.2767	$ 6.2767					
12	EE&C Revenue Adjustment (L5 * L13)	$ 2	$ (309)	$ 13	$ (1)	$ 2	$ (2)	$ 2	$ -	$ -		$ (292)
13	EE&C Unit Rate	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0556	$ -		
14	USP Revenue Adjustment (L5 * L15)	$ 4	$ (530)	$ 23	$ -	$ -	$ -	$ -	$ -	$ -		$ (503)
15	USP Unit Rate	$ 0.3562	$ 0.3562	$ 0.3562	$ -	$ -	$ -	$ -	$ -	$ -		
16	MFC Revenue/Margin Adjustment (L5 * L17)	$ 2	$ (203)		$ (1)	$ 2	$ (2)	$ -	$ -	$ -		$ (201)
17	MFC Unit Rate	$ 0.1362	$ 0.1362		$ 0.0176	$ 0.0176	$ 0.0176	$ -	$ -	$ -		
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ 3	$ (358)	$ 15	$ (6)	$ 18	$ (16)	$ 13	$ -	$ -		$ (331)
19	DSIC Unit Rate	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500			
20	Total Margin Adjustment (L8 + L16 + L18)	$ 51	$ (6,677)	$ 279	$ (124)	$ 372	$ (330)	$ 279	$ -	$ -	$ 476	$ (5,673)
21	Total Unit Margin Adjustment (L20 / L5)	$ 4.4871	$ 4.4871	$ 4.3441	$ 3.7624	$ 3.7275	$ 3.7865	$ 3.3067	$ -	$ -		

Notes:

* Column (10) Adjustment reflective of interdependent relationship of sequential adjustment impacts.

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for PGC

	OCT 2022	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	TOTAL
Original Budget PGC Rate FPFTY	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	
FPFTY PGC Rate	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	
PGC Rate Variance	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	
Total PGC Volumes	3,699	7,394	10,289	13,124	10,566	8,699	4,479	2,017	1,161	939	1,007	1,537	64,912
PGC Revenue Adjustment	$2,816	$5,629	$7,834	$9,992	$8,044	$6,622	$3,410	$1,536	$884	$715	$767	$1,170	$49,419

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for MFC

	OCT 2022	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	TOTAL
Original Budget PGC Rate FPFTY	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	
FPFTY PGC Rate	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	
PGC Rate Variance	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	
Total PGC Volumes-Rate R	2,681	5,356	7,447	9,491	7,649	6,302	3,248	1,460	837	676	725	1,112	
Total PGC Volumes-Rate N	1,018	2,038	2,842	3,633	2,917	2,397	1,231	557	324	264	282	426	
Total PGC Volumes	3,699	7,394	10,289	13,124	10,566	8,699	4,479	2,017	1,161	939	1,007	1,537	64,912
Rate R %	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	
Rate N %	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	
MFC Rate R Adj Rate	$0.0165	$0.0165	$0.0165	$0.0165	$0.0165	$0.0165	$0.0165	$0.0165	$0.0165	$0.0165	$0.0165	$0.0165	
MFC Rate N Adj Rate	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	
Rate R Revenue Variance	$44	$88	$123	$157	$126	$104	$54	$24	$14	$11	$12	$18	
Rate N Revenue Variance	$2	$4	$6	$8	$6	$5	$3	$1	$1	$1	$1	$1	
Total Revenue Variance	$46	$93	$129	$165	$133	$109	$56	$25	$15	$12	$13	$19	$814

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for USP

	OCT 2022	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	TOTAL
Original FPFTY Budget USP Calculation	$983	$1,949	$2,691	$3,409	$2,761	$2,284	$1,188	$531	$298	$237	$256	$401	$16,989
Correct FPFTY Budget USP Calculation	$933	$1,849	$2,554	$3,235	$2,620	$2,167	$1,127	$504	$283	$225	$243	$380	$16,120
Variance to correct Original FPFTY Budget Calculation	($50)	($100)	($138)	($174)	($141)	($117)	($61)	($27)	($15)	($12)	($13)	($21)	($869)
Original FPFTY Budget USP Rate	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	
FPFTY USP Rate	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	
USP Rate Variance	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	
Total Rate R Volumes	3,100	6,146	8,487	10,752	8,707	7,203	3,746	1,675	940	748	807	1,265	53,576
Total Rate R excl CAP Volumes	2,941	5,832	8,053	10,202	8,262	6,834	3,554	1,589	892	710	766	1,200	50,835
USP Rate Revenue Variance	$115	$228	$315	$399	$323	$267	$139	$62	$35	$28	$30	$47	$1,988
Total Revenue Variance	$65	$128	$177	$224	$182	$150	$78	$35	$20	$16	$17	$26	$1,119

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for GPC

	OCT 2022	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	TOTAL
GPC Rate	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	
Volume Variance to Original FPFTY Budget	(96)	(192)	(266)	(339)	(273)	(225)	(116)	(52)	(30)	(24)	(26)	(40)	(1,680)
Revenue Variance	($6)	($13)	($18)	($22)	($18)	($15)	($8)	($3)	($2)	($2)	($2)	($3)	($111)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MMCF)	(283)
$/MCF	$6.00
Excess Take Revenue/Margin	($1,700)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for EEC Rider

	OCT 2022	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	TOTAL
Original FPFTY Budget DS EEC Calculation	$40.6	$67.2	$102.6	$128.1	$118.8	$96.3	$56.7	$34.0	$24.5	$21.1	$21.7	$26.1	$737.7
Correct FPFTY Budget DS EEC Calculation	$40.4	$67.0	$102.2	$127.7	$118.4	$96.0	$56.5	$33.9	$24.5	$21.1	$21.7	$26.0	$735.3
Variance to correct Original FPFTY Budget Calculation	($0.2)	($0.3)	($0.4)	($0.5)	($0.4)	($0.3)	($0.2)	($0.1)	($0.0)	($0.0)	($0.0)	($0.0)	($2.4)
Original Budget FPFTY R/RT Rate	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	
FPFTY R/RT Rate	$0.2077	$0.2077	$0.2077	$0.2077	$0.2077	$0.2077	$0.2077	$0.2077	$0.2077	$0.2077	$0.2077	$0.2077	
R/RT Rate Variance	$0.0530	$0.0530	$0.0530	$0.0530	$0.0530	$0.0530	$0.0530	$0.0530	$0.0530	$0.0530	$0.0530	$0.0530	
R/RT Rate Volumes	3,100	6,146	8,487	10,752	8,707	7,203	3,746	1,675	940	748	807	1,265	53,576
R/RT Revenue Adjustment	$164	$326	$450	$570	$461	$382	$199	$89	$50	$40	$43	$67	$2,840
Original Budget FPFTY N/NT Rate	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	
FPFTY N/NT Rate	$0.0204	$0.0204	$0.0204	$0.0204	$0.0204	$0.0204	$0.0204	$0.0204	$0.0204	$0.0204	$0.0204	$0.0204	
N/NT Rate Variance	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	
N/NT Rate Volumes	1,835	3,485	4,776	6,039	4,890	4,053	2,172	1,077	695	597	627	863	31,109
N/NT Revenue Adjustment	$42	$79	$109	$138	$111	$92	$50	$25	$16	$14	$14	$20	$709
Original Budget FPFTY DS Rate	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	
FPFTY DS Rate	$0.0556	$0.0556	$0.0556	$0.0556	$0.0556	$0.0556	$0.0556	$0.0556	$0.0556	$0.0556	$0.0556	$0.0556	
DS Rate Variance	($0.0053)	($0.0053)	($0.0053)	($0.0053)	($0.0053)	($0.0053)	($0.0053)	($0.0053)	($0.0053)	($0.0053)	($0.0053)	($0.0053)	
DS Rate Volumes	512	856	1,330	1,697	1,550	1,272	738	442	321	277	281	336	9,612
DS Revenue Adjustment	($3)	($5)	($7)	($9)	($8)	($7)	($4)	($2)	($2)	($1)	($1)	($2)	($51)
Original Budget FPFTY LFD Rate	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	
FPFTY LFD Rate	$0.0316	$0.0316	$0.0316	$0.0316	$0.0316	$0.0316	$0.0316	$0.0316	$0.0316	$0.0316	$0.0316	$0.0316	
LFD Rate Variance	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	
LFD Rate Volumes	1,836	2,170	2,487	2,761	2,467	2,275	1,911	1,700	1,546	1,494	1,536	1,593	23,775
LFD Revenue Adjustment	$24	$29	$33	$36	$33	$30	$25	$22	$20	$20	$20	$21	$314
Total Revenue Adjustment	$227	$429	$584	$735	$597	$497	$269	$133	$84	$72	$76	$106	$3,809

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for EE&C Conservation Impact

EE&C Plan (Version 1/15/2019)

Yearly Gas Savings by Rate Class 2020 - 2035 (Cumulative MMBtus)

Rate Class Description	*Fiscal Year* 2020	2021	2022	2023	2024	MMBTU 5 Year Average	BTU	MCF 5 Year Average	Customers FY23 Retail Htg & Choice Htg	EE&C UPC Conservation Adj
Residential (R/RT)	145,463	157,325	171,179	175,233	176,395	165,119	1.034	159,690	497,635	**(0.3)**
Nonresidential (N/NT)	29,620	38,139	45,037	50,308	50,308	42,682	1.034	41,279	53,885	**(0.8)**
Total	**175,083**	**195,464**	**216,217**	**225,540**	**226,703**	**207,802**		**200,969**	**551,520**	

Line #	Description	[1] Rate R Residential-Htg	[2] Rate RT Residential Htg-RT	[3] Rate N Commercial-Htg	[4] Rate NT Commercial Htg-NT	[5] Rate N Industrial	[6] Rate NT Industrial -NT	[7] Total
1	FPFTY Use/Customer ("UPC") (Fully Adjusted) - MCF	88.0	86.2	346.0	689.5	1,109.5	2,242.6	
2	FPFTY UPC (Fully Adjusted-Incl EE&C Impact) - MCF	87.7	85.9	345.2	688.7	1,108.7	2,241.8	
3	Change in UPC -MCF	(0.3)	(0.3)	(0.8)	(0.8)	(0.8)	(0.8)	
4	End of Year FPFTY Customers	513,121	76,480	47,558	16,746	655	456	655,016
5	Annualization Adjustment for Sales - MMCF (L3 * L4) / 1000	(165)	(25)	(36)	(13)	(1)	(0)	(239)
6	Total Revenue Adjustment (L10 + L12 + L14 + L22)	$ (1,865)	$ (120)	$ (365)	$ (48)	$ (5)	$ (1)	$ (2,405)
7	Total Unit Revenue Adjustment (L6 / L5)	11.3277	4.9080	10.0246	3.7556	10.0833	3.8115	10.0515
8	Distribution Margin Adjustment (L5 * L9)	$ (677)	$ (101)	$ (129)	$ (46)	$ (2)	$ (1)	$ (955)
9	Distribution Unit Rate (Rates N, DS Weighted Value by District)	$ 4.1104	$ 4.1104	$ 3.5314	$ 3.5564	$ 3.5873	$ 3.6096	
10	PGC Revenue (L5 * L11)	$ (1,034)	$ -	$ (229)	$ -	$ (3)	$ -	$ (1,265)
11	PGC Unit Rate	$ 6.2767		$ 6.2767		$ 6.2767		
12	EE&C Revenue Adjustment (L5 * L13)	$ (34)	$ (5)	$ (1)	$ (0)	$ (0)	$ (0)	$ (40)
13	EE&C Unit Rate	$ 0.2077	$ 0.2077	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	
14	USP Revenue Adjustment (L5 * L15)	$ (59)	$ (9)					$ (67)
15	USP Unit Rate	$ 0.3562	$ 0.3562					
16	MFC Revenue/Margin Adjustment (L5 * L17)	$ (22)		$ (1)		$ (0)		$ (23)
17	MFC Unit Rate	$ 0.1362		$ 0.0176		$ 0.0176		
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ (40)	$ (6)	$ (7)	$ (2)	$ (0)	$ (0)	$ (54)
19	DSIC Unit Rate	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	
20	Total Margin Adjustment (L8 + L16 + L18)	$ (739)	$ (107)	$ (136)	$ (48)	$ (2)	$ (1)	$ (1,032)
21	Total Unit Margin Adjustment (L20 / L5)	$ 4.4871	$ 4.3441	$ 3.7275	$ 3.7352	$ 3.7862	$ 3.7911	

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for Get Gas Surcharge

	Rate R Residential Htg	Rate N Commercial Htg	Total
Original Budget FPFTY Revenue	$189	$0	$189
FPFTY Revenue	$169	$3	$173
Get Gas Revenue Adjustment	($20)	$3	($16)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for GDE Rider

	OCT 2022	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	TOTAL
Original FPFTY Budget DS GDE Calculation	$2.9	$4.8	$7.5	$9.5	$8.7	$7.2	$4.1	$2.5	$1.8	$1.6	$1.6	$1.9	$54.0
Correct FPFTY Budget DS GDE Calculation	$2.9	$4.8	$7.4	$9.5	$8.7	$7.1	$4.1	$2.5	$1.8	$1.6	$1.6	$1.9	$53.8
Variance to correct Original FPFTY Budget Calculation	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.2)
Original Budget FPFTY DS Rate	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	
FPFTY DS Rate	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	
DS Rate Variance	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	
DS Rate Volumes	515	859	1,333	1,701	1,554	1,275	740	444	323	279	283	338	9,646
DS Revenue Adjustment	$0	$1	$1	$1	$1	$1	$0	$0	$0	$0	$0	$0	$6
Original Budget FPFTY LFD Rate	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	
FPFTY LFD Rate	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	
LFD Rate Variance	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	
LFD Rate Volumes	1,836	2,170	2,487	2,761	2,467	2,275	1,911	1,700	1,546	1,494	1,536	1,593	23,775
LFD Revenue Adjustment	$1	$1	$1	$2	$1	$1	$1	$1	$1	$1	$1	$1	$14
Total Revenue Adjustment	$1	$2	$2	$3	$2	$2	$2	$1	$1	$1	$1	$1	$20

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for DSIC

	@ 0% Unadjusted 2023 TOTAL	@ 5% Adjusted 2023 TOTAL	Revenue Adjustment Total
RES. G	$0	$289	$289
H	$0	$15,433	$15,433
SUBTOTAL R	$0	$15,722	$15,722
RT	$0	$2,247	$2,247
TOTAL	$0	$17,970	$17,970
COM. G	$0	$177	$177
H	$0	$3,656	$3,656
SUBTOTAL C-N	$0	$3,832	$3,832
NT	$0	$2,444	$2,444
DS	$0	$1,292	$1,292
IS	$0	$463	$463
XD-F	$0	$73	$73
XD-I	$0	$31	$31
LFD	$0	$801	$801
TOTAL	$0	$8,937	$8,937
IND.	$0	$143	$143
SUBTOTAL I-N	$0	$143	$143
NT	$0	$191	$191
DS	$0	$313	$313
IS	$0	$500	$500
XD-F	$0	$889	$889
XD-I	$0	$55	$55
LFD	$0	$1,328	$1,328
TOTAL	$0	$3,420	$3,420
GRAND TOTAL	$0	$30,327	$30,327

UGI GAS

EXHIBIT SAE-5(a) – (k)

UGI Utilities Inc.- Gas Division
Future Test Year 2022 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Budget 2022	339,581	991,527	619,606	
Adjustment for Customer/Contract Changes	(199)	16	(90)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(b)/(b)(´
Adjustment for Normalized & Annualized Use/Customer	(1,282)	(15,375)	(5,699)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(c)
Adjustment for PGC		55,658	0	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(d)
Adjustment for MFC		916	916	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(e)
Adjustment for USP		1,102	0	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(f)
Adjustment for GPC		(93)	(93)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(g)
Adjustment for Excess Take		(1,700)	(1,700)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(h)
Adjustment for EEC Rider		3,765	0	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(i)
Adjustment for Get Gas		3	3	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(j)
Adjustment for GDE		20	0	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(k)
Future Test Year 2022	338,100	1,035,839	612,942	

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for Customer/Contract Changes

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total *	[9] Rates LFD, XD, IS Transport-Other **	[10] Grand Total
1	FTY Revenues (Unadjusted)	$ 8,243	$ 566,726	$ 45,977	$ 7,795	$ 161,780	$ 7,778	$ 54,191	$ 33,462	$ 105,574	$ 991,527
2	FTY PGC Revenues	$ (2,218)	$ (269,556)	$ (3,110)	$ (4,015)	$ (87,391)	$ (4,449)	$ 32	(642)	(571)	(371,921)
3	FTY Revenues net of PGC - Margin (Unadjusted)	$ 6,025	$ 297,171	$ 42,867	$ 3,781	$ 74,389	$ 3,329	$ 54,223	$ 32,820	$ 105,002	$ 619,606
4	FTY Average Effective Customers (Unadjusted)	23,843	504,315	80,279	3,301	47,006	662	18,617	1,393	1,022	680,439
5	FTY Average Annual Margin Per Customer (L3 / L4 or Weighted Value by District)	$ 0.253	$ 0.589	$ 0.534	$ 1.160	$ 0.878	$ 4.689	$ 2.913	$ 25.929	$ 102.730	$ 0.911
6	FTY Customers (Fully Adjusted)	23,563	504,723	80,279	3,297	46,979	658	18,617	1,392	1,021	680,529
7	Change in Customers during FTY (L6 - L4)	(280)	408	-	(4)	(27)	(4)	-	(1)	(1)	90
8	Annualization of Margin (L5 * L7)	$ (71)	$ 240	$ -	$ (5)	$ (24)	$ (21)	$ -	$ (11)	$ (199)	$ (90)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4 or Weighted Value by District)	$ 0.346	$ 1.124	$ 0.573	$ 2.376	$ 2.750	$ 11.419	$ 2.911	$ 26.405	$ 103.288	$ 1.457
10	Annualization of Total FTY Revenue (L7 * L9)	$ (97)	$ 458	$ -	$ (10)	$ (74)	$ (50)	$ -	$ (11)	$ (199)	$ 16
11	Annualization Adjustment for FTY PGC Revenues (L10 - L8)	$ (26)	$ 218	$ -	$ (5)	$ (51)	$ (30)	$ -	$ -	$ -	$ 106
12	Total FTY UPC (Unadjusted) - MCF	15.80	90.90	82.10	225.10	343.90	1,242.50	708.00	6,904.90		
13	Annualization Adjustment for FTY Sales - MMCF (L7 * L12)/1000	(4)	37	-	(1)	(9)	(5)	-	$ (3)	(213)	(199)

Notes:
* Adjustments for Rates DS are by customer and not in aggregate
** Column [9] further detailed on UGI Gas Exhibit SAE-5(b)(1)

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for Customer/Contract Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] IS	[5] TOTAL
1	FTY Revenues (Unadjusted)	$ 46,149	$ 35,603	$ 1,902	$ 21,920	$ 105,574
2	FTY PGC Revenues	(571)	-	-	-	(571)
3	FTY Revenues net of PGC - Margin (Unadjusted)	$ 45,578	$ 35,603	$ 1,902	$ 21,920	$ 105,002
4	FTY Average Effective Customers (Unadjusted)	603	56	57	306	1,022
5	FTY Average Annual Margin Per Customer (L3 / L4)	$ 75.579	$ 635.766	$ 33.364	$ 71.616	$ 102.730
6	FTY Customers (Fully Adjusted)	604	56	57	304	1,021
7	Change in Customers during FTY (L6 - L4)	1	-	-	(2)	(1)
8	Annualization of Margin	$ (238)	$ 78	$ -	$ (39)	$ (199)
9	Average Annual Revenue Per Customer (L1 / L4)	$ 76.526	$ 635.766	$ 33.364	$ 71.616	$ 103.288
10	Annualization of Total FTY Revenue	$ (238)	$ 78	$ -	$ (39)	$ (199)
11	Annualization of FTY PGC Revenues (L10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total FTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for FTY Sales - MMCF	(136)	-	-	(77)	(213)

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other	[10] Total
FTY (Unadjusted) Use/Customer ("UPC") - MCF	15.80	90.90	82.10	225.10	343.90	1,242.50	708.00	6,904.90		
FTY UPC (Fully Adjusted) - MCF	16.30	88.30	82.90	215.10	343.60	1,116.70	712.50	6,904.90		
Change in UPC - MCF (L2 - L1)	0.50	(2.60)	0.80	(10.00)	(0.30)	(125.80)	4.50	0.00		
FPFTY Customers (Fully Adjusted)	23,563	504,723	80,279	3,297	46,979	658	18,617	1,392	1,021	680,529
Annualization Adjustment for Sales - MMCF (L3 * L4)/1000)	12	(1,312)	64	(33)	(14)	(83)	85	-	-	(1,282)
Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	$ 133	$ (14,796)	$ 312	$ (330)	$ (141)	$ (832)	$ 278	$ -	$ -	$ (15,375)
Total Unit Revenue Adjustment (L6 / L5)	$ 11.2748	$ 11.2748	$ 4.8566	$ 10.0198	$ 9.9848	$ 10.0461	$ 3.2923	$ -	$ -	
Distribution Margin Adjustment (L5 * L9)	$ 48	$ (5,394)	$ 264	$ (118)	$ (50)	$ (297)	$ 266	$ -	$ -	$ (5,280)
Distribution Unit Rate (Rate N/NT Weighted Value by District)	$ 4.1104	$ 4.1104	$ 4.1104	$ 3.5647	$ 3.5309	$ 3.5884	$ 3.1483	$ -	$ -	
PGC Revenue (L5 * L11)	$ 74	$ (8,237)	$ -	$ (207)	$ (88)	$ (520)	$ -	$ -	$ -	$ (8,978)
PGC Unit Rate	$ 6.2767	$ 6.2767		$ 6.2767	$ 6.2767	$ 6.2767				
EE&C Revenue Adjustment (L5 * L13)	$ 2	$ (273)	$ 13	$ (1)	$ (0)	$ (2)	$ 2	$ -	$ -	$ (258)
EE&C Unit Rate	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0556	$ -	
USP Revenue Adjustment (L5 * L15)	$ 4	$ (467)	$ 23	$ -	$ -	$ -	$ -	$ -	$ -	$ (440)
USP Unit Rate	$ 0.3562	$ 0.3562	$ 0.3562	$ -	$ -	$ -	$ -	$ -	$ -	
MFC Revenue/Margin Adjustment (L5 * L17)	$ 2	$ (179)	$ -	$ (1)	$ (0)	$ (1)	$ -	$ -	$ -	$ (179)
MFC Unit Rate	$ 0.1362	$ 0.1362		$ 0.0176	$ 0.0176	$ 0.0176	$ -	$ -	$ -	
DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ 2	$ (246)	$ 12	$ (5)	$ (2)	$ (12)	$ 10	$ -	$ -	$ (240)
DSIC Unit Rate	$ 0.0390	$ 0.0390	$ 0.0390	$ 0.0390	$ 0.0390	$ 0.0390	$ 0.0390	$ 0.0390	$ -	
Total Margin Adjustment (L8 + L16 + L18)	$ 52	$ (5,819)	$ 276	$ (123)	$ (52)	$ (310)	$ 277	$ -	$ -	$ (5,699)
Total Unit Margin Adjustment (L20 / L5)	$ 4.4342	$ 4.4342	$ 4.2927	$ 3.7227	$ 3.6877	$ 3.7474	$ 3.2719	$ -	$ -	

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for PGC

	OCT 2021	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	TOTAL
Original Budget PGC Rate FPFTY (Weighted Value by District)	$4.8790	$4.8790	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	
FPFTY PGC Rate	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	
PGC Rate Variance	$1.3977	$1.3977	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	
Total PGC Volumes	3,646	7,286	10,139	12,933	10,412	8,571	4,413	1,988	1,145	926	994	1,516	63,969
PGC Revenue Adjustment	$5,096	$10,184	$7,719	$9,846	$7,927	$6,526	$3,360	$1,514	$871	$705	$756	$1,154	$55,658

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for MFC

	OCT 2021	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	TOTAL
Original Budget PGC Rate FTY	$4.8790	$4.8790	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	
FTY PGC Rate	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	
PGC Rate Variance	$1.3977	$1.3977	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	
Total PGC Volumes-Rate R	2,639	5,270	7,327	9,339	7,526	6,201	3,196	1,438	824	666	714	1,094	
Total PGC Volumes-Rate N	1,007	2,016	2,812	3,594	2,886	2,371	1,217	551	320	261	279	421	
Total PGC Volumes	3,646	7,286	10,139	12,933	10,412	8,571	4,413	1,988	1,145	926	994	1,516	63,969
Rate R %	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	
Rate N %	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	
MFC Rate R Adj Rate	$0.03	$0.03	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	
MFC Rate N Adj Rate	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Rate R Revenue Variance	$80	$160	$121	$154	$124	$102	$53	$24	$14	$11	$12	$18	
Rate N Revenue Variance	$4	$8	$6	$8	$6	$5	$3	$1	$1	$1	$1	$1	
Total Revenue Variance	$84	$168	$127	$162	$130	$107	$55	$25	$14	$12	$12	$19	$916

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for USP

	OCT 2021	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	TOTAL
Original FTY Budget USP Calculation	$969	$1,922	$2,653	$3,361	$2,722	$2,252	$1,171	$524	$294	$234	$253	$396	$16,751
Correct FTY Budget USP Calculation	$920	$1,823	$2,517	$3,189	$2,583	$2,137	$1,111	$497	$279	$222	$240	$375	$15,893
Variance to correct Original FTY Budget Calculation	($50)	($98)	($136)	($172)	($139)	($115)	($60)	($27)	($15)	($12)	($13)	($20)	($857)
Original Budget USP Rate FTY	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	
FTY USP Rate	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	
USP Rate Variance	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	
Total Rate R Volumes	3,057	6,060	8,368	10,599	8,585	7,102	3,694	1,652	927	738	796	1,247	52,825
Total Rate R excl CAP Volumes	2,901	5,750	7,939	10,056	8,145	6,738	3,505	1,568	880	700	756	1,184	50,121
USP Rate Revenue Variance	$113	$225	$310	$393	$318	$263	$137	$61	$34	$27	$30	$46	$1,960
Total Revenue Variance	$64	$126	$175	$221	$179	$148	$77	$34	$19	$15	$17	$26	$1,102

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for GPC

	OCT 2021	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	TOTAL
GPC Rate	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	
Volume Variance to Original FTY Budget	(81)	(161)	(224)	(285)	(230)	(189)	(98)	(44)	(25)	(20)	(22)	(33)	(1,414)
Revenue Variance	($5)	($11)	($15)	($19)	($15)	($13)	($6)	($3)	($2)	($1)	($1)	($2)	($93)

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MMCF)		(283)
$/MCF	$	6.00
Excess Take Revenue/Margin	$	(1,700)

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for EEC Rider

	OCT 2021	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	TOTAL
Original FTY Budget DS EEC Calculation	$ 31.5	$ 52.5	$ 81.4	$ 103.9	$ 94.8	$ 77.8	$ 45.1	$ 27.0	$ 19.5	$ 16.9	$ 17.1	$ 20.5	$ 588.1
Correct FTY Budget DS EEC Calculation	$ 31.3	$ 52.3	$ 81.1	$ 103.4	$ 94.4	$ 77.5	$ 44.9	$ 26.9	$ 19.5	$ 16.8	$ 17.1	$ 20.5	$ 585.7
Variance to correct Original FTY Budget Calculation	$ (0.2)	$ (0.3)	$ (0.4)	$ (0.5)	$ (0.4)	$ (0.3)	$ (0.2)	$ (0.1)	$ (0.0)	$ (0.0)	$ (0.0)	$ (0.0)	$ (2.4)
Original Budget FTY R/RT Rate	$ 0.1547	$ 0.1547	$ 0.1547	$ 0.1547	$ 0.1547	$ 0.1547	$ 0.1547	$ 0.1547	$ 0.1547	$ 0.1547	$ 0.1547	$ 0.1547	
FTY R/RT Rate	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.2077	
R/RT Rate Variance	$ 0.0530	$ 0.0530	$ 0.0530	$ 0.0530	$ 0.0530	$ 0.0530	$ 0.0530	$ 0.0530	$ 0.0530	$ 0.0530	$ 0.0530	$ 0.0530	
R/RT Rate Volumes	3,057	6,060	8,368	10,599	8,585	7,102	3,694	1,652	927	738	796	1,247	52,825
R/RT Revenue Adjustment	$ 162	$ 321	$ 443	$ 562	$ 455	$ 376	$ 196	$ 88	$ 49	$ 39	$ 42	$ 66	$ 2,800
Original Budget FTY N/NT Rate	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	
FTY N/NT Rate	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	
N/NT Rate Variance	$ 0.0228	$ 0.0228	$ 0.0228	$ 0.0228	$ 0.0228	$ 0.0228	$ 0.0228	$ 0.0228	$ 0.0228	$ 0.0228	$ 0.0228	$ 0.0228	
N/NT Rate Volumes	1,824	3,463	4,745	6,000	4,858	4,027	2,159	1,071	692	594	624	858	30,917
N/NT Revenue Adjustment	$ 42	$ 79	$ 108	$ 137	$ 111	$ 92	$ 49	$ 24	$ 16	$ 14	$ 14	$ 20	$ 705
Original Budget FTY DS Rate	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	
FTY DS Rate	$ 0.0556	$ 0.0556	$ 0.0556	$ 0.0556	$ 0.0556	$ 0.0556	$ 0.0556	$ 0.0556	$ 0.0556	$ 0.0556	$ 0.0556	$ 0.0556	
DS Rate Variance	$ (0.0053)	$ (0.0053)	$ (0.0053)	$ (0.0053)	$ (0.0053)	$ (0.0053)	$ (0.0053)	$ (0.0053)	$ (0.0053)	$ (0.0053)	$ (0.0053)	$ (0.0053)	
DS Rate Volumes	514	859	1,331	1,699	1,551	1,272	737	442	320	276	281	336	9,618
DS Revenue Adjustment	$ (3)	$ (5)	$ (7)	$ (9)	$ (8)	$ (7)	$ (4)	$ (2)	$ (2)	$ (1)	$ (1)	$ (2)	$ (51)
Original Budget FTY LFD Rate	$ 0.0184	$ 0.0184	$ 0.0184	$ 0.0184	$ 0.0184	$ 0.0184	$ 0.0184	$ 0.0184	$ 0.0184	$ 0.0184	$ 0.0184	$ 0.0184	
FTY LFD Rate	$ 0.0316	$ 0.0316	$ 0.0316	$ 0.0316	$ 0.0316	$ 0.0316	$ 0.0316	$ 0.0316	$ 0.0316	$ 0.0316	$ 0.0316	$ 0.0316	
LFD Rate Variance	$ 0.0132	$ 0.0132	$ 0.0132	$ 0.0132	$ 0.0132	$ 0.0132	$ 0.0132	$ 0.0132	$ 0.0132	$ 0.0132	$ 0.0132	$ 0.0132	
LFD Rate Volumes	1,837	2,171	2,487	2,761	2,469	2,278	1,913	1,702	1,548	1,497	1,538	1,595	23,797
LFD Revenue Adjustment	$ 24	$ 29	$ 33	$ 36	$ 33	$ 30	$ 25	$ 22	$ 20	$ 20	$ 20	$ 21	$ 314
Total Revenue Adjustment	$ 225	$ 424	$ 577	$ 726	$ 590	$ 491	$ 266	$ 132	$ 84	$ 71	$ 75	$ 105	$ 3,765

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for Get Gas Surcharge

	Rate R Residential Htg	Rate N Commercial Htg	Total
Original Budget FTY Revenue	$ 142	$ -	$ 142
FTY Revenue	$ 142	$ 3	$ 145
Get Gas Revenue Adjustment	$ (0)	$ 3	$ 3

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for GDE Rider

	OCT 2021	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	TOTAL
Original FTY Budget DS GDE Calculation	$ 2.89	$ 4.83	$ 7.49	$ 9.55	$ 8.72	$ 7.16	$ 4.15	$ 2.48	$ 1.80	$ 1.55	$ 1.58	$ 1.89	$ 54.08
Correct FTY Budget DS GDE Calculation	$ 2.03	$ 3.44	$ 5.50	$ 7.28	$ 6.48	$ 5.43	$ 3.07	$ 1.84	$ 1.34	$ 1.17	$ 1.16	$ 1.38	$ 40.06
Variance to correct Original FTY Budget Calculation	$ (0.01)	$ (0.02)	$ (0.03)	$ (0.04)	$ (0.03)	$ (0.03)	$ (0.01)	$ (0.00)	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ (0.22)
Original Budget FTY DS Rate	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	
FTY DS Rate	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	
DS Rate Variance	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	
DS Rate Volumes	514	859	1,331	1,699	1,551	1,272	737	442	320	276	281	336	9,618
DS Revenue Adjustment	$ 0	$ 1	$ 1	$ 1	$ 1	$ 1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 6
Original Budget FTY LFD Rate	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	
FTY LFD Rate	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	
LFD Rate Variance	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	
LFD Rate Volumes	1,837	2,171	2,487	2,761	2,469	2,278	1,913	1,702	1,548	1,497	1,538	1,595	23,797
LFD Revenue Adjustment	$ 1	$ 1	$ 1	$ 2	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 14
Total Revenue Adjustment	$ 1	$ 2	$ 2	$ 3	$ 2	$ 2	$ 2	$ 1	$ 1	$ 1	$ 1	$ 1	$ 20

UGI GAS

EXHIBIT SAE-6(a) – (k)

UGI Utilities Inc.- Gas Division
Historic Year 2021 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Actual 2021	308,784	844,210	553,517	
Adjustment for Customer/Contract Changes	547	(1,072)	(648)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	7,441	50,112	27,356	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(c)
Adjustment for PGC		48,477	0	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(d)
Adjustment for MFC		797	797	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(e)
Adjustment for USP		2,852	0	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(f)
Adjustment for GPC		265	265	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(g)
Adjustment for Excess Take		(1,047)	(1,047)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(h)
Adjustment for EEC Rider		(574)	0	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(i)
Adjustment for Get Gas		13	13	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(j)
Adjustment for GDE		(31)	0	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(k)
Historic Year 2021	316,771	944,002	580,253	

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for Customer/Contract Changes

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other *	[10] Grand Total
1	HTY Revenues (Unadjusted)	$ 12,583	$ 451,891	$ 41,749	$ 6,967	$ 127,346	$ 6,641	$ 49,541	$ 46,750	$ 100,742	$ 844,210
2	HTY PGC Revenues	$ (1,868)	$ (196,813)	$ (2,773)	$ (2,902)	$ (62,639)	$ (3,483)	$ (227)	(17,018)	(2,968)	(290,692)
3	HTY Revenues net of PGC - Margin (Unadjusted)	$ 10,714	$ 255,078	$ 38,975	$ 4,065	$ 64,707	$ 3,158	$ 49,314	$ 29,732	$ 97,774	$ 553,517
4	HTY Average Effective Customers (Unadjusted)	24,983	497,392	80,835	3,320	46,406	692	18,687	1,375	985	674,675
5	HTY Average Annual Margin Per Customer (L3 / L4 or Weighted Value by District)	$ 0.420	$ 0.383	$ 0.478	$ 0.841	$ 1.412	$ 4.580	$ (3.781)	$ 19.723	$ 99.222	$ 0.844
6	HTY Customers (Fully Adjusted)	24,549	498,946	77,145	3,316	45,954	707	18,690	1,367	988	671,662
7	Change in Customers during HTY (L6 - L4)	(434)	1,554	(3,690)	(4)	(452)	15	3	(8)	3	(3,013)
8	Annualization of Margin (L5 * L7)	$ (182)	$ 596	$ (1,764)	$ (4)	$ (638)	$ 70	$ (11)	$ (154)	$ 1,439	$ (648)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4 or Weighted Value by District)	$ 0.495	$ 0.632	$ 0.512	$ 2.350	$ 2.818	$ 9.642	$ (3.974)	$ 30.986	$ 102.235	$ 1.325
10	Annualization of Total HTY Revenue (L7 * L9)	$ (215)	$ 982	$ (1,889)	$ (10)	$ (1,274)	$ 148	$ (12)	$ (241)	$ 1,439	$ (1,072)
11	Annualization Adjustment for HTY PGC Revenues (L10 - L8)	$ (32)	$ 386	$ (125)	$ (7)	$ (635)	$ 78	$ (1)	$ (88)	$ -	$ (423)
12	Total HTY UPC (Unadjusted) - MCF (Weighted Value by District)	15.57	50.64	75.71	352.20	327.57	1,181.06	273.19	5,292.63		
13	Annualization Adjustment for HTY Sales - MMCF (L7 * L12)/1000	(7)	79	(279)	(2)	(148)	18	1	(41)	926	547

Notes:

* Column [9] further detailed on UGI Gas Exhibit SAE-6(b)(1)

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for Customer/Contract Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] IS	[5] TOTAL
1	HTY Revenues (Unadjusted)	$ 43,933	$ 31,889	$ 2,081	$ 22,839	$ 100,742
2	HTY PGC Revenues	(1,148)	(1,071)	(88)	(661)	(2,968)
3	HTY Revenues net of PGC - Margin (Unadjusted)	$ 42,785	$ 30,819	$ 1,993	$ 22,177	$ 97,774
4	HTY Average Effective Customers (Unadjusted)	581	53	56	295	985
5	HTY Average Annual Margin Per Customer (L3 / L4)	$ 73.685	$ 578.729	$ 35.463	$ 75.099	$ 99.222
6	HTY Customers (Fully Adjusted)	589	55	57	287	988
7	Change in Customers during HTY (L6 - L4)	8	2	1	(8)	3
8	Annualization of Margin	$ 594	$ 1,494	$ 108	$ (756)	$ 1,439
9	Average Annual Revenue Per Customer (L1 / L4)	$ 75.662	$ 598.832	$ 37.035	$ 77.338	$ 102.235
10	Annualization of Total HTY Revenue	$ 594	$ 1,494	$ 108	$ (756)	$ 1,439
11	Annualization of HTY PGC Revenues (L10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total HTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for HTY Sales - MMCF	341	1,139	(88)	(467)	926

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other	[10] Total
1	HTY (Unadjusted) Use/Customer ("UPC") - MCF	15.60	82.90	76.80	199.40	314.70	1,177.60	668.80	5,443.70		
2	HTY UPC (Fully Adjusted) - MCF	16.30	88.50	82.90	191.20	340.00	1,273.10	711.40	6,978.00		
3	Change in UPC - MCF (L2 - L1)	0.70	5.60	6.10	(8.20)	25.30	95.50	42.60	1,534.30		
4	HTY Customers (Fully Adjusted)	24,549	498,946	77,145	3,316	45,954	707	18,690	1,367	988	671,662
5	Annualization Adjustment for Sales-MMCF (L3*L4)/1000 (District Weighted)	18	2,847	467	(27)	1,174	69	796	2,097	-	7,441
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	$ 175	$ 28,270	$ 2,191	$ (234)	$ 10,207	$ 604	$ 2,884	$ 6,013	$ -	$ 50,112
7	Total Unit Revenue Adjustment (L6/L5)	$ 9.9289	$ 9.9289	$ 4.6877	$ 8.7756	$ 8.6951	$ 8.7505	$ 3.6259	$ 2.8677	$ -	
8	Distribution Margin Adjustment (L5 *L9)	$ 73	$ 11,703	$ 1,922	$ (95)	$ 4,114	$ 246	$ 2,846	$ 5,800	$ -	$ 26,608
9	Distribution Unit Rate (Weighted Value by District)	$ 4.1104	$ 4.1104	$ 4.1104	$ 3.5839	$ 3.5045	$ 3.5592	$ 3.5772	$ 2.7663	$ -	
10	PGC Revenue (L5*L11)	$ 91	$ 14,601	$ -	$ (137)	$ 6,020	$ 354	$ -	$ -	$ -	$ 20,930
11	PGC Unit Rate	$ 5.1283	$ 5.1283		$ 5.1283	$ 5.1283	$ 5.1283				
12	EE&C Revenue Adjustment (L5*L13)	$ 3	$ 440	$ 72	$ 0	$ (3)	$ (0)	$ (2)	$ 128	$ -	$ 638
13	EE&C Unit Rate	$ 0.1547	$ 0.1547	$ 0.1547	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ 0.0609	$ -	
14	USP Revenue Adjustment (L5*L15)	$ 6	$ 1,015	$ 167	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,188
15	USP Unit Rate	$ 0.3565	$ 0.3565	$ 0.3565	$ -	$ -	$ -	$ -	$ -	$ -	
16	MFC Revenue/Margin Adjustment (L5*L17)	$ 2	$ 317	$ -	$ (0)	$ 17	$ 1	$ - 0	$ -	$ -	$ 336
17	MFC Unit Rate	$ 0.1113	$ 0.1113	$ -	$ 0.0144	$ 0.0144	$ 0.0144	$ -	$ -	$ -	
18	DSIC Revenue/Margin Adjustment (L8+L12+L14+L16)*L19	$ 1	$ 193	$ 31	$ (1)	$ 59	$ 4	$ 41	$ 85	$ -	$ 411
19	DSIC Unit Rate	$ 0.0143	$ 0.0143	$ 0.0143	$ 0.0143	$ 0.0143	$ 0.0143	$ 0.0143	$ 0.0143	$ -	
20	Total Margin Adjustment (L8+L16+L18)	$ 76	$ 12,213	$ 1,952	$ (97)	$ 4,190	$ 250	$ 2,886	$ 5,885	$ -	$ 27,356
21	Total Unit Margin Adjustment (L20/L5)	$ 4.2894	$ 4.2894	$ 4.1765	$ 3.6497	$ 3.5692	$ 3.6246	$ 3.6283	$ -	$ -	

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for PGC

	OCT 2020	NOV 2020	DEC 2020	JAN 2021	FEB 2021	MAR 2021	APR 2021	MAY 2021	JUN 2021	JUL 2021	AUG 2021	SEP 2021	TOTAL
PGC Rate HTY	$4.3631	$4.3631	$4.2426	$4.2426	$4.2426	$4.2426	$4.2426	$4.2426	$4.4594	$4.4594	$4.4594	$5.1283	
September HTY PGC Rate	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	
PGC Rate Variance	$0.7652	$0.7652	$0.8857	$0.8857	$0.8857	$0.8857	$0.8857	$0.8857	$0.6689	$0.6689	$0.6689	$0.0000	
Total PGC Volumes	2,541	6,005	9,124	11,357	10,641	7,357	4,123	2,278	1,080	1,099	1,089	1,036	57,732
PGC Revenue Adjustment	$1,944	$4,595	$8,081	$10,059	$9,425	$6,516	$3,652	$2,018	$723	$735	$729	$0	$48,477

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for MFC

	OCT 2020	NOV 2020	DEC 2020	JAN 2021	FEB 2021	MAR 2021	APR 2021	MAY 2021	JUN 2021	JUL 2021	AUG 2021	SEP 2021	TOTAL
PGC Rate HTY	$4.3631	$4.3631	$4.2426	$4.2426	$4.2426	$4.2426	$4.2426	$4.2426	$4.4594	$4.4594	$4.4594	$5.1283	
September HTY PGC Rate	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	
PGC Rate Variance	$0.7652	$0.7652	$0.8857	$0.8857	$0.8857	$0.8857	$0.8857	$0.8857	$0.6689	$0.6689	$0.6689	$0.0000	
Total PGC Volumes-Rate R	1,924	4,490	6,611	8,171	7,697	5,203	2,972	1,606	773	757	732	702	
Total PGC Volumes-Rate N	617	1,515	2,513	3,186	2,945	2,154	1,152	672	307	342	358	334	
Total PGC Volumes	2,541	6,005	9,124	11,357	10,641	7,357	4,123	2,278	1,080	1,099	1,089	1,036	57,732
Rate R %	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	
Rate N %	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	
MFC Rate R Adj Rate	$0.0166	$0.0166	$0.0192	$0.0192	$0.0192	$0.0192	$0.0192	$0.0192	$0.0145	$0.0145	$0.0145	$0.0000	
MFC Rate N Adj Rate	$0.0021	$0.0021	$0.0025	$0.0025	$0.0025	$0.0025	$0.0025	$0.0025	$0.0019	$0.0019	$0.0019	$0.0000	
Rate R Revenue Variance	$31.954	$74.562	$127.058	$157.039	$147.925	$99.994	$57.112	$30.872	$11.223	$10.992	$10.621	$0.000	
Rate N Revenue Variance	$1.321	$3.245	$6.233	$7.902	$7.303	$5.342	$2.856	$1.667	$0.575	$0.640	$0.670	$0.000	
Total Revenue Variance	$33	$78	$133	$165	$155	$105	$60	$33	$12	$12	$11	$0	$797

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for USP

	OCT 2020	NOV 2020	DEC 2020	JAN 2021	FEB 2021	MAR 2021	APR 2021	MAY 2021	JUN 2021	JUL 2021	AUG 2021	SEP 2021	TOTAL
USP Rate HTY	$0.2726	$0.2726	$0.2948	$0.2948	$0.2948	$0.2948	$0.2948	$0.2948	$0.3171	$0.3171	$0.3171	$0.3565	
September HTY USP Rate	$0.3565	$0.3565	$0.3565	$0.3565	$0.3565	$0.3565	$0.3565	$0.3565	$0.3565	$0.3565	$0.3565	$0.3565	
USP Rate Variance	$0.0839	$0.0839	$0.0617	$0.0617	$0.0617	$0.0617	$0.0617	$0.0617	$0.0394	$0.0394	$0.0394	$0.0000	
Total Rate R Volumes	2,205	5,166	7,616	9,415	8,875	5,970	3,400	1,834	889	868	841	806	47,884
Total Rate R excl CAP Volumes	2,083	4,895	7,218	8,923	8,411	5,657	3,221	1,737	842	823	797	764	45,370
USP Rate Revenue Variance	$175	$411	$445	$551	$519	$349	$199	$107	$33	$32	$31	$0	$2,852
Total Revenue Variance	$175	$411	$445	$551	$519	$349	$199	$107	$33	$32	$31	$0	$2,852

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for GPC

	OCT 2020	NOV 2020	DEC 2020	JAN 2021	FEB 2021	MAR 2021	APR 2021	MAY 2021	JUN 2021	JUL 2021	AUG 2021	SEP 2021	TOTAL
GPC Rate HTY	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	
Volume Variance to HTY	174	418	640	797	747	515	286	160	71	73	73	69	4,022
Revenue Variance	$12	$28	$42	$53	$49	$34	$19	$11	$5	$5	$5	$5	$265

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MMCF)	(175)
$/MCF	$6.00
Excess Take Revenue/Margin	($1,047)

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for EEC Rider

	OCT 2020	NOV 2020	DEC 2020	JAN 2021	FEB 2021	MAR 2021	APR 2021	MAY 2021	JUN 2021	JUL 2021	AUG 2021	SEP 2021	TOTAL
Original HTY R/RT Rate	$0.2245	$0.2245	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	
September HTY R/RT Rate	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	
R/RT Rate Variance	($0.0698)	($0.0698)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
R/RT Rate Volumes	2,205	5,166	7,616	9,415	8,875	5,970	3,400	1,834	889	869	841	806	47,886
R/RT Revenue Adjustment	($154)	($361)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($514)
Original HTY N/NT Rate	$0.0425	$0.0425	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	
September HTY N/NT Rate	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	
N/NT Rate Variance	($0.0449)	($0.0449)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
N/NT Rate Volumes	1,259	2,736	4,288	5,440	5,070	3,604	2,067	1,253	661	723	764	743	28,608
N/NT Revenue Adjustment	($57)	($123)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($179)
Original HTY DS Rate	$0.0004	$0.0004	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	
September HTY DS Rate	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	
DS Rate Variance	$0.0605	$0.0605	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
DS Rate Volumes	667	832	1,355	1,498	1,366	1,064	646	422	279	274	266	314	8,983
DS Revenue Adjustment	$40	$50	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$91
Original HTY LFD Rate	$0.0103	$0.0103	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	
September HTY LFD Rate	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	
LFD Rate Variance	$0.0081	$0.0081	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
LFD Rate Volumes	1,685	1,874	2,341	2,574	2,411	2,253	1,864	1,636	1,469	1,408	1,483	1,519	22,516
LFD Revenue Adjustment	$14	$15	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$29
Total Revenue Adjustment	($156)	($418)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($574)

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for Get Gas Surcharge

	Rate R Residential Htg	Rate N Commercial Htg	Total
HTY Revenue	$98	$2	$100
HTY Annualized Revenue	$110	$2	$113
Get Gas Revenue Adjustment	$12	$1	$13

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for GDE Rider

	OCT 2020	NOV 2020	DEC 2020	JAN 2021	FEB 2021	MAR 2021	APR 2021	MAY 2021	JUN 2021	JUL 2021	AUG 2021	SEP 2021	TOTAL
Original HTY DS Rate	$0.0117	$0.0117	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	
September HTY DS Rate	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	
DS Rate Variance	($0.0061)	($0.0061)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
DS Rate Volumes	667	832	1,355	1,498	1,366	1,064	646	422	279	274	266	314	8,983
DS Revenue Adjustment	($4)	($5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)
Original HTY LFD Rate	$0.0117	$0.0117	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	
September HTY LFD Rate	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	
LFD Rate Variance	($0.0061)	($0.0061)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
LFD Rate Volumes	1,685	1,874	2,341	2,574	2,411	2,253	1,864	1,636	1,469	1,408	1,483	1,519	22,516
LFD Revenue Adjustment	($10)	($11)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($22)
Total Revenue Adjustment	($14)	($17)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($31)

UGI GAS

EXHIBIT SAE-7(a) – (c)

Detail for Usage per Customer for FPFTY by Class as shown on UGI Gas Exhibit SAE-4(c)

Residential Non-Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	16.4	26,531	435,108
Rate R	16.3	22,732	370,905
Rate RT	16.9	3,799	64,203

Residential Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	87.8	589,601	51,766,968
Rate R	88.0	513,121	45,174,392
Rate RT	86.2	76,480	6,592,576
Rate RT Total	82.9	80,279	6,656,779

Commercial Non-Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	328.1	4,734	1,553,225
Rate N	215.1	3,295	708,677
Rate NT	492.0	1,415	696,180
Rate DS	6,182.0	24	148,368

Commercial Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	542.9	65,470	35,543,663
Rate N	346.0	47,558	16,455,725
Rate NT	689.5	16,746	11,546,367
Rate DS	6,467.9	1,166	7,541,571
Rate Commercial NT Total	674.1	18,161	12,242,547

Industrial

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	2,796.5	1,313	3,671,805
Rate N	1,109.5	655	726,725
Rate NT	2,242.6	456	1,022,626
Rate DS	9,517.1	202	1,922,454
Rate NT Total	712.5	18,617	13,265,173
Rate DS Total	6,905.5	1,392	9,612,394

Detail for Usage per Customer for FTY by Class as shown on UGI Gas Exhibit SAE-5(c)

Residential Non-Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	16.4	27,362	448,737
Rate R	16.3	23,563	384,534
Rate RT	16.9	3,799	64,203

Residential Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	88.0	581,203	51,145,864
Rate R	88.3	504,723	44,553,288
Rate RT	86.2	76,480	6,592,576

Rate RT Total	82.9	80,279	6,656,779

Commercial Non-Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	328.1	4,736	1,553,882
Rate N	215.1	3,297	709,334
Rate NT	492.0	1,415	696,180
Rate DS	6,182.0	24	148,368

Commercial Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	542.9	64,891	35,229,324
Rate N	343.6	46,979	16,142,435
Rate NT	689.5	16,746	11,546,367
Rate DS	6,467.0	1,166	7,540,522

Rate Commercial NT Total	674.1	18,161	12,242,547

Industrial

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	2,796.5	1,316	3,680,194
Rate N	1,116.7	658	734,811
Rate NT	2,242.6	456	1,022,626
Rate DS	9,518.6	202	1,922,757

Rate NT Total	712.5	18,617	13,265,173
Rate DS Total	6,904.9	1,392	9,611,647

Detail for Usage per Customer for HTY by Class as shown on UGI Gas Exhibit SAE-6(c)

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	16.4	28,152	461,693
Rate R	16.3	24,512	400,177
Rate RT	16.9	3,640	61,516

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	88.2	572,451	50,490,178
Rate R	88.5	498,946	44,154,047
Rate RT	86.2	73,505	6,336,131
Rate RT Total	82.9	77,145	6,397,647

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	328.1	4,723	1,549,616
Rate N	191.2	3,303	631,375
Rate NT	492.0	1,393	685,356
Rate DS	8,625.4	27	232,886

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	542.9	63,970	34,729,313
Rate N	340.0	45,954	15,625,797
Rate NT	689.5	16,856	11,622,212
Rate DS	6,449.4	1,160	7,481,304
Rate Commercial NT Total	674.4	18,249	12,307,568

Industrial

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	2,796.5	1,328	3,713,752
Rate N	1,273.1	707	900,069
Rate NT	2,242.6	441	988,987
Rate DS	10,137.2	180	1,824,696
Rate NT Total	711.4	18,690	13,296,555
Rate DS Total	6,978.0	1,367	9,538,886

UGI GAS

EXHIBIT SAE-8

UGI Utilities, Inc. - Gas Division
No Notice Service (NNS) Rate Calculation

Notes:

1/ Storage Trip Cost ($/mcf) 0.1330

2/ Weekend Load Reduction Factor (%) 15.0%

WELF = Weekend Load Reduction Factor
WD = Weekday Day Use
WE = Weekend Day Use
AVERAGE = Average Daily Use

3/ EQ #1 **WD = (1/(1 - WELF)) * WE**
= (1/(1 - 0.15)) * WE
WD = 1.18 * WE

EQ #2 **AVERAGE = [(5 * WD) + (2 * WE)] / 7**
Step 1 AVERAGE = [5 * ((1/ (1 - WELF)) * WE)) + (2 * WE)] / 7
= [5 * (1/(1 - WELF)) + 2] * WE] / 7
= [5 * (1/(1 - 0.15)) + 2] * WE] / 7
7.90 * WE / 7
Step 2 WE = 0.89 * AVERAGE

4/ EQ #3 **Wkly Imbalance = 5 x (WD - AVERAGE) + 2 (AVERAGE - WE)**
= (5 * WD) - (3 * AVERAGE) - (2 * WE)
= (5 * (1/(1-WELF) * WE) - (3 * AVERAGE) - (2 * WE)
= [(5 * (1/(1-WELF)) - 2) * WE] - (3 * AVERAGE)
= [(5 * (1/(1-0.15)) - 2) * WE] - (3 * AVERAGE)
3.90 * WE - (3 * AVERAGE)
0.47 * AVERAGE

EQ #4 **Unit Cost Calculation ($/mcf)**
= [(Wkly Imbalance) / (7 * AVERAGE)] * STORAGE TRIP COST
= [(0.47 x Average) / (7 x AVERAGE)] x 0.133
0.07 x 0.133
0.0093

EQ #5 **Per Unit of Demand Calculation ($/mcf per month)**
= Unit Cost Demand x 20 days
= 0.0093 x 20
0.1860

Notes:

1/ Weighted average of storage trip costs based on SCQ of storages
2/ Aggregate load reduction for all non-Choice transportation customers electing NNS
Weekend Load Reduction factor percentage based on historical data for the period Nov 2020 through Oct 2021
3/ Assumes WD use approximately equal for all weekdays (work week)
Assumes WE use approximately equal for all weekend days
4/ Assumes levelized deliveries on all days

UGI GAS

EXHIBIT SAE-9

UGI Utilities, Inc. - Gas Division
Monthly Balancing Service (MBS) Rate Calculation

Notes:

1/	Average Capacity Charge for Storage ($/mcf)	1.2920	(A)
2/	Anticipated Average Monthly Imbalance %	2.5737%	(B)
3/	Load Factors & MBS Rate Calculation		

Rate	Load Factor	
DS	27.2%	(C)
LFD	56.1%	(C)
XD Firm	63.1%	(C)
Transportation System Average	55.4%	(D)

MBS Rate Formula
E = [(A / D) - ((A / D) * C)] * B

Rate	MBS Rate ($/mcf)	
DS	0.0437	(E)
LFD	0.0263	(E)
XD Firm	0.0221	(E)

1/ Weighted average of storage capacity and demand costs based on SCQ of storages
2/ Average monthly imbalance percentage includes all non-Choice transportation customers electing MBS
Average monthly imbalance percentage based on historical data for the period Nov 2020 through Oct 2021
3/ Load Factors based on FPFTY throughput and peak capacity for applicable customers by rate class

UGI GAS

EXHIBIT SAE-10

UGI Utilities, Inc. - Gas Division
Merchant Function Charge (MFC) Calculation

		Rate R/RT	Rate N/NT
Total Uncollectible Revenue Requirement	$ 17,957,980		
Allocator 1/		92.51%	6.47%
Uncollectible Revenue Requirement		$ 16,612,927	$ 1,161,881
Total Proposed Revenue		$ 730,289,390	$ 265,365,525
MFC % 2/		2.27%	0.44%

1/ The allocator is based on a 3-year average of uncollectible expenses.
2/ The MFC will be applied to bills of customers in Rate Schedules R & N only.

UGI GAS STATEMENT NO. 9

TIMOTHY J. ANGSTADT

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3030218

UGI Utilities, Inc. - Gas Division

Statement No. 9

Direct Testimony of
Timothy J. Angstadt

Topics Addressed:	**System Operations**
	Operational Response to COVID-19
	System Reliability
	Leak Reductions & Emergency Response
	Employee Additions
	Safety Initiatives
	Environmental Remediation & Programs

Dated: January 28, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Timothy J. Angstadt. My current business address is 1 UGI Drive, Denver, Pennsylvania 17517.

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

A. I am employed as the Vice President of Operations by UGI Utilities, Inc. ("UGI"). UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two (2) operating divisions, the Gas Division ("UGI Gas" or the "Company) and the Electric Division ("UGI Electric"), 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 TJA-1 to my testimony.

Q. What are your responsibilities as Vice President of Operations?

A. As Vice President – Operations, I am UGI's senior executive accountable for over 850 individuals including management, engineering, clerical, and field technicians to operate and maintain the Company's transmission and distribution systems. I am also responsible for overseeing activities and personnel involved with the Company's integrity programs (e.g., leak survey, corrosion control, Geographic Information System ("GIS") mapping, network analysis, safety, Distribution Integrity Management Program ("DIMP"), Transmission Integrity Management Program ("TIMP"), and technical training).

Additionally, I am an executive sponsor of UGI's Safety Culture Initiative and oversee accelerated infrastructure replacement initiatives, customer growth opportunities, capacity constraint improvements, and major installation projects.

Q. Have you presented testimony in proceedings before the Commission?

A. Yes. UGI Gas Exhibit TJA-1 identifies my prior testimony.

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 following topics: (1) natural gas system operations; (2) response to the COVID-19 Pandemic; (3) system safety and reliability; (4) leak reductions and emergency response; (5) employee additions; and (6) safety initiatives and environmental remediation.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. Please see UGI Gas Exhibit TJA-1.

II. NATURAL GAS SYSTEM OPERATIONS

Q. Please provide an overview of the Company's distribution system.

A. UGI Gas provides service to approximately 672,000 residential, commercial, and industrial customers located in forty-five (45) of Pennsylvania's sixty-seven (67) counties and spanning more than 700 municipalities. As of December 31, 2021, the Company operates more than 12,000 miles of gas distribution mains and 300 miles of natural gas transmission mains in the Commonwealth of Pennsylvania.

Q. Please describe UGI Gas's operations centers and support facilities.

A. UGI Gas has operations centers and support facilities throughout its service territory. Additionally, a stand-alone centralized training facility in Reading includes a "safety town" for real-life outdoor training inclusive of leak pinpointing and investigation, a separate welding and tapping center, a safety lab, a service lab, a measurement and regulation lab, and a computer lab. Classrooms and laboratories provide four primary training deliverables: (1) safety; (2) construction and maintenance; (3) measurement and regulation; and (4) utility service.

Q. How does UGI Gas staff its operations?

A. UGI Gas relies upon a mix of employees and contractor resources for its capital, operations, and maintenance programs in order to accomplish many of its initiatives, including gas main and service replacement and installation, mechanical tee remediation, mercury regulator removal, roadway and landscape restoration, leak repairs, meter reading, and general system operation and maintenance. Further, UGI Gas's parent company, UGI Corp., provides management, administrative and support services (*e.g.*, executive management, human resources, legal, finance, accounting, procurement, treasury, IT, and corporate governance).

III. COVID-19 OPERATIONAL IMPACTS AND UGI GAS'S RESPONSE

Q. Please describe the operational impacts of the COVID-19 Pandemic on UGI Gas's operations and the Company's response to those challenges.

A. The Company's experience responding to the COVID-19 Pandemic, and specifically the programs and policies it adopted to assist customers, is detailed in the testimony of

Christopher R. Brown (UGI Gas Statement No. 1). From an operational perspective, COVID-19 impacted the Company's approach to project planning, including the availability of personnel to complete fieldwork. The economic impacts resulting from COVD-19 increased costs, presented challenges in securing necessary supplies, and created issues in the labor market that UGI Gas must respond to in order to maintain its workforce.

Specifically, UGI Gas stopped all non-emergency work that required personnel to be outside their homes for a six-week period beginning in mid-March 2020 and ending on May 4, 2020. The Company then began a ramp up process to restart its construction program, focusing on work that did not involve customer contact. During this ramp up period, the Company initiated Measurement and Regulation ("M&R") station work, as well as direct bury main replacements. By June 2020, and in reliance on the Governor's return to work plan, UGI Gas began to conduct planned customer contact work in areas that had progressed to and maintained a "yellow status" for at least a two-week period. This allowed the Company to undertake certain main insert projects, which resulted in planned customer outages that required relights. UGI Gas also began conducting service renewals during his period. By mid-July 2020, the Company resumed high customer contact activities throughout the service territory.

Q. How has COVID-19 impacted the availability of personnel?

A. Throughout the Pandemic, COVID-19 significantly impacted the availability of personnel and caused project delays. UGI Gas also experienced employee and contractor absences due to illness or quarantine. The result of active COVID-19 cases and contact tracing made staffing challenges a regular factor in the Company's efforts to cover normal operational needs and keep construction projects moving. While COVID-19 impacts persist today, the Company is anticipating that such impacts will be minimal to ongoing operations on a going forward basis.

Another significant and lasting impact resulted from the temporary curtailment in hiring for the Capital Project Management and Capital Construction teams.[1] These new teams were designed to improve UGI Gas's ability to undertake replacement and betterment projects on a more efficient and expeditious basis, which was validated by an independent third-party study. The director roles for the new teams were hired just before the Pandemic began. However, UGI Gas temporarily halted its efforts to staff those teams when the Pandemic started. While the Company began the process of planning for and filling those roles in April 2020, securing candidates was challenging, due to the extremely competitive construction market. In 2021, candidates with flexible skills – particularly those in project management – were in high demand across many industries, including public utilities. Therefore, it has taken longer than initially anticipated to staff the new teams. While staffing challenges persist, the Company continues to make progress on this front, including the expanded use of outside support to meet its needs.

[1] From mid-March 2020 through the end of April 2020, the Company temporarily initiated a new employee hiring freeze until the impacts of COVID-19 on the Company's operations for the remainder of 2020 were clear. This temporary hiring freeze prevented the Company from reaching the headcount level projected by the end of the FY2021.

Q. Has UGI Gas experienced any other COVID-19 impacts that altered its normal project planning process?

A. Yes. The Company experienced delays in obtaining permits and state and local approvals that are needed prior to construction. Some local government offices remained closed after UGI Gas restarted its construction programs. Further, as a result of the need to avoid projects where the Company would be in close proximity to customers, Engineering and Operations modified their planned projects, which also created delays. For instance, some projects that were originally designed (and in some cases permitted) as insert main projects were redesigned as direct bury main replacement projects, which delayed service renewals and tie-overs. Although these actions allowed prioritized work to occur, they still impacted the pace of project completions. These Pandemic-related permit challenges have largely been minimized or eliminated in recent months.

In addition, as work resumed that involved customer contact, the Company addressed a backlog of service renewals, meter relocations, and service tie-overs (associated with work completed during the period that did not involve customer contact). There was also a modest delay of regulatory compliance work that was addressed upon restart of customer contact work streams. The Company addressed this backlog and is now maintaining a pace of ongoing projects commensurate with the Company's pre-COVID-19 work. Finally, the Company experienced and continues to experience supply chain challenges. For example, procurement lead times are much longer for many of the components required for natural gas system maintenance and construction, including pipe, tap fittings, valves, regulator station heaters, and regulator station components. Many of these supply procurement delays surfaced while projects were underway, delaying plant in service timing, extending project spend into additional fiscal periods, and adding resource demobilization and remobilization challenges. While supply chain issues continue to linger in part, the Company has adjusted its procurement activities to help minimize associated impacts.

Q. What actions has UGI Gas taken to reduce its vulnerability to prospective Pandemic-related impacts?

A. The Company has undertaken a number of steps based on its recent experiences responding to the rapidly changing operational landscape created by COVID-19. One important initiative was to diversify its supplier and contractor lists. UGI Gas has actively sought out new parties and new contractors to expand its bidder list for future projects. Doing so will improve the Company's resiliency by providing it with a wider pool of resources. Pandemic-mitigating employee policies, field procedure changes, and expanded inventories of pandemic-related personal protective equipment have positioned UGI Gas to continue typical operations and construction activities through anticipated public health challenges associated with the ongoing Pandemic.

IV. <u>SYSTEM RELIABILITY AND SAFETY</u>

Q. Please describe the physical composition of UGI Gas's distribution system.

A. Due to its long-term operation, the Company's distribution system includes a mixture of pipeline materials indicative of the industry's technological advancement over time. Cast iron mains can be found in the oldest parts of the system. The industry then transitioned to bare steel and wrought iron piping, which were prevalent until the 1960s. The first generation of plastic piping was introduced in the early 1970s. Materials installed since the 1970s include polyethylene ("PE") and coated steel piping. Overall, approximately ninety percent (90%) of UGI Gas's distribution mains consist of contemporary materials, which UGI Gas defines as cathodically-protected steel and plastic. UGI Gas's natural gas distribution system has the highest percentage of contemporary mains among major natural gas distribution companies in Pennsylvania.

Q. Please discuss the Company's action to improve and enhance its distribution system.

A. UGI Gas has been identifying and repairing, improving, or replacing its distribution infrastructure on an accelerated basis through Commission-approved Long Term Infrastructure Improvement Plans ("LTIIP"). The Company's Initial LTIIP[2] and Second LTIIP[3] have resulted in UGI Gas successfully removing more than 463 miles of main over the seven (7) year period from 2014 to 2020, including sixty-six percent (66%) of its total cast iron mains and twenty-two percent (22%) of its total bare steel/wrought iron mains. As of December 31, 2021, the Company has removed an additional seventy-six (76) miles of main. Accordingly, UGI Gas has removed a total of seventy-two percent (72%) of its cast iron mains and twenty-six percent (26%) of its total bare steel/wrought iron mains from the system.

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[2] On December 12, 2013, each of UGI Gas's three predecessor natural gas distribution companies filed Petitions, and received Commission approval, for LTIIPs at Docket Nos. P-2013-2398833, P-2013-2397056, and P-2013-2398835 (collectively referred to as the "Initial LTIIP"). In the Initial LTIIP, the Company identified its plan to replace all of its cast iron main over the 13-year period ending in February 2027 and all of its bare steel and wrought iron main over the 28-year period ending September 2041. The Initial LTIIP period ended on December 31, 2019.

[3] *See Petition of UGI Utilities, Inc. – Gas Division for Approval of its Second Long Term Infrastructure Improvement Plan*, Docket No. P-2019-3012337 (Petition filed on August 21, 2019) (the "Second LTIIP"). The Second LTIIP builds off of the significant acceleration in the rate of infrastructure repairs, improvements and replacements (including the accelerated replacement of cast iron and bare steel pipe) that was achieved by the Initial LTIIP and reflects even further acceleration.

UGI Gas will continue to invest in strengthening and modernizing its distribution facilities serving customers throughout the Company's service territory. This includes the replacement of another 210 total miles of cast iron, bare steel, and wrought iron main during the remaining years of the Second LTIIP. In addition to main replacements in the Second LTIIP, the Company has pursued other infrastructure initiatives through the Second LTIIP, including replacing service lines, meter sets, valves, farm taps, as well as addressing safety concerns relating to measurement and regulation facilities (e.g., making improvements to over-pressure protection equipment) and mechanical tees. These initiatives will make UGI Gas's system safer, more reliable, and easier to operate. Continuing UGI Gas's infrastructure replacement program will allow the Company to provide safe and reliable service both now and into the future.

Q. How does UGI Gas prioritize its pipeline replacement projects?

A. In 2019, UGI Gas began using the Data-Driven Risk Model ("DDRM"). The DDRM is a quantitative model incorporating leak repair data, incident data, and asset population data to calculate a risk index score for facility groupings referred to as Asset Threat Groups ("ATGs"). The Subject Matter Expert ("SME") driven Risk Model is still utilized to supplement risk evaluation to the DDRM and validates DDRM results by incorporating SME input. Optimain also continues to be utilized as a tool to evaluate risk on an individualized segment level and validates DDRM outputs for cast iron and steel mains.

The DDRM provides a quantitative basis for evaluating risk and creates a more stable foundation for comparing year-over-year changes, because of the consistent quantitative underpinning it utilizes. This quantitative underpinning largely resolves the effect of bias toward more recent events (often expressed by qualitative SME models, which tend to weight more heavily recent issues and concerns). Finally, the use of the DDRM helps UGI Gas better evaluate other effective approaches for addressing risk, including effective operations and maintenance programs, additional leak survey activities and damage prevention measures.

Q. What are the Company's current goals for main replacement?

A. UGI Gas is on track to replace all of its cast iron main no later than February 2027. Further, the Company plans to complete its bare steel and wrought iron main replacement no later than September 2041. Given the Company's accelerated pace of bare steel replacement reflected in the Second LTIIP, and continued into the future with necessary regulatory approvals, the Company currently is on pace to replace all bare steel mains a few years early, or by 2038.[4] Specifically, in order to achieve these objectives, the Company's Second LTIIP established the objective of replacing sixty-eight (68) miles of main in calendar year 2021, and seventy (70) miles of main in calendar years 2022 through 2024.

Q. Did UGI Gas achieve its mileage objective in 2021?

A. Yes, the Company achieved and exceeded its mileage objective, by replacing or retiring over seventy-six (76) miles of main in 2021.

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[4] For any given intermediate period, the sequence of projects and the amount of specific facilities to be addressed may be adjusted in response to changing conditions. A variety of factors intrinsic to the natural gas distribution business may cause these changes to occur. These factors include, but are not limited to, state and municipal relocation projects, other private construction projects, system upgrades due to pressure requirements, regulatory changes, and legislative changes.

Q. What is UGI Gas's projection of its replacement and betterment plant in service for the future test year ("FTY") and the fully projected future test year ("FPFTY")?

A. For Fiscal Year ("FY") 2022, the replacement and betterment budget reflects $281.4 million plant in service. FY 2023 plant placed in service for replacement and betterment is budgeted to be $305.8 million. For more detail on the Company's budgeting process, please refer to the direct testimony of Vicky A. Schappell (UGI Gas Statement No. 5).

Q. What is the Company's basis for showing a further increase in plant placed in service in the FTY and FPFTY?

A. Foremost, the Company's annual plant additions over the period 2017-2021 have increased nearly $85 million over the time period, from $296 million in 2017 to $381 million in 2021. The Company anticipates that the cost of its replacement and betterment work will continue to increase through the FPFTY due to a number of different elements. First, the Company is further accelerating the number of miles it will accomplish in the FTY and FPFTY. In addition, these miles of main include large portions of the remaining cast iron main replacement projects, which must be completed by 2027, and are comprised of projects featuring increased complexity, challenging locations, and larger diameter pipes. For these reasons, UGI Gas's budget for the FTY and the FPFTY reflects increased plant additions beyond that amount that the Company had accomplished during the HTY.

Q. What other system reliability improvements has the Company performed recently?

A. In addition to pipeline replacement, the Company's Second LTIIP includes several projects related to natural gas system over pressure protection ("OPP"). Following recent overpressurization guidance issued by the National Transportation Safety Board ("NTSB") in 2019, UGI Gas evaluated the OPP utilized on its low-pressure systems. A total of seventy-three (73) regulator stations serving over 80,000 customers required supplemental OPP to comply with the NTSB's recommendations on OPP. UGI Gas implemented a plan to address supplemental OPP at all seventy-three (73) stations by the end of FY2023. As of September 30, 2021, forty-three (43) of the seventy-three (73) stations have been addressed through the installation of supplemental OPP, station abandonment, or station replacement. These projects were prioritized on a risk reduction basis seeking to maximize the customers served by NTSB-compliant systems meeting the NTSB recommendations. In this regard, over 71,000 of the 80,000 customers within the program are served by NTSB-recommended regulator stations as of September 30, 2021.

Concurrently, UGI Gas also implemented a plan to add remote pressure monitoring capabilities to its low-pressure systems. These capabilities include real-time alarm notifications to allow expedited system pressure correction and adjustment. As of September 30, 2021, remote pressure monitoring was deployed extensively with nearly 95% of all customers served by low-pressure systems having remote pressure monitoring capabilities. 100% customer coverage is planned in FY2022 on UGI Gas's low-pressure systems.

V. <u>LEAK REDUCTIONS AND EMERGENCY RESPONSE</u>

Q. Please discuss UGI Gas's efforts to reduce system leaks.

A. UGI Gas monitors safety and reliability indicators for its natural gas distribution system over time to evaluate corrosion and leak resolution performance, track emergency response, and pursue damage prevention – all of which will drive improvements in employee and public safety. As a part of its DIMP,[5] UGI Gas regularly re-assesses system risks and leak trends to determine if additional or accelerated actions are required to further reduce system leaks.

Leak surveys are an important tool for discovering, monitoring, and remediating leaks. To enhance its leak identification capabilities, UGI Gas initiated a "Mobile Guard" pilot program in June 2021. Pursuant to the pilot, the Company is testing the use of mobile gas leak detection equipment. The leak detection equipment is attached to a Company vehicle and can detect, map, and quantify methane emissions while driving up to 55 miles per hour. The equipment is being used to discover leaks on mains and adjacent service lines. This technology is a more efficient method that may be used to identify methane and ethane emission sources over a greater number of miles than traditional survey methods.

Additionally, the main replacement and modernization work identified by UGI Gas will provide customers with significant improvements in safety and reliability (*e.g.*, reduced leaks). The Company's replacement plans have been identified and prioritized on a risk basis in accordance with UGI Gas's DIMP and TIMP plans.[6] Risk-based prioritization helps ensure that the projects that deliver the most significant risk reductions are addressed first. As the investment plan progresses, customer benefits will manifest over time in terms of reduced leakage rates, fewer main breaks, and fewer unplanned customer interruptions. Furthermore, UGI Gas expects that the amount of lost and unaccounted for gas due to system leakage and measurement inaccuracy will be reduced as leaks are eliminated and meters are replaced.

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[5] 49 C.F.R. § 192.1007.

[6] 49 C.F.R. §§ 195.450 and 195.452.

Q. How does UGI Gas classify leaks?

A. UGI Gas uses a standardized leak classification system consistent with general industry protocols. Specifically, underground leaks are classified as 'A,' 'B,' and 'C.' Class 'C' leaks are deemed hazardous and repaired immediately. Class 'B' leaks may become hazardous if otherwise not repaired, and they are scheduled for repairs within twelve (12) months and not to exceed fifteen (15) months. Class 'A' leaks are deemed non-hazardous and are monitored for changes in severity.

Q. How have UGI Gas's system leaks improved since 2016?

A. UGI Gas has seen a significant reduction in the number of leaks found on its system. This is directly attributable to its prioritization and aggressive replacement of leak-prone mains, services, and other assets. As Table 1 below demonstrates, since 2016, C Leak repairs have decreased by 27.2%, B Leak inventories have decreased by 52.5%, and A Leak inventories have decreased by 21.3%.

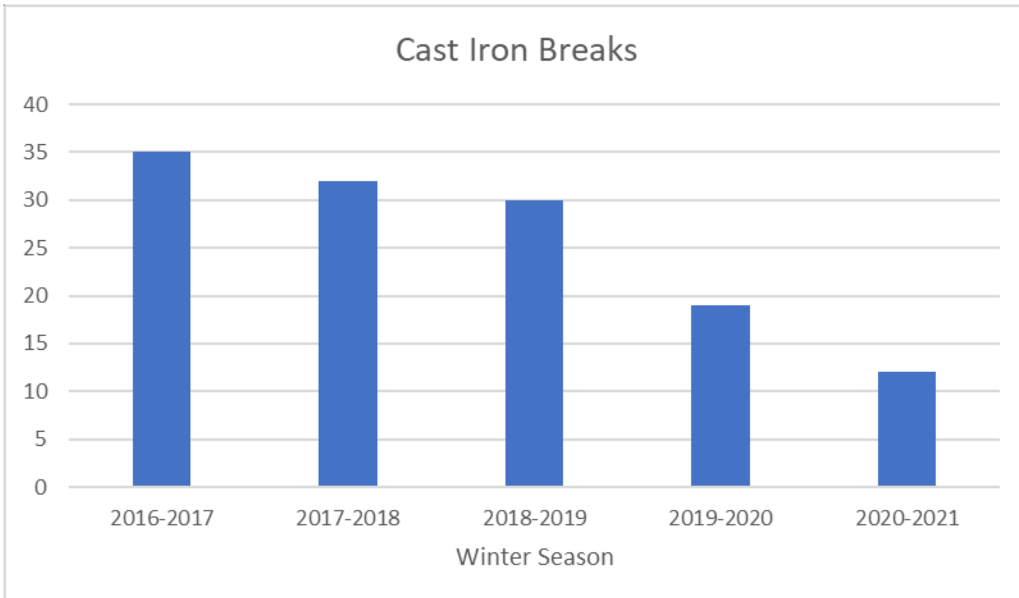
Table 1. Leak Inventories & Repairs

	Calendar Year 2016	Calendar Year 2021	Percent Change
C Leak Repairs	1,496	1,089	27.2% decrease
B Leak Inventory	556	264	52.5% decrease
A Leak Inventory	4,930	3,882	21.3% decrease

Figure 1 below shows the reduction in the number of cast iron breaks each winter season since the 2016-2017 season. There has been an overall sixty-six percent (66%)

reduction in break frequency since the 2016-2017 season. The reduction helps demonstrate effectiveness of cast iron replacement activities.

Figure 1. Cast Iron Main Breaks (2016-2021)



Q. How is UGI Gas's performance in the area of emergency response rate?

A. UGI Gas performs very well in the timely response to emergency notifications/calls. For the Fiscal Year ended September 30, 2021, 98.4% of the time, a first responder arrived on the premises within forty-five (45) minutes of receipt of an emergency call. UGI Gas utilizes a combination of shift coverage and on-call schedules to leverage internal field and supervisory resources to provide emergency response coverage 24-hours per day, 365 days per year. I also note that UGI Gas sets performance goals on a forty-five (45) minute response, which is more stringent than the acceptable odor response time as defined by the

Commission's Safety Division.[7] Moreover, for FY2021, 99.8% of the time a UGI Gas first responder arrived onsite within one hour of the emergency call. This compares favorably to the industry average.

VI. EMPLOYEE ADDITIONS

Q. Does the Company's budget include additional employees for operational purposes in this case?

A. Yes, the Company's budget reflects an increase of twenty-three (23) operations employees. Fifteen (15) of these positions will be added in 2022 and eight (8) will be added in 2023. In addition to these budgeted positions, the Company is preparing to add twenty (20) more employees in 2023 to address staffing needs analysis updates that were completed after the budget process.

Q. What is the driver for these additional staffing needs?

A. The Company faces two significant employee challenges: forecasted retirements and attrition of newer employees. These challenges require an aggressive and multifaceted approach so the Company can continue to accomplish fieldwork critical to safety and reliability, including meeting planned replacement goals pursuant to the Company's LTIIP.

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[7] The Commission's Bureau of Audits issued a Management and Operations Audit Report of the Company in October 2019 (at Docket Nos. D-2018-3002234, D-2018-3002235 and D-2018-3002236), which stated:

> The PUC Gas Safety Division defines acceptable emergency dispatch and response times as 15 minutes and 60 minutes, respectively. However, UGI has established a more stringent 45-minute emergency response key performance indicator of 97.8%. (Audit Report, p. 41).

Q. Please identify the types of employees that are considered operational employees.

A. Operational employees encompass several roles including gas mechanics/field technicians, equipment operators, laborers, meter readers, and contractor inspectors, as well as clerical, supervisory, and leadership staff to support these roles. The majority of UGI's operational employees are union employees who directly perform, or inspect contractors who perform, operation, maintenance, construction, or replacement activities. Most operational employees also perform emergency response activities both during and after business hours. Typically, union employees are hired into apprentice programs as specified in the applicable collective bargaining agreement. Though UGI Gas provides formal and on the job training to new hires, it takes a number of years before these employees can progress to general gas mechanic functions, including emergency response, facility locating and markouts, and leak repair. Employees may then progress to more advanced functions, including contractor inspection or supervisory roles.

Q. Please describe the challenge stemming from forecasted retirements.

A. UGI Gas actively monitors and plans for the anticipated retirement of many experienced utility workers. Table 2 shows the anticipated number of operational employees that are or will be eligible for retirement over the five-year period from FY2022 through FY2026. Of the twenty-eight (28) employees listed for FY2022, twenty-one (21) employees reached retirement age prior to September 30, 2021, but have not retired as of the beginning of FY2022.

Table 2. UGI Gas Operations Employees Aged 65 or Older Per Year

	FY22	FY23	FY24	FY25	FY26
Retirement Count	28	10	12	17	24
Average Tenure (years)	38.0	33.4	36.8	28.9	28.6

On a collective basis, these employees represent decades of operational experience. The Company seeks to increase its total number of operational employees in order to provide an opportunity for both formal training and the on-the-job learning, which normally takes place over time and is necessary to ensure the continuity of the workforce. This is particularly critical for employees who can conduct quality and safety inspections. It takes five (5) years on the job for an employee to become fully qualified to perform gas operations tasks, including contractor inspection work, general tapping and stopping, plastic pipe fusing, regulator station maintenance and troubleshooting, emergency first response on call, and internal crew leadership.

Q. What additional needs are related to employee resource requirements in support of the Company's replacement activities?

A. UGI Gas relies on contractor resources to perform most of its replacement and betterment activity. This limits the overall staffing and equipment UGI Gas is required to maintain, while providing cost effective resource scalability and geographical flexibility not easily achieved with internal resources. UGI Gas utilizes internal resources to coordinate and inspect contractor work performance to ensure quality construction, confirm procedural compliance, and validate contractor payments. These experienced employees are critical to UGI Gas's continued ability to complete projects in a safe, reliable, and fiscally responsible manner. Expanding the number of employees who can conduct capital-related activities will ensure that as the Company's capital activities accelerate, UGI Gas will be able to safely complete its additional infrastructure replacement projects on time in order to achieve its goals of removing all cast iron main from its system by 2027 and all bare steel and wrought iron main by 2041.

Q. What are the challenges posed by the attrition of newer employees?

A. UGI Gas has seen significant turnover of apprentice level employees who remain at the Company for less than five (5) years. Over the last five (5) years, UGI Gas has seen the voluntary departure of one hundred (100) employees with five (5) years of experience or less with the Company. During that same time period, only twenty-seven (27) employees with more than five (5) years of experience (excluding retirements) voluntarily left the Company. While the Company has consistently replaced these apprentice level employees, the ongoing loss of apprentice level employees has created a growing gap of experience between the number of apprentice employees and those that have five (5) or more years of experience.

As I previously described, the loss of experienced employees becomes an impediment when UGI Gas cannot transition enough employees from the apprentice level to the point where they can conduct more complex and technically challenging work. The first step to overcome this attrition is to bring in a greater number of new hires. This is particularly true in light of current market conditions, where UGI Gas also faces competition from many other entities located within its service territory. As a result, UGI Gas must be more aggressive in bringing in more candidates, in order to keep its workforce fully staffed in support of replacement activities in particular.

Q. Is the Company taking any other steps to address the attrition of apprentice level employees?

A. UGI Gas is taking a two-step approach: First, it is seeking to increase the number of apprentice level employees that come in the door. Even if the extremely competitive construction market continues into the future, the Company will continue to work to retain enough employees to ensure a sufficient number of experienced employees capable of undertaking complex projects. However, the Company invests a significant amount of time and resources when hiring, onboarding, and training new employees. Losing relatively new employees puts a strain on many Company resources and results in increased costs. Therefore, a second step is needed to retain more employees. As described in the testimony of Mr. Brown (UGI Gas Statement No. 1), UGI Gas plans to reduce the overall attrition by using a more comprehensive market-based approach to establishing wages and salaries. This will give recent hires an incentive to stay with the Company and move to more senior or supervisory positions. The Company believes these steps can address the combined threat posed by the high rates of both retirement and attrition, while continuing its accelerated capital replacement work.

VII. SAFETY INITIATIVES

Q. What programs does UGI Gas have in place regarding employee, customer, and system safety?

A. Safety performance is a core value to UGI Gas. The Company's success depends on its employees' commitment and dedication to safety. Therefore, UGI Gas maintains a culture that drives employees to perform their day to day responsibilities with a high degree of safety. Moreover, UGI Gas is advancing several initiatives to further develop its safety culture and drive sustainable improvements in safety performance. One such program is the UGI "Making a Difference by Living Our Values" Incentive Program. It rewards employees who demonstrate positive safety behaviors, including but not limited to, leading safety meetings, reporting safety issues, or participating in safety education. Employees can nominate individuals who demonstrate/exhibit safety values, impact/promote safe workplace practices, or significantly impact or improve safety in the Company's operations. Winners are recognized by receiving points, which are redeemable for merchandise, gift cards, etc.

Additionally, the Company is building a new Safety and Health Management System ("SHMS"), which will assist the Company in recognizing and fixing workplace hazards before they cause injury or illness. The program focuses on: Management Leadership, Worker Participation, Hazard Identification & Assessment, Hazard Prevention & Control, Education & Training, and Program Evaluation & Improvement.

Finally, UGI Gas's SHMS incorporates the American Petroleum Institute ("API") Recommended Practice 1173 ("API RP 1173"), which establishes a pipeline safety management systems ("PSMS") framework for corporations that operate hazardous liquids and gas pipelines under the U.S. Department of Transportation's jurisdiction. It provides a framework to reveal and manage risk, promotes a learning environment, and continuously improves pipeline safety and integrity. This continuous improvement effort and framework reduces hazards and prevents incidents.

Q. What other ongoing safety programs does the Company have?

A. Other ongoing safety measures and tools include Smith System driver training; the twenty-four- (24-) hour Triage Nurse Hotline; a fleet management tool that generates a driver safety score utilizing GPS technology; and selective driver monitoring technology. The Company has also adopted multiple programs to enhance its safety protocols. Programs include the "Near Miss/Good Catch" program, which seeks to proactively prevent safety incidents by learning from issues that had the potential for, but did not result in, damage or harm. In addition, the Company uses EcoOnline safety incident software, which facilitates incident management and data collection for various types of incidents and also tracks those incidents through the investigation process. The Company also utilizes ISNetworld vendor safety software to qualify contractors and monitor their performance trends. ISNetworld collects safety information from these contractors and compares them against UGI Gas's established safety standards to make sure they are qualified to perform work for the Company. ISNetworld conducts ongoing monitoring of the contractor's safety information and alerts UGI Gas if a contractor falls below the Company's minimum safety standards – either in UGI Gas's service territory or anywhere else in the country. This helps ensure that UGI Gas's contractors provide safe and reliable service to the Company's community and customers.

Q. What training initiatives is the Company undertaking?

A. The Company recently opened its centralized training facility (the "Training Center"). The Training Center is being used for all new hire and employee progression field training. Initial training for employees acquiring new skills and operator qualifications occur at the

Training Center. It is also being used for ongoing training and operator re-qualification for employees and contractors.

The Company's technical training team has nearly completed aligning UGI Gas's operator qualification program with the American Society of Mechanical Engineers ("ASME") B31Q Standard. Conversion to this standard is expected to be completed in FY2022 and will result in training improvements, including Gas Technical Institute training modules that will be customized to meet UGI Gas's processes and procedures. This work was started in FY2021 and is expected to take several years to complete.

VIII. ENVIRONMENTAL

A. ENVIRONMENTAL REMEDIATION PROGRAM

Q. Please discuss environmental management at UGI Gas.

A. The environmental group at UGI Gas is focused on three (3) main activities: (1) the investigation and remediation of environmental impacts related to historical operations; (2) environmental compliance activities, such as permitting and operational improvements; and (3) sustainability and methane reduction activities.

Q. Please describe the Company's investigation and remediation of environmental impacts related to historical operations.

A. From the late 1800s through the mid-1900s, UGI Gas and its predecessors owned and operated a number of manufactured gas plants ("MGPs") that, prior to the general availability of natural gas, generated gas from other fuel stocks for residential, commercial, and industrial customer use. In Pennsylvania, this process generally used coal as a fuel stock. Some byproducts of this manufacturing process, including coal tars and other residues of the manufactured gas process, are today considered hazardous substances under state and federal environmental laws.

Historically, UGI Gas operated its environmental remediation programs under three (3) consent orders and agreements ("COA") with the Pennsylvania Department of Environmental Protection ("PADEP"). UGI Gas's former utility companies, UGI Penn Natural Gas, Inc. ("UGI PNG") and UGI Central Penn Gas, Inc. ("UGI CPG"), were each parties to separate COAs with PADEP, and a UGI Gas COA was executed in 2016. Following UGI CPG and UGI PNG's merger into UGI Gas, on October 1, 2020, the UGI COA was amended to incorporate the UGI CPG and UGI PNG COAs into a single UGI Gas COA that will terminate on October 1, 2031. This COA obligates the Company to either meet an annual minimum environmental spend commitment or complete a sufficient number of environmental activities to achieve a minimum annual point total. The minimum annual spend for the UGI Gas COA is $5.35 million.

Q. What types of costs does UGI Gas incur with respect to addressing MGP site conditions?

A. UGI Gas incurs costs attributed to site investigations, remediation, and site restoration as well as related PADEP oversight costs. Costs may also be incurred to obtain an environmental covenant at the site to prevent certain uses of the site, and costs associated with transferring the site to a third party (such as with a dedication for public use) once the site has been restored. Costs may also be incurred to purchase a property to secure access to investigate and remediate. Additionally, expert and legal costs are sometimes incurred in interactions with insurance carriers or other potentially responsible parties to ensure that UGI Gas's customers are only paying their equitable share of investigation and remediation costs. Costs may be incurred to implement PADEP workplans if the Company faces opposition to the investigation or remediation of the site. Costs may also be incurred to recover compensation under historical insurance policies to offset the costs that would otherwise be recovered from customers.

Q. What is UGI Gas's projected spending on the MGP program?

A. UGI Gas holds the COA annual minimum spend of $5.35 million as the target projected spend for each year to meet the COA objectives, if minimum annual points cannot be achieved. UGI Gas's average aggregate annual spending over the past three fiscal years is $5.171 million, as shown below in Table 3.

Table 3. Environmental Spent per Fiscal Year

Fiscal Year	**Total**
2019	$4,810,983
2020	$4,243,130
2021	$6,459,545
Total	$15,513,658
Average	$5,171,219

The average amount is used in the calculation of the environmental adjustment shown in UGI Gas Exhibit A, Schedule D-8, as discussed in the direct testimony of Ms. Tracy A. Hazenstab (UGI Gas Statement. No. 2).

Q. Why does environmental spend vary from the minimum environmental spend set by the COA?

A. While the Company uses the environmental minimum spend as a benchmark for budgeting, actual costs may exceed the minimum in certain years due to PADEP requirements, changing environmental standards, and site-specific issues such as sensitive habitat and concentration of contaminants. The 2020 spend was also influenced by the Pandemic, which constrained field activities for a considerable portion of the year. To catch-up for the 2020 target spend differential, additional funds beyond the target of $5.35 million were spent in 2021. In years when the Company is unable to make its minimum spend commitments, it can avail itself of an alternative compliance pathway under each COA that permits the Company to use banked points for remedial work completed in past years.

Q. What is UGI Gas's goal for restoration of the MGP sites?

A. UGI Gas strives to restore each site for beneficial reuse that becomes an asset to the Company or the community. Because these MGP sites are located within the Company's existing service territory, restoration of the sites for beneficial reuse, whether in the form of urban redevelopment or the creation of a new public space, directly benefits UGI Gas's customers.

B. EMISSIONS REDUCTIONS PROGRAMS

Q. How does UGI Gas quantify the environmental impact of its operations?

A. In addition to the ESG program areas discussed in Mr. Brown's testimony (*e.g.*, oil to gas conversion, EE&C, etc.) (UGI Gas Statement No. 1) that reduce emissions, UGI Gas has been a partner in the United States Environmental Protection Agency's ("EPA") voluntary

Natural Gas STAR program since its inception. Natural Gas STAR provides a framework to encourage partner companies to implement methane emissions reducing technologies and practices and document their voluntary emission reduction activities. On March 30, 2016, UGI Gas joined with thirty-two (32) other natural gas utilities to launch the EPA's Natural Gas STAR Methane Challenge Program. As a founding member of the STAR Methane Challenge, UGI Gas has committed to making and tracking emissions reductions. Participation in this voluntary program includes a commitment to replace infrastructure to achieve a reduction in fugitive methane emissions. UGI Gas reduced fugitive methane emissions by 5.6% in 2019-2020 (at the time of this filing, the EPA Methane Challenge STAR Program report for 2020-2021 has not yet been published).

UGI Gas continues to add Compressed Natural Gas ("CNG") vehicles to its fleet. Currently, the fleet is made up of twelve percent (12%) CNG-powered vehicles, with plans to increase the number to twenty percent (20%) by the end of 2023. Three (3) of the Company's operations locations have CNG filling stations (Archbald, Wilkes-Barre, and Bethlehem) with plans to add another station near its Middletown office. Utilizing nearby commercial CNG fueling stations makes it feasible to convert fleets to CNG in smaller operations centers.

Q. Does that conclude your testimony?

A. Yes, it does.

UGI GAS

EXHIBIT TJA-1

TIMOTHY J. ANGSTADT

UGI UTILITIES, INC.
VICE PRESIDENT – OPERATIONS

Summary

Engineering and Operations executive with over 22 years of broad experience in natural gas transmission and distribution activities, including operations and maintenance, engineering, regulatory compliance, capital budgeting and construction, project management, technology implementation, and business process transformation. As Vice President – Operations:

- Leads a team of over 850 individuals including management, engineering, clerical, and field technicians to operate and maintain over 12,000 miles of natural gas transmission and distribution pipelines and related assets, serving over 672,000 customers in Pennsylvania and Maryland.
- Champion/executive sponsor of UGI's Safety Culture Initiative; member of executive steering team responsible for the ongoing improvement of safety culture, performance, and leadership throughout the company.

Prior Positions with UGI Utilities, Inc.

Vice President – Operations (Denver, Pa.)	February 2019 - Present
Program Director – UNITE (UGI's Next Info. Technology Enterprise) (Reading, Pa.)	February 2016 – February 2019
Director – Operations, South Region (Reading, Pa.)	June 2012 – February 2016
Operations Manager – West Region (Harrisburg/Middletown, Pa.)	July 2008 – June 2012
Manager – Operational Support (Reading, Pa.)	December 2007 – July 2008
Manager – UGI/Penn Natural Gas Integration (Wilkes-Barre/Reading, Pa.)	November 2006 – December 2007
Engineer – Customer Service and Performance Systems (Reading, Pa.)	June 2005 – November 2006
Operations/Construction and Maintenance Superintendent (Reading, Pa.)	September 2003 – June 2005
Engineer II – Gas Utility Headquarters (Reading, Pa.)	January 2003 – September 2003
Engineer I/II – Reading Area (Reading, Pa.)	January 2000-January 2003
Engineering Assistant – Reading Area (Reading, Pa.)	June 1999 – August 1999

Education

MiF, The Pennsylvania State University, Malvern, Pa.
MBA, The Pennsylvania State University, Malvern, Pa.
BS, Mechanical Engineering, The Pennsylvania State University, State College, Pa.

Prior testimony provided to the Pennsylvania Public Utility Commission:

Docket No. R-2019-3015162 UGI Utilities, Inc. Gas Division - Base Rate Case Proceeding

UGI GAS STATEMENT NO. 10

CONSTANCE E. HEPPENSTALL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3030218

UGI Utilities, Inc. – Gas Division

Statement No. 10

Direct Testimony of
Constance E. Heppenstall

Topics Addressed: **Cost of Service Allocation**

Date: January 28, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Constance E. Heppenstall. My business address is 1010 Adams Avenue, Audubon, 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. My title is Senior Project Manager, Rate Studies. My duties and responsibilities include the preparation of accounting and financial data for revenue requirement and cash working capital claims, 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 ("PA PUC" or the "Commission"), the Arizona Corporation Commission, the Kentucky Public Service Commission, the Virginia State Corporation Commission, the Missouri Public Service Commission, the Hawaii Public Utilities Commission, the West Virginia Public Service Commission, the Indiana Utility Regulatory Commission, the California Public Utilities Commission, the Public Utilities Commission of Ohio, and the New Jersey Board of Public Utilities concerning revenue requirements, cost of service allocation, and rate design. A list of cases in which I have testified is attached to my testimony.

Q. What involvement have you had in preparing past cost of service studies for UGI Gas?

A. Since 2006, I have assisted with the preparation of all of UGI Gas's allocated cost of service studies, except for the one utilized in the Company's 2020 Gas Base Rate Case at Docket No. R-2019-3015162.

Q. What is your educational background?

A. I have a Bachelor of Arts in Economics from the University of Virginia, Charlottesville, Virginia and a Master of Science in Industrial Administration from the Tepper School of Business at Carnegie Mellon University, Pittsburgh, Pennsylvania.

Q. Would you please describe your professional affiliations?

A. I am a member of the American Water Works Association, the National Association of Water Companies, and the Pennsylvania Municipal Authorities Association.

Q. Briefly describe your work experience.

A. I joined the Valuation and Rate Division of Gannett Fleming, Inc. in August 2006, as a Rate Analyst and was promoted to my current position in 2012. Prior to my employment at Gannett Fleming, Inc., I was a Vice President of PriMuni, LLP where I developed financial analyses to test proprietary software in order to ensure its pricing accuracy in accordance with securities industry's conventions. From 1987 to 2001, I was employed by Commonwealth Securities and Investments, Inc. as a public finance professional where I created and implemented financial models for public finance clients in order to create debt structures to meet clients' needs. From 1986 to 1987, I was a public finance associate with Mellon Capital Markets.

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. 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, 2023," 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 12 months ending September

30, 2023 ("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 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 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 purchased gas cost volumes for Rate R and Rate N customers, as shown in the development of Factor 1.

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 costs related to these mains is based on Factor 4, which weights the factors related to average daily throughput volumes and from maximum day extra capacity demand.

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. In addition, certain Interruptible volumes that are 100% interruptible were excluded from Factor 4.

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 39.9% allocated based on average daily usage and 60.1% on excess above average day usage. See Factor 3 for the calculation of the firm service load factor.

Q. Please discuss the allocation of costs related to Load Dispatching, Measuring and Regulation ("M&R") Station Equipment, and operational costs related to large mains.

A. The costs related to Load Dispatching and M&R Station Equipment are allocated based on Factor 4A. This factor is similar to the allocation in Factor 4, but it includes average daily throughput volumes related to XD Firm customers as these customers benefit from this equipment. Operational costs related to large mains are allocated based the allocation of rate base for large and directly assigned mains, Factor 17.

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, as developed in Factor 6C. Costs related to meters in Accounts 381, 382, 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, as developed in Factor 6. The costs related to House Regulators are allocated to Rate R and N classes based the weighted number of regulators, or Factor 6A. Finally, the costs associated with Industrial Measuring and Regulating Equipment are allocated based on the costs of meters and measuring and regulating equipment for the Rate DS, LFD, XD-Firm, and Interruptible classes.

Q. **Please explain the allocation of Distribution Operation and Maintenance Other Expenses.**

A. These expenses were allocated based on Factors 10 and 11. These factors are based on costs previously allocated as described above.

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, as shown in the development of Factor 19. Costs associated with customer assistance programs are allocated directly to the residential class.

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

A. Customer accounting and certain customer service costs were allocated to service classifications on the basis of the number of customers, using Factor 7. Costs related to customer assistance programs were directly allocated to the Rate R class. The Energy Efficiency and Conservation program costs were allocated based on the revenue from the EEC Rider. Sales expenses, except for costs related to Service Representatives, were allocated to the Rate R and N classes based on number of customers, Factor 8. The costs related to Service Representatives, who serve the larger customers, were allocated to the large customer classes of DS, LFG, XD-Firm, and Interruptible based on number of customers in these classes, Factor 7A. Administrative and general costs were allocated on the basis of the allocated direct operation and maintenance costs, excluding gas production expenses, using Factor 12. Labor related pension and benefits are allocated based on an operation and maintenance direct labor expense, as shown in Factor 13.

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 Company witness Sherry A. Epler (UGI Gas Statement No. 8) 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-Firm Service is presented in Schedule H of UGI Gas Exhibit D.

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

A. The costs related to Rate LFD and Rate XD-Firm 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.

CONSTANCE E. HEPPENSTALL – LIST OF CASES TESTIFIED

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
1.	2010	AZ CC	W-01303A-09-0343 and SW-01303A-09-0343	Arizona American Water Company	Rate Consolidation
2.	2010	PA PUC	R-2010-2179103	City of Lancaster – Bureau of Water	Revenue Requirements
3.	2012	PA PUC	R-2012-2311725	Hanover Borough	Cost of Service/Revenue Requirements
4.	2012	PA PUC	R-2012-2310366	City of Lancaster – Sewer Fund	Revenue Requirements
5.	2013	PA PUC	R-2013-2350509	City of DuBois – Bureau of Water	Revenue Requirements
6.	2013	PA PUC	R-2013-2390244	City of Bethlehem – Bureau of Water	Revenue Requirements
7.	2014	PA PUC	R-2014-2418872	City of Lancaster – Bureau of Water	Revenue Requirements
8.	2014	PA PUC	R-2014-2428304	Hanover Borough	Revenue and Revenue Requirements
9.	2015	KY PSC	Case No.2015-000143	Northern Kentucky Water District	Cost of Service
10.	2016	PA PUC	R-2016-2554150	City of DuBois – Bureau of Water	Cost of Service/Revenue Requirements
11.	2016	AZ CC	WS-01303A-16-0145	EPCOR Water Arizona, Inc.	Cost of Service/Rate Design
12.	2017	MO PSC	WR-2017-0285	Missouri-American Water Company	Cost of Service/Rate Design
13.	2017	MO PSC	SR-2017-0286	Missouri-American Water Company	Cost of Service/Rate Design
14.	2017	VA SCC	PUR-2017-00082	Aqua Virginia, Inc	Cost of Service
15.	2017	AZ CC	WS-01303A-17-0257	EPCOR Water Arizona, Inc	Cost of Service/Rate Design
16.	2017	HI PUC	2017-0446	Hana Water Systems, LLC – North	Cost of Service/Rate Design
17.	2017	HI PUC	2017-0447	Hana Water Systems, LLC – South	Cost of Service/Rate Design
18.	2018	PA PUC	2018-200208	SUEZ Water Pennsylvania	Revenue Requirements
19.	2018	KY PSC	2018-00208	Water Service Corp of KY	Cost of Service/Rate Design
20.	2018	WV PSC	18-0573-W-42t	West Virginia American Water Co.	Cost of Service
21.	2018	IN IRC	50208	Indiana American Water Company	Cost of Service/Demand Study
22.	2018	KY PSC	2018-00291	Northern Kentucky Water District	Cost of Service/Rate Design
23.	2018	KY PSC	2018-0358	Kentucky American Water	Cost of Service/Rate Design
24.	2019	PA PUC	2019-3006904	Newtown Artesian Water Co.	Revenue Reqmts./Rate Design
25.	2019	PA PUC	2019-3010955	City of Lancaster – Sewer Fund	Rev. Reqmts./Cost of Service/Rates
26.	2020	PA PUC	2020-3017206	Philadelphia Gas Works	Cost of Service
27.	2020	PA PUC	2020-3019369	Pennsylvania American Water Co.	Cost of Service/Rate Design
28.	2020	PA PUC	2020-3019371	Pennsylvania American Water Co.	Cost of Service/Rate Design
29.	2020	PA PUC	2020-3020256	City of Bethlehem	Rev. Reqmts./Cost of Service/Rates
30.	2020	CA PUC	A2101003	San Jose Water Company	Rate Design
31.	2020	VA SCC	PUR-2020-00106	Aqua Virginia, Inc.	Cost of Service
32.	2021	OH PUC	21-0595-WW-AIR	Aqua Ohio, Inc	Cost of Service
33.	2021	OH PUC	21-0596-ST-AIR	Aqua Ohio, Inc	Cost of Service
34.	2021	PA PUC	R-2021-3026116	Hanover Borough	Cost of Service
35.	2021	NJ BPU	WR21071007	Atlantic City Sewerage Co.	Rev. Reqmts./Cost of Service/Rates
36.	2021	PA PUC	R-2021-3027385	Aqua Pennsylvania	Cost of Service/Rate Design
37.	2021	PA PUC	R-2021-3027386	Aqua Pennsylvania	Cost of Service/Rate Design
38.	2021	PA PUC	R-2021-3026682	City of Lancaster – Bureau of Water	Cost of Service/Rate Design

UGI GAS STATEMENT NO. 11

JOHN D. TAYLOR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3030218

UGI Utilities, Inc. – Gas Division

Statement No. 11

Direct Testimony

of

John D. Taylor, Managing Partner
Atrium Economics, LLC

Topics Addressed: **Weather Normalization Rider**

Dated: January 28, 2022

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Direct Testimony of John D. Taylor

I. INTRODUCTION

Q. Please state your name, affiliation, and business address.

A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC ("Atrium Economics" or "Atrium") as a Managing Partner. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company").

Q. Please describe your professional background and education.

A. As a utility pricing and policy expert, I support a variety of energy and utility related projects regarding matters pertaining to economics, finance, and public policy. In the public utility space, I have assisted with asset divestitures, allocated class cost of service studies, rate of return calculations, cash working capital impacts, tax litigation, revenue allocation, rate design, auction analysis, and affiliate cost allocation. I have reviewed and analyzed these subject matters considering the accounting treatment for, the financial investment in, and the operational configuration of a company's assets. For utility rate cases, I have performed: allocated class cost of service studies; revenue allocation; rate design; valuation modeling; affiliate cost allocation; and various cost of service analyses. Also, I have filed testimony on class cost of service studies, return on equity, and statistical audit sampling. Specifically, I have presented expert testimony in Indiana, Maine, Massachusetts, Minnesota, New Hampshire, North Carolina, Illinois, Delaware, Pennsylvania, Washington, West Virginia, British Columbia, and the Federal Energy Regulatory Commission ("FERC"). Regarding my educational background and professional background, I studied electrical and mechanical engineering and worked for an industrial inspection company, which provided hands-on experience with electric utility assets and equipment. I received an undergraduate degree in Environmental Economics, with an emphasis in econometrics and regulatory policy. I also earned a Masters in Economics from American University in Washington, DC. A copy of my resume is provided as UGI Gas Exhibit JDT-1.

Q. Mr. Taylor, have you previously testified before the Pennsylvania Public Utility Commission ("Commission") or any other regulatory authority?

A. Yes. I have presented expert testimony before FERC and numerous state and provincial regulatory commissions, including the Commission.

Q. What is your assignment in this proceeding?

A. UGI Gas requested that Atrium Economics assist with the development of a Weather Normalization Adjustment ("WNA") mechanism that could be applied to the monthly billings of certain UGI Gas's Residential (Rates R and RT) and Non-Residential (Rates N and NT) customer classes. UGI Gas's proposed WNA Rider is presented in UGI Gas Exhibit F – Proposed Tariff, Rider K "WNA", Weather Normalization Adjustment Rider.

Q. Please summarize the content of your testimony.

A. I will present the Company's proposed WNA mechanism, which is designed to stabilize distribution revenues for certain heating sensitive rate classes from experienced weather variability. My testimony consists of (a) support and rationale for a WNA mechanism, (b) a summary of UGI Gas's proposed WNA, (c) detailed components of UGI Gas's proposed WNA, and (d) a summary of weather normalization adjustments used in Pennsylvania and across the U.S.

II. LIST OF EXHIBITS SPONSORED IN TESTIMONY

Q. What Exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following Exhibits:

- UGI Gas Exhibit JDT – 1, Resume;
- UGI Gas Exhibit JDT – 2, Survey of WNA Mechanisms; and
- UGI Gas Exhibit Exhibit F – Proposed Tariff, Rider K "WNA", Weather Normalization Adjustment Rider.

III. SUPPORT & RATIONALE FOR A WNA MECHANISM

Q. How are weather-normalized gas volumes used to derive a gas utility's base rates?

A. Typically, as part of the rate design in a base rate proceeding, a utility's volumetric unit rates for gas service are derived by dividing the appropriate costs, to be recovered through volumetric based rates, by the anticipated weather-normalized gas sales volumes. These rates are designed to provide the utility with an opportunity to recover the costs it incurs to provide utility service, at the levels determined in the utility's rate case under normal weather conditions. To the extent any costs are subject to recovery in a volumetric charge, the recovery of such amounts is entirely dependent upon the volumes of gas usage experienced by the utility. Therefore, the recovery of costs in a volumetric component of rates will always lead to a difference in recovery of actual costs because actual weather conditions will by and large never match the normalized weather conditions used to set rates.

Q. Please explain how weather influences the recovery of costs for a gas utility and costs to customers.

A. As a result of the volumetric rates described above, if actual temperatures are normal (as described in Section V below), the utility has a reasonable opportunity to fully recover its fixed costs of service at established sales levels, and the customers' payment for service reflects the costs of the utility. Unfortunately, normal temperatures seldom, if ever, occur. Therefore, because of abnormal weather and a rate design that is based, in substantial part, on customer usage, the amount of distribution revenue (i.e., non-gas sales revenues and non-reconcilable surcharge revenues) collected from customers can vary widely from the revenue requirement level authorized by the regulator. In the case of warmer weather, the utility may under recover its costs and need to pursue cost management efforts that help stabilize and support the overall financial health and performance of the company. In the case of colder weather, customers experience higher bill cost burdens which may negatively impact customer abilities to manage utility costs.

Q. What portion of UGI Gas's fixed costs is recovered through its current volumetric distribution charges?

A. As shown on UGI Gas Exhibit E – Proof of Revenue, at proposed rates, approximately 64% of distribution revenues for Rates R and RT is recovered through the volumetric distribution charge. For UGI Gas's small commercial customers receiving service under Rates N and NT, approximately 83% of distribution revenue is recovered through the volumetric distribution charge.

Q. Please explain how fluctuations in weather over time impact a gas utility's temperature-sensitive customers and the utility's financial performance.

A. Since the bills of gas customers are largely based on the level of gas usage, temperature-sensitive customers' monthly bills can vary widely due to changing weather conditions. Under traditional ratemaking methods, if actual temperatures were colder than normal, the typical gas customer would use more gas, pay more for service (through volumetric charges), and potentially overpay its share of fixed costs. This occurs because the unit rates used to recover fixed costs are not reduced to recognize the higher gas volumes used by customers during colder weather. Since the gas utility's level of fixed costs does not change, the higher gas volumes applied against the same unit rate would generate comparatively higher distribution revenues than the level of fixed costs established for ratemaking purposes. Conversely, in warmer than normal weather, the reverse situation would occur. Customers' gas usage decreases with warmer temperatures, thus generating comparatively lower distribution revenues than required to recover the gas utility's total fixed costs that do not decrease due to warm weather.

IV. <u>PROPOSED WNA MECHANISM</u>

Q. Please define and describe the concept of a WNA mechanism.

A. The utility's distribution rates, which are set to allow the utility to recover its authorized level of distribution revenues, are based on expected throughput during normal weather. When actual weather deviates from normal weather, there will be a difference between actual and projected distribution revenues. A WNA mechanism adjusts a customer's bill due to these variations from normal weather (i.e., temperature variations or heating degree day variations) in order to have the bill reflect normal weather conditions. For billing periods that are colder than normal, a credit will be applied to the bill. For billing periods that are warmer than normal, a surcharge is applied to the bill. WNA mechanisms are typically effective for usage during the heating season calendar months (e.g., October through May). WNAs reduce the amount of variation in both customer bills and utility revenues by making a compensating adjustment for the difference between actual weather and normal weather.

Q. Are WNA mechanisms different from Revenue Decoupling?

A. Revenue Decoupling is a regulatory mechanism that separates a utility's distribution revenues from its level of sales, thereby "breaking the link" so that the utility may recover an established amount of revenues (regardless of weather, customer conservation, etc.), even as sales fluctuate. WNA mechanisms only account for the changes in sales that occur due to the difference between actual weather and normal weather. In the case of the Company's specific proposal, the WNA will only address weather related impacts and will only do so for certain of the Company's customer classes; thus, while providing a level of revenue stability related to weather changes, it does not completely decouple revenues from all sales related variances as full revenue decoupling would provide.

Q. Do WNA mechanisms differ in their design?

A. Yes. Gas utilities typically use two types of WNA mechanisms: (1) a mechanism that adjusts current billings on a monthly billing basis as the bill is being calculated and issued; and (2) a mechanism that adjusts billings on a lagged basis where the adjustment appears on the customer's bill(s) from a few to several months after a variation from normal weather is experienced.

Q. Which type of WNA mechanism is the Company proposing to implement?

A. The Company proposes to implement a WNA mechanism that adjusts billings on a monthly billing basis as the bill is being calculated and issued.

Q. Why has the Company chosen to adopt a WNA mechanism of this type?

UGI Gas has chosen this type of WNA mechanism because, by adjusting current billings on a monthly billing basis, the customer can more readily link the resulting billing adjustment with the weather causing the adjustment. In a cold winter with high gas bills, customers will receive the benefits of WNA bill reductions more quickly. The monthly bills will reflect the specific period in which the colder weather occurs. In addition, the utility's financial statements will reflect the cash flow effect of the monthly billing WNA mechanism sooner than a lagged WNA mechanism.

Q. Please describe the Company's proposed WNA.

A. The key elements of the Company's proposed WNA mechanism are as follows:

- It applies to UGI Gas's Residential customers receiving service under Rates R and RT and UGI Gas's Non-Residential customers served under Rates N and NT.
- It adjusts billings on a current monthly basis and uses adjustment factors which are representative of each customer's consumption characteristics.
- It is effective for the billing months of October through May.
- It adjusts the amount billed to each customer to offset the impact of actual heating degree days ("AHDD") variations from normal heating degree days ("NHDD").

Q. What are the benefits of the weather normalization adjustment mechanism for UGI Gas and its customers?

A. For an applicable customer, a WNA is advantageous because:

1. It reduces bill variability due to weather in the month when the variation occurs and provides bill relief in severely cold months.
2. The WNA will improve customer satisfaction by providing more stable annual bill amounts and mitigating volatility in monthly gas bills. This will help customers budget for and pay their bills.
3. Customers will continue to benefit from their energy conservation efforts, as the actual usage on each customer's bill is utilized to calculate the WNA adjustment, and that usage level will reflect the conservation behaviors of each customer.

For UGI Gas, a WNA is a fair and equitable rate mechanism because:

1. UGI Gas's volumetric delivery service rates are based on the volumes of gas it expects to sell under normal weather conditions. The WNA mechanism will improve the ability to match the level of distribution revenues, established to recover fixed costs, with the amount reflected in the monthly customer billings.
2. Deviations from normal weather can result in differences in actual and projected recovery of the Company's annual non-gas distribution costs when actual weather experienced is colder or warmer than normal, respectively. Therefore, such deviations can produce erratic financial results for the Company.

Q. Is UGI Gas's proposed WNA similar to other WNA mechanisms in place for gas distribution utilities in Pennsylvania?

A. Yes. UGI Gas's proposed WNA shares similarities with both Columbia Gas of Pennsylvania's ("Columbia") WNA rider,[1] and Philadelphia Gas Works' ("PGW") WNA clause.[2] The WNA applies to Residential heating customers for all three utilities, and Non-Residential heating customers for UGI Gas and PGW. The specific calculation of UGI Gas's proposed WNA rate is most similar to the calculation of Columbia's WNA rider.[3] Finally, like Columbia and PGC, UGI Gas is proposing annual reporting for the WNA to the Commission and only applies only during the heating season months.

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[1] Columbia Gas of Pennsylvania, Inc., "Rider WNA – Weather Normalization Adjustment", Rates and Rules for furnishing gas service, https://www.columbiagaspa.com/docs/librariesprovider14/rates-and-tariffs/pennsylvania-tariff.pdf?sfvrsn=41, pdf at page 187.

[2] Philadelphia Gas Works, "Weather Normalization Adjustment Clause", Gas Service Tariff, https://www.pgworks.com/uploads/pdfs/PGW_Gas_Service_Tariff_Through_Supplement_145.pdf, pdf at page 150.

[3] There are a few differences in function. Columbia uses a November through May heating season and applies a 3% deadband, whereas PGW uses a heating season of October through May and applies a 1% deadband.

V. COMPONENTS OF UGI GAS'S PROPOSED WNA MECHANISM

Q. Please explain how UGI Gas's proposed WNA mechanism will operate.

A. UGI Gas's proposed WNA mechanism will adjust the amount billed to each customer served under Rates R, RT, N, and NT to effectively weather normalize distribution revenues recovered from these two rate schedules during the cold weather heating season. It is a customer bill specific calculation applied to monthly billing cycles during the months of October through May.

Q. What is the Company's basis for determining normal weather for its Pennsylvania gas distribution system?

A. Since 2009, UGI Gas has defined normal weather as the average annual heating degree days ("HDD") calculated for a 15-year period, with the most recent period ending December 31, 2019. It is updated every 5 years with the next recalculation due for the period ending December 31, 2024. This is further discussed in the direct testimony of Company witness Sherry A. Epler (UGI Gas Statement No. 8).

Q. Would the adjustment to customers' bills be calculated on a calendar month or on a billing cycle month basis?

A. The customer adjustments would be made on a billing cycle basis. This approach allows the adjustments to be calculated at the end of each customer's meter reading billing cycle and incorporated into the original bill sent to each customer. This approach provides for an accurate and timely adjustment for the customer. There is no additional time lag between when the customer experiences the bill variability and when the weather normalizing adjustment is made.

Q. In the context of WNA riders, what are deadbands?

A. A deadband applies to WNA riders such that the adjustment is not triggered if AHDDs are within a certain threshold of the NHDDs. Thus, no adjustment applies to the bill if weather falls within that threshold and some weather variability flows to customer bills and is seen in the associated utility distribution revenues. Columbia's WNA mechanism utilizes a 3% deadband, and PGW's WNA mechanism utilizes a 1% deadband.

Q. Does UGI Gas's proposal include a deadband?

A. No. The UGI Gas proposal does not include a deadband. The Company believes the application of a deadband adds unnecessary complexity to the rider, which is a concern for customer communication and education. Also, in principle, the WNA's intended goal is to stabilize billings and distribution revenues from readily identified weather related variances, not just "some" element of weather variance that may be arbitrarily established.

Q. Please provide a formulaic representation of the WNA mechanism that you just described.

A. The Company's proposed WNA formula that is applied to bills of Residential and Non-Residential customers under Rate Schedules R/RT and N/NT for the heating season of October through May is shown below:[4]

$$\mathrm{WNBC} = \mathrm{BLMC} + \left[\frac{\mathrm{NHDD}}{\mathrm{AHDD}} \mathrm{x}\ (\mathrm{AMC} - \mathrm{BLMC})\right]$$

$$\mathrm{WNAC} = \mathrm{WNBC} - \mathrm{AMC}$$

$$\mathrm{WNA} = \mathrm{WNAC\ x\ Distribution\ Charge}$$

- WNA = Weather Normalization Adjustment will be applied to bills of Residential and Non-Residential customers under Rate Schedules R/RT and N/NT, for any billing period during the heating season October through May. WNA will not be applicable for the billing period if AMC is less than the BLMC.

- WNBC = Weather Normalized Billing Ccfs ("WNBC") will be calculated as the Base Load Monthly Ccfs ("BLMC") added to the product of (1) the Normal Heating Degree Days ("NHDD") divided by the Actual Heating Degree Days ("AHDD") and (2) the Actual Monthly Ccfs ("AMC") less the BLMC. Weather Normalized Billing Ccfs (WNBC) will only be calculated if the AMC exceeds the BLMC.

- BLMC = Base Load Monthly Ccfs for each customer shall be established for each customer using the customer's actual average daily consumption from the billing system, measured in Ccfs, using bills with read dates of June 21st thru September 20th over a 36-month period multiplied by the number of days in the billing period. The average daily base load is recalculated monthly using the most recent 36 months of bill history. If less than 12 months of bill history is available for the customer, an average base load for the related customer class will be applied.

- NHDD = Normal Heating Degree Days shall be applied on a Delivery Region specific basis as determined by the customer's geographical location and, for any given day within a billing period, shall be based upon the Delivery Region's 15-year average for the given day. NHDD shall be updated every 5 years using the methodology established in the Company's general rate case proceeding at R-2021-3030218 with the next scheduled update of the NHDD to be effective on October 1, 2025, and thereafter every 5 years.

[4] The full proposed tariff language is provided as UGI Gas Exhibit F – Current Tariffs, Rate Schedule "WNA", Weather Normalization Adjustment Rider.

- AHDD = Actual Heating Degree Days shall be the actual experienced heating degree days during the billing cycle for the customer's assigned Delivery Region, as determined by the customer's geographical location. A Delivery Region's AHDD shall be based upon experienced actual Gas Day temperatures as reported by the National Oceanic and Atmospheric Administration (NOAA) for weather stations located within that Delivery Region pursuant to the application of the Company's established Delivery Region calculation methodology.

- The period for which both NHDD and AHDD will be measured for each billing period used for the WNA calculation will be based on the starting day of the customer's billing cycle minus one day through last day of customer's billing cycle minus one day. If AHDD is unavailable for any day(s) during that period, the respective NHDD for the same day(s) will also be excluded from the calculation, thereby excluding any days missing AHDD from the WNBC calculation.

- AMC = Actual Monthly Ccfs will be subtracted from the WNBC to compute the Weather Normalized Adjustment Ccfs ("WNAC").

- The WNAC shall then be multiplied by the applicable Rate Schedule Distribution Charge based on service rendered to compute the WNA amount that will be charged or credited to each Residential and Non-Residential customer served under Rate Schedules R, RT, N and NT.

Q. Please explain the process the Company will follow to calculate the WNA.

A. For each billing cycle, the Company will adjust the heat sensitive load to account for the ratio of normal weather to actual weather and then recalculate the bill. The process works as follows:

- For each billing cycle and each applicable customer, the Company will calculate the weather normalized billing Ccfs by multiplying the heat sensitive load (actual Ccfs less base load Ccfs) times the ratio of the normal HDDs for the billing cycle to the actual HDDs; i.e., $\left[\frac{\mathrm{NHDD}}{\mathrm{AHDD}} \mathrm{x}\ (\mathrm{AMC} - \mathrm{BLMC})\right]$. This adjusted heat sensitive load will then be added to the base load Ccfs to calculate the Weather Normalized Billing Ccfs (WNBC); i.e., $\mathrm{WNBC} = \mathrm{BLMC} + \left[\frac{\mathrm{NHDD}}{\mathrm{AHDD}} \mathrm{x}\ (\mathrm{AMC} - \mathrm{BLMC})\right]$.

- The Company will then determine the Weather Normalized Adjustment Ccfs ("WNAC") of each applicable customer for each billing cycle by subtracting the actual monthly Ccfs from the Weather Normalized Billing Ccfs; i.e., WNAC = WNBC-AMC.

- This Weather Normalized Adjustment Ccfs is then multiplied by the applicable rate class's volumetric distribution charge to develop the Weather Normalization Adjustment that will be applied on the customer's bill. WNA=WNAC x Distribution Charge.

Q. Have tariff pages been developed that reflect the computational details and process of the proposed WNA mechanism?

A. Yes. The appropriate tariff pages to implement the proposed WNA mechanism are presented in UGI Gas Exhibit F (Proposed Tariff), Rider C - "WNA", Weather Normalization Adjustment Rider.

Q. When does the Company propose to implement the WNA?

A. Although intended to apply for bills during the months of October through May on a forward basis, assuming the effective date of new rates is in October 2022 in this proceeding, UGI Gas is proposing the WNA will initially be implemented beginning with bills rendered on and after November 1, 2022. Thereafter in subsequent years, the WNA will apply for billings during each October through May period.

Q. What additional filing(s) would occur related to the Weather Normalization Adjustment Rider?

A. The Company will file weather normalization information with the Commission annually on or before December 1st for WNA data related to the 12-month period ending September of that same year. The filing will contain the following information on the WNA mechanism: (a) monthly WNA billed revenue; and (b) monthly actual and normal HDD data.

Q. How does the proposed WNA align with the Statements of Policy as outlined by the Commission in the alternative rate making Docket No. M-2015-2518883?

A. Each rate consideration identified in the Statement of Policy is listed below along with the relevant effect the proposed WNA has on each rate consideration:

1. *Please explain how the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.*

   - UGI Gas's proposed WNA is designed to recover distribution revenues needed to satisfy the cost-of-service requirement determined in this proceeding, while mitigating the variance between actual and projected distribution revenues due to weather. UGI Gas recovers a significant portion of fixed costs through volumetric rates. These fixed costs do not vary with the amount of gas delivered to customers and are composed of fixed operation and maintenance ("O&M") expenses, administrative and general expenses, depreciation, certain taxes, a portion of working capital requirements, and return on investment. These costs also do not vary in the short-term with changes in temperature. In the absence of Straight Fixed Variable ("SFV") rate design; where all fixed costs are recovered in a fixed monthly charge, a WNA mechanism will better align distribution revenues with cost causation principles; appropriately accounting for variation in usage due to weather.

2. *Please explain how the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.*

   - UGI Gas's WNA proposal has no identifiable impact on capacity utilization.

3. *Please explain whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.*

   - Customer specific usage factors corresponding to their individual demand (the BLMC for each customer) is continually updated and reflects the level of demand associated with the customer's anticipated consumption levels.

4. *<u>How the ratemaking mechanism and rate design limit or eliminate interclass and intraclass cost shifting</u>.*

    - Since the proposed WNA mechanism is applying rates which are based upon the specific revenue allocation and rate design approved by the Commission, it will mitigate the potential for interclass or intraclass cost shifting related to weather driven usage variances from those weather assumptions used in establishing rates.

5. *<u>Please explain how the WNA limits or eliminates disincentives for the promotion of efficiency programs</u>.*

    - The proposed WNA only addresses variations due to weather. The WNA does not negatively impact energy efficiency programs. Moreover, UGI Gas maintains a robust Energy Efficiency & Conservation ("EE&C") program, which it has voluntarily implemented for its customers and will use to continue promoting energy efficiency measures.

6. *<u>Please explain how the WNA impacts customer incentives to employ efficiency measures and distributed energy resources</u>.*

    - Customers will continue to have an incentive to employ energy efficiency measures and distributed energy resources because a reduction in usage still reduces their overall bill and the portion of their bill that is subject to the WNA mechanism.

7. *<u>Please explain how the WNA impacts low-income customers and support consumer assistance programs</u>.*

    - Under the WNA mechanism, certain customers enrolled in the Customer Assistance Program ("CAP") who pay an "average bill" amount will see lower bill variability for distribution costs during colder than average periods, while CAP customers who are paying on a percent-of-income basis will see little to no impact.

8. *<u>Please explain how the WNA impacts customer rate stability principles</u>.*

    - The WNA mechanism will provide customers more stable annual bills and directly mitigate volatility in their monthly costs.

9. *<u>Please explain how weather impacts utility revenue under the WNA</u>.*

    - The proposed WNA adjusts a customer's bill due to variations from normal weather and is employed for usage during the heating season months (October – May). It only applies to certain of the Company's customer classes (Rates R, RT, N and NT) and it does not ensure the utility will recover 100% of its authorized distribution revenues, but it does reduce the amount of weather-related variation in both customer bills and associated utility distribution revenues.

10. *Please explain how the WNA impacts the frequency of rate case filings and affects regulatory lag*.

- The WNA is not anticipated to impact the frequency of rate cases or have an impact on regulatory lag.

11. *Please explain if the WNA interacts with other revenue sources, such as Section 1307 automatic adjustment surcharges, 66 Pa.C.S. § 1307 (relating to sliding scale of rates; adjustments), riders such as 66 Pa.C.S. § 2804(9) (relating to standards for restructuring of electric industry) or system improvement charges, 66 Pa.C.S. § 1353 (relating to distribution system improvement charge)*.

- The Company's proposed WNA (appearing as Rider C – WNA in the Tariff) only applies to distribution related charges that are recovering the base distribution revenue requirement from applicable WNA customer classes for the heating season of October through May. Specifically, the billing for the Company's Riders, including Rider F – USP, Rider G – EE&C, and Rider B – PGC, will continue to be based on actual monthly usage.

12. *Please explain whether the WNA includes appropriate consumer protections*.

- The WNA mechanism will result in an adjusted bill that reflects the revenues that would be recovered under normal weather, i.e., the same normal weather used to set rates. UGI Gas will not recover additional distribution revenues due to colder than average temperatures that result in higher-than-normal usage from customers.

13. *Please explain whether the WNA is understandable to customers*.

- UGI Gas's WNA is not a new concept to the regulated utility industry. Similar versions have been successfully implemented by other Pennsylvania natural gas distribution companies. UGI Gas has proposed a WNA tariff that provides detailed information to the customer of how the mechanism works based on successful working versions found in the tariffs of other Pennsylvania natural gas distribution companies that have implemented a WNA tariff. Further, educational materials and customer service training will be developed upon approval of the mechanism, as well as appropriate notice being provided to customers related to the WNA being approved pursuant to the Commission's alternative ratemaking notice requirements.

14. *<u>Please explain how the WNA will support improvements in utility reliability</u>*.

- UGI Gas's cost of service is inclusive of investments and costs to continue to enhance the safety and reliability of its system. The proposed WNA will help minimize the volatility of the recovery of these costs.

VI. <u>WIDESPREAD INDUSTRY USE OF WNA MECHANISMS</u>

Q. Are WNA mechanisms like the one the Company proposes widely accepted in the natural gas industry?

Yes. UGI Gas Exhibit JDT – 2 presents a survey conducted by Atrium Economics, with input from an American Gas Association survey,[5] which shows that many U.S. gas utilities, across a wide geographic area, have implemented WNA mechanisms. Specifically, the survey results (provided in Figure 1 below) show there are 27 states that have approved WNAs for gas companies serving 66 different service territories. Currently, As of November 2021, Atrium's research indicates that two additional gas utilities, Duke Energy in Kentucky and New Mexico Gas, have pending WNA proposals before their respective regulatory commissions. While four other gas utilities in Kentucky already have WNA mechanisms in operation, New Mexico would be added to the list of states if New Mexico Gas's WNA proposal is approved.

[5] American Gas Association "Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms: Current List" site: https://www.aga.org/sites/default/files/aga_innovative_rates_december_2016.pptx

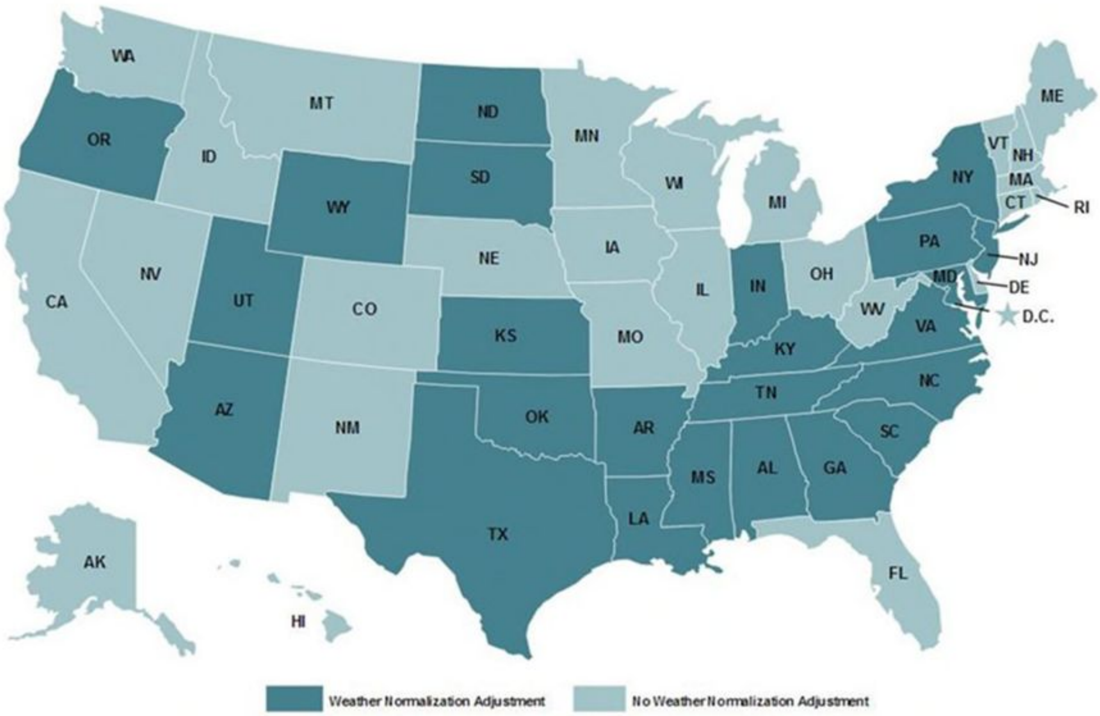

Figure 1 – Map of US States with WNA Mechanisms

Q. Are decoupling mechanisms common across the industry?

A. Yes, decoupling mechanisms are an increasingly common ratemaking tool throughout the natural gas industry. Table 1 below summarizes various approved and proposed decoupling mechanisms for 40 states in the U.S. and the District of Columbia. Along with WNAs, Revenue Normalization Adjustments ("RNA") and Straight Fixed Variable ("SFV") rate design make up the other decoupling mechanisms noted.

Table 1 – RNA, SFV, and WNA Mechanisms across the U.S.

	Decoupling Mechanism				Decoupling Mechanism		
State Name	**RNA**	**SFV**	**WNA**	**State Name**	**RNA**	**SFV**	**WNA**
Alabama			WNA	Nevada	RNA		
Arizona	RNA		WNA	New Hampshire	Proposed		
Arkansas	RNA		WNA	New Jersey	RNA		WNA
California	RNA			New York	RNA		WNA
Connecticut	RNA			North Carolina	RNA		WNA
Delaware	Proposed			North Dakota		SFV	WNA
Florida		SFV		Ohio		SFV	
Georgia		SFV	WNA	Oklahoma		SFV	WNA
Idaho	RNA			Oregon	RNA		WNA
Illinois	RNA	SFV		Pennsylvania			WNA
Indiana	RNA		WNA	Rhode Island	RNA		
Kansas			WNA	South Carolina			WNA
Kentucky			WNA	South Dakota			WNA
Louisiana			WNA	Tennessee	RNA		WNA
Maryland	RNA		WNA	Texas			WNA
Massachusetts	RNA			Utah	RNA		WNA
Michigan	RNA			Virginia	RNA		WNA
Minnesota	RNA			Washington	RNA		
Mississippi			WNA	Wyoming	RNA		WNA
Nebraska		SFV		Washington, D.C.	Proposed		

Q. Do any members of the peer group used to inform the recommended return on equity for UGI Gas in this proceeding have similar mechanisms?

A. Yes, as indicated above WNA mechanisms and decoupling mechanisms are common ratemaking mechanisms across the industry. As indicated in the testimony of Company witness Paul R. Moul (UGI Gas Statement No. 6), the utilities included in his Gas Group (the peer group) already have tariff mechanisms for stabilization of revenues due to variation in weather, either through similar WNA mechanisms as that proposed by UGI

Gas or through full revenue decoupling mechanisms. The implementation of UGI Gas's proposed WNA mechanism would place UGI Gas on a more comparable footing to the benchmark proxy group that Paul R. Moul uses in his direct testimony to establish the proposed return on equity.

Q. Have WNA proposals recently been authorized by the Commission?

A. Yes. In a December 6, 2018 Order, the Commission authorized the continuation of Columbia's WNA mechanism that had earlier been implemented on a pilot basis. Chairperson Gladys Brown Dutrieuille, provided the following statement in the Order supporting the continuation of the WNA mechanism:

> "I commend the parties for their commitment to this mechanism. … The Weather Normalization Adjustment works bi-directionally to insulate customers from high bills during the extremely cold months, while also limiting the decline in revenue for Columbia during unseasonably warm heating months. This…stabilizes Columbia's cash flow, and in turn, allows Columbia to more acutely focus on operational items within its control; namely infrastructure upgrades and repairs. Further, since this decoupling mechanism is only applied to the distribution component of the bill, and not the natural gas commodity charge, incentives for efficient consumption are maintained." [6]

Q. Do you believe UGI Gas's proposed WNA mechanism is fair to both the Company and its customers?

A. Yes. The proposed WNA mechanism strikes an appropriate balance between the interests of both the Customer and the Company. UGI Gas would be simply billing its customers in a manner to reflect the normal weather conditions that underlie its Commission-

[6] Pennsylvania Public Service Commission Docket No. R-2018-2647577.

authorized base rates on a monthly billing basis. Moreover, the WNA mechanism provides the Company a reasonable opportunity to earn its allowed rate of return on its investment and removes bill variability due a factor outside of customer's control, variations in weather.

VII. CONCLUSION

Q. Please summarize how implementing the proposed WNA mechanism results in fair and equitable ratemaking.

A. The Company's proposed WNA mechanism results in fair and equitable ratemaking due to the following:

- The WNA helps to break the link between the gas consumption of the Company's customers and its distribution revenue recovery, and better aligns the interests of UGI Gas and its customers. The fixed costs embedded in UGI Gas's volumetric rates for distribution service do not vary in the short-term with changes in temperature.

- The WNA addresses a factor beyond the Company's and customers' control, weather variability. This variability contributes to increased volatility in customers' bills, and increased volatility in the Company's recovery of costs.

- Customers receive greater stability in the non-gas portion of their utility bills, a benefit during the winter months when gas prices tend to be at their highest, and a particular benefit for low-income customers with high bills during the lengthy heating seasons in UGI Gas's service areas.

For these reasons, I urge the Commission to approve the Company's proposed WNA mechanism.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT JDT-1

ATRIUM ECONOMICS
CENTERED ON ENERGY

John D. Taylor

Managing Partner

Mr. Taylor is a utility pricing expert with experience developing cost of service studies for both electric and gas utilities and transmission companies. He has deep experience with developing residential and commercial rates, analyzing midstream transportation and storage capacity resources, and assessing the relationship between price signals and the adoption of distributed generation assets.

He has filed testimony as an expert witness on class cost of service studies for both electric and natural gas utilities, return on equity, and on the appropriate use of statistical analysis during audit testing. Mr. Taylor has supported projects involving financial analysis, regulatory support and strategy, market assessment, litigation support, and organizational and operations reviews. He has an expert knowledge of cost allocation principles for utility cost of service studies and for affiliate transaction and service agreements. Mr. Taylor's work often involves providing support for regulatory proceedings by conducting various studies and analyses related to revenue requirements, affiliate transactions, class cost of service, and cash working capital studies. He has also been involved in the sale of generating assets as sell side advisors, supporting due diligence efforts, financial analyses, and regulatory approval processes.

EDUCATION

M.A., Economics, American University

B.A., Environmental Economics, University of North Carolina at Asheville

YEARS EXPERIENCE

15

RELEVANT EXPERTISE

Utility Costing and Pricing, Expert Witness Testimony, Transaction Facilitation, Revenue Requirements, Statistics, Valuation, Market Studies, Rate Case Management, New Product and Service Development, Strategic Business Planning, Marketing and Sales

EXPERT WITNESS TESTIMONY PRESENTATION

United States

- Delaware Public Service Commission
- Federal Energy Regulatory Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Maine Public Service Commission
- Massachusetts Department of Public Utilities
- Minnesota Public Utilities Commission
- New Hampshire Public Utilities Commission
- North Carolina Utilities Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission
- Public Service Commission of West Virginia

Canada

- Alberta Utilities Commission
- British Columbia Utilities Commission
- Ontario Energy Board

REPRESENTATIVE EXPERIENCE

Rate Design and Regulatory Proceedings

Mr. Taylor has worked on dozens of electric and gas rate cases including the development of revenue requirements, class cost of service studies, and projects related to utility rate design issues. Specifically, he has:

- Lead expert and witness for class costs of service studies across North America and worked on dozens of other class cost of service and rate design projects for other lead witnesses.
- Developed WNA mechanism for a gas utility including back casting results and supporting expert witness testimony and exhibits.
- Developed revenue requirement model to comply with a new performance-based formula ratemaking process for a Midwest electric utility.
- Supported the developed of time of use rates, demand rates, economic development rates, load retention rates, and line extension policies.
- Analyzed and summarized allocation methodology for a shared services company.
- Assessed the reasonableness of costs through various benchmarking efforts.
- Led the effort to collect and organize plant addition documentation for six Midwest utilities associated with the state commission's audit of rate base.
- Supported lead-lag analyses and testimonies.
- Analyzed customer usage profiles to support reclassification of rate classes for a gas utility.
- Helped conduct a marginal cost analysis to support rate design testimony.

Litigation Support and Expert Testimony

Mr. Taylor has testified in several cases on class cost of service studies and statistical audit methods. He has also supported numerous other expert testimonies. Specifically, he has:

- Filed testimony as an expert witness on allocated class cost of service studies for both electric and gas utilities.
- Filed testimony as an expert witness on the application of statistical analysis.
- Filed testimony before FERC on the rate of return for an Annual Transmission Revenue Requirement and participated in FERC settlement conferences.
- Part of two-person expert witness team that provided an expert report to the British Columbia Utilities Commission on the use of facilities for transportation balancing services for Fortis BC.
- Part of two-person expert witness team that provided an expert report on affiliate transactions and capitalized overhead allocations for Hydro One on three separate occasions.
- Sole expert for expert report on affiliate allocations for Alectra utilities, the second largest publicly owned electric utility in North America. This was conducted shortly after the merger of four distinct utilities.
- Sole expert for expert report on the allocation of overhead costs between transmission and distribution businesses for EPCOR.

Transaction Experience

Mr. Taylor has been involved with several generating asset transactions supporting both buy side and sell side analysis and due diligence. His work has included:

- Worked as buy side advisor for a large water utility in the mid-Atlantic region including supporting the review of revenue requirements, rates, and forecasts.
- Helped facilitate and manage processes for a nuclear plant auction by processing Q&A, collecting relevant documentation and managing the virtual data room for auction participants.
- Supported the auction process for steam and chilled water distribution and generation assets in the Midwest.
- Supported the development of a financial model to ascertain the net present value of several competing wholesale power purchase agreements and guided the client with a decision matrix for the qualitative aspects of the offers.
- Provided research on comparable transactions, previous mergers and acquisitions, and potential transaction opportunities for several clients.

Financial Analysis and Market Research

Other financial analysis and market research Mr. Taylor has conducted include:

- Estimated the rate impact and costs associated with moving California energy market to 100% renewable.
- Assessed the consequences of a divestiture on the cost of service model for a New England gas distribution company.
- Developed distributed CNG/LNG market studies for two separate utilities and two separate competitive market participants.
- Modeling alternative mechanisms for the allocation of overhead costs to a nuclear plant.

UGI GAS

EXHIBIT JDT-2

Company	State	Tariff Available	Year Approved
ENSTAR Natural Gas Company	Alaska	none	
Spire Alabama, Inc.	Alabama	Temperature Adjustment Rider	2018
Spire Gulf, Inc.	Alabama	Weather Impact Normalization Factor (WINF)	2017
Arkansas Oklahoma Gas Corp.	Arkansas	Weather Normalization Adjustment (WNA)	2018
Black Hills Energy Arkansas, Inc. (d/b/a Black Hills Energy)	Arkansas	Weather Normalization Adjustment (WNA) Rider	2018
CenterPoint Energy Resources Corp.	Arkansas	Weather Normalization Adjustment (WNA)	
Arizona Public Service Company	Arizona	Lost Fixed Cost Recovery (LFCR) Mechanism	2020
Southwest Gas Corporation	Arizona	Delivery Charge Adjustment (DCA) Provision (Decoupling Mechanism)	2021
UNS Gas, Inc.	Arizona	Lost Fixed Cost Recovery (LFCR)	
Pacific Gas & Electric Company	California		
San Diego Gas & Electric Company	California		
Southern California Gas Company	California		
Southwest Gas Corporation	California	Fixed Cost Adjustment Mechanism (FCAM)	2014
Atmos Energy Corporation	Colorado	General Rate Schedule Adjustment (GRSA) Rider	
Black Hills Colorado Gas, Inc. (d/b/a Black Hills Energy)	Colorado	none	
Rocky Mountain Natural Gas, LLC (d/b/a Black Hills Energy)	Colorado	none	
Public Service Company of Colorado (d/b/a Xcel Energy)	Colorado	Pilot Revenue Decoupling Mechanism (RDM)	
Connecticut Natural Gas Corporation (d/b/a Avangrid)	Connecticut	Decoupling Mechanism	
Southern Connecticut Gas Company (d/b/a Avangrid)	Connecticut	Decoupling Mechanism	
Yankee Gas Services Company (d/b/a Eversource)	Connecticut	Revenue Decoupling Mechanism (RDM) Rider	
Washington Gas Light Company	DC	Gas Supply Realignment Adjustment (GSRA)	
Washington Gas Light Company	DC	Plant Recovery Adjustment (PRA)	2011
Chesapeake Utilities Corporation	Delaware	none - legislature-mandated revenue decoupled rate designs were repealed in 2009	
Delmarva Power & Light Company	Delaware	none - legislature-mandated revenue decoupled rate designs were repealed in 2009	
Florida Public Utilities Company	Florida	none	
Peoples Gas System (a division of Tampa Electric Co) (d/b/a Emera)	Florida	none	
Atlanta Gas Light Company	Georgia	Georgia Rate Adjustment Mechanism (GRAM)	
Black Hills Iowa Gas Utility Company, LLC (d/b/a Black Hills Energy)	Iowa	none	
Interstate Power and Light Company (d/b/a Alliant Energy)	Iowa	none	
MidAmerican Energy Company (d/b/a Berkshire Hathaway Energy)	Iowa	none	
Avista Corporation	Idaho	Fixed Cost Adjustment Mechanism	
Intermountain Gas Company (d/b/a MDU Resources Group)	Idaho	none	

Company	State	Tariff Available	Year Approved
Ameren Illinois Company (d/b/a Ameren)	Illinois	none	
MidAmerican Energy Company (d/b/a Berkshire Hathaway Energy)	Illinois	none	
Northern Illinois Gas Company	Illinois		
North Shore Gas Company	Illinois		
Peoples Gas Light and Coke Company	Illinois		
Indiana Gas Company, Inc. (d/b/a CenterPoint Energy Resources Corp.)	Indiana	Normal Temperature Adjustment (NTA)	2008
Northern Indiana Public Service Company (d/b/a NiSource)	Indiana	none	
Southern Indiana Gas & Electric Company (d/b/a CenterPoint Energy Resources Corp.)	Indiana	Normal Temperature Adjustment (NTA)	2021
Atmos Energy Corporation	Kansas	Weather Normalization Adjustment (WNA) Rider	
Black Hills Kansas Gas Utility Company, LLC (d/b/a Black Hills Energy)	Kansas	Weather Normalization Adjustment (WNA) Rider	2015
Kansas Gas Service Company, Inc. (d/b/a ONE Gas)	Kansas	Weather Normalization Adjustment (WNA) Rider	2019
Atmos Energy Corporation	Kentucky	Weather Normalization Adjustment (WNA) Rider	
Columbia Gas of Kentucky, Inc. (d/b/a NiSource)	Kentucky	Weather Normalization Adjustment (WNA)	2009
Delta Natural Gas Company, Inc.	Kentucky	none	
Duke Energy Kentucky, Inc. (d/b/a Duke Energy)	Kentucky	Weather Normalization Adjustment (WNA) Rider	2019
Louisville Gas & Electric Company	Kentucky	Weather Normalization Adjustment (WNA) Clause	2019
Atmos Energy Corporation	Louisiana	Rate Stabilization Clause - Rider RSC	
Atmos Energy Corporation	Louisiana	Weather Normalization Adjustment - Rider WNA	
Entergy Louisiana, LLC (d/b/a Entergy)	Louisiana	Rate Stabilization Plan (RSP) Rider	2020
Entergy New Orleans, LLC (d/b/a Entergy)	Louisiana	Gas Formula Rate Plan Rider	2020
CenterPoint Energy Resources Corp.	Louisiana	Weather Normalization Adjustment (WNA) Rider	
Columbia Gas (Bay State Gas Company) of Massachusetts, Inc. (d/b/a Eversource)	Massachusetts	Revenue Decoupling Adjustment Clause (RDAC)	2020
The Berkshire Gas Company (d/b/a Avangrid)	Massachusetts	Revenue Decoupling Adjustment Clause	2020
Boston Gas Company (d/b/a National Grid)	Massachusetts	Revenue Decoupling Mechanism Clause	2018
Colonial Gas Company (d/b/a National Grid)	Massachusetts	Revenue Decoupling Mechanism Clause	2018
Fitchburg Gas & Electric Light Company (d/b/a Unitil)	Massachusetts	Revenue Decoupling Adjustment Clause	2020
Liberty Utilities (New England Natural Gas Company) Corporation (d/b/a Liberty Utilities)	Massachusetts	Revenue Decoupling Adjustment Clause	2019
NSTAR Gas Company (d/b/a Eversource)	Massachusetts	Revenue Decoupling Adjustment Clause	2020

Company	State	Tariff Available	Year Approved
Baltimore Gas & Electric Company	Maryland		
Chesapeake Utilities Corporation	Maryland		
Columbia Gas of Maryland, Inc. (d/b/a NiSource)	Maryland	Weather Normalization Adjustment (WNA)	2016
Washington Gas Light Company	Maryland		
Maine Natural Gas (d/b/a Avangrid)	Maine	none	
Summit Natural Gas of Maine, Inc.	Maine	none	
Consumers Energy Company	Michigan	RDM authorized in Sept 2019	
DTE Gas Company	Michigan	RDM authorized in Sept 2018	
Michigan Gas Utilities Corporation	Michigan	terminated RDM in 2015	
CenterPoint Energy Resources Corp.	Minnesota	Revenue Decoupling Rider (RD Rider)	
Minnesota Energy Resources Corporation	Minnesota	Revenue Decoupling Mechanism (RDM)	2019
Northern States Power Company (d/b/a Xcel Energy)	Minnesota	State Energy Policy Rate Rider	
Empire District Gas Company (d/b/a Liberty Utilities)	Missouri	none	
Midstates Natural Gas Corporation (d/b/a Liberty Utilities)	Missouri	Weather Normalization Adjustment Rider (WNAR)	2020
Missouri Gas Energy (d/b/a Spire)	Missouri	Weather Normalization Adjustment Rider (WNAR)	2018
Spire Missouri, Inc. (d/b/a Spire)	Missouri	Weather Normalization Adjustment Rider (WNAR)	2018
Summit Natural Gas of Missouri, Inc.	Missouri	none	
Atmos Energy Corporation	Mississippi	Weather Normalization Adjustment (WNA) Rider	
Atmos Energy Corporation	Mississippi	Stable Rate Adjustment (SRA) Rider	
CenterPoint Energy Resources Corp.	Mississippi	Weather Normalization Adjustment (WNA)	2012
MDU Resources Group, Inc.	Montana	none	
NorthWestern Corporation	Montana		
Piedmont Natural Gas Company, Inc. (d/b/a Duke Energy)	North Carolina	Margin Decoupling Tracker	2008
Public Service Company of North Carolina, Inc. (d/b/a Dominion Energy)	North Carolina	Customer Usage Tracker - Rider C	
MDU Resources Group, Inc.	North Dakota	Distribution Delivery Stabilization Mechanism (DDSM)	
Northern States Power Company (d/b/a Xcel Energy)	North Dakota		
Black Hills Nebraska Gas, LLC (d/b/a Black Hills Energy)	Nebraska	none	
NorthWestern Energy	Nebraska	none	
MidAmerican Energy Company (d/b/a Berkshire Hathaway Energy)	Nebraska	none	
Liberty Utilities (EnergyNorth Natural Gas) Corp.	New Hampshire	Normal Weather Adjustment (NWA) - effective Nov. 1, 2021	2021
Northern Utilities, Inc. (d/b/a Unitil)	New Hampshire		
Elizabethtown Gas Company	New Jersey		
New Jersey Natural Gas Company	New Jersey		
Public Service Electric and Gas Company	New Jersey		
South Jersey Gas Company	New Jersey		
New Mexico Gas Company, Inc. (d/b/a Emera)	New Mexico	none	

Company	State	Tariff Available	Year Approved
Sierra Pacific Power Company (d/b/a NV Energy)	Nevada	Deferred Energy Accounting Adjustment (DEAA)	2021
Southwest Gas Corporation	Nevada	General Revenues Adjustment Mechanism (GRAM)	2020
Consolidated Edison Company of New York, Inc. (d/b/a Consolidated Edison, Inc.)	New York	Revenue Decoupling Mechanism (RDM) Adjustment	2020
Consolidated Edison Company of New York, Inc. (d/b/a Consolidated Edison, Inc.)	New York	Weather Normalization Adjustment (WNA)	2019
KeySpan Gas East (Brooklyn Union of Long Island) Corporation (d/b/a National Grid)	New York	Revenue Decoupling Mechanism (RDM) Adjustment	
KeySpan Gas East (Brooklyn Union of Long Island) Corporation (d/b/a National Grid)	New York	Weather Normalization Adjustment (WNA)	2021
Niagara Mohawk Power Corporation (d/b/a National Grid)	New York	Revenue Decoupling Mechanism (RDM) Adjustment	2018
Niagara Mohawk Power Corporation (d/b/a National Grid)	New York	Weather Normalization Adjustment (WNA)	2018
Orange and Rockland Utilities, Inc. (d/b/a Consolidated Edison, Inc.)	New York	Revenue Decoupling Mechanism (RDM) Adjustment	2019
Orange and Rockland Utilities, Inc. (d/b/a Consolidated Edison, Inc.)	New York	Weather Normalization Adjustment (WNA)	2019
Rochester Gas & Electric Corporation (d/b/a Avangrid)	New York	Revenue Decoupling Mechanism (RDM) Adjustment	2020
Rochester Gas & Electric Corporation (d/b/a Avangrid)	New York	Weather Normalization Adjustment (WNA)	2016
Columbia Gas of Ohio, Inc. (d/b/a NiSource)	Ohio	none	
Duke Energy Ohio, Inc. (d/b/a Duke Energy)	Ohio	none	
The East Ohio Gas Company (d/b/a Dominion Energy)	Ohio	none	
Vectren Energy Delivery of Ohio, Inc.	Ohio		
Oklahoma Natural Gas Company (d/b/a ONE Gas)	Oklahoma	Temperature Adjustment Clause	2010
CenterPoint Energy Resources Corp.	Oklahoma	Weather Normalization Adjustment (WNA)	
Arkansas Oklahoma Gas Corp.	Oklahoma	Weather Normalization Adjustment (WNA)	
Avista Corporation	Oregon	Decoupling Mechanism	
Cascade Natural Gas Corporation	Oregon		
Northwest Natural Gas Company	Oregon		

Company	State	Tariff Available	Year Approved
Columbia Gas of Pennsylvania, Inc. (d/b/a NiSource)	Pennsylvania	Rider WNA - Weather Normalization Adjustment	2013
National Fuel Gas Distribution Corporation	Pennsylvania	none	
PECO Energy Company (d/b/a Exelon)	Pennsylvania	none	
Peoples Natural Gas Company, LLC	Pennsylvania	none	
Peoples TWP LLC	Pennsylvania	none	
Philadelphia Gas Works	Pennsylvania	Weather Normalization Adjustment Clause	2002
Narragansett Electric Company	Rhode Island		
Piedmont Natural Gas Company, Inc. (d/b/a Duke Energy)	South Carolina		
Dominion Energy South Carolina, Inc.	South Carolina		
MDU Resources Group, Inc.	South Dakota	Distribution Delivery Stabilization Mechanism (DDSM)	
NorthWestern Corporation	South Dakota		
MidAmerican Energy Company (d/b/a Berkshire Hathaway Energy)	South Dakota	none	
Piedmont Natural Gas Company, Inc. (d/b/a Duke Energy)	Tennessee	Weather Normalization Adjustment (WNA) Rider	
Chattanooga Gas Company	Tennessee		
Atmos Energy Corporation	Tennessee	Weather Normalization Adjustment (WNA) Rider	
CenterPoint Energy Resources Corp.	Texas	none	
Texas Gas Service Company, Inc. (d/b/a ONE Gas) (Borger/Skellytown Serv Area)	Texas	Weather Normalization Adjustment Clause	
Texas Gas Service Company, Inc. (d/b/a ONE Gas) (Central Gulf Serv Area)	Texas	Weather Normalization Adjustment Clause	
Texas Gas Service Company, Inc. (d/b/a ONE Gas) (North Texas Serv Area)	Texas	Weather Normalization Adjustment Clause	
Texas Gas Service Company, Inc. (d/b/a ONE Gas) (Rio Grande Valley Serv Area)	Texas	Weather Normalization Adjustment Clause	
Texas Gas Service Company, Inc. (d/b/a ONE Gas) (West Texas Serv Area)	Texas	Weather Normalization Adjustment Clause	
Atmos Energy Corporation (Mid-Tex Division)	Texas	Weather Normalization Adjustment (WNA)	
Atmos Energy Corporation (West Texas Division)	Texas	Weather Normalization Adjustment (WNA) Rider	
Dominion Energy Utah, Inc. (d/b/a Dominion Energy)	Utah	Weather Normalization Adjustment (WNA)	
Vermont Gas Systems, Inc.	Vermont	none	
Columbia Gas of Virginia, Inc. (d/b/a NiSource)	Virginia	Weather Normalization Adjustment (WNA)	2016
Columbia Gas of Virginia, Inc. (d/b/a NiSource)	Virginia	Revenue Normalization Adjustment (RNA)	2019
Roanoke Gas Company	Virginia	Weather Normalization Adjustment (WNA)	2004
Virginia Natural Gas, Inc.	Virginia	Weather Normalization Adjustment (WNA)	
Washington Gas Light Company	Virginia	Weather Normalization Adjustment (WNA)	2007
Atmos Energy Corporation	Virginia	Weather Normalization Adjustment (WNA)	

Company	State	Tariff Available	Year Approved
Avista Corporation	Washington	Decoupling Mechanism	
Cascade Natural Gas Corporation	Washington		
Puget Sound Energy, Inc.	Washington		
Madison Gas & Electric Company	Wisconsin	none	
Northern States Power Company (d/b/a Xcel Energy)	Wisconsin	none	
Wisconsin Electric Power Company	Wisconsin	none	
Wisconsin Gas, LLC	Wisconsin	none	
Wisconsin Power & Light Company (d/b/a Alliant Energy)	Wisconsin	none	
Wisconsin Public Service Corporation	Wisconsin	revenue decoupling mechanism from 2009 to 2013	
Hope Gas, Inc. (d/b/a Dominion Energy)	West Virginia	none	
Mountaineer Gas Company	West Virginia	none	
Black Hills Wyoming Gas, LLC. (d/b/a Black Hills Energy)	Wyoming	Revenue Adjustment Mechanism (RAM)	
Cheyenne Light, Fuel & Power Company (d/b/a Black Hills Energy)	Wyoming	none	
Dominion Energy Wyoming, Inc. (d/b/a Dominion Energy)	Wyoming	Weather Normalization Adjustment (WNA)	
MDU Resources Group, Inc.	Wyoming	none	