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. 7 – VICKY A. SCHAPPELL
UGI GAS STATEMENT NO. 8 – DYLAN W. D'ASCENDIS
UGI GAS STATEMENT NO. 9 – DARIN T. ESPIGH
UGI GAS STATEMENT NO. 10 – SHERRY A. EPLER
UGI GAS STATEMENT NO. 11 – JOHN D. TAYLOR
UGI GAS STATEMENT NO. 12 – BRIAN J. MEILINGER

UGI UTILITIES, INC. – GAS DIVISION
PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 63

DOCKET NO. R-2025-3059523

Issued: January 28, 2026 **Effective: March 29, 2026**

UGI GAS STATEMENT NO. 7

VICKY A. SCHAPPELL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 7

Direct Testimony of
Vicky A. Schappell

Topics Addressed: Capital Planning

Dated: January 28, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vicky A. Schappell. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

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

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

Q. Please describe your educational background and work experience.

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

Q. What are your responsibilities as Senior Manager?

A. As Senior Manager, I supervise a team of Analysts responsible for the preparation of the annual capital budgets for UGI Gas and UGI Electric. I am responsible for obtaining budget inputs from various departments including Engineering, Operations, Corrosion, Marketing, Information Technology ("IT"), and the Building and Grounds Departments. I collaborate with the Vice President of Operations, the Vice President of Global Engineering, the Director of Engineering Design, the Director Sales, the Director of Pipeline System Planning and Optimization, the Director Financial Planning and Analysis and Senior Engineering Managers to monitor annual capital budget performance and develop strategies to limit variances in capital installations and spending. I also work closely with the President of UGI in developing the overall capital spend strategy. In this role, I have also prepared testimony with supporting exhibits and schedules, and sponsored responses to discovery requests for past base rate cases. Also, I am responsible for preparing UGI Gas's Annual Asset Optimization Plan. Additionally, I had an integral role in developing an expanded capital spending monitoring process necessary for managing the Company's accelerated capital investments programs.

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

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

Q. What is the purpose of your testimony?

A. My testimony will address the capital planning process used by UGI Gas which supports the plant in service expenditures included in the proposed rates in this proceeding, specifically as related to plant additions for the future test year ending September 30, 2026("FTY"), and the fully projected future test year ending September 30, 2027 ("FPFTY" or "FY2027").

Q. Are you sponsoring any exhibits in this proceeding?

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

II. CAPITAL PLANNING

Q. What is the total plant in service budget for UGI Gas for the FPFTY that is reflected in the proposed rates?

A. The total budgeted plant additions for UGI Gas for the FPFTY is $507,994,000.

Q. What are the specific project categories included in the capital budget for UGI Gas?

A. UGI Gas has four main categories that make up its capital budgets: (1) replacement and betterment infrastructure; (2) new business; (3) IT; and (4) other capital spending. I will describe each of these categories and the projects associated with them, as well as the total dollars attributable to each category below.

Q. What process does UGI Gas use to develop its capital budget?

A. UGI Gas's capital budget starts by identifying the four critical areas where the Company must make capital investments to maintain safe and reliable service to customers. For each of these budget areas, the Company then identifies all of the projects or categories of projects that are planned to occur in each fiscal year of a two-year forecast. Once those projects are determined, the Company identifies the FERC accounting treatment for each project. In this case, the Company presents them as part of the budgeted plant additions in Exhibit A, Schedule C-2. The process used to develop Exhibit A is further described in the direct testimony of Tracy A. Hazenstab (UGI Gas Statement No. 2).

Q. How does Schedule C-2 show plant additions?

A. Schedule C-2 is an accounting presentation based on FERC accounts. For purposes of developing Schedule C-2, budgeted dollars in each budget category are broken out by the

FERC account numbers that drive the accounting for depreciation. Schedule C-2 is split between Distribution Plant and General and Common Plant. The General and Common Plant includes only the distribution portion of the plant additions for UGI Gas.

Q. Have you prepared an exhibit that shows UGI Gas's plant additions broken down by budget project categories?

A. Yes, I have. UGI Gas Exhibit VAS-2 reflects the Company's plant additions broken out by the different project categories for the five-year period from fiscal year 2023 through fiscal year 2027. The exhibit splits the four budget project categories between Distribution Plant and General and Common Plant, consistent with the categories on Schedule C-2. In addition, UGI Gas Exhibit VAS-2 shows a historical comparison of the total budgeted plant placed in service versus actual plant placed in service additions for the three-year period from fiscal year 2023 through fiscal year 2025. I will describe how the Company's performance history supports the reasonableness of the Company's FTY and FPFTY plant additions in greater detail later in my testimony.

Q. Please comment on the presentations shown in UGI Gas Exhibit VAS-2 and Schedule C-2.

A. While the forecasted total plant in service figures match for the FTY and the FPFTY, there is a difference in the presentation of how UGI Gas Exhibit VAS-2 and Schedule C-2 present plant additions, and it is important to understand how these budget presentations align. Specifically, UGI Gas Exhibit VAS-2 shows how the Company's four individual budget categories constitute the Company's total Plant Additions and how they map into the Distribution and General and Common Plant on Schedule C-2. Exhibit VAS-2 shows that three of the four budget categories fall into both of the plant categories (i.e., Distribution Plant and General & Common Plant) when describing the budget by FERC accounts. IT projects are the only budget category where projects fall exclusively into one FERC plant account – General and Common Plant – when recorded for accounting purposes.

Q. Why is it important to understand the relationship between the Company's budgeting process and the reflection of the budget in Schedule C-2?

A. When the Company plans for future plant additions, it utilizes a project-based build-up and does not directly budget using the FERC accounts, as work streams do not directly correlate to the format shown in Schedule C-2. When the Company budgets and then executes on its budget, it first looks at the total for the budget category, and then examines its overall budgeted projects on a total additions basis, because its operations and work streams are divided in the same manner to achieve core utility objectives. Ultimately, the Company manages to the total overall budget. As a result of this process, it is more reasonable to review the Distribution and General and Common Plant levels together when considering how the Company performed to its budget, rather than the accounting distinction set forth in Schedule C-2. Thus, to properly compare historical budgeted plant additions to actuals for ratemaking purposes, the Distribution and General and Common Plant additions should be reviewed in total.

Q. Turning to the capital budget categories, what are replacement and betterment projects?

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

Q. Please describe the prioritization process that is used to evaluate R&B projects.

A. Projects are prioritized for inclusion in the budget according to the condition of, and risks associated with, existing assets, including those factors affecting safety and reliability. In determining the condition of an existing asset, the Company considers various criteria including, but not limited to the replacement of cast iron and bare steel pipe, which are more susceptible to failure from corrosion, cracks, and leakage (as compared to other pipe materials). This comprehensive approach is ultimately utilized which targets the highest risk mains first and incorporates considerations related to the efficient deployment of capital and resources. UGI Gas has also committed to replacing identified priority plastic pipe, in addition to cast iron and bare steel pipe as defined in its Third Long Term Infrastructure Improvement Plan ("LTIIP") as discussed below. Risk evaluations for mains are based on numerous factors, including condition, age, coating, type of ground cover, geographical proximity to structures and prior leak and/or break history. UGI Gas reviews these factors annually to identify the highest risk pipe segments and prioritize them for replacement.[1] Specifically, commercial risk evaluation software is used in concert with a team of Subject Matter Experts to evaluate, prioritize, and bundle replacement projects. Furthermore, UGI Gas's Distribution Integrity Management Program ("DIMP") and Transmission Integrity Management Program ("TIMP") provide a detailed listing and weighting of factors considered in the risk-based evaluation, which may cause specific projects to be reprioritized for replacement on a more accelerated basis

UGI Gas's prioritization of projects for its capital budgets is consistent with its DIMP and LTIIP, which is described in more detail in the direct testimony of UGI Gas witness, Jill E. Walter (UGI Gas Statement No. 3). LTIIP replacement investments are identified and prioritized on a risk basis in accordance with UGI Gas's DIMP.

Q. Has there been any update in UGI Gas's priorities for its R&B investments?

A. Yes. As of the end of calendar year 2026, the Company will have completed its cast iron retirement, removing 407 miles from service since this program began in 2013. Beginning in calendar year 2027, the Company shift its R&B focus to bare steel retirement, as well as vintage plastic identification and replacement.

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

A. UGI Gas's LTIIP guides the formulation of the overall R&B capital budget. Within the

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

various categories of the LTIIP, R&B projects are selected and prioritized according to the risk-based evaluation process that I described above. The total anticipated budgeted plant additions associated with R&B projects in the FPFTY is $383,642,000 of which $383,135,000 is included in Distribution plant additions and $507,000 is included in General and Common Plant Additions.

Q. What are new business projects?

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

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

A. The new business portion of the capital budget is developed according to forecasts of new business opportunities, projections of customer conversions, and plans for new construction and development projects. The total anticipated budgeted plant additions associated with new business projects in the FPFTY is $75,690,000; these additions are included in Distribution plant additions.

Q. What are IT projects?

A. IT projects enhance the Company's IT systems in a number of ways. These projects involve hardware and software applications which improve the Company's processes and methods across a wide range of operational concerns or needs, such as capital project management, cybersecurity, customer communications, billing as well as other areas. Further, these projects facilitate the Company's ability to enter, store, retrieve, and send data and information related to such projects. The total anticipated budgeted plant additions associated with IT projects in the FTY is $43,732,000. Of this amount, $18,818,000 relates to one specific large IT project, Field Services Management ("FSM"), which has a planned in-service date of July 2026as presented in the Company's 2025 Gas Base Rate Case.[2] The total anticipated budgeted plant additions associated with IT projects in the FPFTY is $12,032,000 and these projects are included in General and Common Plant Additions.

Q. Please describe the prioritization process used to evaluate IT projects.

A. IT projects are prioritized for inclusion in the budget based on identified business needs. UGI relies on an IT Prioritization Committee to develop a prioritized budget based on overall business impact, availability of system support, and resource availability. Examples of IT projects include the Pipeline Risk Management – DIMP project that went into service in September 2025. This project focused on standardizing a tool to maintain compliance and mitigate asset risk.

Q. What are Other capital projects?

A. Other capital projects include building-related projects, corrosion control projects, capital tool purchases, and fleet purchases. Building-related projects consist of building and land

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[2] See the Direct Testimony of Vicky A. Schappell, UGI Gas Statement No. 5. *See also*, *Pa. PUC v. UGI Gas*, R-2024-3052716 (Recommended Decision issued on August 8, 2025 recommending approval of the Joint Petition for Approval of All Issues without modification). No party challenged the Company's FSM and related IT Plan.

purchases, building improvements/renovations, and the purchase of furniture. Corrosion control projects include upgrades and replacements of cathodic protection systems for mains. Capital tool projects encompass new tool purchases for field use during capital projects. These tools include tapping and stopping equipment, safety tools, and leak detection equipment. Fleet purchases are needed to maintain a reliable mode of transportation for field employees along with certain specialty equipment required to perform daily functions. These acquisitions include SUVs, pickup trucks, cargo vans, service body trucks, compressor crew trucks, vacuum trucks, aerial lift trucks, dump trucks, backhoes, excavators, forklifts, and equipment trailers for backhoes and excavators. The total anticipated budgeted plant additions associated with Other projects in the FPFTY is $36,630,000 of which $5,597,000 is included in Distribution plant additions and $31,032,000 is included in General and Common Plant Additions (UGI Gas Exhibit VAS-2).

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

A. The prioritization process for Other capital projects is specific to the need being addressed. Building-related projects are prioritized for inclusion in the budget based on safety, security, regulatory, or financial and strategic needs. Regulatory driven projects may originate from compliance requirements or certain audit observations. Physical security audits may prompt the installation of fencing, gates and access controls. Corrosion control projects involving coated steel main replacements are prioritized for inclusion in the budget according to requirements set forth in the Federal Gas Safety Regulations (49 C.F.R. Part

192).[3] Corrosion control projects also may depend on unrepairable leakages or emerging main issues. Capital tool projects are prioritized for inclusion in the budget according to the useful life of the existing assets. Fleet purchases are prioritized for inclusion in the budget based on age, condition, maintenance costs, and mileage of the existing asset.

Q. Please discuss some of the key drivers which support the increase in UGI Gas's FPFTY plant additions as compared to the HTY.

A. The planned capital for FY2027 includes cost increases in R&B associated with complexity, location and size of the remaining bare steel replacement projects, as well as general resource cost increases. It also includes priority plastic pipe as Distribution System Improvement Charge-eligible property that will be replaced through the LTIIP on an accelerated basis to reduce associated leaks and overall risks on the Company's distribution system, as defined in the Company's Third LTIIP at Docket No. P-2024-3050769. The Company's total planned 2027 replacement miles will be 75 to 85 miles. This includes a planned abandonment of a large section of a wrought iron and bare steel line in the northern part of the Company' service territory due to corrosion. This is compared to the approximately 63 miles of cast iron, bare steel and wrought iron main that were removed and replaced in FY2025.

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

Q. How can UGI Gas's actual in-service plant additions be compared to budgeted in service plant additions historically in order to demonstrate Company performance?

A. As shown in UGI Gas Exhibit VAS-2, over the past three years, the Company's total budgeted in service plant additions were $1,295,956,000, while the total actual in-service plant additions were $1,280,839,000. Thus, UGI Gas's plant in service performance as viewed by variance to budget can be shown to be under 1.2% ($1,295,956,000/$1,280,839,000) over the three-year period. UGI Gas Exhibit VAS-2 also shows that over the past five years, the Company's total budgeted in service plant additions were $2,083,368, while the total actual in-service plant additions were $2,085,134. Thus, UGI Gas's plant in service performance as viewed by variance to budget can be shown to be 0.1% ($2,085,134/$2,083,368) over the five-year period. This close correlation is indicative of the Company's ability to perform in developing a plan for plant additions and reliably executing to that plan. Importantly, the Company manages its budgets in total and as any budget changes are made dollars are reallocated between the four main budget categories, described above, such that the total plant additions align as close as possible to the total plant addition actuals.

Q. What process does UGI Gas utilize when developing its capital budgets?

A. During the Company's annual capital budget process, which occurs during the summer/fall, a two-year budget is prepared. The first year of the capital budget is the basis for the FTY. The second year is a preliminary budget and is the basis for the FPFTY. During the budget process, project managers estimate the total project costs and budgeted in-service dates at the project level based on the current data available. These estimated in-service dates are the basis for the budgeted plant additions as further discussed in the testimony of UGI Gas witness Amy M. Keller (UGI Gas Statement No. 5). As the Company transitions from one budget year to the next, and the preliminary budget year becomes the active budget year, the Company makes certain adjustments to its budget for known and measurable changes in the assumptions about operating conditions that supported the preliminary budget. For example, the Company adjusts its project lists on an annual basis based on operational demands, such as the need to reprioritize projects based on emerging service needs or unanticipated equipment condition changes.

Q. What metric is utilized by the Company to track plant addition performance?

A. Exhibit VAS-2 compares plant additions placed in service (i.e., actuals) to the budgeted plant additions between 2023 and 2025 in order to track actual plant addition performance. The exhibit provides these figures by the four above-described budget categories. It also separates them by Distribution Plant and General and Common Plant. Taken together, the Distribution and General and Common Plant categories calculate total Plant Additions. Finally, the exhibit calculates the plant in service as a percent of budget metric for each year and over the three-year period by dividing actuals by budgets.

Specifically, during this three-year period, the Company's plant additions averaged 98.8% of its budget. The percentage of plant additions is calculated by dividing the actual plant additions by the budgeted plant additions (Actual / Forecast). This close correlation between budgeted and actual plant placed in service over a three-year period shows that UGI Gas's budget process is very effective at identifying its required plant additions, and UGI Gas's capital deployment and management activities perform actual work in near identical level to budgeted levels. In total, this comparative metric supports the Company's ability to successfully plan and execute on the claimed level of plant in service in this case.

III. <u>CONCLUSION</u>

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT VAS-1

Vicky A. Schappell

Senior Manager – Capital Planning

WORK EXPERIENCE

UGI Utilities, Inc. (Denver, PA)

Senior Manager – Capital Planning	May 2024-Present
Principal Analyst - Capital Planning	January 2020-May 2024
Senior Analyst - Capital Planning	April 2018-January 2020
Senior Supervisor Plant Accounting	December 2014-April 2018
Senior Analyst - General Ledger	September 2011-December 2014
Analyst II – General Ledger	September 2008-September 2011

Teleflex Medical (Reading, PA)

Accounting Supervisor	December 2007-September 2008
Senior Accountant – Financial Reporting	March 2003-December 2007
Staff Accountant – Financial Reporting	October 1999-March 2003

Heffler, Radetich & Saitta, LLP (Philadelphia, PA)

Auditor	May 1997-October 1999

Education

B.S. in Accounting, Shippensburg University,
1997

Previous Testimony

UGI Gas Base Rate Case	Docket No. R-2019-3015162
UGI Gas Base Rate Case	Docket No. R-2021-3030218
UGI Electric Base Rate Case	Docket No. R-2022-3037368
UGI Gas Base Rate Case	Docket No. R-2024-3052716

UGI GAS

EXHIBIT VAS-2

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

Description	Budget 2025	Actual 2025	Budget 2024	Actual 2024	Budget 2023	Actual 2023	Budget 2022	Actual 2022	Budget 2021	Actual 2021	5 Year Total Budget	5 Year Total Actual	3 Year Total Budget	3 Year Total Actual
Natural Gas Production														
Replacement and Betterment										(207)	-	(207)	-	-
Subtotal Natural Gas Production	-	-	-	-	-	-	-	-	-	(207)	-	(207)	-	-
Transmission Plant														
Replacement and Betterment		698		(3)		(241)		(53)		305	-	706	-	454
Growth		142						(239)		239	-	142	-	142
Other		112				(71)		90		(10)	-	120	-	40
Subtotal Transmission Plant	-	952	-	(3)	-	(313)	-	(202)	-	534	-	968	-	636
Distribution														
Replacement and Betterment	315,140	290,910	259,662	243,367	317,228	302,171	281,270	293,795	247,853	229,239	1,421,153	1,359,483	892,030	836,449
Growth	67,447	77,260	67,452	68,926	67,961	92,260	69,493	77,289	65,503	84,264	337,855	400,000	202,860	238,446
Other	6,731	3,955	4,750	5,202	6,100	6,896	7,248	5,573	6,350	5,165	31,178	26,791	17,580	16,053
IT											-	-	-	-
Subtotal Distribution	389,317	372,126	331,864	317,496	391,289	401,327	358,011	376,657	319,706	318,668	1,790,187	1,786,273	1,112,469	1,090,948
General and Common Plant														
Replacement and Betterment	377	1,100	554	838	341	255	178	339	220	437	1,671	2,969	1,272	2,193
Growth	-									1	-	1	-	-
Other	17,132	22,656	33,504	34,384	52,960	48,386	26,375	30,937	58,650	46,404	188,620	182,768	103,595	105,426
IT	12,665	11,289	15,539	23,630	50,414	46,717	13,839	15,091	10,433	15,632	102,890	112,359	78,619	81,635
Subtotal General and Common Plant	30,174	35,044	49,598	58,852	103,715	95,358	40,392	46,368	69,302	62,474	293,181	298,096	183,487	189,255
Total Plant Additions	419,491	408,122	381,462	376,346	495,003	496,372	398,404	422,823	389,008	381,469	2,083,368	2,085,131	1,295,956	1,280,839
	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)
Plant Additions Placed in Service as % of Budget	**(2) / (1)**	**97.3%**	**(2) / (1)**	**98.7%**	**(2) / (1)**	**100.3%**	**(2) / (1)**	**106.1%**	**(2) / (1)**	**98.1%**	**(2) / (1)**	**100.1%**	**(2) / (1)**	**98.8%**

Forecasted Performance

Description	FPFTY Budget 2027	FTY Budget 2026
Distribution		
Replacement and Betterment	383,135	311,002
Growth	75,690	74,698
Other	5,597	10,061
Subtotal Distribution	464,423	395,762
General and Common Plant		
Replacement and Betterment	507	524
Growth		
Other	31,032	30,565
IT	12,032	43,732
Subtotal General and Common Plant	43,572	74,820
Total Forecasted Plant Additions	507,994	470,582

UGI GAS STATEMENT NO. 8

DYLAN W. D’ASCENDIS

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 8

Direct Testimony of
Dylan W. D’Ascendis

Topics Addressed: **Return on Equity**

Dated: January 28, 2026

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DIRECT TESTIMONY OF DYLAN W. D'ASCENDIS

I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is Dylan W. D'Ascendis. My business address is 1820 Chapel Ave., W., Suite 300, Cherry Hill, N.J. 08003. I am a Partner at ScottMadden, Inc.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND AND EXPERIENCE?

A. I have offered expert testimony on behalf of investor-owned utilities before over 40 state regulatory commissions in the United States, the Federal Energy Regulatory Commission, the National Energy Regulator in Canada, the Alberta Utility Commission, one American Arbitration Association panel, and the Superior Court of Rhode Island on issues including, but not limited to, common equity cost rate, rate of return, valuation, capital structure, class cost of service, and rate design.

On behalf of the American Gas Association ("AGA"), I calculate the AGA Gas Index, which serves as the benchmark against which the performance of the American Gas Index Fund ("AGIF") is measured on a monthly basis. The AGA Gas Index and AGIF are a market capitalization-weighted index and mutual fund, respectively, comprised of the common stocks of the publicly traded corporate members of the AGA.

I am a member of the Society of Utility and Regulatory Financial Analysts ("SURFA"). In 2011, I was awarded the professional designation "Certified Rate of Return Analyst" by SURFA, which is based on education, experience, and the successful completion of a comprehensive written examination.

I am also a member of the National Association of Certified Valuation Analysts ("NACVA") and was awarded the professional designation "Certified Valuation Analyst" by the NACVA in 2015.

I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I have also received a Master of Business Administration with high honors and concentrations in Finance and International Business from Rutgers University.

The details of my educational background and expert witness appearances are included in Appendix A.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. The regulatory commissions before whom I have testified are identified in Appendix A.

II. <u>PURPOSE OF DIRECT TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Direct Testimony is to present evidence and provide the Pennsylvania Public Utility Commission ("Commission") with a recommendation regarding UGI Utilities, Inc. – Gas Division's ("UGI Gas" or the "Company") return on common equity ("ROE") for its natural gas distribution operations, and to provide an assessment of the capital structure to be used for ratemaking purposes. My testimony relies upon Company records, public documents, my personal knowledge and education, and my professional experience.

Q. HAVE YOU PREPARED ANY EXHIBITS OR SCHEDULES IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. My analyses and conclusions are supported by the data presented in Exhibit B as Schedules DWD-1 through DWD-10, which have been prepared by me or under my direct supervision and control.

Q. WHAT IS YOUR RECOMMENDED COMMON EQUITY COST RATE?

A. I recommend that the Commission authorize UGI Gas the opportunity to earn an ROE of 10.75% on its jurisdictional rate base, based on its actual capital structure. The Company's requested capital structure consists of 45.75% long-term debt, at an embedded debt cost rate of 5.17%, and 54.25% common equity, to which my recommended ROE of 10.75% would apply. The overall rate of return is summarized on page 1 of Schedule DWD-1 and in Table 1 below:

Table 1: Summary of Recommended Weighted Average Cost of Capital

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	45.75%	5.17%	2.37%
Common Equity	54.25%	10.75%	5.83%
Total	100.00%		8.20%

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ROE.

A. My recommended ROE of 10.75% is summarized on page 2 of Schedule DWD-1. I have assessed the market-based common equity cost rates of companies of relatively similar, but not necessarily identical, risk to UGI Gas. Using companies of relatively comparable risk as proxies is consistent with the principles of fair rate of return established in the *Hope*[1]

[1] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*").

and *Bluefield*[2] decisions. No proxy group can be identical in risk to any single company. Consequently, there must be an evaluation of relative risk between the Company and the proxy group to determine if it is appropriate to adjust the proxy group's indicated rate of return.

My recommendation results from the application of several cost of common equity models, specifically the Discounted Cash Flow ("DCF") model, the Risk Premium Model ("RPM"), and the Capital Asset Pricing Model ("CAPM"), to the market data of a proxy group of seven (7) natural gas utility companies ("Gas Utility Proxy Group") whose selection criteria will be discussed below. In addition, I applied the DCF model, RPM, and CAPM to a Non-Price Regulated Proxy Group similar in total risk to the Gas Utility Proxy Group. The results derived from each cost of common equity model are as follows:

Table 2: Summary of Common Equity Cost Rate

Discounted Cash Flow Model (DCF)	10.53%
Risk Premium Model (RPM)	10.41% - 10.80%
Capital Asset Pricing Model (CAPM)	10.17% - 11.30%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	10.96% - 11.35%
Indicated Range of Common Equity Cost Rates Before Adjustments for Company-Specific Risk	10.17% - 11.35%
Business Risk Adjustment	0.05%
Flotation Cost Adjustment	0.12%
Indicated Range of Common Equity Cost Rates after Adjustment	10.34% - 11.52%
Recommended Cost of Equity	10.75%

[2] *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1923) ("*Bluefield*").

As shown in Table 2, the indicated range of common equity cost rates applicable to the Gas Utility Proxy Group is between 10.17% and 11.35%.

After determining the Gas Utility Proxy Group ROE, one must conduct a relative risk analysis to determine whether additional adjustments to the Gas Utility Proxy Group ROE are warranted to reflect the unique risk of the Company. My relative risk analyses show that adjustments to the Gas Utility Proxy Group indicated range of ROEs to reflect the Company's unique business risks are necessary. From the indicated range of ROEs after adjustment, I recommend the Commission approve a specific ROE of 10.75% for the Company's jurisdictional rate base.

III. GENERAL PRINCIPLES

Q. WHAT GENERAL PRINCIPLES HAVE YOU CONSIDERED IN ARRIVING AT YOUR RECOMMENDED COMMON EQUITY COST RATE OF 10.75%?

A. In unregulated industries, marketplace competition is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. Assuring that the utility can fulfill its obligations to the public, while providing safe and reliable service at all times, requires a level of earnings sufficient to maintain the integrity of presently invested capital. Sufficient earnings also permit the attraction of needed new capital at a reasonable cost, for which the utility must compete with other firms of comparable risk, consistent with the fair rate of return standards established by the U.S. Supreme Court in the previously cited *Hope* and *Bluefield* cases.

The U.S. Supreme Court affirmed the fair rate of return standards in *Hope*, when it stated:

> The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346 12 S.Ct. 400,402. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[3]

In summary, the U.S. Supreme Court has found a return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity. As discussed above, and in keeping with established regulatory standards, that return should be commensurate with the returns expected elsewhere for investments of equivalent risk. The Commission's decision in this proceeding, therefore, should provide the Company with the opportunity to earn a return that is: (1) adequate to attract capital at reasonable cost and terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks.

Lastly, the required return for a regulated public utility is established on a stand-alone basis, i.e., for the utility operating company at issue in a rate case. Parent entities, like other investors, have capital constraints and must look at the attractiveness of the expected risk-adjusted return of each investment alternative in their capital budgeting

[3] *Hope*, 320 U.S. 591 (1944), at 603.

process. That is, utility holding companies that own many utility operating companies have choices as to where they will invest their capital within the holding company family. Therefore, the opportunity cost concept applies regardless of the source of the funding, public funding or corporate funding.

When funding is provided by a parent entity, the return still must be sufficient to provide an incentive to allocate equity capital to the subsidiary or business unit rather than other internal or external investment opportunities. That is, the regulated subsidiary must compete for capital with all the parent company's affiliates, and with other, similarly situated companies. In that regard, investors value corporate entities on a sum-of-the-parts basis and expect each division within the parent company to provide an appropriate risk-adjusted return.

It therefore is important that the authorized ROE reflects the risks and prospects of the utility's operations and supports the utility's financial integrity from a stand-alone perspective, as measured by its combined business and financial risks. Consequently, the ROE authorized in this proceeding should be sufficient to support the operational (i.e., business risk) and financing (i.e., financial risk) of the Company's utility subsidiary on a stand-alone basis.

Q. WITHIN THAT BROAD FRAMEWORK, HOW IS THE COST OF CAPITAL ESTIMATED IN REGULATORY PROCEEDINGS?

A. Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment (i.e., rate base). The fair rate of return for a regulated utility is based on its weighted average cost of capital, in which, as noted earlier, the costs of the individual sources of capital are weighted by their respective book values.

The cost of capital is the return investors require to make an investment in a firm. Investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm.

The cost of capital (i.e., the combination of the costs of debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset (whether debt or equity securities) represents a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.

Whereas the cost of debt is contractually defined and can be directly observed as the interest rate or yield on debt securities, the cost of common equity must be estimated based on market data and various financial models. Because the cost of common equity is premised on opportunity costs, the models used to determine it are typically applied to a group of "comparable" or "proxy" companies.

In the end, the estimated cost of capital should reflect the return that investors require in light of the subject company's business and financial risks, and the returns available on comparable investments.

Q. IS THE AUTHORIZED RETURN SET IN REGULATORY PROCEEDINGS GUARANTEED?

A. No, it is not. Consistent with the *Hope* and *Bluefield* standards, the ratemaking process should provide the utility a reasonable opportunity to recover its return of, and return on, its reasonably incurred investments, but it does not guarantee that return. While a utility may have control over some factors that affect the ability to earn its authorized return (e.g., management performance, operating and maintenance expenses, etc.), there are several factors beyond a utility's control that affect its ability to earn its authorized return. Those may include factors such as weather, the economy, and the prevalence and magnitude of regulatory lag.

A. Business Risk

Q. PLEASE DEFINE BUSINESS RISK AND EXPLAIN WHY IT IS IMPORTANT FOR DETERMINING A FAIR RATE OF RETURN.

A. The investor-required return on common equity reflects investors' assessment of the total investment risk of the subject firm. Total investment risk is often discussed in the context of business and financial risk.[4]

Business risk reflects the uncertainty associated with owning a company's common stock without the company's use of debt and/or preferred stock financing. One way of considering the distinction between business and financial risk is to view the former as the uncertainty of the expected earned return on common equity, assuming the firm is financed with no debt.

Examples of business risks generally faced by utilities include, but are not limited to, the regulatory environment, mandatory environmental compliance requirements, customer mix and concentration of customers, service territory economic growth, market demand, risks and uncertainties of supply, operations, capital intensity, size, the degree of operating leverage, emerging technologies, the vagaries of weather, and the like, all of which have a direct bearing on earnings.

[4] As will be discussed later in this testimony, another definition of total risk is systematic risk plus unsystematic risk.

Although analysts, including ratings agencies, may categorize business risks individually, as a practical matter, such risks are interrelated and not wholly distinct from one another. When determining an appropriate return on common equity, the relevant issue is where investors see the subject company in relation to other similarly situated utility companies (i.e., the Gas Utility Proxy Group). To the extent investors view a company as being exposed to higher risk, the required return will increase, and vice versa.

For regulated utilities, business risks are both long-term and near-term in nature. Whereas near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, long-term business risks reflect the prospect of an impaired ability of investors to obtain both a fair rate of return on, and return of, their capital. Moreover, because utilities accept the obligation to provide safe, adequate, and reliable service at all times (in exchange for a reasonable opportunity to earn a fair return on their investment), they generally do not have the option to delay, defer, or reject capital investments. Because those investments are capital-intensive, utilities generally do not have the option to avoid raising external funds during periods of capital market distress, if necessary.

Because utilities invest in long-lived assets, long-term business risks are of paramount concern to equity investors. That is, the risk of not recovering the return on their investment extends far into the future. The timing and nature of events that may lead to losses, however, also are uncertain and, consequently, those risks and their implications for the required return on equity tend to be difficult to quantify. Regulatory commissions (like investors who commit their capital) must review a variety of quantitative and qualitative data and apply their reasoned judgment to determine how long-term risks weigh in their assessment of the market-required return on common equity.

B. Financial Risk

Q. PLEASE DEFINE FINANCIAL RISK AND EXPLAIN WHY IT IS IMPORTANT FOR DETERMINING A FAIR RATE OF RETURN.

A. Financial risk is the additional risk created by the introduction of debt and preferred stock into the capital structure. The higher the proportion of debt and preferred stock in the capital structure, the higher the financial risk to common equity owners (i.e., failure to receive dividends due to default or other covenants). Therefore, consistent with the basic financial principle of risk and return, common equity investors require higher returns as compensation for bearing higher financial risk.

Q. CAN BOND AND CREDIT RATINGS BE A PROXY FOR A FIRM'S COMBINED BUSINESS AND FINANCIAL RISKS TO EQUITY OWNERS (I.E., INVESTMENT RISK)?

A. Yes, similar bond ratings/issuer credit ratings reflect, and are representative of, similar combined business and financial risks (i.e., total risk) faced by bond investors.[5] Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are roughly similar from a debtholder perspective. The caveat is that these debtholder risk measures do not translate directly to risks for common equity.

IV. UGI GAS AND GAS THE UTILITY PROXY GROUP

Q. ARE YOU FAMILIAR WITH UGI GAS'S OPERATIONS?

A. Yes. UGI Gas provides natural gas utility service to over 706,000 customers in certificated portions of 46 eastern and central Pennsylvania counties. UGI Utilities, Inc. holds an A3

[5] Risk distinctions within S&Ps bond rating categories are recognized by a plus or minus, *e.g*., an S&P rating can be an A+, A, or A-. Similarly, risk distinction for Moody's ratings are distinguished by numerical rating gradations, *e.g*., a Moody's rating can be A1, A2 and A3.

rating from Moody's, and is not rated by S&P. The Company is not publicly traded, as it is an indirectly owned operating subsidiary of UGI Corporation ("UGI Corp."). UGI Corp. is publicly traded on the NYSE under ticker symbol UGI.

Q. WHY IS IT NECESSARY TO DEVELOP A PROXY GROUP WHEN ESTIMATING THE ROE FOR THE COMPANY?

A. Because the Company is not publicly traded and does not have publicly traded equity securities, it is necessary to develop groups of publicly traded, comparable companies to serve as "proxies" for the Company. In addition to the analytical necessity of doing so, the use of proxy companies is consistent with the *Hope* and *Bluefield* comparable risk standards, as discussed above. I have selected two proxy groups that, in my view, are fundamentally risk-comparable to the Company: a Gas Utility Proxy Group, and a Non-Price Regulated Proxy Group, which is comparable in total risk to the Gas Utility Proxy Group.[6]

Even when proxy groups are carefully selected, it is common for analytical results to vary from company to company. Despite the care taken to ensure comparability, because no two companies are identical, market expectations regarding future risks and prospects will vary within the proxy group. Therefore, it is common for analytical results to reflect a seemingly wide range, even for a group of similarly situated companies. At issue is how to estimate the ROE from within that range. That determination will be best informed by employing a variety of sound analyses that necessarily must consider the sort of quantitative and qualitative information discussed throughout my Direct Testimony. Additionally, a relative risk analysis between the Company and the Gas Utility Proxy

[6] The development of the Non-Price Regulated Proxy Group is explained in more detail in Section V.

Group must be made to determine whether or not explicit Company-specific adjustments need to be made to the Gas Utility Proxy Group's indicated results.

Q. PLEASE EXPLAIN HOW YOU SELECTED THE COMPANIES IN THE GAS UTILITY PROXY GROUP.

A. The companies selected for the Utility Proxy Group met the following criteria:

(i) They were included in the Natural Gas Utility Group of *Value Line Investment Survey's Standard Edition* as of August 22, 2025 ("*Value Line*");

(ii) They have 60% or greater of fiscal year 2024 total operating income derived from, and 60% or greater of fiscal year 2024 total assets attributable to, regulated gas distribution operations;

(iii) At the time of preparation of this testimony, they had not publicly announced that they were involved in any major merger or acquisition activity (i.e., one publicly-traded utility merging with or acquiring another) or any other major development;

(iv) They have not cut or omitted their common dividends during the five years ended 2024 or through the time of preparation of this testimony;

(v) They have *Value Line* and Bloomberg Professional Services ("Bloomberg") adjusted Beta coefficients ("beta");

(vi) They have positive *Value Line* five-year dividends per share growth rate projections; and

(vii) They have *Value Line*, Zacks, or S&P Capital IQ consensus five-year earnings per share growth rate projections.

The following seven companies met these criteria:

Table 3: Utility Proxy Group Screening Results

Company	**Ticker**
Atmos Energy Corporation	ATO
Chesapeake Utilities Corp.	CPK
New Jersey Resources Corporation	NJR
NiSource Inc.	NI
Northwest Natural Holding Company	NWN
ONE Gas, Inc.	OGS
Southwest Gas Holdings, Inc.	SWX

V. CAPITAL STRUCTURE

Q. WHAT IS UGI GAS'S REQUESTED CAPITAL STRUCTURE?

A. UGI Gas's requested ratemaking capital structure consists of 45.75% long-term debt and 54.25% common equity.

Q. WHAT ARE THE TYPICAL SOURCES OF CAPITAL COMMONLY CONSIDERED IN ESTABLISHING A UTILITY'S CAPITAL STRUCTURE?

A. Common equity and long-term debt are commonly considered in establishing a utility's capital structure, because they are the typical sources of capital financing a utility's rate base.

Q. PLEASE EXPLAIN.

A. Long-lived assets are typically financed with long-lived securities, so that the overall term structure of the utility's long-term liabilities (both debt and equity) closely match the life of the assets being financed. As stated by Brigham and Houston:

> In practice, firms don't finance each specific asset with a type of capital that has a maturity equal to the asset's life. However, academic studies do show that most firms tend to finance short-term assets from short-term sources and long-term assets from long-term

sources.[7]

Whereas short-term debt has a maturity of one year or less, long-term debt may have maturities of thirty (30) years or longer. Although there are practical financing constraints, such as the need to "stagger" long-term debt maturities, the general objective is to extend the average life of long-term debt. Still, long-term debt has a finite life, which is likely to be less than the life of the assets included in rate base. Common equity, on the other hand, is outstanding into perpetuity. Thus, common equity more accurately matches the life of the going concern of the utility, which is also assumed to operate in perpetuity. Consequently, it is both typical and important for utilities to have significant proportions of common equity in their capital structures.

Q. HOW DOES THE COMPANY'S REQUESTED COMMON EQUITY RATIO OF 54.25% COMPARE WITH THE COMMON EQUITY RATIO MAINTAINED BY THE GAS UTILITY PROXY GROUP?

A. As shown on page 2 of Schedule DWD-2, common equity ratios range from 39.40% to 60.96% for fiscal year 2024 for the Gas Utility Proxy Group. I also considered *Value Line* projected capital structures for the utilities for 2028-2030. That analysis shows a range of projected common equity ratios between 44.00% and 60.00%.[8]

In addition to comparing the Company's requested common equity ratio with common equity ratios currently maintained by the Gas Utility Proxy Group, I also compared the Company's common equity ratio with the equity ratios maintained by the operating subsidiaries of the Gas Utility Proxy Group. As shown on page 3 of Schedule

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[7] Eugene F. Brigham and Joel F. Houston, Fundamentals of Financial Management, Concise 4th Ed., Thomson South-Western, 2004, at 574.

[8] See, pages 2 through 8 of Schedule DWD-3.

DWD-2, common equity ratios of the operating utility subsidiaries of the companies in the Gas Utility Proxy Group range from 47.86% to 59.93% for fiscal year 2024, for the Gas Utility Proxy Group's operating subsidiaries. The Company's requested common equity ratio of 54.25% is reasonable and consistent with the range of common equity ratios maintained by the operating utility subsidiaries of the Gas Utility Proxy Group.

Q. GIVEN THE RANGE OF EQUITY RATIOS PRESENT WITHIN THE UTILITY PROXY GROUP, IS UGI GAS'S REQUESTED EQUITY RATIO OF 54.25% APPROPRIATE FOR RATEMAKING PURPOSES?

A. Yes, it is. The Company's requested equity ratio of 54.25% is appropriate for ratemaking purposes in the current proceeding because it is within the range of the common equity ratios currently maintained, and expected to be maintained, by the Gas Utility Proxy Group and its operating subsidiaries.

VI. <u>COMMON EQUITY COST RATE MODELS</u>

Q. IS IT IMPORTANT THAT COST OF COMMON EQUITY MODELS BE MARKET-BASED?

A. Yes. While a public utility operates a regulated business within the states in which it operates, it still must compete for equity in capital markets along with all other companies of comparable risk, which includes non-utilities. The cost of common equity is thus determined based on equity market expectations for the returns of those companies. If an individual investor is choosing to invest their capital among companies of comparable risk, they will choose a company providing a higher return over a company providing a lower return.

Q. ARE YOUR COST OF COMMON EQUITY MODELS MARKET-BASED?

A. Yes. The DCF model uses market prices in developing the model's dividend yield component. The RPM uses bond ratings and expected bond yields that reflect the market's assessment of bond/credit risk. In addition, betas (β), which reflect the market/systematic risk component of equity risk premium, are derived from regression analyses of market prices. The CAPM is market-based for many of the same reasons that the RPM is market-based (i.e., the use of expected bond yields and betas). Selection criteria for comparable risk non-price regulated companies are based on regression analyses of market prices and reflect the market's assessment of total risk.

Q. WHAT ANALYTICAL APPROACHES DID YOU USE TO DETERMINE THE COMPANY'S ROE?

A. As discussed earlier, I have relied on the DCF model, the RPM, and the CAPM, which I applied to the Gas Utility Proxy Group described above. I also applied these same models to the Non-Price Regulated Proxy Group described later in this section.

I rely on these models because reasonable investors use a variety of tools and do not rely exclusively on a single source of information or single model. Moreover, the models on which I rely focus on different aspects of return requirements and provide different insights into investors' views of risk and return. The DCF model, for example, estimates the investor-required return assuming a constant expected dividend yield and growth rate in perpetuity, while Risk Premium-based methods (i.e., the RPM and CAPM approaches) provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the cost of common equity. Just as the use of market data for the Gas Utility Proxy Group adds the reliability necessary to inform expert judgment in arriving at a recommended common equity cost rate, the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

The use of multiple models also makes intuitive sense when we consider that market prices are set by the buying and selling behavior of multiple investors, whose circumstances, objectives, and constraints vary over time and across market conditions. We cannot assume a single method is the best measure of the factors motivating those decisions for all investors at all times. Giving undue weight to a single method runs the very real risk of ignoring important information provided by other methods.

In other words, no single model is more reliable than all others under all market conditions. Intuition suggests it is more appropriate to use as many methods as we reasonably can and to reflect the many factors motivating investment decisions as best we can. In this instance, intuition, financial theory,[9] and financial practice reach a common conclusion: we should apply and reasonably consider multiple methods when estimating the ROE.

A. Discounted Cash Flow Model

Q. WHAT IS THE THEORETICAL BASIS OF THE DCF MODEL?

A. The theory underlying the DCF model is that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory indicates that an investor buys a stock for an expected total return rate, which is derived

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[9] As Brigham explains: "Whereas debt and preferred stocks are contractual obligations which have easily determined costs, it is not at all easy to estimate [the ROE]. However, three methods can be used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods should not be regarded as mutually exclusive – no one dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand." Eugene F. Brigham, Louis C. Gapenski, Financial Management, Theory and Practice, 7th ed., The Dryden Press, 1994, at 341.

from the cash flows received from dividends and market price appreciation. Mathematically, the dividend yield on market price plus a growth rate equals the capitalization rate, i.e., the total common equity return rate expected by investors.

$$K_e = (D_0\ (1+g))/P + g$$

where:

K_e = the required Return on Common Equity;

D_0 = the annualized Dividend Per Share;

P = the current stock price; and

g = the growth rate.

Q. WHICH VERSION OF THE DCF MODEL DID YOU USE?

A. I used the single-stage constant growth DCF model in my analyses.

Q. PLEASE DESCRIBE THE DIVIDEND YIELD YOU USED IN APPLYING THE CONSTANT GROWTH DCF MODEL.

A. The unadjusted dividend yields are based on the proxy companies' dividends as of October 31, 2025, divided by the average closing market price for the 60 trading days ended October 31, 2025.[10]

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE DIVIDEND YIELD.

A. Because dividends are paid periodically (quarterly), as opposed to continuously (daily), an adjustment must be made to the dividend yield. This is often referred to as the discrete, or the Gordon Periodic, version of the DCF model.

DCF theory calls for using the full growth rate, or D_1, in calculating the model's dividend yield component. Since the companies in the Gas Utility Proxy Group increase

[10] *See,* Column 1, page 1 of Schedule DWD-3.

their quarterly dividends at various times during the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the dividend yield component, or $D_{1/2}$. Because the dividend should be representative of the next 12-month period, this adjustment is a conservative approach that does not overstate the dividend yield. Therefore, the actual average dividend yields in Column 1, page 1 of Schedule DWD-3 have been adjusted upward to reflect one-half the average projected growth rate shown in Column 6.

Q. PLEASE EXPLAIN THE BASIS FOR THE GROWTH RATES YOU APPLY TO THE GAS UTILITY PROXY GROUP IN YOUR CONSTANT GROWTH DCF MODEL.

A. Investors are likely to rely on widely available financial information services, such as *Value Line*, Zacks, and S&P Capital IQ. Investors realize that analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as companies' abilities to effectively manage the effects of changing laws and regulations, and ever-changing economic and market conditions. For these reasons, I used analysts' five-year forecasts of earnings per share growth in my DCF analysis.

Over the long run, there can be no growth in dividends per share without growth in earnings per share. Security analysts' earnings expectations have a more significant influence on market prices than dividend expectations. Thus, using projected earnings growth rates in a DCF analysis provides a better match between investors' market price appreciation expectations and the growth rate component of the DCF.

Q. PLEASE SUMMARIZE THE CONSTANT GROWTH DCF MODEL RESULTS.

A. The results of applying the DCF model to the Gas Utility Proxy Group are shown on page 1 of Schedule DWD-3 and in Table 4, below:

Table 4: DCF Model Results for the Utility Proxy Group

Mean	10.35%
Median	10.71%
Average of Mean and Median	10.53%

In arriving at a conclusion for the constant growth DCF-indicated common equity cost rate for the Gas Utility Proxy Group, I relied on an average of the mean and the median results of the DCF, specifically 10.53% applicable to the Gas Utility Proxy Group. This approach takes into consideration all proxy company results while mitigating high and low side outliers of those results.

B. The Risk Premium Model

Q. PLEASE DESCRIBE THE THEORETICAL BASIS OF THE RPM.

A. The RPM is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on a company's assets and earnings. As a result, investors require higher returns from common stocks than from bonds to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, investors' required common equity returns cannot be directly determined or observed. According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively), and use that premium to derive a cost rate of common equity. The cost of common equity equals the expected cost rate for long-term debt capital, plus a risk premium over that cost rate, to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on the corporation's assets and earnings upon liquidation.

Q. PLEASE EXPLAIN THE TOTAL MARKET APPROACH RPM.

A. The total market approach RPM adds a prospective public utility bond yield to an average of: (1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium, (2) an equity risk premium based on the S&P Utilities Index, and (3) an equity risk premium based on authorized ROEs for natural gas distribution utilities.

Q. PLEASE EXPLAIN THE BASIS OF THE EXPECTED BOND YIELD OF 5.49% APPLICABLE TO THE UTILITY PROXY GROUP.

A. The first step in the total market approach RPM analysis is to determine the expected bond yield. Because both ratemaking and the cost of capital, including the common equity cost rate, are prospective in nature, a prospective yield on similarly-rated long-term debt is essential. I relied on a consensus forecast of about 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the first calendar quarter of 2027, and *Blue Chip Financial Forecast's* ("*Blue Chip*") long-term projections for 2027 to 2031, and 2032 to 2036. As shown on line 1, page 1 of Schedule DWD-4, the average expected yield on Moody's Aaa-rated corporate bonds is 5.10%. In order to adjust the expected Aaa-rated corporate bond yield to an equivalent A2-rated public utility bond yield, I made an upward adjustment of 0.39%, which represents a recent spread between Aaa-rated corporate bonds and A2-rated public utility bonds.[11] Adding that recent 0.39% spread to the expected Aaa-rated corporate bond yield of 5.10% results in an expected A2-rated public utility bond yield of 5.49%. Since the Gas Utility Proxy Group's average Moody's long-term issuer rating is A3, another adjustment to the expected A2-rated public utility bond is needed to reflect the difference in bond ratings. An upward adjustment of

[11] As shown on line 2 and explained in note 2, page 1 of Schedule DWD-4.

0.07%, which represents one-third of a recent spread between A2-rated and Baa2-rated public utility bond yields, is necessary to make the prospective bond yield applicable to an A3-rated public utility bond.[12] Adding the 0.07% to the 5.49% prospective A2-rated public utility bond yield results in a 5.56% expected bond yield applicable to the Gas Utility Proxy Group.

Table 5: Summary of the Calculation of the Gas Utility Proxy Group Projected Bond Yield[13]

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (*Blue Chip*)	5.10%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.39%
Adjustment to Reflect the Gas Utility Proxy Group's Average Moody's Bond Rating of A3	0.07%
Prospective Bond Yield Applicable to the Gas Utility Proxy Group	5.56%

Q. PLEASE EXPLAIN HOW THE BETA-DERIVED EQUITY RISK PREMIUM IS DETERMINED.

A. The components of the beta-derived risk premium model are: (1) an expected market equity risk premium over corporate bonds, and (2) the beta. The derivation of the beta-derived equity risk premium that I applied to the Gas Utility Proxy Group is shown on lines 1 through 8, on page 6 of Schedule DWD-4. The total beta-derived equity risk premium I applied is based on an average of three historical market data-based equity risk premiums, a *Value Line*-based equity risk premium, and combined *Value Line*, Bloomberg, and S&P Capital IQ-based equity risk premium. Each of these is described below.

12 As shown on line 4 and explained in note 3, page 1 of Schedule DWD-4.
13 As shown on page 1 of Schedule DWD-4.

Q. HOW DID YOU DERIVE A MARKET EQUITY RISK PREMIUM BASED ON LONG-TERM HISTORICAL DATA?

A. To derive a historical market equity risk premium, I used the most recent holding period returns for the large company common stocks less the average historical yield on Moody's Aaa/Aa-rated corporate bonds for the period 1928 to 2024. The use of holding period returns over a very long period of time is appropriate because it is consistent with the long-term investment horizon presumed by investing in a going concern, i.e., a company expected to operate in perpetuity.

The long-term arithmetic mean monthly total return rate on large company common stocks was 12.05% and the long-term arithmetic mean monthly yield on Moody's Aaa/Aa-rated corporate bonds was 5.95% from 1928 to 2024. As shown on line 1 of page 6 of Schedule DWD-4, subtracting the mean monthly bond yield from the total return on large company stocks results in a long-term historical equity risk premium of 6.10%.

I used the arithmetic mean monthly total return rates for the large company stocks and yields (income returns) for the Moody's Aaa/Aa-rated corporate bonds, because they are appropriate for the purpose of estimating the cost of capital as noted in Kroll's Stocks, Bonds, Bills, and Inflation ("SBBI") Yearbook 2023 ("SBBI - 2023").[14] The use of the arithmetic mean return rates and yields is appropriate because historical total returns and equity risk premiums provide insight into the variance and standard deviation of returns needed by investors in estimating future risk when making a current investment. If investors relied on the geometric mean of historical equity risk premiums, they would have no insight into the potential variance of future returns because the geometric mean relates

[14] SBBI-2023, at 193.

the change over many periods to a constant rate of change, thereby obviating the year-to-year fluctuations, or variance, which is critical to risk analysis.

Q. PLEASE EXPLAIN THE DERIVATION OF THE REGRESSION-BASED MARKET EQUITY RISK PREMIUM.

A. To derive the regression-based market equity risk premium of 7.13% shown on line 2, page 6 of Schedule DWD-4, I used the same monthly annualized total returns on large company common stocks relative to the monthly annualized yields on Moody's Aaa/Aa-rated corporate bonds as mentioned above. I modeled the relationship between interest rates and the market equity risk premium using the observed monthly market equity risk premium as the dependent variable, and the monthly yield on Moody's Aaa/Aa-rated corporate bonds as the independent variable. I then used a linear Ordinary Least Squares ("OLS") regression, in which the market equity risk premium is expressed as a function of the Moody's Aaa/Aa-rated corporate bond yield:

$$RP = \alpha + \beta\,(R_{Aaa/Aa})$$

where:

RP = the market equity risk premium;

α = the regression intercept coefficient;

β = the regression slope coefficient; and

$R_{Aaa/Aa}$ = the Moody's Aaa/Aa rated corporate bond yield.

Q. PLEASE EXPLAIN THE DERIVATION OF THE PRPM EQUITY RISK PREMIUM.

A. The PRPM, published in the *Journal of Regulatory Economics*,[15] was developed from the work of Robert F. Engle, who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic time series with time-varying volatility" or ARCH.[16] Engle found that volatility changes over time and is related from one period to the next, especially in financial markets. Engle discovered that volatility of prices and returns clusters over time and is, therefore, highly predictable and can be used to predict future levels of risk and risk premiums.

The PRPM estimates the risk-return relationship directly, as the predicted equity risk premium is generated by predicting volatility or risk. The PRPM is not based on an <u>estimate</u> of investor behavior, but rather on an evaluation of the results of that behavior (i.e., the variance of historical equity risk premiums).

The inputs to the model are the historical returns on large company stocks minus the historical monthly yield on Moody's Aaa/Aa-rated corporate bonds from January 1928 through October 2025. Using a generalized form of ARCH, known as GARCH, I calculated the projected equity risk premium using Eviews© statistical software. When the GARCH model is applied to the historical return data, it produces a predicted GARCH variance series and a GARCH coefficient. Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it produces the predicted annual equity risk premium. The resulting PRPM predicted a market equity risk premium of 7.48%.[17]

[15] Pauline M. Ahern, Frank J. Hanley, and Richard A. Michelfelder, "A New Approach for Estimating the Equity Risk Premium for Public Utilities", The Journal of Regulatory Economics (December 2011), 40:261-278.
[16] Autoregressive conditional heteroscedasticity; see also www.nobelprize.org.
[17] Shown on line 3, page 6 of Schedule DWD-4.

Q. PLEASE EXPLAIN THE DERIVATION OF A PROJECTED EQUITY RISK PREMIUM BASED ON *VALUE LINE* SUMMARY & INDEX DATA FOR YOUR RPM ANALYSIS.

A. As noted above, because both ratemaking and the cost of capital are prospective, a prospective market equity risk premium is needed. The derivation of the forecasted or prospective market equity risk premium can be found in note 4, page 6 of Schedule DWD-4. Consistent with my calculation of the dividend yield component in my DCF analysis, this prospective market equity risk premium is derived from an average of the three- to five-year median market price appreciation potential by *Value Line* for the 13 weeks ended October 31, 2025, plus an average of the median estimated dividend yield for the common stocks of the 1,700 firms covered in *Value Line* (Standard Edition).[18]

The average median expected price appreciation is 40%, which translates to an 8.78% annual appreciation, and when added to the average of *Value Line's* median expected dividend yields of 2.13%, equates to a forecasted annual total return rate on the market of 10.91%. The forecasted Moody's Aaa-rated corporate bond yield of 5.10% is deducted from the total market return of 10.91%, resulting in an equity risk premium of 5.81%, as shown on line 4, page 6 of Schedule DWD-4.

Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM BASED ON THE S&P 500 COMPANIES.

A. Using data from *Value Line*, Bloomberg, and S&P Capital IQ, I calculated an expected total return on the S&P 500 companies using expected dividend yields and long-term growth estimates as a proxy for capital appreciation. The expected total return for the S&P

[18] As explained in detail in note 4, page 6 of Schedule DWD-4.

500 is 17.67%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 5.10% results in a 12.57% projected equity risk premium as shown on page 6, line 5 of Schedule DWD-4.

Q. WHAT IS YOUR CONCLUSION OF A BETA-DERIVED EQUITY RISK PREMIUM FOR USE IN YOUR RPM ANALYSIS?

A. I gave equal weight to all five equity risk premiums based on each source – historical, *Value Line* Summary & Index, and aggregate *Value Line*, Bloomberg, and S&P Capital IQ Market DCF in arriving at a 7.82% equity risk premium.

Table 6: Summary of the Calculation of the Equity Risk Premium Using Total Market Returns[19]

Historical Spread Between Total Returns of Large Stocks and Aaa and Aa-Rated Corporate Bond Yields (1928 – 2024)	6.10%
Regression Analysis on Historical Data	7.13%
PRPM Analysis on Historical Data	7.48%
Prospective Equity Risk Premium using Total Market Returns from *Value Line Summary & Index* less Projected Aaa Corporate Bond Yields	5.81%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P 500 less Projected Aaa Corporate Bond Yields	12.57%
Average	7.82%

After calculating the average market equity risk premium of 7.82%, I adjusted it by beta to account for the risk of the Gas Utility Proxy Group. As discussed below, beta is a meaningful measure of prospective relative risk to the market as a whole, and is a logical way to allocate a company's, or proxy group's, share of the market's total equity risk premium relative to corporate bond yields.

19 As shown on page 6 of Schedule DWD-4.

Q. WHAT MEASURES OF BETA DO YOU USE IN DETERMINING YOUR BETA-ADJUSTED EQUITY RISK PREMIUM?

A. I use two measures of beta to calculate my beta-adjusted equity risk premium: (1) the average of *Value Line* and Bloomberg betas; and (2) *Value Line* betas. As will be discussed in detail below, Bloomberg betas may not accurately reflect the risks of the Gas Utility Proxy Group at this time and should be viewed with caution.

Q. WHAT ARE THE BETA VALUES YOU WILL APPLY TO THE MARKET EQUITY RISK PREMIUM?

A. As shown on pages 1 and 2 of Schedule DWD-6, the Gas Utility Proxy Group's average blended beta is 0.61, and its average *Value Line* beta is 0.76. Applying these betas to the market equity risk premium of 7.82% results in equity risk premiums of 4.77% and 5.94%, respectively.

Q. HOW DID YOU DERIVE THE EQUITY RISK PREMIUM BASED ON THE S&P UTILITY INDEX AND MOODY'S A2-RATED PUBLIC UTILITY BONDS?

A. I estimated three equity risk premiums based on S&P Utility Index holding period returns, and one equity risk premium based on the expected returns of the S&P Utilities Index, using *Value Line*, Bloomberg, and S&P Capital IQ data. Turning first to the S&P Utility Index holding period returns, I derived a long-term monthly arithmetic mean equity risk premium between the S&P Utility Index total returns of 10.59% and monthly Moody's A2-rated public utility bond yields of 6.42% from 1928 to 2024, to arrive at an equity risk premium of 4.16%.[20] I then used the same historical data to derive an equity risk premium of 5.00% based on a regression of the monthly equity risk premiums. The final S&P Utility

[20] As shown on line 1, page 9 of Schedule DWD-5.

Index holding period equity risk premium involved applying the PRPM using the historical monthly equity risk premiums from January 1928 to October 2025 to arrive at a PRPM-derived equity risk premium of 4.22% for the S&P Utility Index.

I then derived expected total returns on the S&P Utilities Index of 11.89% using data from *Value Line*, Bloomberg, and S&P Capital IQ respectively, and subtracted the prospective Moody's A2-rated public utility bond yield of 5.49%.[21] This resulted in equity risk premium of 6.40%. As with the market equity risk premiums, I averaged the four risk premiums to arrive at my utility-specific equity risk premium of 4.95%.

Table 7: Summary of the Calculation of the Equity Risk Premium Using S&P Utility Index Holding Returns[22]

Historical Spread Between Total Returns of the S&P Utilities Index and A2-Rated Utility Bond Yields (1928 – 2024)	4.16%
Regression Analysis on Historical Data	5.00%
PRPM Analysis on Historical Data	4.22%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P Utilities Index less Projected A2 Utility Bond Yields	6.40%
Average	4.95%

Q. HOW DID YOU DERIVE AN EQUITY RISK PREMIUM OF 4.84% BASED ON AUTHORIZED ROES FOR NATURAL GAS DISTRIBUTION UTILITIES?

A. The equity risk premium of 4.84% shown on page 10 of Schedule DWD-4 is the result of a regression analysis based on regulatory awarded ROEs related to the yields on Moody's A2-rated public utility bonds and contains the graphical results of a regression analysis of 852 rate cases for natural gas distribution utilities which were fully litigated during the period from January 1, 1980 through October 31, 2025. It shows the implicit equity risk

[21] Derived on line 4, page 1 of Schedule DWD-4.
[22] As shown on page 9 of Schedule DWD-4.

premium relative to the yields on A2-rated public utility bonds immediately prior to the issuance of each regulatory decision. It is readily discernible that there is an inverse relationship between the yield on A2-rated public utility bonds and equity risk premiums. In other words, as interest rates decline, the equity risk premium rises and vice versa, a result consistent with financial literature on the subject.[23] I used the regression results to estimate the equity risk premium applicable to the projected yield on Moody's A2-rated public utility bonds. Given the expected A2-rated utility bond yield of 5.49%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 4.84%.

Q. WHAT IS YOUR CONCLUSION OF THE RANGE OF EQUITY RISK PREMIUMS FOR USE IN YOUR TOTAL MARKET APPROACH RPM FOR THE GAS UTILITY PROXY GROUP?

A. The range of equity risk premiums I applied to the Gas Utility Proxy Group is from 4.85% to 5.24%, which is the average of the beta-adjusted equity risk premium for the Gas Utility Proxy Group, the S&P Utilities Index, and the authorized return utility equity risk premium.

[23] *See, e.g.,* Robert S. Harris and Felicia C. Marston, "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts", Journal of Applied Finance, Vol. 11, No. 1, 2001, at 11-12; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, "The Risk Premium Approach to Measuring a Utility's Cost of Equity", Financial Management, Spring 1985, at 33-45.

Table 8: Summary of Conclusions for the Equity Risk Premium for the Gas Utility Proxy Group[24]

Beta-Adjusted Equity Risk Premium	4.77% - 5.94%
S&P Utilities Index Equity Risk Premium	4.95%
Authorized ROE Equity Risk Premium	4.84%
Average	4.85% - 5.24%

Q. WHAT IS THE INDICATED RANGE OF RPM COMMON EQUITY COST RATES BASED ON THE TOTAL MARKET APPROACH?

A. As shown on line 7, page 1 of Schedule DWD-4, and shown on Table 9, below, I calculated a range of indicated common equity cost rates from 10.41% to 10.80% for the Gas Utility Proxy Group based on the total market approach RPM.

Table 9: Summary of the Total Market Return Risk Premium Model[25]

Prospective Moody's Utility Bond Yield Applicable to the Gas Utility Proxy Group	5.56%
Prospective Equity Risk Premium	4.85% - 5.24%
Indicated Cost of Common Equity	10.41% - 10.80%

C. The Capital Asset Pricing Model

Q. PLEASE EXPLAIN THE THEORETICAL BASIS OF THE CAPM.

A. CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by the beta (β). A beta less than 1.0 indicates lower variability than the market as a whole, while a beta greater than 1.0 indicates greater variability than the market.

The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors only require

24 As shown on page 5 of Schedule DWD-4.
25 As shown on page 1 of Schedule DWD-4.

compensation for systematic risk, which is the result of macroeconomic and other events that affect the returns on all assets. The model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market as measured by the beta. The traditional CAPM model is expressed as:

$$R_s = R_f + \beta\,(R_m - R_f)$$

Where: R_s = Return rate on the common stock;

R_f = Risk-free rate of return;

R_m = Return rate on the market as a whole; and

β = Adjusted beta (volatility of the security relative to the market as a whole).

Numerous tests of the CAPM have measured the extent to which security returns and beta are related as predicted by the CAPM, confirming its validity. The empirical CAPM ("ECAPM") reflects the reality that while the results of these tests support the notion that the beta is related to security returns, the empirical Security Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[26] The ECAPM reflects this empirical reality.

Q. WHY IS THE USE OF THE ECAPM APPROPRIATE IN DETERMINING THE ROE FOR THE COMPANY?

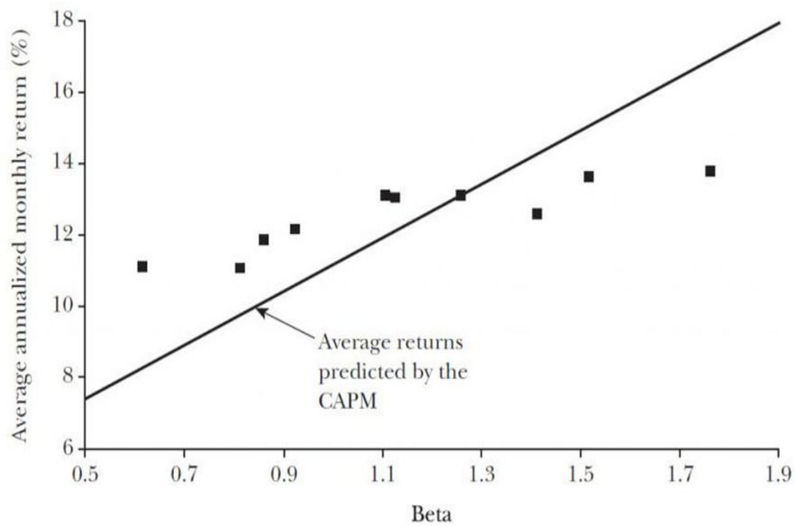
A. The ECAPM is a well-established model that has been relied on in both academic and regulatory settings. Fama & French clearly state regarding Figure 2, below, that "[t]he

[26] Roger A. Morin, Modern Regulatory Finance (Public Utility Reports, Inc., 2021), at page 223 ("Morin").

returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[27]

Figure 2 http://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



In addition, Morin observes that while the results of these tests support the notion that beta is related to security returns, the empirical SML described by the CAPM formula is not as steeply sloped as the predicted SML. Morin states:

> With few exceptions, the empirical studies agree that … low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.[28]
>
> * * *
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $K = RF + x\,(RM - RF) + (1-x)\ \beta(RM - RF)$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship [is] Return = 0.0829 +

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[27] Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence", Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004 at 33 ("Fama & French").

[28] Morin, at 207.

0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:

$$K = RF + 0.25(RM - RF) + 0.75\ \beta(RM - RF)$$[29]

Fama & French provide similar support for the ECAPM when they state:

The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too 'flat.'… The regressions consistently find that the intercept is greater than the average risk-free rate… and the coefficient on beta is less than the average excess market return… This is true in the early tests… as well as in more recent cross-section regressions tests, like Fama and French (1992).[30]

Finally, Fama & French further note:

Confirming earlier evidence, the relation between beta and average return `for the ten portfolios is much flatter than the Sharpe-Linter CAPM predicts. The returns on low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return is 11.1 percent. The predicted return on the portfolio with the t beta is 16.8 percent per year; the actual is 13.7 percent.[31]

Clearly, the justification from Morin and Fama & French, along with their reviews of other academic research on the CAPM, validate the use of the ECAPM. In view of theory and practical research, I have applied both the traditional CAPM and the ECAPM to the companies in the Gas Utility Proxy Group and averaged the results.

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[29] Morin, at 221.
[30] Fama & French, at 32.
[31] Fama & French, at 33.

Q. IS THERE ADDITIONAL EVIDENCE THAT SUPPORTS THE VALIDITY OF THE ECAPM?

A. Yes, there is. The empirical issues with the CAPM have been present since the presentation of the model, as noted by Dianna R. Harrington in her text Modern Portfolio Theory & the Capital Asset Pricing Model:

> So far we have learned some very interesting things about the CAPM and reality. Some of the earliest work tested realized data (history) against data generated by simulated portfolios. Early studies by Douglas (1969) and Lintner (Douglas [1969]) showed discrepancies between what was expected on the basis of the CAPM and the actual relationships that were apparent in the capital markets. Theoretically, the minimal rate of return from the portfolios (the intercept) and the actual risk-free rate for the period should have been equal. They were not.
>
> * * *
>
> Another study, now more famous than Lintner's was done by Black, Jensen, and Scholes (1972). Lintner had used what is called a cross-sectional method (looking at a number of stock returns during one time period), whereas Black, Jensen, and Scholes used a time-series method (using returns for a number of stocks over several time periods). To make their test, Black, Jensen, and Scholes assumed that what had happened in the past was a good proxy for the investor expectations (a frequent assumption in CAPM tests). Using historical data, they generated estimates using what we call the market model:
>
> $$R_{jt} = \alpha_j + \beta_j (R_{mt}) + \varepsilon_j$$
>
> Where:
> R = total returns
> β = the slope of the line (the incremental return for risk)
> α = the intercept or a constant (expected to be 0 over time and across all firms)
> ε = an error term (expected to be random, without information)
> m = the market proxy
> j = the firm or portfolio
> t = the time period
>
> Instead of using single stocks, they formed portfolios in an effort to wash out one source of error; because betas of single firms are quite unstable.
>
> On the basis of the CAPM, they expected to find
>
> 1. That the intercept was equal to the risk-free rate (their proxy was the Treasury bill rate)

2. That the capital market line had a positive slope and that riskier (higher beta) securities provided higher return

Instead they found

1. That the intercept was different from the risk-free rate
2. That high-risk securities earned less and low-risk securities earned more than predicted by the model
3. That the intercept seemed to depend on the beta of any asset: high-beta stocks had a different intercept than low-beta stocks

* * *

Fama and MacBeth (1974) criticized the Black, Jensen, and Scholes study (hereafter called BJS). In a reformulation of the study, they supported the first of the BJS findings. They found that the intercept exceeded the risk-free proxy, but did not find the evidence to support the other BJS conclusions.[32]

Harrington discusses Black's potential solution to this phenomenon:

Black's replacement for the risk-free asset was a portfolio that had no covariability with the market portfolio. Because the relevant risk in the CAPM is systematic risk, a risk-free asset would be the one with no volatility relative to the market – that is, a portfolio with a beta of zero. All investor-perceived levels of risk could be obtained from various linear combinations of Black's zero-beta portfolio and the market portfolio… Since R_z (the rate of return of the zero-beta asset) and R_m are uncorrelated (as R_f and R_m were assumed to be in the simple CAPM), the investor can choose from various combinations of R_z and R_m. On segment R_mY, R_z, is sold short and proceeds are invested in R_m. On segment R_zR_m, portions of the zero-beta portfolio are purchased. At R_m, the investor is fully invested in the market portfolio. The equilibrium CAPM was rewritten by Black as follows:

$$E(R_i) = (1 - \beta_i) E(R_z) + \beta_i E(R_m)$$

Where:

E indicates expected,
$E(R_z)$ is less than $E(R_m)$, and
R_z holdings over the whole market must be in equilibrium. That is, the number of short sellers and lenders of securities must be equal.

Black's adaptation is intriguing. The result of using this model is a capital market line that has a less steep slope and a higher intercept than those of

[32] Dianna R. Harrington, Modern Portfolio Theory & the Capital Asset Pricing Model – A User's Guide, Prentice-Hall, Inc. 1983, at 43-45.

> the simple CAPM. If Black's model is more correct in its description of investor behavior in the marketplace, then the use of the simple model would produce equity return predictions that would be too low for stocks with betas greater than one and too high for stocks with betas of less than one.[33]

Q. HAVE OTHER JURISDICTIONS CONSIDERED THE ECAPM?

A. Yes, it has been accepted in Alaska, Minnesota, Mississippi, Nevada, New York, and Virginia.[34]

Q. WHAT BETAS DID YOU USE IN YOUR CAPM ANALYSIS?

A. As discussed previously, I use: (1) the average of the *Value Line* and Bloomberg betas, which is consistent with prior testimony, and (2) *Value Line* betas. While both *Value Line* and Bloomberg adjust their calculated (or "raw") betas to reflect the tendency of beta to regress to the market mean of 1.00, *Value Line* calculates beta over a five-year period, while Bloomberg's calculation is based on two years of data.

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33 Dianna R. Harrington, Modern Portfolio Theory & the Capital Asset Pricing Model – A User's Guide, Prentice-Hall, Inc. 1983, at 30-31.

34 The Regulatory Commission of Alaska, Docket P-97-7, Order Rejecting 1997, 1998, 1999 and 2000 Filed TAPS Rates; Setting Just and Reasonable Rates; Requiring Refunds and Filings; and Outlining Phase II Issues, November 27, 2002, at 146; Minnesota Public Utilities Commission, MPUC Docket No. G011/GR-15-736, In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota, Findings of Fact, Conclusions of Law, and Recommendation, August 19, 2016, at 29; Mississippi Public Service Commission, Docket No. 01-UN-0548, Notice of Intent of Mississippi Power Company to Change Rates for Electric Service in its Certificated Areas in the Twenty-Three Counties of Southeast Mississippi, Final Order, December 3, 2001, at 19; Public Utilities Commission of Nevada, Docket No. 20-02023, Application of Southwest Gas Corporation for authority to increase its retail natural gas utility service rates for Southern and Northern Nevada, Order, September 23, 2020, at 35; New York Public Service Commission, Case 16-G-0058, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plans, December 16, 2016, at 32; In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina, Docket No. E-22, Sub 562 Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, February 24, 2020, at 40.

Q. WHY ARE YOU PRESENTING YOUR MODEL RESULTS EXCLUSIVELY USING *VALUE LINE* BETAS ALONGSIDE YOUR TRADITIONAL ANALYSIS?

A. I am presenting my updated model results in this way because recent and historical data show that Bloomberg betas may not accurately reflect the risk of the Gas Utility Proxy Group at this time.

Q. HOW DOES BLOOMBERG CALCULATE BETA?

A. As discussed above, beta is the covariance of a stock relative to a market index divided by the variance of the market return. Bloomberg calculates its beta using two years of weekly return data relative to the S&P 500 Index.

Q. WHAT IS A COVARIANCE?

A. A covariance is comprised of two measures: (1) the relative volatility of the stock, which is the standard deviation of the weekly returns of the stock divided by the standard deviation of the weekly return of the index returns;[35] and (2) the correlation of weekly stock and market index returns.[36]

Q. WHAT HAS THE BLOOMBERG BETA BEEN FOR THE GAS UTILITY PROXY GROUP SINCE 2005?

A. As shown in Chart 1, below, the Gas Utility Proxy Group average adjusted beta generally has ranged between 0.60 and 0.90, with some high side exceptions (2007-2008 and 2020-2022) and low side exceptions (2018-2020, second half 2024 – present).

Chart 1: Bloomberg Adjusted beta for the Gas Utility Proxy Group 2005-Present[37]

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[35] A relative volatility greater than 1.0 indicates that particular security is more volatile than the market during that calculation period. A relative volatility below 1.0 indicates that the security has less volatility than the market over that calculation period.

[36] Correlations range from negative one to positive one. The closer the correlation is to zero the weaker the relationship. Positive values indicate a positive correlation, where the values of both variables tend to increase together

[37] Source of Information: Bloomberg Professional Services.

Q. WHAT HAVE THE COMPONENTS OF BETA (I.E., RELATIVE VOLATILITY AND CORRELATION) SHOWN DURING THAT PERIOD?

A. As shown on Chart 2, the Gas Utility Proxy Group's relative volatility was generally above 1.0, indicating higher volatility than the S&P 500. On Chart 3, the two-year rolling correlation between the Gas Utility Proxy Group and the S&P 500 has varied over the period 2005 – 2025.

Chart 2: Relative Volatility for the Utility Proxy Group 2005-Present[38]

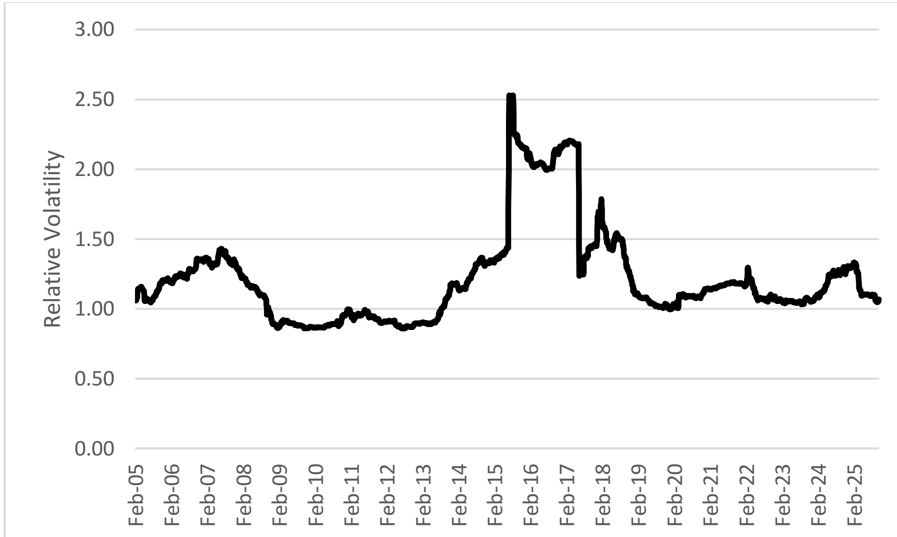
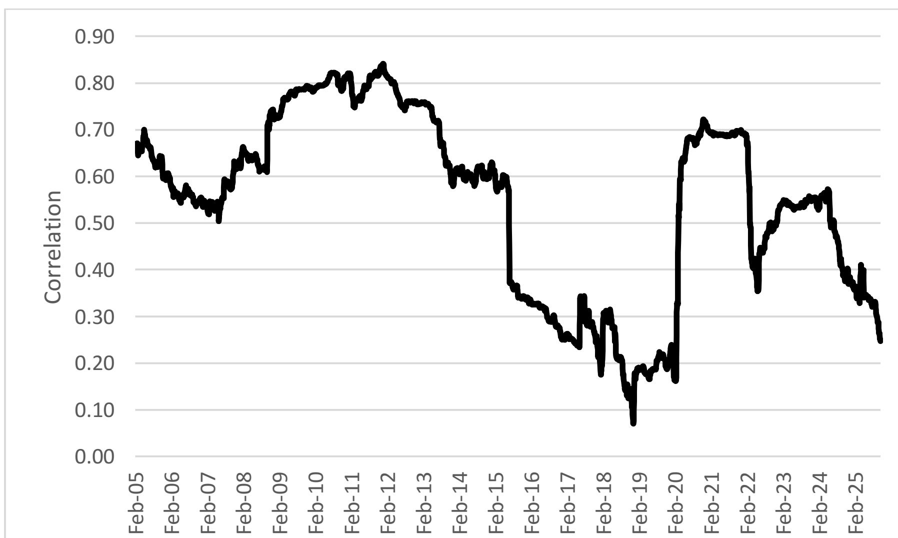


Chart 3: Correlation of the Utility Proxy Group Relative to the S&P 500 Index 2005-Present[39]



Importantly, as shown on Chart 3, during market distress (i.e., the Great Recession and the COVID-19 pandemic), the correlation of the Gas Utility Proxy Group returns and the S&P 500 returns approached 1.0, showing that utilities, as represented by the Gas

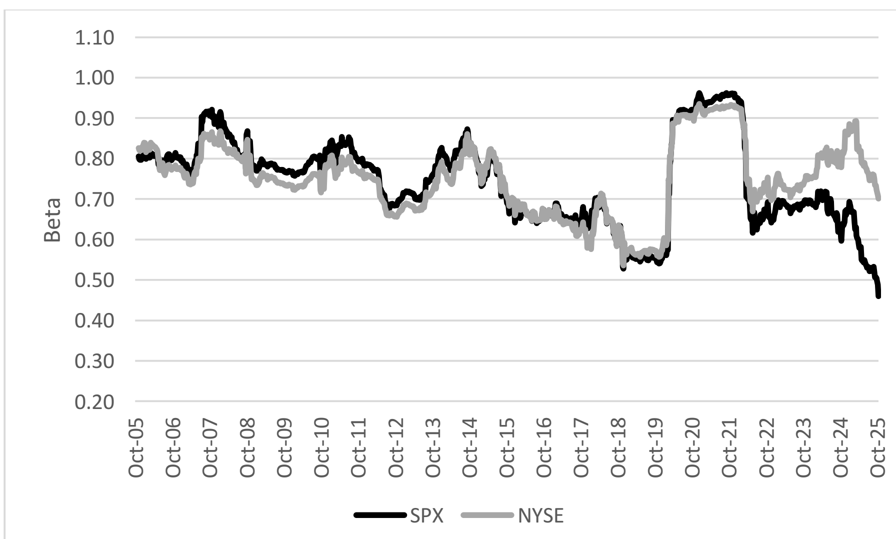
38 Source of Information: S&P Capital IQ.
39 Source of Information: S&P Capital IQ.

Utility Proxy Group, do not possess defensive qualities and should not be considered defensive stocks nor are they safe harbor investments in times of market distress.

Q. DOES THE LOWER CORRELATION OF THE GAS UTILITY PROXY GROUP RETURNS RELATIVE TO THE S&P 500 RETURNS ALONE NECESSITATE THE EXCLUSION OR MITIGATION OF BLOOMBERG BETAS?

A. No. Just as the investor required return varies under different market conditions, so do the model inputs. To determine whether Bloomberg's default betas calculated relative to the S&P 500 Index are accurately reflecting the risk of the Gas Utility Proxy Group, I compared them with betas calculated using two years of weekly returns relative to the New York Stock Exchange ("NYSE"). The comparison between two-year S&P 500 and NYSE betas are put forth in Chart 4, below:

Chart 4: Comparison of Two-Year S&P 500 and NYSE Betas for the Gas Utility Proxy Group 2005-Present[40]



[40] Source of Information: Bloomberg Professional Services.

As shown on Chart 4, the two-year S&P 500 and NYSE betas are generally consistent until approximately 2024, when the spread between them expanded beyond historical ranges as shown on Chart 5, below:

Chart 5: Spread Between Two-Year S&P and NYSE Betas for the Gas Utility Proxy Group 2005-Present[41]

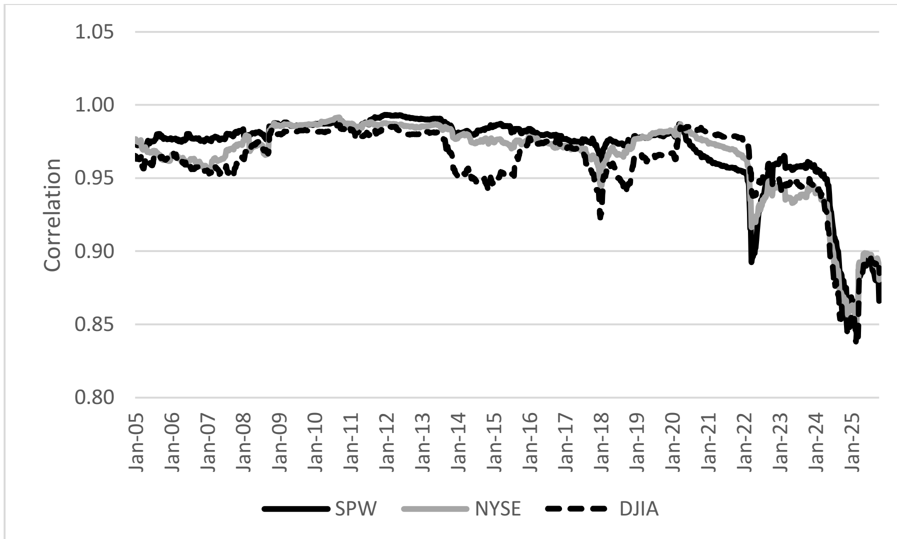
In view of Chart 5, it is clear that the relationship between the S&P 500 and NYSE is dislocated. To determine which index was distorting the risk of the Gas Utility Proxy Group, I compared the S&P 500 returns with those of the NYSE and other market indices.

Q. WHICH MARKET INDICES DID YOU USE IN YOUR COMPARISON?

A. In my comparison, I ran correlations between the returns of the S&P 500 and three other market indices: (1) the NYSE; (2) the Dow Jones Industrial Average ("DJIA"); and (3) the S&P 500 Equal Weighed Index ("SPW"). I ran the correlations for the same 2005-2025 period in the prior charts, which is put forth in Schedule DWD-5 and Chart 6, below:

[41] Source of Information: Bloomberg Professional Services.

Chart 6: Correlation between the S&P 500 Relative to Various Market Indices 2005-Present[42]



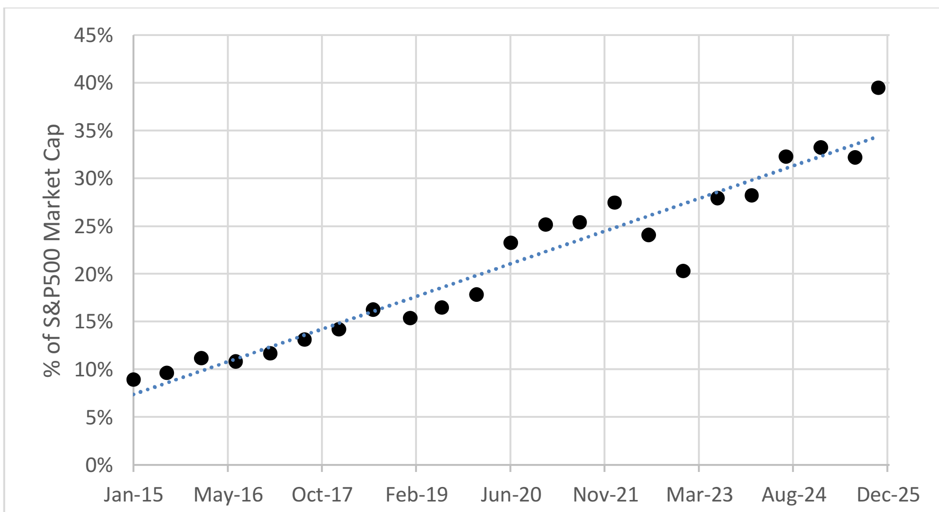
As shown in Chart 6, the two-year rolling correlation between S&P 500's returns and the other market indices' returns generally ranged between 0.95 and 1.00 for the entire period but has recently dipped below 0.85 for each of the measures, indicating that the relationship between the S&P 500 and the other market indices are strained. As shown on pages 2 through 4 of Schedule DWD-5, the two-year rolling correlations of the other market indices are within historical boundaries, whereas, as shown in Chart 6, the correlation in returns between the S&P 500 and the other three indices dropped below 0.90 for an extended period of time. Stated differently, the recent relationship between the S&P 500 Index and the other market indices is inconsistent with their historical relationships while the other market indices have maintained their historical relationships with each other.

[42] Source of Information: Bloomberg Professional Services.

Q. WHY IS THE RELATIONSHIP BETWEEN THE S&P 500 AND OTHER MARKET INDICES DEGRADING?

A. I believe that the concentration of the "Magnificent Seven"[43] ("Mag7") as a percentage of the S&P 500 market capitalization could explain why the two-year rolling correlations between the S&P 500 and the other market indices are degrading. Since 2015, the Mag7 stocks' percentage of the S&P 500 market capitalization has increased from 8.91% to 39.46% as shown on Chart 7, below:

Chart 7: Magnificent Seven Stocks Percentage of S&P 500 Market Capitalization 2015-Present[44]



Q. DOES THE CONCENTRATION AFFECT THE CALCULATION OF BETA FOR THE GAS UTILITY PROXY GROUP?

A. Yes, it does. I evaluated the two-year rolling correlation between the Utility Proxy Group's weekly returns and those returns for the Mag7 and the remaining 493 companies that comprise the S&P 500 index. As shown on Table 10, below, the Gas Utility Proxy

[43] The "Magnificent Seven" stocks are: (1) Apple, Inc.; (2) Amazon.com, Inc.; (3) Alphabet, Inc.; (4) Meta Platforms, Inc.; (5) Microsoft Corporation; (6) NVIDIA Corporation; and (7) Tesla, Inc.

[44] Source of Information: Bloomberg Professional Services.

Group's returns had a **negative** 0.1346 correlation with the Mag7 returns and a **positive** 0.1810 correlation with the rest of the S&P 500, indicating opposite relationships between the Gas Utility Proxy Group and the two subsets of the S&P 500.

Table 10: Correlation between the Gas Utility Proxy Group's Weekly Returns and those of the Magnificent Seven Stocks and the Remaining 493 Component Companies of the S&P 500 October 31, 2025[45]

	Correlation Coefficient 10/31/2025	
	Mag7	Remaining 493
Utility Proxy Group Weekly Returns	-0.1346	0.1810

Given the disconnection of the relationship between the Mag7 and the remaining members of the S&P 500 Index relative to the Gas Utility Proxy Group, the concentration of the Mag7 stocks within the S&P 500 Index, and the S&P 500's degrading relationship to other market indices, Bloomberg betas do not accurately reflect the risk of the Gas Utility Proxy Group as compared to the market, and therefore should be viewed with caution.

Q. PLEASE SUMMARIZE YOUR REASONING AS IT PERTAINS TO YOUR USE OF BETA IN YOUR ANALYSIS.

A. While the cost of capital and the inputs to cost of capital models vary based on market conditions, these variations should not lead an analyst to eliminate or mitigate a specific input. After investigating historical relationships between betas calculated relative to the S&P 500 and NYSE and the relative volatility and correlation of those betas, I discovered that these relationships are currently not within historical ranges and needed to be investigated further. I then compared returns for the S&P 500 to those of the NYSE, SPW, and DJIA, and discovered that those relationships also have departed from historical benchmarks. Importantly, the NYSE, SPW, and DJIA continue to show high levels of

[45] Source of Information: S&P Capital IQ.

correlation with each other. I then investigated the companies that comprised the S&P 500 and found that the Mag7 stocks' return now has an outsized influence on the return on the S&P 500. Looking at the correlations of Gas Utility Proxy Group returns related to Mag7 stocks and the remaining 493 stocks that comprise the S&P 500 Index, I discovered opposite relationships (i.e., negative correlation with Mag7 stocks and positive correlations with the remaining 493 stocks). Given the above, I believe that using the S&P 500 Index to calculate betas may not accurately reflect the risk of the Gas Utility Proxy Group and therefore should be viewed with caution. To reflect this in my analysis, I present my analysis using my traditional application of the models as presented in prior testimonies in Pennsylvania and elsewhere, and also present my model results exclusively using *Value Line* betas, which are calculated relative to the NYSE.

Q. PLEASE DESCRIBE YOUR SELECTION OF A RISK-FREE RATE OF RETURN.

A. As shown in Schedule DWD-6, the risk-free rate for both the applications of the CAPM is 4.53%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the first calendar quarter of 2027, and long-term projections for the years 2027 to 2031 and 2032 to 2036.

Q. WHY DID YOU USE THE PROJECTED 30-YEAR TREASURY YIELD IN YOUR ANALYSES?

A. The yield on long-term U.S. Treasury bonds is almost risk-free and its term is consistent with the long-term cost of capital to public utilities measured by the yields on Moody's A2-rated public utility bonds; the long-term investment horizon inherent in utilities' common stocks; and the long-term life of the jurisdictional rate base to which the allowed fair rate of return (i.e., cost of capital) will be applied. In contrast, short-term U.S. Treasury yields are more volatile and largely a function of Federal Reserve monetary policy.

Q. PLEASE EXPLAIN THE ESTIMATION OF THE EXPECTED RISK PREMIUM FOR THE MARKET USED IN YOUR CAPM ANALYSIS.

A. The basis of the market risk premium is explained in detail in note 1 on page 3 of Schedule DWD-6. As discussed above, the market risk premium is derived from an average of three historical data-based market risk premiums, one *Value Line* data-based market risk premium, and one *Value Line*, Bloomberg, and S&P Capital IQ data-based market risk premium.

The long-term income return on U.S. Government securities of 12.29% was deducted from the monthly historical total market return of 4.99%, which results in an historical market equity risk premium of 7.31%.[46] I applied a linear OLS regression to the monthly annualized historical returns on the S&P 500 relative to historical yields on long-term U.S. Government Securities. That regression analysis yielded a market equity risk premium of 7.96%. The PRPM market equity risk premium is 8.35% and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through October 2025.[47]

The *Value Line*-derived forecasted total market equity risk premium is derived by deducting the forecasted risk-free rate of 4.53%, discussed above, from the *Value Line* projected total annual market return of 10.91%, resulting in a forecasted total market equity risk premium of 6.38%.

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46 SBBI - 2023, at Appendix A-1 (1) through A-1 (3) and Appendix A-7 (19) through A-7 (21); Bloomberg Professional Services.

47 As shown on page 3 of Schedule DWD-6.

The S&P 500 projected market equity risk premium using *Value Line*, Bloomberg and S&P Capital IQ data is derived by subtracting the projected risk-free rate of 4.53% from the projected total return of the S&P 500 of 17.67%. The resulting market equity risk premium is 13.14%.

These five market risk premium measures, when averaged, result in an average total market equity risk premium of 8.63%.

Table 11: Summary of the Calculation of the Market Risk Premium for Use in the CAPM[48]

Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2024)	7.31%
Regression Analysis on Historical Data	7.96%
PRPM Analysis on Historical Data	8.35%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected 30-Year Treasury Bond Yields	6.38%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from for the S&P 500 less Projected 30-Year Treasury Bond Yields	13.14%
Average	8.63%

Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE TRADITIONAL AND EMPIRICAL CAPM TO THE GAS UTILITY PROXY GROUP?

A. As shown on page 1 and 2 of Schedule DWD-6, the average of the mean and median CAPM result using my traditional approach is 10.17%. The average of the mean and median CAPM using only *Value Line* betas is 11.30%. Given the above, a reasonable range of CAPM cost rates is from 10.17% to 11.30%.

[48] As shown on page 3 of Schedule DWD-6.

D. Common Equity Cost Rates for Proxy Group of Domestic, Non-Price Regulated Companies based on the DCF, RPM, and CAPM

Q. WHY DO YOU ALSO CONSIDER A PROXY GROUP OF DOMESTIC, NON-PRICE REGULATED COMPANIES?

A. Since the purpose of rate regulation is to be a substitute for marketplace competition, non-price regulated firms operating in the competitive marketplace make an excellent proxy if they are comparable in total risk to the Gas Utility Proxy Group being used to estimate the cost of common equity. The selection of such domestic, non-price regulated competitive firms theoretically and empirically results in a proxy group which is comparable in total risk to the Gas Utility Proxy Group, since all of these companies compete for capital in the exact same markets. Moreover, *Hope* and *Bluefield* cases do not specify that comparable risk companies had to be utilities.

Q. HOW DID YOU SELECT NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE GAS UTILITY PROXY GROUP?

A. In order to select a proxy group of domestic, non-price regulated companies similar in total risk to the Gas Utility Proxy Group, I relied on betas and related statistics derived from *Value Line* regression analyses of weekly market prices over the most recent 260 weeks (i.e., five years). As shown on Schedule DWD-7, these selection criteria resulted in a proxy group of thirty-two domestic, non-price regulated firms comparable in total risk to the Gas Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and diversifiable company-specific risks. The criteria used in selecting the domestic, non-price regulated firms was:

(i) They must be covered by *Value Line* (Standard Edition);

(ii) They must be domestic, non-price regulated companies, i.e., not utilities;

(iii) Their unadjusted betas must lie within plus or minus two standard deviations of the average unadjusted beta of the Gas Utility Proxy Group; and

(iv) The residual standard errors of the *Value Line* regressions which gave rise to the unadjusted betas must lie within plus or minus two standard deviations of the average residual standard error of the Gas Utility Proxy Group.

Betas measure market, or systematic, risk, which is not diversifiable. The residual standard errors of the regressions measure each firm's company-specific, diversifiable risk. Companies that have similar betas and similar residual standard errors resulting from the same regression analyses have similar total investment risk.

Q. DID YOU CALCULATE COMMON EQUITY COST RATES USING THE DCF MODEL, THE RPM, AND THE CAPM FOR THE NON-PRICE REGULATED PROXY GROUP?

A. Yes. Because the DCF model, RPM, and CAPM have been applied in an identical manner as described above, I will not repeat the details of the rationale and application of each model. One exception is in the application of the RPM, where I did not use public utility-specific equity risk premiums.

Page 2 of Schedule DWD-8 derives the constant growth DCF model common equity cost rate. As shown, the indicated common equity cost rate, using the constant growth DCF for the Non-Price Regulated Proxy Group comparable in total risk to the Gas Utility Proxy Group, is 11.29%.

Pages 3 through 5 of Schedule DWD-8 contain the data and calculations that support the range of indicated RPM common equity cost rates from 10.94% to 11.64%.

As shown on line 1, page 3 of Schedule DWD-8, the consensus prospective yield on Moody's Baa2-rated corporate bonds for the six quarters ending in the first quarter of 2027, and for the years 2027 to 2031 and 2032 to 2036, is 5.89%.[49] Since the Non-Price Regulated Proxy Group has an average Moody's long-term issuer rating of A3, another adjustment to the expected Baa2-rated public utility bond is needed to reflect the difference in bond ratings. A downward adjustment of 0.19%, which represents two-thirds of a recent spread between A2-rated and Baa2-rated corporate bond yields, is necessary to make the prospective bond yield applicable to an A2-rated corporate bond.[50] Subtracting the 0.19% from the 5.89% prospective Baa2-rated corporate bond yield results in a 5.70% expected bond yield applicable to the Non-Price Regulated Proxy Group.

When beta-adjusted risk premiums of 5.24% and 5.94%[51] relative to the Non-Price Regulated Proxy Group are added to the prospective A2-rated corporate bond yield of 5.70%, the indicated range of RPM common equity cost rates are from 10.94% to 11.64%.

Pages 6 and 7 of Schedule DWD-8 contains the inputs and calculations that support my range of indicated CAPM/ECAPM common equity cost rates from 10.68% to 11.29%.

Q. WHAT IS THE INDICATED RANGE OF COMMON EQUITY COST RATES BASED ON THE NON-PRICE REGULATED PROXY GROUP COMPARABLE IN TOTAL RISK TO THE GAS UTILITY PROXY GROUP?

A. As shown on page 1 of Schedule DWD-8, the results of the common equity models applied to the Non-Price Regulated Proxy Group – which group is comparable in total risk to the Gas Utility Proxy Group – are as follows:

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49 *Blue Chip Financial Forecasts*, June 2, 2025 at 14 and October 31, 2025 at 2.
50 As shown on line 2 and explained in note 2, page 3 of Schedule DWD-8.
51 Derived on page 5 of Schedule DWD-8.

Table 12: Summary of Model Results Applied to the Non-Price Regulated Proxy Group[52]

Discounted Cash Flow Model	11.29%
Risk Premium Model	10.94% - 11.64%
Capital Asset Pricing Model	10.68% - 11.29%
Mean	10.97% - 11.41%
Median	10.94% - 11.29%
Average of Mean and Median	10.96% - 11.35%

The average of the mean and median of these models indicate a range of cost rates from 10.96% to 11.35%. While I do not consider these results in determining my recommended range of ROEs, I note that they are comparable to my Gas Utility Proxy Group indicated results.

VII. RANGE OF COMMON EQUITY COST RATES BEFORE ADJUSTMENTS

Q. WHAT IS THE RANGE OF INDICATED COMMON EQUITY COST RATES PRODUCED BY YOUR ROE MODELS?

A. The range of indicated ROEs produced from my analysis is from 10.17% to 11.35%. The indicated results of the DCF model, RPM, and CAPM fall within that indicated range. I used multiple cost of common equity models as primary tools in arriving at my recommended common equity cost rate, because no single model is so inherently precise that it can be relied on to the exclusion of other theoretically sound models. Using multiple models adds reliability to the estimated common equity cost rate, with the prudence of using multiple cost of common equity models supported in both the financial literature and regulatory precedent. Based on these common equity cost results, I conclude that a range of common equity cost rates between 10.17% and 11.35% is reasonable.

[52] As shown on page 1 of Schedule DWD-8.

VIII. <u>ADJUSTMENTS TO THE COMMON EQUITY COST RATE</u>

Q. IS IT NECESSARY TO CONDUCT A RELATIVE RISK ANALYSIS BETWEEN THE GAS UTILITY PROXY GROUP AND THE COMPANY?

A. Yes. After a proxy group-specific ROE is determined, one must conduct a relative risk analysis to determine whether additional adjustments need to be made to reflect the unique risk of the subject company.

A. Business Risk Adjustment

Q. DOES UGI GAS'S SMALLER SIZE RELATIVE TO THE GAS UTILITY PROXY GROUP COMPANIES INCREASE ITS BUSINESS RISK?

A. Yes. UGI Gas's smaller size relative to the Gas Utility Proxy Group companies indicates greater relative business risk for the Company because, all else being equal, size has a material bearing on risk.

Size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues, and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers would have a greater effect on a small company than on a bigger company with a larger, more diverse, customer base.

As further evidence illustrates that smaller firms are riskier, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Kroll's <u>Cost of Capital Navigator: U.S. Cost of Capital Module</u> ("<u>Kroll</u>") discusses the nature of the small-size phenomenon, providing an indication of the magnitude of the size premium based on several measures of size. In discussing "Size as a Predictor of Equity Premiums," Kroll states:

> The size effect is based on the empirical observation that companies of smaller size are associated with greater risk and, therefore, have greater cost of capital [sic]. The "size" of a company is one of the most important risk elements to consider when developing cost of equity capital estimates for use in valuing a business simply because size has been shown to be a *predictor* of equity returns. In other words, there is a significant (negative) relationship between size and historical equity returns - as size *decreases*, returns tend to *increase*, and vice versa. (footnote omitted) (emphasis in original)[53]

Furthermore, in "The Capital Asset Pricing Model: Theory and Evidence," Fama and French note size is indeed a risk factor which must be reflected when estimating the cost of common equity. On page 38, they note:

> **. . .** the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the market return and are priced separately from market betas.[54]

Based on this evidence, Fama and French proposed their three-factor model which includes a size variable in recognition of the effect size has on the cost of common equity.

Also, it is a basic financial principle that the use of funds invested, and not the source of funds, is what gives rise to the risk of any investment.[55] Eugene Brigham, a well-known authority, states:

> A number of researchers have observed that portfolios of small-firms (sic) have earned consistently higher average returns than those of large-firm stocks; this is called the "small-firm effect." On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; **what the small-firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of the large firms.** (emphasis added)[56]

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53 Kroll: Cost of Capital Navigator: U.S. Cost of Capital Module, "Size as a Predictor of Equity Returns," at 1.

54 Fama & French, at 25-43.

55 Richard A. Brealey and Stewart C. Myers, Principles of Corporate Finance (McGraw-Hill Book Company, 1996), at 204-205, 229.

56 Eugene F. Brigham, Fundamentals of Financial Management, Fifth Edition (The Dryden Press, 1989), at 623.

Consistent with the financial principle of risk and return discussed above, increased relative risk due to small size must be considered in the allowed rate of return on common equity. Therefore, the Commission's authorization of a cost rate of common equity in this proceeding must appropriately reflect the unique risks of UGI Gas's natural gas distribution operations, including its small size, which is justified and supported above by evidence in the financial literature.

Q. INTERVENING WITNESSES OFTEN CITE A STUDY BY DR. ANNIE WONG FOR THE PROPOSITION THAT THERE IS NO SIZE PREMIUM FOR UTILITIES. DOES THIS STUDY ESTABLISH THAT CONTENTION?

A. No, it does not. In the Wong study, Dr. Wong attempted to relate a change in beta to the size effect. Dr. Wong's beta study is incorrect, as beta is a measure of market risk, whereas size is a company-specific, or diversifiable risk. While betas may contain some measure of diversifiable risk, betas have low explanatory power. As shown in Schedule DWD-10, the R-Squared, which measures the variability of returns applicable to beta, is approximately 0.18 for my Gas Utility Proxy Group, which means approximately 82% of the variation of the Gas Utility Proxy Group's returns are unexplained by beta.

Q. IS THERE ALSO A PUBLISHED RESPONSE TO DR. WONG'S ARTICLE?

A. Yes, there is. In response to Professor Wong's article, *The Quarterly Review of Economics and Finance* published an article in 2003, authored by Thomas M. Zepp, which commented on the Wong article often cited by intervening witnesses. Relative to Dr. Wong's results, Dr. Zepp concluded in the Abstract on page 1 of his article: "Her weak results, however, do not rule out the possibility of a small firm effect for utilities."[57] Dr. Zepp also noted on

[57] Thomas M. Zepp, "Utility Stocks and the Size Effect --- Revisited", *The Quarterly Review of Economics and Finance*, 43 (2003), at 578-582.

page 582 that: "Two other studies discussed here support a conclusion that smaller water utility stocks are more risky than larger ones. To the extent that water utilities are representative of all utilities, there is support for smaller utilities being more risky than larger ones."[58]

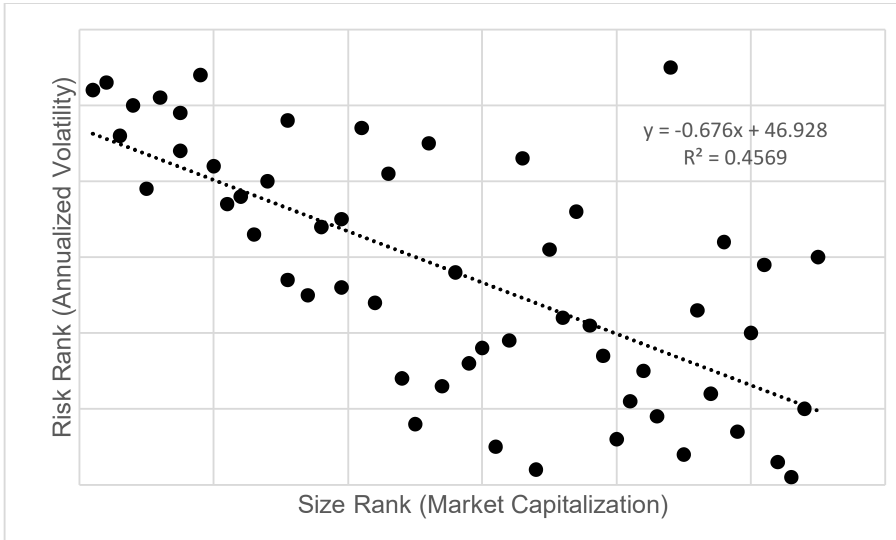
Q. HAVE YOU PERFORMED STUDIES LINKING SIZE AND RISK FOR UTILITY COMPANIES?

A. Yes, I have performed two studies that link size and risk for utility companies. My first study included the universe of electric, gas, and water companies included in *Value Line* Standard Edition. For each of the utilities, the annualized volatility (a measure of risk)[59] was calculated, and each company was ranked by its current market capitalization (a measure of size) as reported by *Value Line*. Ranking the companies by size (smallest to largest) and risk (most risky to least risky), results in the scatterplot shown on Chart 8, below:

[58] Thomas M. Zepp, "Utility Stocks and the Size Effect --- Revisited", *The Quarterly Review of Economics and Finance*, 43 (2003), at 578-583.

[59] Annualized volatility equals the standard deviation of returns over the period multiplied by the square root of 252, or the approximate number of trading days in a year.

Chart 8: Relationship Between Size and Risk for the *Value Line* Universe of Utility Companies[60]



As shown in Chart 8 above, as company size decreases (increasing size rank), the annualized volatility increases, linking size and risk for utilities, which is significant at 95.0% confidence level.

The second study used the same universe of companies, but instead of annualized volatility, I used the *Value Line* Safety Ranking, which is another measure of total risk.[61] After ranking the companies by size and Safety Ranking, I made a scatterplot of those data, as shown on Chart 9, below:

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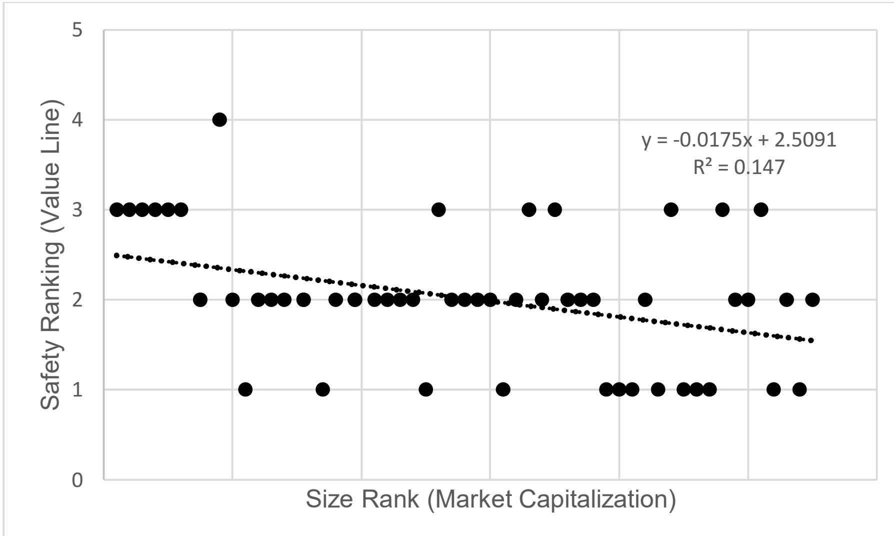
60 Source: *Value Line*

61 *Value Line* also ranks stocks for Safety by analyzing the total risk of a stock compared to the approximately 1,700 stocks in the *Value Line* universe. Each of the stocks tracked in the *Value Line Investment Survey* is ranked in relationship to each other, from 1 (the highest rank) to 5 (the lowest rank). Safety is a quality rank, not a performance rank, and stocks ranked 1 and 2 are most suitable for conservative investors; those ranked 4 and 5 will be more volatile. Volatility means prices can move dramatically and often unpredictably, either down or up. The major influences on a stock's Safety rank are the company's financial strength, as measured by balance sheet and financial ratios, and the stability of its price over the past five years.

Chart 9: Relationship Between Size and Safety Ranking for the *Value Line* Universe of Utility Companies[62]



Similar to the first study, as company size decreases, Safety Ranking degrades, indicating a link between size and risk for utilities. This study is also significant at the 95% confidence level. The assertion that size and risk are not linked for utility companies should be dismissed by the Commission.

Q. IS THERE A WAY TO QUANTIFY A RELATIVE RISK ADJUSTMENT DUE TO UGI GAS'S GREATER BUSINESS RISK RELATIVE TO THE GAS UTILITY PROXY GROUP?

A. Yes. In the absence of other empirical methods, I compared UGI Gas's and the Gas Utility Proxy Group's relative size, as measured by market capitalization on October 31, 2025.

[62] Source: *Value Line*.

Table 13: Size as Measured by Market Capitalization for the Company and the Gas Utility Proxy Group

	Market Capitalization* ($ Millions)	**Times Greater Than the Company**
UGI Gas	$3,901.539	
Gas Utility Proxy Group Median	$ 4,801.525	1.2x
*From page 1 of Schedule DWD-9.		

The Company's market capitalization was at $3.90 billion as of October 31, 2025, compared with the median market capitalization of the Utility Proxy Group of $4.80 billion as of October 31, 2025. The Gas Utility Proxy Group's market capitalization is 1.2 times the size of UGI Gas's market capitalization.

As a result, it is necessary to upwardly adjust the indicated range of common equity cost rates to reflect UGI Gas's greater risk due to its smaller relative size. The determination is based on the size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 to 2024 period. The average size premium for the Gas Utility Proxy Group with a market capitalization of $4.80 billion falls in the 5th decile, while UGI Gas's market capitalization of $4.80 billion places the Company in the 6th decile. The size premium spread between the 5th decile and the 6th decile is 0.26%. Even though a 0.26% upward size adjustment is indicated, I conservatively applied a size premium of 0.05% to UGI Gas's indicated range of common equity cost rates.

Q. DOES THIS COMMISSION CONSIDER SIZE IN DETERMINING THE AUTHORIZED ROE?

A. Yes. In Docket No. R-2019-3008212, the Commission stated:

> Based on the evidence of record, we agree with the recommendation of the ALJs that the Company be awarded a DCF cost of common equity which

> is one standard deviation about the average of the mean and median proxy group ROE from the Company's DCF analysis. In so doing, we recognize that the Company's size is a factor in assessing its ability to attract capital. Accordingly, we shall reject Citizens' Exception No. 10, I&E's Exception No. 4, and the OCA's Exception No. 7, consistent with the following discussion.
>
> We are not convinced by the arguments of I&E and the OCA that the ALJs erred in awarding a size adjustment to Citizens'. Rather, we are of the same position as the ALJs that the Company's witness Mr. D'Ascendis offered persuasive record evidence that there is a general inverse relationship between size and risk, such that smaller utilities like Citizens' face greater risk.[63]

Q. WHAT WOULD BE THE ROE RESULT USING THE COMMISSION'S METHOD IN THIS CASE?

A. The average of the mean and median DCF model result is 10.53%, as shown on page 1 of Schedule DWD-3. The standard deviation of those results is 1.51%. Adding the standard deviation to the average of the mean and median DCF result would indicate an ROE of 12.04% for UGI Gas, which is higher than my ultimate recommendation in this case. In view of this, my size adjustment should be considered conservative.

B. Flotation Cost Adjustment

Q. WHAT ARE FLOTATION COSTS?

A. Flotation costs are those costs associated with the sale of new issuances of common stock. They include market pressure and the mandatory unavoidable costs of issuance (e.g., underwriting fees and out-of-pocket costs for printing, legal, registration, etc.). For every dollar raised through debt or equity offerings, the Company receives less than one full dollar in financing.

[63] Pennsylvania Public Utility Commission, Docket No. R-2019-3008212, Opinion and Order, at 103.

Q. WHY IS IT IMPORTANT TO RECOGNIZE FLOTATION COSTS IN THE ALLOWED COMMON EQUITY COST RATE?

A. It is important because there is no other mechanism in the ratemaking paradigm through which such costs can be recognized and recovered. Because these costs are real, necessary, and legitimate, recovery of these costs should be permitted. As noted by Morin:

> The costs of issuing these securities are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit the recovery of these costs….
>
> The simple fact of the matter is that common equity capital is not free…[Flotation costs] must be recovered through a rate of return adjustment.[64]

Q. SHOULD FLOTATION COSTS BE RECOGNIZED ONLY IF THERE WAS AN ISSUANCE DURING THE TEST YEAR OR THERE IS AN IMMINENT POST-TEST YEAR ISSUANCE OF ADDITIONAL COMMON STOCK?

A. No. As noted above, there is no mechanism to recapture such costs in the ratemaking paradigm other than an adjustment to the allowed common equity cost rate. Flotation costs are charged to capital accounts and are not expensed on a utility's income statement. As such, flotation costs are analogous to capital investments, albeit negative, reflected on the balance sheet. Recovery of capital investments relates to the expected useful lives of the investment. Since common equity has a very long and indefinite life (assumed to be infinity in the standard regulatory DCF model), flotation costs should be recovered through an adjustment to common equity cost rate, even when there has not been an issuance during

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64 Morin, at 329.

the test year, or in the absence of an expected imminent issuance of additional shares of common stock.

Historical flotation costs are a permanent loss of investment to the utility and should be taken into account. When any company, including a utility, issues common stock, flotation costs are incurred for legal, accounting, printing fees, and the like. For each dollar of issuing market price, a small percentage is expensed and is permanently unavailable for investment in utility rate base. Since these expenses are charged to capital accounts and not expensed on the income statement, the only way to restore the full value of that dollar of issuing price with an assumed investor required return of 10% is for the net investment, $0.95, to earn more than 10% to net back to the investor a fair return on that dollar. In other words, if a company issues stock at $1.00 with 5% in flotation costs, it will net $0.95 in investment. Assuming the investor in that stock requires a 10% return on their invested $1.00 (i.e., a return of $0.10), the company needs to earn approximately 10.5% on its invested $0.95 to receive a $0.10 return.

Q. DO THE COMMON EQUITY COST RATE MODELS YOU HAVE USED ALREADY REFLECT INVESTORS' ANTICIPATION OF FLOTATION COSTS?

A. No. All of these models assume no transaction costs. The literature is quite clear that these costs are not reflected in the market prices paid for common stocks. For example, Brigham and Daves confirm this and provide the methodology utilized to calculate the flotation adjustment.[65] In addition, Morin confirms the need for such an adjustment even when no new equity issuance is imminent.[66] Consequently, it is proper to include a flotation cost

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65 Eugene F. Brigham and Phillip R. Daves, Intermediate Financial Management, 9th Edition, Thomson/Southwestern, at p. 342.

66 Morin, at 339.

adjustment when using cost of common equity models to estimate the common equity cost rate.

Q. WHAT IS THE IMPACT TO INVESTORS IF THE RECOVERY OF FLOTATION COSTS IS DENIED?

A. Denying recovery of issuance costs penalizes the investors that fund the utility operations. As shown on page 2 of Schedule DWD-11, because of flotation costs, an authorized return of 10.85% would be required to realize an ROE of 10.75% (i.e., a 10-basis point flotation cost adjustment). If flotation costs are not recovered, the growth rate falls and the ROE decreases to 10.65% (i.e., below the required return).[67]

Q. DO YOU AGREE THAT FLOTATION COSTS CAN BE RECOVERED AS AN EXPENSE RATHER THAN AN ADJUSTMENT TO THE ROE?

A. No, I do not. The reason being is due to opportunity cost. When an entity issues equity or debt, the net proceeds of that capital is generally used to finance rate base, which is entitled to a return of (depreciation) and a return on (the weighted average cost of capital). Because the cost of issuing the capital would otherwise go to financing rate base, the costs of that capital would need to be recovered on an ongoing basis.

Q. HAVE OTHER REGULATORY COMMISSIONS ALLOWED FLOTATION COSTS IN THE ALLOWED ROE?

A. Yes, they have. For example, in Peoples Gas System, Inc.'s ("PGS") recent 2023 rate proceeding, the Florida Public Service Commission stated the following regarding my proposed flotation cost adjustment:

> In PGS's last rate case in 2008, we did not make a specific adjustment for flotation costs, but in our order we stated that we have traditionally recognized

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[67] Schedule DWD-11, page 2 is provided for illustrative purposes only. Please note that I have not relied on the results of the analysis in determining my recommended ROE or range.

> a reasonable adjustment for flotation costs in the determination of the investor required return...We find witness D'Ascendis's method to determine the flotation cost is credible and provided persuasive evidence for his recommendation to include a flotation cost of 9 basis points.[68]

Given the above, I recommend this Commission also correctly include flotation costs in the allowed ROE.

Q. HOW DID YOU CALCULATE THE FLOTATION COST ALLOWANCE?

A. I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs in accordance with the method cited in literature by Brigham and Daves, as well as by Morin. The flotation cost adjustment recognizes the actual costs of issuing equity that were incurred by UGI Corp. Based on the issuance costs shown on page 1 of Schedule DWD-11, an adjustment of 0.12% is required to reflect the flotation costs applicable to the Gas Utility Proxy Group.

Q. WHAT IS THE INDICATED COST OF COMMON EQUITY AFTER YOUR COMPANY-SPECIFIC ADJUSTMENTS?

A. Applying the 0.05% business risk adjustment and the 0.12% flotation cost adjustment to the indicated range of common equity cost rates between 10.17% and 11.35% results in a range of common equity cost rates between 10.34% and 11.52%.[69]

IX. CONCLUSION

Q. WHAT IS YOUR RECOMMENDED ROE FOR UGI GAS?

A. Given the discussion above and the results of my analytical models, I conclude that an appropriate ROE for the Company is 10.75%.

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[68] *In re: Petition for rate increase by Peoples Gas System, Inc.*, Docket No. 20230023-GU, Order Granting in Part and Denying in Part Peoples Gas System, Inc.'s Petition for a Rate Increase, at 68 (December 27, 2023).

[69] A credit risk adjustment is not necessary in this proceeding, as UGI Gas's long-term issuer rating is equivalent to the average long-term issuer rating of the Gas Utility Proxy Group.

Q. IN YOUR OPINION, IS YOUR PROPOSED ROE OF 10.75% FAIR AND REASONABLE TO UGI AND ITS CUSTOMERS?

A. Yes, it is.

Q. IN YOUR OPINION, IS UGI GAS'S PROPOSED CAPITAL STRUCTURE CONSISTING OF 45.75% LONG-TERM DEBT AND 54.25% COMMON EQUITY FAIR AND REASONABLE?

A. Yes, it is.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

APPENDIX A

for

Dylan W. D'Ascendis

Appendix A - Resume and Testimony Listing of:

Dylan W. D'Ascendis, CRRA, CVA
Partner
Framingham, MA Office

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). Dylan joined ScottMadden in 2016 and is a leading expert witness with respect to cost of capital, capital structure, and valuation. He has served as a consultant for investor-owned and municipal utilities and authorities for 17 years. Dylan has testified as an expert witness on over 150 occasions regarding rate of return, cost of service, rate design, and valuation before more than 40 regulatory jurisdictions in the United States and Canada, an American Arbitration Association panel, and the Superior Court of Rhode Island. He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured. Dylan holds a B.A. in economic history from the University of Pennsylvania and an M.B.A. with concentrations in finance and international business from Rutgers University.

Areas of Specialization

- Expert Witness Testimony
- Rates and Regulation
- Return on Equity
- Valuation
- Utility Regulations
- Rate Case Planning, Management, and Support
- Utility Benchmarking

Recent Articles and Speeches

- "Decoupling, Risk Impacts, and the Cost of Capital." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. The Electricity Journal. March 2020
- "Decoupling Impact and Public Utility Conservation Investment." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. Energy Policy Journal. 130 (2019), 311-319
- "Establishing Alternative Proxy Groups." Presentation before the Society of Utility and Regulatory Financial Analysts: 51st Financial Forum. April 4, 2019. New Orleans, LA
- "Past Is Prologue: Future Test Year." Presentation before the National Association of Water Companies 2017 Southeast Water Infrastructure Summit. May 2, 2017. Savannah, GA
- "Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Pauline M. Ahern, and Frank J. Hanley. The Electricity Journal. May 2013
- "Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks." Presentation before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum. April 17-18, 2013. Indianapolis, IN

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to the city
- Co-authored a valuation report on behalf of a large investor-owned utility in response to a new state regulation which allowed the appraised value of acquired assets into rate base

Sponsor	Date	Case/Applicant	Docket No.	Subject
Regulatory Commission of Alaska				
Goat Lake Hydro, Inc.	12/24	Goat Lake Hydro, Inc.	Docket No. TA7-521	Rate of Return
Alaska Power Company	08/23	Alaska Power Company	Docket No. TA 909-2 / U-23-054	Capital Structure
ENSTAR Natural Gas Company	08/22	ENSTAR Natural Gas Company	Docket No. TA334-4	Rate of Return
Cook Inlet Natural Gas Storage Alaska, LLC	07/21	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. TA45-733	Capital Structure
Alaska Power Company	09/20	Alaska Power Company; Goat Lake Hydro, Inc.; BBL Hydro, Inc.	Tariff Nos. TA886-2; TA6-521; TA4-573	Capital Structure
Alaska Power Company	07/16	Alaska Power Company	Docket No. TA857-2	Rate of Return
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	02/23	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	Proceeding ID. 27084	Determination of Cost-of-Capital Parameters
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	01/20	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2021 Generic Cost of Capital, Proceeding ID. 24110	Rate of Return
Arizona Corporation Commission				
EPCOR Water Arizona, Inc.	09/25	EPCOR Water Arizona, Inc.	Docket No.WS-01303A-24-0130	Annual Formula Rate Adjustment Mechanism
EPCOR Water Arizona, Inc.	06/24	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-24-0130	Rate of Return
Arizona Water Company	05/24	Arizona Water Company – Northern Group	Docket No. W-01445A-24-0117	Rate of Return
Foothills Water & Sewer, LLC	10/23	Foothills Water & Sewer, LLC	Docket No. WS-21182A-23-0292	Rate of Return and Fair Value Rate Base
Arizona Water Company	12/22	Arizona Water Company – Eastern Group	Docket No. W-01445A-22-0286	Rate of Return
EPCOR Water Arizona, Inc.	08/22	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-22-0236	Rate of Return
EPCOR Water Arizona, Inc.	06/20	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-20-0177	Rate of Return
Arizona Water Company	12/19	Arizona Water Company – Western Group	Docket No. W-01445A-19-0278	Rate of Return
Arizona Water Company	08/18	Arizona Water Company – Northern Group	Docket No. W-01445A-18-0164	Rate of Return
Arkansas Public Service Commission				
Summit Utilities Arkansas, Inc.	01/24	Summit Utilities Arkansas, Inc.	Docket No. 23-079-U	Rate of Return
Southwestern Electric Power Co.	07/21	Southwestern Electric Power Co.	Docket No. 21-070-U	Return on Equity
CenterPoint Energy Resources Corp.	05/21	CenterPoint Arkansas Gas	Docket No. 21-004-U	Return on Equity
California Public Utilities Commission				
Union Pacific Railroad Co – dba Keene Water System	03/25	Union Pacific Railroad Co – dba Keene Water System	Docket No. A25-03-016	Rate of Return
Southwest Gas Corporation	07/24	Southwest Gas Corporation	Docket No. A24-09-001	Return on Equity
San Gabriel Valley Water Company	05/23	San Gabriel Valley Water Company	Docket No. A23-05-001	Return on Equity
City of Edmonton, Canada				
EPCOR Water Services, Inc.	05/24	EPCOR Water Services, Inc.	Performance Based Regulation Application	Cost of Capital

Sponsor	Date	Case/Applicant	Docket No.	Subject
Colorado Public Utilities Commission				
Atmos Energy Corporation	08/22	Atmos Energy Corporation	Docket No. 22AL-0348G	Rate of Return
Summit Utilities, Inc.	04/18	Colorado Natural Gas Company	Docket No. 18AL-0305G	Rate of Return
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Rate of Return
Commission of the Canada Energy Regulator				
Trans-Northern Pipelines Inc.	11/22	Trans-Northern Pipelines Inc.	Docket No. C-22197	Cost of Capital
Delaware Public Service Commission				
Artesian Water Company, Inc.	04/25	Artesian Water Company, Inc.	Docket No. 25-0436	Rate of Return
Delmarva Power & Light Co.	09/24	Delmarva Power & Light Co.	Docket No. 24-1044 (Gas)	Return on Equity
Tidewater Utilities, Inc.	08/24	Tidewater Utilities, Inc.	Docket No. 24-0991	Rate of Return
Delmarva Power & Light Co.	07/24	Delmarva Power & Light Co.	Docket No. 24-0868	Alternative Forms of Rate Regulation
Artesian Water Company, Inc.	04/23	Artesian Water Company, Inc.	Docket No. 23-0601	Rate of Return
Delmarva Power & Light Co.	12/22	Delmarva Power & Light Co.	Docket No. 22-0897 (Electric)	Return on Equity
Delmarva Power & Light Co.	01/22	Delmarva Power & Light Co.	Docket No. 22-002 (Gas)	Return on Equity
Delmarva Power & Light Co.	11/20	Delmarva Power & Light Co.	Docket No. 20-0149 (Electric)	Return on Equity
Delmarva Power & Light Co.	10/20	Delmarva Power & Light Co.	Docket No. 20-0150 (Gas)	Return on Equity
Tidewater Utilities, Inc.	11/13	Tidewater Utilities, Inc.	Docket No. 13-466	Capital Structure
Public Service Commission of the District of Columbia				
Washington Gas Light Company	08/24	Washington Gas Light Company	Formal Case No. 1180	Rate of Return
Washington Gas Light Company	04/22	Washington Gas Light Company	Formal Case No. 1169	Rate of Return
Washington Gas Light Company	09/20	Washington Gas Light Company	Formal Case No. 1162	Rate of Return
Federal Energy Regulatory Commission				
LS Power Grid California, LLC	10/20	LS Power Grid California, LLC	Docket No. ER21-195-000	Rate of Return
Florida Public Service Commission				
Peoples Gas System, Inc.	03/25	Peoples Gas System, Inc.	Docket No. 20250029-GU	Return on Equity
Tampa Electric Company	04/24	Tampa Electric Company	Docket No. 20240025-EI	Return on Equity
Peoples Gas System, Inc.	04/23	Peoples Gas System, Inc.	Docket No. 20230023-GU	Rate of Return
Tampa Electric Company	04/21	Tampa Electric Company	Docket No. 20210034-EI	Return on Equity
Peoples Gas System, Inc.	09/20	Peoples Gas System, Inc.	Docket No. 20200051-GU	Rate of Return
Utilities, Inc. of Florida	06/20	Utilities, Inc. of Florida	Docket No. 20200139-WS	Rate of Return
Hawaii Public Utilities Commission				
Kaupulehu Waste Water Company	02/25	Kaupulehu Waste Water Company	Docket No. 2023-0456	Rate of Return
Launiupoko Irrigation Company, Inc.	12/20	Launiupoko Irrigation Company, Inc.	Docket No. 2020-0217 / Transferred to 2020-0089	Capital Structure
Lanai Water Company, Inc.	12/19	Lanai Water Company, Inc.	Docket No. 2019-0386	Cost of Service / Rate Design
Manele Water Resources, LLC	08/19	Manele Water Resources, LLC	Docket No. 2019-0311	Cost of Service / Rate Design
Kaupulehu Water Company	02/18	Kaupulehu Water Company	Docket No. 2016-0363	Rate of Return
Aqua Engineers, LLC	05/17	Puhi Sewer & Water Company	Docket No. 2017-0118	Cost of Service / Rate Design
Hawaii Resources, Inc.	09/16	Laie Water Company	Docket No. 2016-0229	Cost of Service / Rate Design
Illinois Commerce Commission				
Ameren Illinois Company d/b/a Ameren Illinois	01/25	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 25-0084 (Gas)	Return on Equity
Aqua Illinois, Inc.	01/24	Aqua Illinois, Inc.	Docket No. 24-0044	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Ameren Illinois Company d/b/a Ameren Illinois	01/23	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 23-0082 (Electric)	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/23	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 23-0067 (Gas)	Return on Equity
Utility Services of Illinois, Inc.	02/21	Utility Services of Illinois, Inc.	Docket No. 21-0198	Rate of Return
Ameren Illinois Company d/b/a Ameren Illinois	07/20	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 20-0308	Return on Equity
Utility Services of Illinois, Inc.	11/17	Utility Services of Illinois, Inc.	Docket No. 17-1106	Cost of Service / Rate Design
Aqua Illinois, Inc.	04/17	Aqua Illinois, Inc.	Docket No. 17-0259	Rate of Return
Utility Services of Illinois, Inc.	04/15	Utility Services of Illinois, Inc.	Docket No. 14-0741	Rate of Return
Indiana Utility Regulatory Commission				
Aqua Indiana, Inc.	03/16	Aqua Indiana, Inc. Aboite Wastewater Division	Docket No. 44752	Rate of Return
Twin Lakes, Utilities, Inc.	08/13	Twin Lakes, Utilities, Inc.	Docket No. 44388	Rate of Return
Kansas Corporation Commission				
Atmos Energy Corporation	07/25	Atmos Energy Corporation	26-ATMG-026-RTS	Rate of Return
Atmos Energy Corporation	07/19	Atmos Energy Corporation	19-ATMG-525-RTS	Rate of Return
Kentucky Public Service Commission				
PPL Corporation	05/25	Kentucky Utilities Company / Louisville Gas & Electric Company	2025-00113 / 00114	Rate of Return
Atmos Energy Corporation	09/24	Atmos Energy Corporation	2024-00276	Rate of Return
Bluegrass Water Utility Operating Company	02/23	Bluegrass Water Utility Operating Company	2022-00432	Return on Equity
Atmos Energy Corporation	07/22	Atmos Energy Corporation	2022-00222	PRP Rider Rate
Water Service Corporation of KY	06/22	Water Service Corporation of KY	2022-00147	Rate of Return
Atmos Energy Corporation	07/21	Atmos Energy Corporation	2021-00304	PRP Rider Rate
Atmos Energy Corporation	06/21	Atmos Energy Corporation	2021-00214	Rate of Return
Duke Energy Kentucky, Inc.	06/21	Duke Energy Kentucky, Inc.	2021-00190	Return on Equity
Bluegrass Water Utility Operating Company	10/20	Bluegrass Water Utility Operating Company	2020-00290	Return on Equity
Louisiana Public Service Commission				
Utilities, Inc. of Louisiana	05/21	Utilities, Inc. of Louisiana	Docket No. U-36003	Rate of Return
Southwestern Electric Power Company	12/20	Southwestern Electric Power Company	Docket No. U-35441	Return on Equity
Atmos Energy Corporation	04/20	Atmos Energy Corporation	Docket No. U-35535	Rate of Return
Louisiana Water Service, Inc.	06/13	Louisiana Water Service, Inc.	Docket No. U-32848	Rate of Return
Maine Public Utilities Commission				
Northern Utilities, Inc. d/b/a Unitil	05/23	Northern Utilities, Inc. d/b/a Unitil	Docket No. 2023-00051	Return on Equity
Summit Natural Gas of Maine, Inc.	03/22	Summit Natural Gas of Maine, Inc.	Docket No. 2022-00025	Rate of Return
The Maine Water Company	09/21	The Maine Water Company	Docket No. 2021-00053	Rate of Return
Maryland Public Service Commission				
Washington Gas Light Company	05/23	Washington Gas Light Company	Case No. 9704	Rate of Return
FirstEnergy Service Company	03/23	Potomac Edison Company	Case No. 9695	Rate of Return
Washington Gas Light Company	08/20	Washington Gas Light Company	Case No. 9651	Rate of Return
FirstEnergy Corporation	08/18	Potomac Edison Company	Case No. 9490	Rate of Return
Massachusetts Department of Public Utilities				
Unitil Corporation	09/23	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 23-80	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Unitil Corporation	09/23	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 23-81	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 19-130	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 19-131	Rate of Return
Liberty Utilities	07/15	Liberty Utilities d/b/a New England Natural Gas Company	D.P.U. 15-75	Rate of Return
Minnesota Public Utilities Commission				
Northern States Power Company	11/01	Northern States Power Company	Docket No. G002/GR-21-678	Return on Equity
Northern States Power Company	10/21	Northern States Power Company	Docket No. E002/GR-21-630	Return on Equity
Northern States Power Company	11/20	Northern States Power Company	Docket No. E002/GR-20-723	Return on Equity
Mississippi Public Service Commission				
Atmos Energy Corporation	06/25	Atmos Energy Corporation	Docket No. 2025-UN-59	Rate of Return
Great River Utility Operating Co.	07/22	Great River Utility Operating Co.	Docket No. 2022-UN-86	Rate of Return
Atmos Energy Corporation	03/19	Atmos Energy Corporation	Docket No. 2015-UN-049	Capital Structure
Atmos Energy Corporation	07/18	Atmos Energy Corporation	Docket No. 2015-UN-049	Capital Structure
Missouri Public Service Commission				
Confluence Rivers Utility Operating Company, Inc.	01/23	Confluence Rivers Utility Operating Company, Inc.	Case No. WR-2023-0006/SR-2023-0007	Rate of Return
Spire Missouri, Inc.	12/20	Spire Missouri, Inc.	Case No. GR-2021-0108	Return on Equity
Indian Hills Utility Operating Company, Inc.	10/17	Indian Hills Utility Operating Company, Inc.	Case No. SR-2017-0259	Rate of Return
Raccoon Creek Utility Operating Company, Inc.	09/16	Raccoon Creek Utility Operating Company, Inc.	Case No. SR-2016-0202	Rate of Return
Public Utilities Commission of Nevada				
Southwest Gas Corporation	09/23	Southwest Gas Corporation	Docket No. 23-09012	Return on Equity
Southwest Gas Corporation	09/21	Southwest Gas Corporation	Docket No. 21-09001	Return on Equity
Southwest Gas Corporation	08/20	Southwest Gas Corporation	Docket No. 20-02023	Return on Equity
New Hampshire Public Utilities Commission				
Unitil Energy Systems, Inc.	5/25	Unitil Corporation	Docket No. DE 25-025	Return on Equity
Aquarion Water Company of New Hampshire, Inc.	12/20	Aquarion Water Company of New Hampshire, Inc.	Docket No. DW 20-184	Rate of Return
New Jersey Board of Public Utilities				
Middlesex Water Company	06/25	Middlesex Water Company	Docket No. WR25060372	Rate of Return
Atlantic City Electric Company	11/24	Atlantic City Electric Company	Docket No. ER24110854	Rate of Return
New Jersey Natural Gas Company	01/24	New Jersey Natural Gas Company	Docket No. GR24010071	Rate of Return
Middlesex Water Company	05/23	Middlesex Water Company	Docket No. WR23050292	Rate of Return
FirstEnergy Service Company	03/23	Jersey Central Power & Light Co.	Docket No. ER23030144	Rate of Return
Atlantic City Electric Company	02/23	Atlantic City Electric Company	Docket No. ER23020091	Return on Equity
Middlesex Water Company	05/21	Middlesex Water Company	Docket No. WR21050813	Rate of Return
Atlantic City Electric Company	12/20	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
FirstEnergy Service Company	02/20	Jersey Central Power & Light Co.	Docket No. ER20020146	Rate of Return
Aqua New Jersey, Inc.	12/18	Aqua New Jersey, Inc.	Docket No. WR18121351	Rate of Return
Middlesex Water Company	10/17	Middlesex Water Company	Docket No. WR17101049	Rate of Return
Middlesex Water Company	03/15	Middlesex Water Company	Docket No. WR15030391	Rate of Return
The Atlantic City Sewerage Company	10/14	The Atlantic City Sewerage Company	Docket No. WR14101263	Cost of Service / Rate Design
Middlesex Water Company	11/13	Middlesex Water Company	Docket No. WR1311059	Capital Structure
New Mexico Public Regulation Commission				
New Mexico Gas Company	09/23	New Mexico Gas Company	Case No. 23-00255-UT	Return on Equity

Sponsor	Date	Case/Applicant	Docket No.	Subject
Southwestern Public Service Co.	11/22	Southwestern Public Service Co.	Case No. 22-00286-UT	Return on Equity
Southwestern Public Service Co.	01/21	Southwestern Public Service Co.	Case No. 20-00238-UT	Return on Equity
North Carolina Utilities Commission				
Carolina Water Service, Inc.	07/25	Carolina Water Service, Inc.	Docket No. W-354, SUB 450	Rate of Return
Aqua North Carolina Inc.	04/25	Aqua North Carolina Inc.	Docket No. W-218, Sub 629	Rate of Return
Pluris Hampstead, LLC	09/24	Pluris Hampstead, LLC	Docket No. W-1305, Sub 38	Rate of Return
Old North State Water Co., Inc.	06/24	Old North State Water Co., Inc.	Docket No. W-1300, Sub 100	Rate of Return
Carolina Water Service, Inc.	07/22	Carolina Water Service, Inc.	Docket No. W-354 Sub 400	Rate of Return
Aqua North Carolina, Inc.	06/22	Aqua North Carolina, Inc.	Docket No. W-218 Sub 573	Rate of Return
Carolina Water Service, Inc.	07/21	Carolina Water Service, Inc.	Docket No. W-354 Sub 384	Rate of Return
Piedmont Natural Gas Co., Inc.	03/21	Piedmont Natural Gas Co., Inc.	Docket No. G-9, Sub 781	Return on Equity
Duke Energy Carolinas, LLC	07/20	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1214	Return on Equity
Duke Energy Progress, LLC	07/20	Duke Energy Progress, LLC	Docket No. E-2, Sub 1219	Return on Equity
Aqua North Carolina, Inc.	12/19	Aqua North Carolina, Inc.	Docket No. W-218 Sub 526	Rate of Return
Carolina Water Service, Inc.	06/19	Carolina Water Service, Inc.	Docket No. W-354 Sub 364	Rate of Return
Carolina Water Service, Inc.	09/18	Carolina Water Service, Inc.	Docket No. W-354 Sub 360	Rate of Return
Aqua North Carolina, Inc.	07/18	Aqua North Carolina, Inc.	Docket No. W-218 Sub 497	Rate of Return
North Dakota Public Service Commission				
Northern States Power Company	09/21	Northern States Power Company	Case No. PU-21-381	Rate of Return
Northern States Power Company	11/20	Northern States Power Company	Case No. PU-20-441	Rate of Return
Public Utilities Commission of Ohio				
Aqua Ohio, Inc.	07/25	Aqua Ohio, Inc.	Case No. 25-0594-WW-AIR	Rate of Return
FirstEnergy	06/24	Ohio Edison Co., Cleveland Electric Illuminating Co., Toledo Edison Co.	Case No. 24-0468-EL-AIR	Rate of Return
Aqua Ohio, Inc.	11/22	Aqua Ohio, Inc.	Case No. 22-1094-WW-AIR	Rate of Return
Duke Energy Ohio, Inc.	10/21	Duke Energy Ohio, Inc.	Case No. 21-887-EL-AIR	Return on Equity
Aqua Ohio, Inc.	07/21	Aqua Ohio, Inc.	Case No. 21-0595-WW-AIR	Rate of Return
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Case No. 16-0907-WW-AIR	Rate of Return
Oklahoma Corporation Commission				
Summit Utilities Oklahoma, Inc.	6/25	Summit Utilities Oklahoma, Inc.	Docket No. PUD25-000028	Return on Equity
Pennsylvania Public Utility Commission				
The York Water Company	05/25	The York Water Company	Docket Nos. R-2025-3053442 & R-2025-3053573	Rate of Return
Valley Energy, Inc.	04/25	C&T Enterprises	Docket No. R-2025-3054393	Rate of Return
Wellsboro Electric Company	04/25	C&T Enterprises	Docket No. R-2025-3054392	Rate of Return
Citizens' Electric Company of Lewisburg	04/25	C&T Enterprises	Docket No. R-2025-3054394	Rate of Return
FirstEnergy	04/24	Pennsylvania Electric Company	Docket No. R-2024-3047068	Rate of Return
Columbia Water Company	05/23	Columbia Water Company	Docket No. R-2023-3040258	Rate of Return
Borough of Ambler	06/22	Borough of Ambler – Bureau of Water	Docket No. R-2022-3031704	Rate of Return
Citizens' Electric Company of Lewisburg	05/22	C&T Enterprises	Docket No. R-2022-3032369	Rate of Return
Valley Energy Company	05/22	C&T Enterprises	Docket No. R-2022-3032300	Rate of Return
Community Utilities of Pennsylvania, Inc.	04/21	Community Utilities of Pennsylvania, Inc.	Docket No. R-2021-3025207	Rate of Return
Vicinity Energy Philadelphia, Inc.	04/21	Vicinity Energy Philadelphia, Inc.	Docket No. R-2021-3024060	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Delaware County Regional Water Control Authority	02/20	Delaware County Regional Water Control Authority	Docket No. A-2019-3015173	Valuation
Valley Energy, Inc.	07/19	C&T Enterprises	Docket No. R-2019-3008209	Rate of Return
Wellsboro Electric Company	07/19	C&T Enterprises	Docket No. R-2019-3008208	Rate of Return
Citizens' Electric Company of Lewisburg	07/19	C&T Enterprises	Docket No. R-2019-3008212	Rate of Return
Steelton Borough Authority	01/19	Steelton Borough Authority	Docket No. A-2019-3006880	Valuation
Mahoning Township, PA	08/18	Mahoning Township, PA	Docket No. A-2018-3003519	Valuation
SUEZ Water Pennsylvania Inc.	04/18	SUEZ Water Pennsylvania Inc.	Docket No. R-2018-000834	Rate of Return
Columbia Water Company	09/17	Columbia Water Company	Docket No. R-2017-2598203	Rate of Return
Veolia Energy Philadelphia, Inc.	06/17	Veolia Energy Philadelphia, Inc.	Docket No. R-2017-2593142	Rate of Return
Emporium Water Company	07/14	Emporium Water Company	Docket No. R-2014-2402324	Rate of Return
Columbia Water Company	07/13	Columbia Water Company	Docket No. R-2013-2360798	Rate of Return
Penn Estates Utilities, Inc.	12/11	Penn Estates, Utilities, Inc.	Docket No. R-2011-2255159	Capital Structure / Long-Term Debt Cost Rate
South Carolina Public Service Commission				
Blue Granite Water Co.	12/19	Blue Granite Water Company	Docket No. 2019-292-WS	Rate of Return
Carolina Water Service, Inc.	02/18	Carolina Water Service, Inc.	Docket No. 2017-292-WS	Rate of Return
Carolina Water Service, Inc.	06/15	Carolina Water Service, Inc.	Docket No. 2015-199-WS	Rate of Return
Carolina Water Service, Inc.	11/13	Carolina Water Service, Inc.	Docket No. 2013-275-WS	Rate of Return
United Utility Companies, Inc.	09/13	United Utility Companies, Inc.	Docket No. 2013-199-WS	Rate of Return
Utility Services of South Carolina, Inc.	09/13	Utility Services of South Carolina, Inc.	Docket No. 2013-201-WS	Rate of Return
Tega Cay Water Services, Inc.	11/12	Tega Cay Water Services, Inc.	Docket No. 2012-177-WS	Capital Structure
South Dakota Public Service Commission				
Northern States Power Company	06/22	Northern States Power Company	Docket No. EL22-017	Rate of Return
Tennessee Public Utility Commission				
CSWR – Limestone Water Utility Operating Company	07/24	CSWR – Limestone Water Utility Operating Company	Docket No. 24-00044	Capital Structure, Cost of Debt, Return on Equity
Piedmont Natural Gas Company	07/20	Piedmont Natural Gas Company	Docket No. 20-00086	Return on Equity
Public Utility Commission of Texas				
Oncor Electric Delivery Co. LLC	06/25	Oncor Electric Delivery Co. LLC	Docket No. 58306	Return on Equity
Aqua Texas, Inc.	06/25	Aqua Texas, Inc.	Docket No. 58124	Rate of Return
CSWR TX Utility Operating Co, LLC	12/24	CSWR TX Utility Operating Co, LLC	Docket No. 57386	Rate of Return
BVRT Utility Holding Co., LLC	07/24	Texas Water Utilities, LP	Docket No. 56664	Rate of Return
Texas Water Utilities, LP	06/24	Texas Water Utilities, LP	Docket No. 56665	Rate of Return
Southwestern Public Service Co.	02/23	Southwestern Public Service Co.	Docket No. 54634	Return on Equity
CSWR – Texas Utility Operating Company, LLC	02/23	CSWR – Texas Utility Operating Company, LLC	Docket No. 54565	Rate of Return
Oncor Electric Delivery Co. LLC	05/22	Oncor Electric Delivery Co. LLC	Docket No. 53601	Return on Equity
Southwestern Public Service Co.	02/21	Southwestern Public Service Co.	Docket No. 51802	Return on Equity
Southwestern Electric Power Co.	10/20	Southwestern Electric Power Co.	Docket No. 51415	Rate of Return
Texas Railroad Commission				
Atmos Energy Corporation – Mid-Texas Division	11/24	Atmos Energy Corporation – Mid-Texas Division	Docket No. OS-24-00019196	Return on Equity

Sponsor	Date	Case/Applicant	Docket No.	Subject
Atmos Energy Corporation – West Texas Division	10/24	Atmos Energy Corporation – West Texas Division	Docket No. OS-24-00018879	Return on Equity
Atmos Pipeline – Texas, a Division of Atmos Energy Corporation	05/23	Atmos Pipeline – Texas, a Division of Atmos Energy Corporation	Docket No. OS-23-00013758	Return on Equity
Virginia State Corporation Commission				
Washington Gas Light Company	07/25	Washington Gas Light Company	PUR-2025-00091	Return on Equity
Aqua Virginia, Inc.	07/25	Aqua Virginia, Inc.	PUR-2025-00071	Rate of Return
Aqua Virginia, Inc.	07/23	Aqua Virginia, Inc.	PUR-2023-00073	Rate of Return
Washington Gas Light Company	06/22	Washington Gas Light Company	PUR-2022-00054	Return on Equity
Virginia Natural Gas, Inc.	04/21	Virginia Natural Gas, Inc.	PUR-2020-00095	Return on Equity
Massanutten Public Service Corporation	12/20	Massanutten Public Service Corporation	PUE-2020-00039	Return on Equity
Aqua Virginia, Inc.	07/20	Aqua Virginia, Inc.	PUR-2020-00106	Rate of Return
WGL Holdings, Inc.	07/18	Washington Gas Light Company	PUR-2018-00080	Rate of Return
Atmos Energy Corporation	05/18	Atmos Energy Corporation	PUR-2018-00014	Rate of Return
Aqua Virginia, Inc.	07/17	Aqua Virginia, Inc.	PUR-2017-00082	Rate of Return
Massanutten Public Service Corp.	08/14	Massanutten Public Service Corp.	PUE-2014-00035	Rate of Return / Rate Design
Public Service Commission of West Virginia				
FirstEnergy Service Company	05/23	Monongahela Power Company and The Potomac Edison Company	Case No. 23-0460-E-42T	Return on Equity
FirstEnergy Service Company	12/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0857-E-CN (ELG)	Return on Equity
FirstEnergy Service Company	11/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0813-E-P (Solar)	Return on Equity

UGI GAS STATEMENT NO. 9

DARIN T. ESPIGH

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 9

Direct Testimony of
Darin T. Espigh

Topics Addressed: **Taxes and Tax Adjustments**

Dated: January 28, 2026

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Darin T. Espigh. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

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

A. I am employed by UGI Corporation ("UGI Corp.") as Senior Manager Natural Gas Tax Accounting. UGI Corp. is the parent company of UGI Utilities, Inc. ("UGI"). UGI has two operating divisions, the 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. What are your principal duties and responsibilities as Senior Manager Natural Gas Tax Accounting for UGI Corp.?

A. My primary duties as Senior Manager Natural Gas Tax Accounting include the preparation of tax data to be reported in UGI Corp.'s various United States Securities and Exchange Commission and regulatory filings, as well as its various federal and state income and non-income tax related filings. Additionally, I maintain the current and deferred income tax accrual and expense accounts, perform tax research, and assist UGI with tax matters as they arise. I also manage the reporting of UGI's various tax filings with its local, state, and federal jurisdictions.

Q. Please describe your educational background and professional experience.

A. They are set forth in my resume attached as UGI Gas Exhibit DTE-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, 2027 ("FPFTY"). I will also explain the tax adjustments made to the results of UGI Gas's historic test year ended September 30, 2025 ("HTY") and future test year ending September 30, 2026 ("FTY").

Q. Have you testified previously before this Commission?

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

Q. Mr. Espigh, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the UGI Gas Exhibits: DTE-1 and DTE-2. 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 items. 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 as indicated on the master list accompanying this filing.

II. TAX ADJUSTMENTS

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. 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 and the FTY. This information is provided to comply with the Commission's filing requirements and provides a basis for comparing UGI Gas's FPFTY claims with adjusted actual book results from the HTY and adjusted FTY results. 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 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 $950,000 is brought forward to Schedule D-3, page 2, line 54.

B. INCOME TAXES

Q. Please discuss the Company's claim for income tax expense.

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 tax expense is 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 income 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. Schedule D-33, 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 Dylan A. D'Ascendis (UGI Gas Statement No. 8) and shown on Schedule B-7. The resulting interest expense on line 6 is subtracted from operating income before interest and taxes 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, which appears as ($150,731) on line 10. Next, the statutory state corporate net income tax rate was applied (as further described below in Section G of my testimony) to determine the *pro forma* state income tax expense shown on line 13. Regarding the pro forma federal income tax expense, lines 14 through 19 show the calculation at current and proposed rates. Next, 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, which shows the net income tax expense. 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* combined income tax expense at present rates is $50.2 million and the *pro forma* income tax expense at proposed rates for the FPFTY is $76.4 million. As explained below in Section E, this figure is not required to be reduced by a consolidated income tax adjustment. Moreover, the pro forma income tax at present rates and the pro forma income tax revenue increase calculated in Schedule D-33 appear in Schedule D-1, which comprises the Company's claimed income tax expense.

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 $5.2 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, 2027. This amount is deducted from rate base. The total shown on line 9 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 9 of Schedule C-6 and on line 6 of Schedule A-1, the ADIT offset is $716.8 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 9 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 DTE-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-2025-3059523, UGI Gas chose 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.

Q. Has UGI Gas adopted the new IRS safe harbor accounting method guidance under Revenue Procedure (Rev. Proc.) 2023-15 for determining qualified repairs deductions?

A Yes, effective for tax year September 30, 2024, UGI Gas adopted the safe harbor method under Rev. Proc 2023-15 for purposes of determining the applicable repairs deduction for tax purposes. These results are the basis for the estimated repairs deductions used in this rate case. The adoption of the new guidance only clarifies what expenditures qualify as tax deductions. There has been no change in the Company's accounting treatment of repair deductions.

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 also 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. Moreover, it is my understanding that the requirements of Section 1301.1(b) no longer apply pursuant to Section 1301.1(c) as of December 31, 2025. Thus, the Company has not calculated a hypothetical consolidated tax adjustment for purposes of Section 1301.1(b).

F. DEVELOPMENT TAX CREDITS

Q. Does UGI Gas claim a Development Tax Credit on its tax return?

A. Yes, UGI Gas claims a development tax credit on its federal income tax return under Internal Revenue Code Section 41. Qualifying activities for the Development Tax Credit are those that are intended to develop or improve the functionality, performance, reliability, or quality of a new or existing business product, process, technique, formula, invention or software. The activity must be technological in nature, have technical uncertainty and involve a process of experimentation. The credit was first claimed on the Company's federal income tax return for the year ended September 30, 2022, which was filed in 2023. For the purpose of this case, prior years' results were used to estimate the future benefit of the tax credit anticipated in the FPFTY. The benefit of $275,000 is included with the investment tax credit on line 30, of Schedule D-33.

G. PENNSYLVANIA TAX RATE CHANGE

Q. Are you familiar with the Pennsylvania corporate net income tax rate change?

A. Yes. On July 8, 2022, Governor Wolf signed into law Act 53, which reduced the state corporate net income tax rate from the then-current 9.99% to 4.99% over a nine-year period. The initial reduction to 8.99% was effective for tax years beginning in calendar year 2023. Thus, the initial reduction applied to Fiscal Year End September 30, 2024.

Q. How has the Company accounted for the recently enacted Pennsylvania tax rate change?

The Company's claim for income taxes reflects the applicable state tax rate in effect for the HTY (i.e., 8.49%), FTY (i.e., 7.99%) and FPFTY (i.e., 7.49%). As explained above, the initial reduction applied to our HTY. The State Tax Adjustment Surcharge ("STAS") mechanism will adjust the Company's rates as applicable for future reductions to the state corporate net income tax rate.

Q. How is the Company applying the Pennsylvania corporate net income tax rate change to its Repairs Tax method?

A. Consistent with historic treatment as described in Section D of this testimony, the Company's state regulatory liability associated with its repairs tax method will continue to represent the tax benefit, based on the rate in effect, that ratepayers have not yet received.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT DTE-1

DARIN ESPIGH, CPA

PROFESSIONAL EXPERIENCE

UGI UTILITIES, INC., Denver, PA — ***March 2022 - Present***
Senior Manager of Natural Gas Tax Accounting

Manage the accounting for income taxes in accordance with ASC 740 for Natural Gas business segment. Provide technical accounting guidance and expertise on tax accounting, planning and compliance matters. Oversee and review the preparation of information supporting various regulatory filings. Oversee and review the preparation of various tax related filings. Manage 1 direct report.

JBS USA, Greeley, CO — ***2014 – March 2022***
Senior Tax Manager, Tax Accounting and Global Reporting

Manage tax accounting and reporting under ASC 740 including effective rate development, perm development, valuation allowances, ABP 23 indefinite reinvestment assertions, financial statement footnotes, management of global deferred inventory and FIN48/FAS 5 analysis for international consolidated financial statements. Responsible for IFRS adjustments and reporting package to Brazilian parent company. Interface with internal and external auditors. Managed tax accounting aspects of a large global reorganization. Design and streamline provision reporting packages to meet increased demands of public reporting.

Managed both federal and state income tax compliance. Responsible for attribution memos related to the preparation of Form 5472, R&D Credits, Sec 163(j), Schedule G and Schedule O compliance for more than 10 separate federal tax returns. Supervised income tax audits. Managed documentation and notice requirements related to the Foreign Investment in Real Property Tax Act (FIRPTA) related to distributions of U.S. real property interests by foreign corporations. Managed, trained and developed staff in tax accounting and financial reporting and compliance.

UGI UTILITIES, INC., Reading, PA — ***2007 to 2014***
Senior Tax Analyst

Responsible for quarterly and annual tax accounting and reporting under ASC 740 including effective rate development, maintenance and classification of deferred inventory balances and account reconciliations. Calculate annual provision to return adjustment for year-end provision. Interface with internal and external auditors on tax related matters. Provide budget and forecast amounts for all tax related items. Preparation of tax data to support external regulatory reporting including Base Rate Case filings.

Preparation of income tax return support submitted to corporate for inclusion in the consolidated income tax return. Responsible for indirect tax compliance.

BERTZ & COMPANY, CPA's, Lancaster, PA — ***2000 to 2007***
Senior Associate

Responsible for preparation of individual, corporate, partnership, nonprofit and payroll tax returns. Charged with the preparation of financial statements including required disclosures for a wide range of industries including construction, hospitality and retail food establishments. Supervised, trained and developed staff on client engagements.

Managed audit engagements of retirement plans and homeowner associations. Gained experience on a variety of other audits.

HATTER, HARRIS & BEITTEL, LLP, Lancaster, PA — ***1994 to 2000***
Senior Associate

Prepared individual, corporate, partnership, nonprofit and payroll tax returns. Managed review and compilation engagements. Managed nonprofit audit. Developed significant experience in audits of school districts, retail and manufacturing businesses. Gained strong working knowledge of financial statements and related disclosures for engagements of all levels. Trained and developed new staff.

EDUCATION & CREDENTIALS

Bachelor of Science in Accounting – Messiah College, Grantham, PA – May 1994

Certified Public Accountant

Previous Testimony:

UGI Electric Base Rate Case	Docket No. R-2022-3037368
UGI Gas Base Rate Case	Docket No. R-2024-3052716

UGI GAS

EXHIBIT DTE-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
9/30/2026					$ 708,090
10/31/2026	3,000	335	91.78%	2,753	710,843
11/30/2026	926	305	83.56%	774	711,617
12/31/2026	1,214	274	75.07%	912	712,529
1/31/2027	614	243	66.58%	409	712,938
2/28/2027	646	215	58.90%	380	713,318
3/31/2027	1,728	184	50.41%	871	714,189
4/30/2027	750	154	42.19%	316	714,506
5/31/2027	926	123	33.70%	312	714,818
6/30/2027	3,633	93	25.48%	926	715,743
7/31/2027	2,638	62	16.99%	448	716,192
8/31/2027	1,863	31	8.49%	158	716,350
9/30/2027	7,585	1	0.27%	21	**$ 716,371**

UGI GAS STATEMENT NO. 10

SHERRY A. EPLER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 10

Direct Testimony of
Sherry A. Epler

Topics Addressed:	**Test Year Sales and Revenues**
	Tariff Changes

Dated: January 28, 2026

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, including certain 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, 2025 ("HTY"), future test year ending September 30, 2026 ("FTY"), and fully projected future test year ending September 30, 2027 ("FPFTY"); and (2) certain proposed tariff modifications.

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

A. Yes. Company witness John D. Taylor, who is employed as Managing Partner by Atrium Economics, LLC (UGI Gas Statement No. 11), is sponsoring allocation of the proposed revenue increase and rate design, in addition to his other testimony topics, using 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 (10 year Normal Heating Degree Days), UGI Gas Exhibit SAE-3 (Normalized Multi-Year and Normalized 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, Future Test Year, and Historic 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 master list accompanying this filing, that were prepared by me or under my direction.

[redacted] TEST YEAR SALES AND REVENUE

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

A. FPFTY sales and revenues were developed by incorporating annualizing and normalizing adjustments to the Company's 2027 fiscal year sales and revenue budgets to reflect end of FPFTY conditions for ratemaking purposes. The development of the initial sales and revenue budgets which were utilized as the starting point prior to adjustments is described in the testimony of Vivian K. Ressler (UGI Gas Statement No. 4). 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 to present sales and revenue on a comparable ratemaking basis. A summary of projected use per customer by class group for the FPFTY, FTY, and HTY is 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 residential Rates R (retail service) and RT (transportation service), the regression analysis was performed on a total Rate R/RT basis 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." Weather normalized sales for Rate RT-Heating customers for the 12 months ended September 30, 2025, were then utilized to mathematically derive the separate Rate R-Heating use per customer values (from the combined Rate R/RT-Heating use per customer regression value).

Actual sales were normalized for Rate R-Non-Heating and Rate RT-Non-Heating, in total, for the 12-month period ended September 30, 2025, to eliminate potential switching impacts that could distort use per customer analyses. These data were used to project combined Rate R/RT-Non-Heating use per customer in total. Weather normalized sales for Rate RT-Non-Heating customers for the 12 months ended September 30, 2025, were then utilized to mathematically derive the separate Rate R-Non-Heating customer values (from the combined Rate R/RT-Non-Heating 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 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." To 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, 2025, as this class is much smaller in number than the Rate

N-Commercial Heating class. Rate DS-Commercial Heating use per customer was then established based on budgeted 2027 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 Non-Heating, Rate NT-Commercial Non-Heating and Rate DS-Commercial Non-Heating, in total, to reflect the 12 months ended September 30, 2025, in order to project combined Rates N/NT/DS-Commercial Non-Heating use per customer in total and eliminate potential switching impacts that could distort use per customer analyses. To separate the combined Rate N/NT/DS-Commercial Non-Heating value into respective Rate N, Rate NT and Rate DS values, Rate NT-Commercial Non-Heating was based on weather normalized sales for Rate NT-Commercial Non-Heating, for the 12 months ended September 30, 2025, and Rate DS-Commercial Non-Heating was based on budgeted 2027 sales for Rate DS-Commercial Non-Heating, 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 Non-Heating use per customer values (from the combined Rates N/NT/DS-Commercial Non-Heating 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, 2025, in order to project combined Rates N/NT/DS-Industrial use per customer in total and eliminate potential switching impacts that could distort use per customer analyses. To 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, 2025. Rate DS-Industrial was based on budgeted 2027 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 ("HDDs") of 5,218. This annual normal HDD calculation is derived from a composite, sales-weighted value (by system demand) for each of the Company's four delivery regions, and the respective normal heating degree values. As proposed in this proceeding, and discussed in the Direct Testimony of John D. Taylor, UGI Gas Statement No. 11, normal HDDs are now defined based upon an average over a 10-year period with the most recent update of the 10-year period ending December 31, 2024. UGI Gas Exhibit SAE-2 provides supporting detail by year for the 10-year normal HDDs. Please see the Direct Testimony of John D. Taylor, UGI Gas Statement No. 11 for supporting detail on the determination of Normal HDD values and the frequency of Normal HDD updates.

Q. Please describe the adjustments made to the budget for the 12 months ending September 30, 2027, to develop FPFTY sales and revenues.

A. A summary of all adjustments made to the 2027 budget 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 4,382 MMcf and a decrease to revenue of $49.761 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 decrease of 3,925 Residential Heating customers (Rate R) from budgeted levels to anticipated end-of-test-year levels and a net decrease of 1,338 Commercial Heating customers (Rate N) from budgeted levels to anticipated end-of-FPFTY levels on September 30, 2027.

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, these adjustments decrease sales by 834 MMcf and decrease projected revenues by $11.756 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. Adjustments for large transportation customers are developed by UGI Gas's marketing personnel following their review of individual large customer accounts and market segments. The adjustments reflect annualizing anticipated increases or reductions from original individual customer budgeted sales and revenues. Given there were no known changes since the development of the original budget, there are no quantified adjustments to the original budget for the Large Transport and Interruptible customers shown on UGI Gas Exhibit SAE-4(b)(1).

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

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) HDDs; (3) lagged HDDs; and (4) weighted time trend. While use per customer, HDDs, and lagged HDDs 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 HDDs to reflect a "weighted trend," which more accurately reflects that the trends' impacts 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 beginning October 2003 through, now, September 2025. 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, 2020, 2022, and 2025 Gas Base Rate Cases. Specifically, to forecast the Commercial Heating rate group use per customer, the Company utilized three variables: (1) use per customer; (2) HDDs; and (3) lagged HDDs. For the Commercial Heating group, the Company used the period beginning October 2012 through, now, September 2025 for regression modeling, or the entire 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 HDDs 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 2027 budget, of 3,308 MMcf, and a net revenue decrease, from the fiscal 2027 budget, of $37,090 million, inclusive of PGC revenues.

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

A. The Company has continued 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. Consequently, the multi-year regression period more accurately projects usage per customer during the period rates are likely to be in effect. This methodology is consistent with that utilized in the last nine 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 the results of both 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 during the 12 month period ending September 30, 2025. 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, thus capturing the ongoing base trend in declining use per customer.

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

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, 2025. UGI Gas Exhibit SAE-4(d) provides the calculations for these adjustments. This adjustment increases PGC revenues for the FPFTY by $1.938 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, 2025. The MFC Adjustment increases projected revenues by $0.039 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, 2025. 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 2025 data in comparison to the budgeted sales volume for CAP customers, which was calculated using end of Fiscal Year 2024 data. The USP adjustment decreases revenues by $0.480 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 2027 planned budget. The GPC adjustment decreases revenues by $0.257 million. Additional details for these three adjustments are provided in 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" shown on UGI Gas Exhibit SAE-4(a) is detailed in UGI Gas Exhibit SAE-4(h) and 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 "Adjustment for STAS" as shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for STAS" shown on UGI Gas Exhibit SAE-4(a) is detailed in UGI Gas Exhibit SAE-4(i) and annualizes the revenue for the State Tax Adjustment Surcharge ("STAS") for the FPFTY based on the STAS Rider rate in effect as of December 1, 2025. This adjustment increases revenues by $0.116 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, 2025. This adjustment decreases revenues by $0.001 million and is detailed on UGI Exhibit SAE-4(j).

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 240 MMcf and decreases revenues by $3.000 million as detailed on UGI Gas Exhibit SAE-4(k).

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

A. The "Adjustment for GDE Rider" annualized the revenue for the Gas Delivery Enhancement ("GDE") Rider for the FPFTY based on GDE Rider rate in effect as of December 1, 2025. This adjustment decreases revenues by $0.185 million and is detailed 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 0.33% DSIC E-Factor rate in effect as of December 1, 2025, to FPFTY revenues. The FPFTY budget utilized a rate of 0.0%. This adjustment applies a 0.33% DSIC rate in order to annualize the DSIC to end of FPFTY conditions. The 0.33% rate is currently projected to be effective at the end of the FTY, and that 0.33% rate will remain in place through 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 pursuant to 66 Pa. C.S. § 1358(b)(1). This adjustment increases revenues by $2.615 million and is shown in detail 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. Pursuant to the terms of the Revenue Sharing Incentive Mechanism in Section 11 of the UGI Gas tariff, these revenues are appropriately treated as below the line for ratemaking purposes and, thus, have been excluded.

[redacted] DEVELOPMENT OF SALES AND REVENUES FOR THE FTY AND HTY

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

A. Budgeted sales and revenues serve as the starting point for developing 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 that are contained in the FPFTY but not the FTY.

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

A. Historic sales and revenues serve as the starting point for developing 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 Weather Normalization Adjustment ("WNA"), EEC Conservation Impact, GDE Rider, and DSIC. The "Adjustment for WNA" in the HTY removes the revenues associated with the actual WNA revenue recorded in the HTY revenues and margins in order to not double count certain weather-related impacts, as the Adjustment for Normalized & Annualized Use/Customer fully incorporates weather related usage impacts. The EEC Conservation Impact is not required, as the actual HTY sales and revenue reflect such impacts. The adjustments for the GDE Rider and the DSIC are discussed above.

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

A. For the reasoning stated below, the Company is proposing to retain the current Rate NNS service rates at this time and not recalculate those rates. 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 revenue generated by Rate NNS charges is reflected as a credit to PGC rates, because the capacity used for this service is otherwise paid for by PGC customers.

Q. How has UGI Gas historically approached the updating of Rate NNS?

A. As part of the settlement of its 2019 Gas Base Rate Case, the parties agreed to a methodology for calculating Rate NNS (see Joint Petition for Approval of Unopposed Settlement of All Issues, paragraph No. 53, filed on July 22, 2019, at Docket Nos. R-2018-3006814, *et al.*, which was approved by the Commission's Opinion and Order entered on October 4, 2019, in that proceeding). In cases since the 2019 Gas Base Rate Case, UGI Gas has used the methodology specified to calculate a rate – consistently a rate decrease – and has proposed that rate decrease in its filed case. In each of those cases, UGI Gas has met strong opposition to its proposal. If the Company were to update the tariffed Rate NNS charge to reflect current cost elements in this case, using the 2019 Gas Base Rate Case methodology, the Company would be proposing a decrease to Rate NNS. However, as noted above, the Company is proposing to retain the current Rate NNS rate. However, as noted above, the Company is proposing to retain the current Rate NNS rate.

Q. Why is the Company proposing to retain the current Rate NNS rate in this case?

A. UGI Gas believes that the use of the service by customers over time indicates that the current rate, which has been in place since 2019, is appropriately priced for the value it delivers to participating customers, while also providing stable affordability benefits to PGC customers. Importantly, the Company's actions in this regard recognize the historic cost assignment methodology differences between the Company and certain of the public advocates. UGI Gas believes its Rate NNS approach in this proceeding balances the interests of different customer classes.

Q. Has the Company shown the development of the recalculated Rate NNS charge, even though it is not proposing to change Rate NNS?

A. UGI Gas Exhibit SAE-8 shows the recalculation of the Rate NNS charge. Again, this recalculation was developed based on the same methodology used in the Company's 2019 Gas Base Rate Case. As seen on UGI Gas Exhibit SAE-8, the proposed NNS rate would be $0.1700 per Mcf/d of an elected daily no notice allowance ("NNA") tolerance quantity. This compares to the current NNS rate of $0.2200 per Mcf/d of elected NNA, which was established in the Company's 2022 Gas Base Rate Case (see Paragraph 44 in the Recommended Decision issued on July 28, 2022 at Docket Nos. R-2021-3030218, *et al.*); the current rate was also retained in the Company's 2025 Gas Base Rate Case at Docket No. R-2024-3052716, in Paragraph 55 of the Commission-approved Joint Petition for

Settlement of All Issues dated July 10, 2025. This current rate is proposed to be retained as part of this initial filing.

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 Base 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, 2025, are: \$0.0177/Mcf for Rates DS and IS; \$0.0103/Mcf for Rate LFD; and \$0.0104/Mcf for Rate XD. As seen on UGI Gas Exhibit

SAE-9, the proposed MBS rates will be: $0.0198/Mcf for Rates DS and IS; $0.0113/Mcf for Rate LFD; and $0.0116/Mcf for Rate XD. These Rate MBS increases are principally driven by increases to the average capacity charge.

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 2.37%, and the MFC for the commercial class will be 0.47%. 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 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, 2026, to provide an enrollee figure that reflects the actual ongoing impacts on CAP enrollment. This proposal is consistent with the establishment of the CAP enrollee figure in the UGI Gas 2020 Rate Case at Docket No. R-2019-3015162.

[redacted] 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. 63 to UGI Gas Tariff No. 7 and Proposed Supplement No. 63 to UGI Gas Tariff No. 7S. More significant proposed changes to the tariffs include:

- Rule 8.4, Billing and Payment, has clarifying language added to explain that Budget Billing will be reviewed and adjusted on a quarterly basis .
- Section 8.14 was added to specify the acceptable and Applicable Forms of Payment that customers may remit to the Company for payment of public utility service.
- The State Tax Adjustment Surcharge, Rider A, has been rolled into rates and reset to 0.00%.
- Rider C, Weather Normalization Adjustment, applicability has been updated to continue as a pilot ending on October 31, 2032, in place of the existing October 31, 2027, date. In Calculation of Adjustment Amount, subsection (d), the Weather Normalization Adjustment NHDD has been changed to the Delivery Region's 10-year average in place of the existing 15-year average for the given day. Additionally, NHDD has been changed to being updated at every rate case in place of the existing 5 years.
- Rider D – MFC has been set to 2.37% for PGC Residential Customers and 0.47% 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, 2026, in place of the existing September 30, 2025 date.
- Rider I – DSIC has been reset to 0.00% in accordance with 66 Pa. C.S. § 1358(b)(1).
- Rule 16 – USP Rider has been updated to reflect that the 9.2% adjustment element contained in the Annual Reconciliation shall apply to the actual number of CAP enrollees as of September 30, 2026, in order to appropriately track related costs for recovery between the Rider and base rates. Additionally, language has been added to allow the USP Rider to apply on a fully negotiated basis for certain Rate XD customers to contribute to Rider USP and otherwise lower USP costs borne by the Company's residential customers.
- Rule 22 - References to outdated Effective Date in heading removed.
- Rate LFD has clarifying language added for Annual Minimum Bill, which allows the Company and customer to reach agreement on a higher Annual Minimum Bill amount. Updated residential and commercial purchase of receivables rates due to the change in the MFC.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT SAE-1

Sherry Epler

Senior Manager, Tariff & Supplier Administration

<u>Work Experience</u>

<u>UGI Utilities, Inc., Denver, PA</u>

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

<u>UGI Utilities, Inc., Reading, PA</u>

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

<u>Education</u>

Bachelor of Science, Accounting, Albright College, 1995

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

<u>Previous testimony provided before the Pennsylvania Public Utility Commission</u>:

Docket No. R-2021-3023618	UGI Electric Division Base Rate Case
Docket No. R-2021-3030218	UGI Gas Division Base Rate Case
Docket No. R-2022-3037368	UGI Electric Division Base Rate Case
Docket No. R-2024-3052716	UGI Gas Division Base Rate Case

UGI GAS

EXHIBIT SAE-2

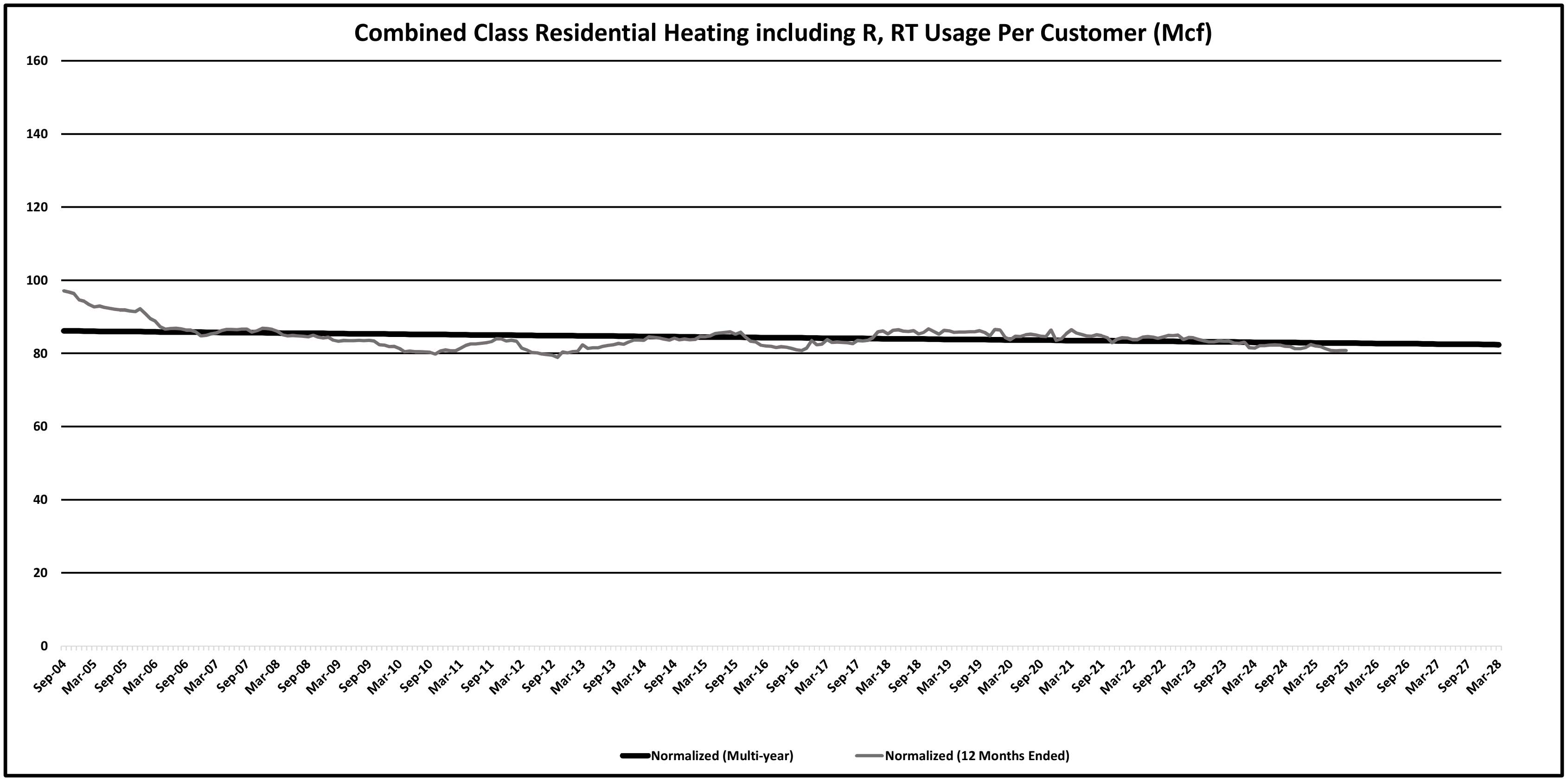
UGI Utilities, Inc. - Gas Division
10 Year Normal Heating Degree Days (2015-2024)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Average *
Jan	1,247	1,139	966	1,159	1,153	932	1,030	1,231	829	994	1,069
Feb	1,292	923	722	776	908	799	978	876	753	782	881
Mar	974	586	878	912	834	607	658	684	745	611	749
Apr	420	475	270	579	329	504	397	459	320	349	410
May	93	227	214	67	126	234	214	102	175	101	155
Jun	38	27	38	32	30	21	21	17	34	12	27
Jul	8	4	3	4	2	0	6	1	1	1	0
Aug	13	4	23	3	9	4	3	4	6	15	8
Sep	51	57	94	63	39	101	63	90	79	39	68
Oct	392	326	237	373	275	317	190	386	299	287	309
Nov	525	595	694	780	773	514	728	593	685	569	647
Dec	640	982	1,096	891	928	946	765	970	760	963	895
Totals	5,692	5,345	5,236	5,639	5,406	4,980	5,050	5,411	4,685	4,724	5,218

*Average adjusted for rounding of 10 year calculation and normal representation of Heating Degree Days falling consecutively through normal year

UGI GAS

EXHIBIT SAE-3(a) – (b)


Combined Class Residential Heating including R, RT Usage Per Customer (Mcf)
160
140
120
100
80
60
40
20
0
Sep-04
Mar-05
Sep-05
Mar-06
Sep-06
Mar-07
Sep-07
Mar-08
Sep-08
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Mar-11
Sep-11
Mar-12
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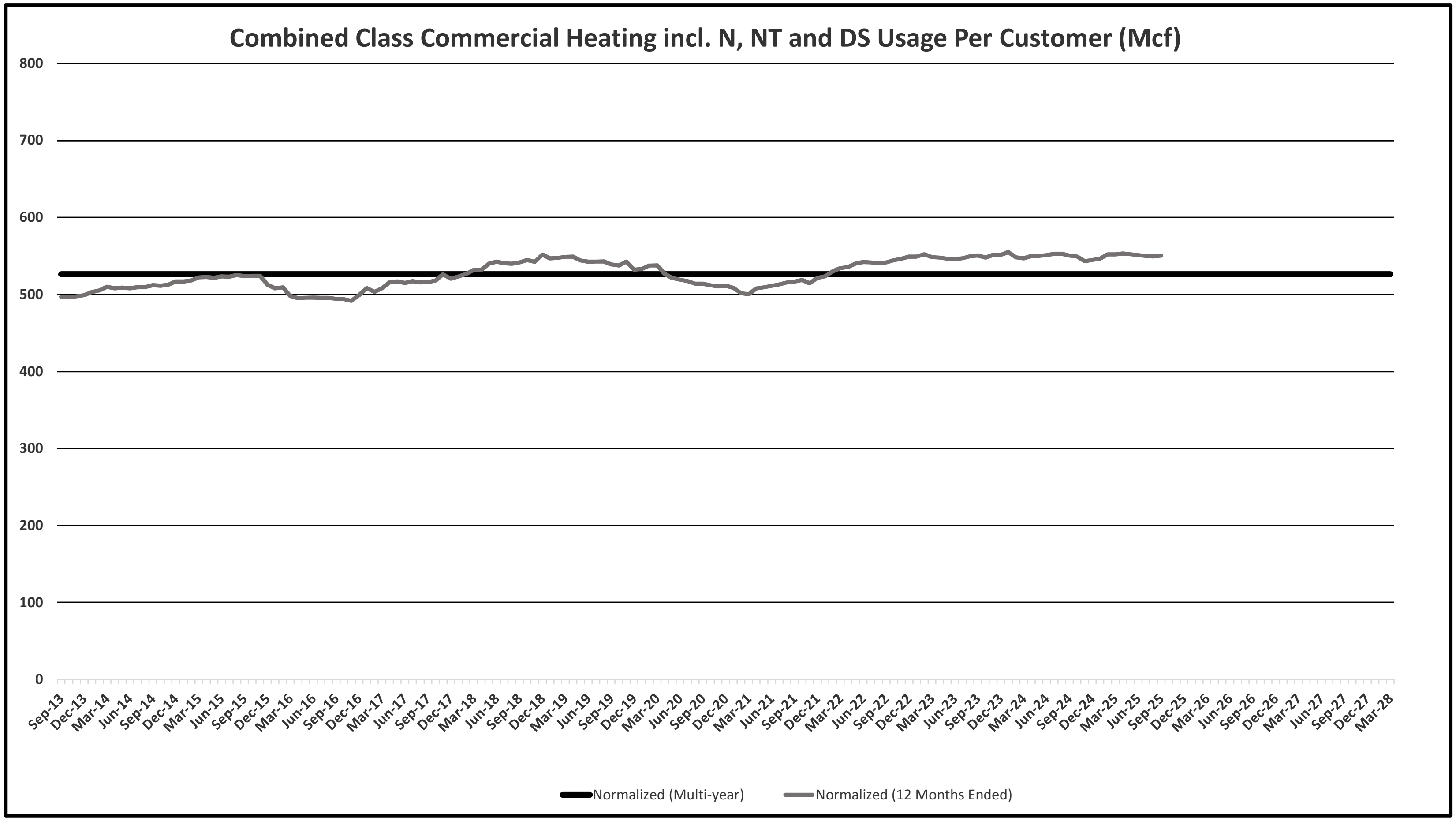
Sep-25
Mar-26
Sep-26
Mar-27
Sep-27
Mar-28
Normalized (Multi-year)
Normalized (12 Months Ended)


Combined Class Commercial Heating 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
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Dec-16
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Sep-27
Dec-27
Mar-28
Normalized (Multi-year)
Normalized (12 Months Ended)

UGI GAS

EXHIBIT SAE-4(a) – (m)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year 2027 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Budget 2027	343,586	1,270,313	795,899	
Adjustment for Customer/Contract Changes	(834)	(11,756)	(5,856)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-4(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	(3,308)	(37,090)	(16,560)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-4(c)
Adjustment for PGC		1,938	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(d)
Adjustment for MFC		39	39	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(e)
Adjustment for USP		(480)	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(f)
Adjustment for GPC		(257)	(257)	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 STAS		116	116	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(i)
Adjustment for EEC Rider		(1)	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(j)
Adjustment for EEC Conservation Impact	(240)	(3,000)	(1,467)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(k)
Adjustment for GDE		(185)	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(l)
Adjustment for DSIC		2,615	2,615	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(m)
Fully Projected Future Test Year 2027	339,204	1,220,551	772,828	

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
($ 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)	$ 8,302	$ 744,900	$ 62,495	$ 10,191	$ 204,625	$ 9,584	$ 71,572	$ 36,322	$ 122,323	$ 1,270,313
2	FPFTY PGC Revenues	$ (2,392)	$ (341,620)	$ (5,371)	$ (5,349)	$ (111,591)	$ (5,636)	$ (521)	(836)	(1,096)	(474,414)
3	FPFTY Revenues net of PGC - Margin (Unadjusted)	$ 5,909	$ 403,280	$ 57,123	$ 4,842	$ 93,034	$ 3,947	$ 71,051	$ 35,486	$ 121,226	$ 795,899
4	FPFTY Average Effective Customers (Unadjusted)	19,610	537,257	81,742	3,100	46,767	627	20,567	1,305	985	711,960
5	FPFTY Average Annual Margin Per Customer (L3 / L4)	$ 0.301	$ 0.751	$ 0.699	$ 1.562	$ 1.989	$ 6.296	$ 3.455	$ 27.192	$ 123.073	$ 1.118
6	FPFTY Customers (Fully Adjusted)	19,178	533,332	81,742	3,081	45,429	613	20,567	1,305	985	706,232
7	Change in Customers during FPFTY (L6 - L4)	(432)	(3,925)	-	(19)	(1,338)	(14)	-	-	-	(5,728)
8	Annualization of Margin (L5 * L7)	$ (130)	$ (2,946)	$ -	$ (30)	$ (2,662)	$ (88)	$ -	$ -	$ -	$ (5,856)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4)	$ 0.423	$ 1.386	$ 0.765	$ 3.287	$ 4.375	$ 15.285	$ 3.480	$ 27.833	$ 124.186	$ 1.784
10	Annualization of Total FPFTY Revenue (L7 * L9)	$ (183)	$ (5,442)	$ -	$ (62)	$ (5,854)	$ (214)	$ -	$ -	$ -	$ (11,756)
11	Annualization Adjustment for FPFTY PGC Revenues (L10 - L8)	$ (53)	$ (2,496)	$ -	$ (33)	$ (3,193)	$ (126)	$ -	$ -	$ -	$ (5,900)
12	Total FPFTY UPC (Unadjusted) - MCF	16.20	84.60	79.60	255.40	352.50	1,330.60	701.70	6,795.40		
13	Annualization Adjustment for FPFTY Sales - MMCF (L7 * L12)/1000	(7)	(332)	-	(5)	(472)	(19)	-	-	-	(834)

Notes:

* Column [9] further detailed on UGI Gas Exhibit SAE-4(b)(1)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
($ 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)	$ 60,378	$ 39,075	$ 2,294	$ 20,576	$ 122,323
2	FPFTY PGC Revenues	(1,096)	-	-	-	(1,096)
3	FPFTY Revenues net of PGC - Margin (Unadjusted)	$ 59,282	$ 39,075	$ 2,294	$ 20,576	$ 121,226
4	FPFTY Average Effective Customers (Unadjusted)	638	54	57	236	985
5	FPFTY Average Annual Margin Per Customer (L3 / L4)	$ 92.918	$ 723.603	$ 40.253	$ 87.186	$ 123.073
6	FPFTY Customers (Fully Adjusted)	638	54	57	236	985
7	Change in Customers during FPFTY (L6 - L4)	-	-	-	-	-
8	Annualization of Margin	$ -	$ -	$ -	$ -	$ -
9	Average Annual Revenue Per Customer (L1 / L4)	$ 94.637	$ 723.603	$ 40.253	$ 87.186	$ 124.186
10	Annualization of Total FPFTY Revenue	$ -	$ -	$ -	$ -	$ -
11	Annualization of FPFTY PGC Revenues (L10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total FPFTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for FPFTY Sales - MMCF	-	-	-	-	-

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year- 12 Months Ended September 30, 2027
($ 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	16.20	84.60	79.60	255.40	352.50	1,330.60	701.70	6,795.40			
2	FPFTY UPC (Fully Adjusted) - MCF	15.90	82.70	76.50	238.90	322.40	655.60	691.80	6,795.40			
3	Change in UPC - MCF (L2 - L1)	(0.30)	(1.90)	(3.10)	(16.50)	(30.10)	(675.00)	(9.90)	0.00			
4	FPFTY Customers (Fully Adjusted)	19,178	533,332	81,742	3,081	45,429	613	20,567	1,305	985	-	706,232
5	Annualization Adjustment for Sales - MMCF (L3 * L4)/1000)	(6)	(1,013)	(253)	(51)	(1,367)	(414)	(204)	-	-	-	(3,308)
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	$ (81)	$ (14,271)	$ (1,815)	$ (565)	$ (15,196)	$ (4,598)	$ (881)	$ -		$ 317	$ (37,090)
7	Total Unit Revenue Adjustment (L6 / L5)	$ 14.0834	$ 14.0834	$ 7.1620	$ 11.1127	$ 11.1127	$ 11.1127	$ 4.3263	$ -	$ -		
8	Distribution Margin Adjustment (L5 * L9)	$ (36)	$ (6,416)	$ (1,604)	$ (219)	$ (5,880)	$ (1,779)	$ (876)	$ -			$ (16,811)
9	Distribution Unit Rate	$ 6.3317	$ 6.3317	$ 6.3317	$ 4.3004	$ 4.3004	$ 4.3004	$ 4.3004	$ 3.3651	$ -		
10	PGC Revenue (L5 * L11)	$ (39)	$ (6,839)	$ -	$ (343)	$ (9,228)	$ (2,792)	$ -	$ -		$ (179)	$ (19,420)
11	PGC Unit Rate	$ 6.7486	$ 6.7486		$ 6.7486	$ 6.7486	$ 6.7486					
12	EE&C Revenue Adjustment (L5 * L13)	$ (1)	$ (197)	$ (49)	$ (1)	$ (35)	$ (11)	$ (5)	$ -			$ (300)
13	EE&C Unit Rate	$ 0.1940	$ 0.1940	$ 0.1940	$ 0.0259	$ 0.0259	$ 0.0259	$ 0.0259	$ 0.0449	$ -		
14	USP Revenue Adjustment (L5 * L15)	$ (4)	$ (645)	$ (161)	$ -	$ -	$ -	$ -	$ -	$ -		$ (810)
15	USP Unit Rate	$ 0.6363	$ 0.6363	$ 0.6363	$ -	$ -	$ -	$ -	$ -	$ -		
16	MFC Revenue/Margin Adjustment (L5 * L17)	$ (1)	$ (175)		$ (2)	$ (52)	$ (16)					$ (245)
17	MFC Unit Rate	$ 0.1728	$ 0.1728		$ 0.0378	$ 0.0378	$ 0.0378					
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -
19	DSIC Unit Rate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
20	Total Margin Adjustment (L8 + L16 + L18)	$ (37)	$ (6,591)	$ (1,604)	$ (221)	$ (5,932)	$ (1,795)	$ (876)	$ -		$ 496	$ (16,560)
21	Total Unit Margin Adjustment (L20 / L5)	$ 6.5045	$ 6.5045	$ 6.3317	$ 4.3382	$ 4.3382	$ 4.3382	$ 4.3004	$ -	$ -		

Notes:

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

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for PGC

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	TOTAL
Original Budget PGC Rate FPFTY	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	
FPFTY PGC Rate	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	
PGC Rate Variance	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	
Total PGC Volumes	2,933	6,712	10,282	12,384	10,578	9,251	4,534	2,318	1,512	1,069	1,136	1,235	63,945
PGC Revenue Adjustment	$89	$203	$312	$375	$321	$280	$137	$70	$46	$32	$34	$37	$1,938

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for MFC

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	TOTAL
Original Budget PGC Rate FPFTY	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	
FPFTY PGC Rate	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	
PGC Rate Variance	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	
Total PGC Volumes-Rate R	2,133	4,910	7,406	8,816	7,519	6,622	3,285	1,684	1,101	727	761	834	
Total PGC Volumes-Rate N	801	1,801	2,876	3,568	3,060	2,629	1,249	635	411	342	375	401	
Total PGC Volumes	2,933	6,712	10,282	12,384	10,578	9,251	4,534	2,318	1,512	1,069	1,136	1,235	63,945
Rate R %	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	
Rate N %	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	
MFC Rate R Adj Rate	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	
MFC Rate N Adj Rate	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	
Rate R Revenue Variance	$2	$4	$6	$7	$6	$5	$3	$1	$1	$1	$1	$1	
Rate N Revenue Variance	$0	$0	$0	$1	$1	$0	$0	$0	$0	$0	$0	$0	
Total Revenue Variance	$2	$4	$6	$7	$6	$6	$3	$1	$1	$1	$1	$1	$39

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for USP

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	TOTAL
Original FPFTY Budget USP Calculation	$1,503	$3,460	$5,226	$6,209	$5,291	$4,649	$2,303	$1,182	$779	$516	$538	$591	$32,247
Updated FPFTY Budget USP Calculation	$1,501	$3,455	$5,219	$6,200	$5,284	$4,642	$2,299	$1,180	$778	$515	$537	$590	$32,202
Variance to Original FPFTY Budget Calculation	($2)	($5)	($7)	($9)	($7)	($7)	($3)	($2)	($1)	($1)	($1)	($1)	($46)
Original FPFTY Budget USP Rate	$0.6450	$0.6450	$0.6450	$0.6450	$0.6450	$0.6450	$0.6450	$0.6450	$0.6450	$0.6450	$0.6450	$0.6450	
FPFTY USP Rate	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	
USP Rate Variance	($0.0087)	($0.0087)	($0.0087)	($0.0087)	($0.0087)	($0.0087)	($0.0087)	($0.0087)	($0.0087)	($0.0087)	($0.0087)	($0.0087)	
Total Rate R Volumes	2,438	5,612	8,476	10,070	8,582	7,541	3,735	1,918	1,263	837	872	959	52,302
Total Rate R excl CAP Volumes	2,327	5,357	8,091	9,613	8,192	7,197	3,565	1,830	1,205	799	833	915	49,925
USP Rate Revenue Variance	($20)	($47)	($70)	($84)	($71)	($63)	($31)	($16)	($10)	($7)	($7)	($8)	($434)
Total Revenue Variance	($22)	($52)	($78)	($92)	($79)	($69)	($34)	($18)	($12)	($8)	($8)	($9)	($480)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year- 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for GPC

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	TOTAL
GPC Rate FPFTY	$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	(171)	(396)	(619)	(762)	(652)	(563)	(271)	(136)	(87)	(68)	(75)	(88)	(3,888)
Revenue Variance	($11)	($26)	($41)	($50)	($43)	($37)	($18)	($9)	($6)	($4)	($5)	($6)	($257)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
($ 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- 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for STAS

	@ 0% Unadjusted 2027 TOTAL	@.01% Adjusted 2027 TOTAL	Revenue Adjustment Total
Residential-Non Htg	$ -	$ 1	$ 1
Residential-Heating	$ -	$ 73	$ 73
Residential-RT	$ -	$ 6	$ 6
Total R/RT	$ -	$ 79	$ 79
Commercial-Non Htg	$ -	$ 1	$ 1
Commercial- Htg	$ -	$ 18	$ 18
Industrial	$ -	$ 0	$ 0
Com/Ind NT	$ -	$ 7	$ 7
Total N/NT	$ -	$ 27	$ 27
Total DS	$ -	$ 4	$ 4
Total LFD	$ -	$ 6	$ 6
Total XD-F	$ -	$ -	$ -
Total Interruptible	$ -	$ -	$ -
Grand Total	$ -	$ 116	$ 116

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for EEC Rider

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	TOTAL
Original Budget FPFTY R/RT Rate	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	
FPFTY R/RT Rate	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	
R/RT 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	
R/RT Rate Volumes	2,438	5,612	8,476	10,070	8,582	7,541	3,735	1,918	1,263	837	872	959	52,302
R/RT Revenue Adjustment	$32	$74	$112	$133	$113	$100	$49	$25	$17	$11	$12	$13	$690
Original Budget FPFTY N/NT Rate	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	
FPFTY N/NT Rate	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	
N/NT Rate Variance	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	
N/NT Rate Volumes	1,588	3,234	4,997	6,090	5,240	4,514	2,291	1,257	938	760	815	855	32,580
N/NT Revenue Adjustment	($16)	($33)	($51)	($62)	($53)	($46)	($23)	($13)	($10)	($8)	($8)	($9)	($332)
Original Budget FPFTY DS Rate	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	
FPFTY DS Rate	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	
DS Rate Variance	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	
DS Rate Volumes	469	791	1,231	1,588	1,421	1,179	683	413	291	248	254	301	8,868
DS Revenue Adjustment	($21)	($35)	($54)	($70)	($62)	($52)	($30)	($18)	($13)	($11)	($11)	($13)	($389)
Original Budget FPFTY LFD Rate	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	
FPFTY LFD Rate	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	
LFD Rate Variance	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	
LFD Rate Volumes	2,178	2,440	2,722	2,939	2,626	2,543	2,211	2,050	1,900	1,877	1,911	1,945	27,342
LFD Revenue Adjustment	$2	$3	$3	$3	$3	$3	$2	$2	$2	$2	$2	$2	$30
Total Revenue Adjustment	($2)	$9	$10	$4	$0	$5	($2)	($3)	($4)	($6)	($6)	($7)	($1)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for EE&C Conservation Impact

EE&C Plan (Version 10/01/2025)

Yearly Gas Savings by Rate Class 2026 - 2041 (Cumulative MMBtus)

Rate Class Description	*Fiscal Year* 2026	2027	2028	2029	2030	MMBTU 5 Year Average	BTU	MCF 5 Year Average	Customers FY27 Retail Htg & Choice Htg	EE&C UPC Conservation Adj
Residential (R/RT)	187,035	198,006	206,266	214,128	223,043	205,696	1.033	199,124	611,318	**(0.3)**
Nonresidential (N/NT)	35,354	38,780	41,988	46,016	48,158	42,059	1.033	40,716	65,129	**(0.6)**
Total	**222,389**	**236,786**	**248,254**	**260,144**	**271,201**	**247,755**		**239,840**	**676,447**	

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
FPFTY Use/Customer ("UPC") (Fully Adjusted) - MCF	82.7	79.4	322.4	674.9	655.6	2,053.9	
FPFTY UPC (Fully Adjusted-Incl EE&C Impact) - MCF	82.4	79.1	321.8	674.3	655.0	2,053.3	
Change in UPC -MCF	(0.3)	(0.3)	(0.6)	(0.6)	(0.6)	(0.6)	
End of Year FPFTY Customers	533,332	77,986	45,429	18,631	613	456	676,447
Annualization Adjustment for Sales - MMCF (L3 * L4) / 1000	(174)	(25)	(28)	(12)	(0)	(0)	(240)
Total Revenue Adjustment (L10 + L12 + L14 + L22)	$ (2,447)	$ (182)	$ (316)	$ (50)	$ (4)	$ (1)	$ (3,000)
Total Unit Revenue Adjustment (L6 / L5)	14.0834	7.1620	11.1127	4.3263	11.1127	4.3263	12.5084
Distribution Margin Adjustment (L5 * L9)	$ (1,100)	$ (161)	$ (122)	$ (50)	$ (2)	$ (1)	$ (1,436)
Distribution Unit Rate	$ 6.3317	$ 6.3317	$ 4.3004	$ 4.3004	$ 4.3004	$ 4.3004	
PGC Revenue (L5 * L11)	$ (1,172)	$ -	$ (192)	$ -	$ (3)	$ -	$ (1,367)
PGC Unit Rate	$ 6.7486		$ 6.7486		$ 6.7486		
EE&C Revenue Adjustment (L5 * L13)	$ (34)	$ (5)	$ (1)	$ (0)	$ (0)	$ (0)	$ (40)
EE&C Unit Rate	$ 0.1940	$ 0.1940	$ 0.0259	$ 0.0259	$ 0.0259	$ 0.0259	
USP Revenue Adjustment (L5 * L15)	$ (111)	$ (16)					$ (127)
USP Unit Rate	$ 0.6363	$ 0.6363					
MFC Revenue/Margin Adjustment (L5 * L17)	$ (30)		$ (1)		$ (0)		$ (31)
MFC Unit Rate	$ 0.1728		$ 0.0378		$ 0.0378		
DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSIC Unit Rate	$ -	$ -	$ -	$ -	$ -	$ -	
Total Margin Adjustment (L8 + L16 + L18)	$ (1,130)	$ (161)	$ (123)	$ (50)	$ (2)	$ (1)	$ (1,467)
Total Unit Margin Adjustment (L20 / L5)	$ 6.5045	$ 6.3317	$ 4.3382	$ 4.3004	$ 4.3382	$ 4.3004	

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for GDE Rider

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	TOTAL
Original Budget FPFTY DS Rate	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	
FPFTY DS Rate	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	
DS Rate Variance	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	
DS Rate Volumes	469	791	1,231	1,588	1,421	1,179	683	413	291	248	254	301	8,868
DS Revenue Adjustment	($2)	($4)	($6)	($8)	($7)	($6)	($3)	($2)	($1)	($1)	($1)	($2)	($45)
Original Budget FPFTY LFD Rate	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	
FPFTY LFD Rate	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	
LFD Rate Variance	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	
LFD Rate Volumes	2,178	2,440	2,722	2,939	2,626	2,543	2,211	2,050	1,900	1,877	1,911	1,945	27,342
LFD Revenue Adjustment	($11)	($12)	($14)	($15)	($13)	($13)	($11)	($10)	($10)	($10)	($10)	($10)	($139)
Total Revenue Adjustment	($14)	($16)	($20)	($23)	($21)	($19)	($15)	($13)	($11)	($11)	($11)	($11)	($185)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year- 12 Months Ended September 30, 2027
($ in Thousands)

Adjustment for DSIC

	@ 0% Unadjusted 2027 TOTAL	@0.33% Adjusted 2027 TOTAL	Revenue Adjustment Total
Residential-Non Htg	$ -	$ 20	$ 20
Residential-Heating	$ -	$ 1,412	$ 1,412
Residential-RT	$ -	$ 199	$ 199
Total R/RT	$ -	$ 1,631	$ 1,631
Commercial-Non Htg	$ -	$ 15	$ 15
Commercial- Htg	$ -	$ 280	$ 280
Industrial	$ -	$ 7	$ 7
Com/Ind NT	$ -	$ 233	$ 233
Total N/NT	$ -	$ 534	$ 534
Total DS	$ -	$ 118	$ 118
Total LFD	$ -	$ 193	$ 193
Total XD-F	$ -	$ 64	$ 64
Total Interruptible	$ -	$ 73	$ 73
Grand Total	$ -	$ 2,615	$ 2,615

UGI GAS

EXHIBIT SAE-5(a) – (l)

UGI Utilities Inc.- Gas Division
Future Test Year 2026 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Budget 2026	343,090	1,256,178	787,256	
Adjustment for Customer/Contract Changes	(981)	(11,976)	(5,772)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	(3,141)	(35,047)	(15,964)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(c)
Adjustment for PGC		2,994	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(d)
Adjustment for MFC		60	60	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(e)
Adjustment for USP		480	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(f)
Adjustment for GPC		(235)	(235)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(g)
Adjustment for Excess Take		(1,700)	(1,700)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(h)
Adjustment for STAS		205	205	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(i)
Adjustment for EEC Rider		(7)	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(j)
Adjustment for GDE		(184)	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(k)
Adjustment for DSIC		(338)	(338)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(l)
Future Test Year 2026	338,968	1,210,430	763,512	

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2026
($ 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)	$ 8,535	$ 733,593	$ 62,205	$ 10,210	$ 203,505	$ 9,705	$ 71,281	$ 35,926	$ 121,219	$ 1,256,178
2	FTY PGC Revenues	$ (2,462)	$ (336,525)	$ (5,310)	$ (5,371)	$ (111,100)	$ (5,704)	$ (521)	(834)	(1,095)	(468,922)
3	FTY Revenues net of PGC - Margin (Unadjusted)	$ 6,073	$ 397,068	$ 56,895	$ 4,840	$ 92,405	$ 4,000	$ 70,760	$ 35,092	$ 120,124	$ 787,256
4	FTY Average Effective Customers (Unadjusted)	20,245	531,109	81,742	3,121	46,668	637	20,567	1,304	984	706,377
5	FTY Average Annual Margin Per Customer (L3 / L4)	$ 0.300	$ 0.748	$ 0.696	$ 1.551	$ 1.980	$ 6.280	$ 3.440	$ 26.911	$ 122.077	$ 1.114
6	FTY Customers (Fully Adjusted)	19,789	527,108	81,742	3,103	45,208	625	20,567	1,304	984	700,430
7	Change in Customers during FTY (L6 - L4)	(456)	(4,001)	-	(18)	(1,460)	(12)	-	-	-	(5,947)
8	Annualization of Margin (L5 * L7)	$ (137)	$ (2,991)	$ -	$ (28)	$ (2,891)	$ (75)	$ -	$ -	$ 351	$ (5,772)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4)	$ 0.422	$ 1.381	$ 0.761	$ 3.272	$ 4.361	$ 15.235	$ 3.466	$ 27.551	$ 123.190	$ 1.778
10	Annualization of Total FTY Revenue (L7 * L9)	$ (192)	$ (5,526)	$ -	$ (59)	$ (6,367)	$ (183)	$ -	$ -	$ 351	$ (11,976)
11	Annualization Adjustment for FTY PGC Revenues (L10 - L8)	$ (55)	$ (2,535)	$ -	$ (31)	$ (3,476)	$ (107)	$ -	$ -	$ -	$ (6,205)
12	Total FTY UPC (Unadjusted) - MCF	16.20	84.60	79.60	255.40	352.50	1,327.80	701.70	6,783.40		
13	Annualization Adjustment for FTY Sales - MMCF (L7 * L12)/1000	(7)	(338)	-	(5)	(515)	(16)	-	-	(99)	(981)

Notes:

* Column [9] further detailed on UGI Gas Exhibit SAE-5(b)(1)

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2026
($ 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)	$ 60,462	$ 38,765	$ 2,276	$ 19,716	$ 121,219
2	FTY PGC Revenues	(1,095)	-	-	-	(1,095)
3	FTY Revenues net of PGC - Margin (Unadjusted)	$ 59,367	$ 38,765	$ 2,276	$ 19,716	$ 120,124
4	FTY Average Effective Customers (Unadjusted)	637	55	58	234	984
5	FTY Average Annual Margin Per Customer (L3 / L4)	$ 93.197	$ 704.820	$ 39.233	$ 84.258	$ 122.077
6	FTY Customers (Fully Adjusted)	638	54	57	235	984
7	Change in Customers during FTY (L6 - L4)	1	(1)	(1)	1	-
8	Annualization of Margin	$ 37	$ (177)	$ -	$ 491	$ 351
9	Average Annual Revenue Per Customer (L1 / L4)	$ 94.917	$ 704.820	$ 39.233	$ 84.258	$ 123.190
10	Annualization of Total FTY Revenue	$ 37	$ (177)	$ -	$ 491	$ 351
11	Annualization of FTY PGC Revenues (L10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total FTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for FTY Sales - MMCF	21	(366)	-	245	(99)

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2026
($ 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	FTY (Unadjusted) Use/Customer ("UPC") - MCF	16.20	84.60	79.60	255.40	352.50	1,327.80	701.70	6,783.40		
2	FTY UPC (Fully Adjusted) - MCF	15.90	83.00	76.50	239.80	321.40	719.10	691.80	6,783.40		
3	Change in UPC - MCF (L2 - L1)	(0.30)	(1.60)	(3.10)	(15.60)	(31.10)	(608.70)	(9.90)	0.00		
4	FTY Customers (Fully Adjusted)	19,789	527,108	81,742	3,103	45,208	625	20,567	1,304	984	700,430
5	Annualization Adjustment for Sales - MMCF (L3 * L4)/1000)	(6)	(843)	(253)	(48)	(1,406)	(380)	(204)	-	-	(3,141)
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	$ (84)	$ (11,878)	$ (1,815)	$ (538)	$ (15,624)	$ (4,228)	$ (881)	$ -	$ -	$ (35,047)
7	Total Unit Revenue Adjustment (L6 / L5)	$ 14.0834	$ 14.0834	$ 7.1620	$ 11.1127	$ 11.1127	$ 11.1127	$ 4.3263	$ -	$ -	
8	Distribution Margin Adjustment (L5 * L9)	$ (38)	$ (5,340)	$ (1,604)	$ (208)	$ (6,046)	$ (1,636)	$ (876)	$ -	$ -	$ (15,748)
9	Distribution Unit Rate	$ 6.3317	$ 6.3317	$ 6.3317	$ 4.3004	$ 4.3004	$ 4.3004	$ 4.3004	$ 3.3651	$ -	
10	PGC Revenue (L5 * L11)	$ (40)	$ (5,692)	$ -	$ (327)	$ (9,488)	$ (2,567)	$ -	$ -	$ -	$ (18,114)
11	PGC Unit Rate	$ 6.7486	$ 6.7486		$ 6.7486	$ 6.7486	$ 6.7486				
12	EE&C Revenue Adjustment (L5 * L13)	$ (1)	$ (164)	$ (49)	$ (1)	$ (36)	$ (10)	$ (5)	$ -	$ -	$ (267)
13	EE&C Unit Rate	$ 0.1940	$ 0.1940	$ 0.1940	$ 0.0259	$ 0.0259	$ 0.0259	$ 0.0259	$ 0.0449	$ -	
14	USP Revenue Adjustment (L5 * L15)	$ (4)	$ (537)	$ (161)	$ -	$ -	$ -	$ -	$ -	$ -	$ (702)
15	USP Unit Rate	$ 0.6363	$ 0.6363	$ 0.6363	$ -	$ -	$ -	$ -	$ -	$ -	
16	MFC Revenue/Margin Adjustment (L5 * L17)	$ (1)	$ (146)		$ (2)	$ (53)	$ (14)				$ (216)
17	MFC Unit Rate	$ 0.1728	$ 0.1728		$ 0.0378	$ 0.0378	$ 0.0378				
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	DSIC Unit Rate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
20	Total Margin Adjustment (L8 + L16 + L18)	$ (39)	$ (5,486)	$ (1,604)	$ (210)	$ (6,099)	$ (1,650)	$ (876)	$ -	$ -	$ (15,964)
21	Total Unit Margin Adjustment (L20 / L5)	$ 6.5045	$ 6.5045	$ 6.3317	$ 4.3382	$ 4.3382	$ 4.3382	$ 4.3004	$ -	$ -	

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for PGC

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
Original Budget PGC Rate FTY	$6.6061	$6.6061	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	
FTY PGC Rate	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	
PGC Rate Variance	$0.1425	$0.1425	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	
Total PGC Volumes	2,907	6,654	10,197	12,284	10,493	9,175	4,496	2,299	1,499	1,061	1,127	1,225	63,417
PGC Revenue Adjustment	$414	$948	$309	$372	$318	$278	$136	$70	$45	$32	$34	$37	$2,994

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for MFC

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
Original Budget PGC Rate FTY	$6.6061	$6.6061	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	$6.7183	
FTY PGC Rate	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	$6.7486	
PGC Rate Variance	$0.1425	$0.1425	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	$0.0303	
Total PGC Volumes-Rate R	2,109	4,855	7,323	8,718	7,435	6,548	3,248	1,665	1,089	719	752	824	
Total PGC Volumes-Rate N	799	1,799	2,874	3,566	3,058	2,627	1,248	634	410	341	374	401	
Total PGC Volumes	2,907	6,654	10,197	12,284	10,493	9,175	4,496	2,299	1,499	1,061	1,127	1,225	63,417
Rate R %	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	
Rate N %	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	
MFC Rate R Adj Rate	$0.0036	$0.0036	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	
MFC Rate N Adj Rate	$0.0008	$0.0008	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	
Rate R Revenue Variance	$8	$18	$6	$7	$6	$5	$3	$1	$1	$1	$1	$1	
Rate N Revenue Variance	$1	$1	$0	$1	$1	$0	$0	$0	$0	$0	$0	$0	
Total Revenue Variance	$8	$19	$6	$7	$6	$6	$3	$1	$1	$1	$1	$1	$60

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for USP

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
Original FTY Budget USP Calculation	$1,444	$3,324	$5,020	$6,103	$5,201	$4,569	$2,263	$1,162	$766	$507	$529	$581	$31,469
Updated FTY Budget USP Calculation	$1,442	$3,319	$5,013	$6,094	$5,194	$4,563	$2,260	$1,160	$765	$507	$528	$580	$31,425
Variance to Original FTY Budget Calculation	($2)	($5)	($7)	($9)	($7)	($6)	($3)	($2)	($1)	($1)	($1)	($1)	($44)
Original FTY Budget USP Rate	$0.6257	$0.6257	$0.6257	$0.6402	$0.6402	$0.6402	$0.6402	$0.6402	$0.6402	$0.6402	$0.6402	$0.6402	
FTY USP Rate	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	$0.6363	
USP Rate Variance	$0.0106	$0.0106	$0.0106	($0.0039)	($0.0039)	($0.0039)	($0.0039)	($0.0039)	($0.0039)	($0.0039)	($0.0039)	($0.0039)	
Total Rate R Volumes	2,413	5,556	8,392	9,972	8,499	7,467	3,699	1,899	1,251	829	864	949	51,790
Total Rate R excl CAP Volumes	2,304	5,304	8,012	9,520	8,113	7,127	3,530	1,813	1,194	791	825	907	49,440
USP Rate Revenue Variance	$24	$56	$85	$101	$86	$76	$37	$19	$13	$8	$9	$10	$524
Total Revenue Variance	$22	$52	$78	$92	$79	$69	$34	$18	$12	$8	$8	$9	$480

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for GPC

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
GPC Rate FTY	$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	(156)	(361)	(568)	(700)	(599)	(517)	(248)	(125)	(80)	(62)	(69)	(81)	(3,565)
Revenue Variance	($10)	($24)	($37)	($46)	($40)	($34)	($16)	($8)	($5)	($4)	($5)	($5)	($235)

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2026
($ 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 Test Year- 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for STAS

	Unadjusted 2026 TOTAL	@ 0.01% Adjusted 2026 TOTAL	Revenue Adjustment Total
Residential-Non Htg	$ (1)	$ 1	$ 2
Residential-Heating	$ (51)	$ 73	$ 124
Residential-RT	$ (5)	$ 6	$ 11
Total R/RT	$ (56)	$ 80	$ 136
Commercial-Non Htg	$ (1)	$ 1	$ 2
Commercial- Htg	$ (13)	$ 20	$ 33
Industrial	$ (0)	$ 1	$ 1
Com/Ind NT	$ (5)	$ 7	$ 13
Total N/NT	$ (20)	$ 29	$ 49
Total DS	$ (3)	$ 4	$ 7
Total LFD	$ (7)	$ 6	$ 13
Total XD-F	$ -	$ -	$ -
Total Interruptible	$ -	$ -	$ -
Grand Total	$ (86)	$ 120	$ 205

UGI Utilities Inc.- Gas Division
Future Test Year- 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for EEC Rider

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
Original Budget FTY R/RT Rate	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	
FTY R/RT Rate	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	$0.1940	
R/RT 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	
R/RT Rate Volumes	2,413	5,556	8,392	9,972	8,499	7,467	3,699	1,899	1,251	829	864	949	51,790
R/RT Revenue Adjustment	$32	$73	$111	$132	$112	$99	$49	$25	$17	$11	$11	$13	$684
Original Budget FTY N/NT Rate	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	
FTY N/NT Rate	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	$0.0259	
N/NT Rate Variance	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	($0.0102)	
N/NT Rate Volumes	1,586	3,231	4,995	6,088	5,239	4,512	2,290	1,256	938	759	815	855	32,563
N/NT Revenue Adjustment	($16)	($33)	($51)	($62)	($53)	($46)	($23)	($13)	($10)	($8)	($8)	($9)	($332)
Original Budget FTY DS Rate	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	
FTY DS Rate	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	$0.0449	
DS Rate Variance	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	($0.0439)	
DS Rate Volumes	467	788	1,227	1,583	1,416	1,177	682	413	291	248	254	301	8,845
DS Revenue Adjustment	($21)	($35)	($54)	($69)	($62)	($52)	($30)	($18)	($13)	($11)	($11)	($13)	($388)
Original Budget FTY LFD Rate	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	
FTY LFD Rate	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	$0.0357	
LFD Rate Variance	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	
LFD Rate Volumes	2,167	2,428	2,719	2,939	2,626	2,543	2,211	2,050	1,900	1,877	1,911	1,945	27,315
LFD Revenue Adjustment	$2	$3	$3	$3	$3	$3	$2	$2	$2	$2	$2	$2	$30
Total Revenue Adjustment	($2)	$8	$9	$3	($1)	$4	($2)	($4)	($4)	($6)	($6)	($7)	($7)

UGI Utilities Inc.- Gas Division
Future Test Year Period- 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for GDE Rider

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
Original Budget FTY DS Rate	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	
FTY DS Rate	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	
DS Rate Variance	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	
DS Rate Volumes	467	788	1,227	1,583	1,416	1,177	682	413	291	248	254	301	8,845
DS Revenue Adjustment	($2)	($4)	($6)	($8)	($7)	($6)	($3)	($2)	($1)	($1)	($1)	($2)	($45)
Original Budget FTY LFD Rate	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	
FTY LFD Rate	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	$0.0004	
LFD Rate Variance	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	($0.0051)	
LFD Rate Volumes	2,167	2,428	2,719	2,939	2,626	2,543	2,211	2,050	1,900	1,877	1,911	1,945	27,315
LFD Revenue Adjustment	($11)	($12)	($14)	($15)	($13)	($13)	($11)	($10)	($10)	($10)	($10)	($10)	($139)
Total Revenue Adjustment	($13)	($16)	($20)	($23)	($21)	($19)	($15)	($13)	($11)	($11)	($11)	($11)	($184)

UGI Utilities Inc.- Gas Division
Future Test Year- 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for DSIC

	Unadjusted 2026 TOTAL	@0.33% Adjusted 2026 TOTAL	Revenue Adjustment Total
Residential-Non Htg	$23	$21	($3)
Residential-Heating	$1,601	$1,422	($179)
Residential-RT	$230	$205	($26)
Total R/RT	$1,855	$1,647	($208)
Commercial-Non Htg	$18	$16	($2)
Commercial- Htg	$344	$306	($39)
Industrial	$15	$13	($2)
Com/Ind NT	$264	$234	($30)
Total N/NT	$641	$569	($72)
Total DS	$133	$118	($15)
Total LFD	$223	$198	($25)
Total XD-F	$84	$74	($9)
Total Interruptible	$79	$70	($9)
Grand Total	$3,015	$2,677	($338)

UGI GAS

EXHIBIT SAE-6(a) – (k)

UGI Utilities Inc.- Gas Division
Historic Test Year 2025 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Actual 2025	321,629	1,137,255	718,427	
Adjustment for Customer/Contract Changes	(1,938)	(10,270)	(5,921)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	(656)	(4,503)	(1,093)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(c)
Adjustment for WNA		(16,327)	(16,327)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(d)
Adjustment for PGC		51,422	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(e)
Adjustment for MFC		907	907	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(f)
Adjustment for USP		7,370	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(g)
Adjustment for GPC		(86)	(86)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(h)
Adjustment for Excess Take		(2,199)	(2,199)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(i)
Adjustment for STAS		43	43	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(j)
Adjustment for EEC Rider		16	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(k)
Historic Test Year 2025	319,035	1,163,630	693,752	

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ 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 net of WNA (Unadjusted)	$ 8,165	$ 619,588	$ 53,943	$ 8,618	$ 170,650	$ 7,954	$ 65,540	$ 50,460	$ 136,011	$ 1,120,928
2	HTY PGC Revenues	$ (2,233)	$ (279,839)	$ (4,739)	$ (4,442)	$ (91,044)	$ (4,543)	$ (505)	(16,078)	(15,406)	(418,829)
3	HTY Revenues net of PGC and WNA - Margin (Unadjusted)	$ 5,932	$ 339,749	$ 49,204	$ 4,175	$ 79,606	$ 3,411	$ 65,035	$ 34,382	$ 120,605	$ 702,099
4	HTY Average Effective Customers (Unadjusted)	21,010	525,925	81,167	3,136	45,320	676	20,780	1,301	978	700,293
5	HTY Average Annual Margin Per Customer (L3 / L4)	$ 0.282	$ 0.646	$ 0.606	$ 1.331	$ 1.757	$ 5.046	$ 3.130	$ 26.427	$ 123.318	$ 1.003
6	HTY Customers (Fully Adjusted)	20,477	519,287	82,349	3,105	44,978	673	20,620	1,295	975	693,759
7	Change in Customers during HTY (L6 - L4)	(533)	(6,638)	1,182	(31)	(342)	(3)	(160)	(6)	(3)	(6,534)
8	Annualization of Margin (L5 * L7)	$ (150)	$ (4,288)	$ 717	$ (41)	$ (601)	$ (15)	$ (501)	$ (159)	$ (882)	$ (5,921)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4)	$ 0.389	$ 1.178	$ 0.665	$ 2.748	$ 3.765	$ 11.767	$ 3.154	$ 38.786	$ 139.071	$ 1.601
10	Annualization of Total HTY Revenue (L7 * L9)	$ (207)	$ (7,820)	$ 786	$ (85)	$ (1,288)	$ (35)	$ (505)	$ (233)	$ (882)	$ (10,270)
11	Annualization Adjustment for HTY PGC Revenues (L10 - L8)	$ (57)	$ (3,532)	$ 69	$ (44)	$ (687)	$ (20)	$ (4)	$ (74)	$ -	$ (4,349)
12	Total HTY UPC (Unadjusted) - MCF	15.90	81.20	76.80	234.60	345.00	1,151.20	693.70	7,029.70		
13	Annualization Adjustment for HTY Sales - MMCF (L7 * L12)/1000	(8)	(539)	91	(7)	(118)	(3)	(111)	(42)	(1,200)	(1,938)

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

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ 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)	$ 67,832	$ 39,433	$ 2,984	$ 25,762	$ 136,011
2	HTY PGC Revenues	(11,173)	(267)	(23)	(3,943)	(15,406)
3	HTY Revenues net of PGC - Margin (Unadjusted)	$ 56,659	$ 39,167	$ 2,961	$ 21,819	$ 120,605
4	HTY Average Effective Customers (Unadjusted)	626	56	58	238	978
5	HTY Average Annual Margin Per Customer (L3 / L4)	$ 90.510	$ 699.407	$ 51.051	$ 91.675	$ 123.318
6	HTY Customers (Fully Adjusted)	632	56	58	229	975
7	Change in Customers during HTY (L6 - L4)	6	-	-	(9)	(3)
8	Annualization of Margin	$ 322	$ -	$ -	$ (1,204)	$ (882)
9	Average Annual Revenue Per Customer (L1 / L4)	$ 108.358	$ 704.168	$ 51.441	$ 108.243	$ 139.071
10	Annualization of Total HTY Revenue	$ 322	$ -	$ -	$ (1,204)	$ (882)
11	Annualization of HTY PGC Revenues (L10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total HTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for HTY Sales - MMCF	129	-	-	(1,329)	(1,200)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ 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	15.90	81.20	76.80	234.60	345.00	1,151.20	693.70	7,029.70		
2	HTY UPC (Fully Adjusted) - MCF	15.90	83.20	76.60	231.00	307.60	1,184.80	691.10	7,065.70		
3	Change in UPC - MCF (L2 - L1)	0.00	2.00	(0.20)	(3.60)	(37.40)	33.60	(2.60)	36.00		
4	HTY Customers (Fully Adjusted)	20,477	519,287	82,349	3,105	44,978	673	20,620	1,295	975	693,759
5	Annualization Adjustment for Sales - MMCF (L3 * L4)/1000)	-	1,039	(16)	(11)	(1,682)	23	(54)	47	-	(656)
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	$ -	$ 13,549	$ (103)	$ (120)	$ (18,006)	$ 242	$ (218)	$ 154		$ (4,503)
7	Total Unit Revenue Adjustment (L6 / L5)	$ -	$ 13.0456	$ 6.2820	$ 10.7042	$ 10.7042	$ 10.7042	$ 4.0676	$ 3.3074	$ -	$ 6.8675
8	Distribution Margin Adjustment (L5 * L9)	$ -	$ 5,376	$ (85)	$ (43)	$ (6,456)	$ 87	$ (206)	$ 143		$ (1,184)
9	Distribution Unit Rate	$ 5.1764	$ 5.1764	$ 5.1764	$ 3.8378	$ 3.8378	$ 3.8378	$ 3.8378	$ 3.0611	$ -	
10	PGC Revenue (L5 * L11)	$ -	$ 6,861		$ (74)	$ (11,113)	$ 149				$ (4,176)
11	PGC Unit Rate	$ 6.6061	$ 6.6061		$ 6.6061	$ 6.6061	$ 6.6061				
12	EE&C Revenue Adjustment (L5 * L13)	$ -	$ 188	$ (3)	$ (0)	$ (61)	$ 1	$ (2)	$ 4		$ 127
13	EE&C Unit Rate	$ 0.1808	$ 0.1808	$ 0.1808	$ 0.0361	$ 0.0361	$ 0.0361	$ 0.0361	$ 0.0888	$ -	
14	USP Revenue Adjustment (L5 * L15)	$ -	$ 650	$ (10)	$ -	$ -	$ -	$ -	$ -	$ -	$ 640
15	USP Unit Rate	$ 0.6257	$ 0.6257	$ 0.6257							
16	MFC Revenue/Margin Adjustment (L5 * L17)	$ -	$ 156		$ (0)	$ (49)	$ 1				$ 107
17	MFC Unit Rate	$ 0.1500	$ 0.1500		$ 0.0291	$ 0.0291	$ 0.0291				
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ -	$ 318	$ (5)	$ (2)	$ (328)	$ 4	$ (10)	$ 7		$ (16)
19	DSIC Unit Rate	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500		
20	Calculated Total Margin Adjustment (L8 + L16 + L18)	$ -	$ 5,850	$ (90)	$ (45)	$ (6,833)	$ 92	$ (216)	$ 150		$ (1,093)
21	Total Unit Margin Adjustment (L20 / L5)	$ -	$ 5.6330	$ 5.4755	$ 4.0620	$ 4.0620	$ 4.0620	$ 4.0315	$ 3.2186	$ -	$ 1.6664

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for WNA Revenues

			WNA Revenue/Margin
Rate R	Residential-Non Htg	$	(55)
Rate R	Residential-Htg	$	(10,180)
Rate RT	RT	$	(1,407)
Rate N	Commercial-Non Htg	$	(75)
Rate N	Commercial-Htg	$	(2,485)
Rate N	Industrial	$	(116)
Rate NT	NT Total	$	(2,010)
	Total	$	(16,327)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for PGC

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
Actual PGC Rate HTY	$4.5259	$4.5259	$5.6281	$5.6281	$5.6281	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	
September HTY PGC Rate	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	
PGC Rate Variance	$2.0802	$2.0802	$0.9780	$0.9780	$0.9780	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Total PGC Volumes	2,556	5,444	10,628	13,898	11,035	6,706	4,082	1,875	1,069	982	1,079	947	60,302
PGC Revenue Adjustment	$5,318	$11,325	$10,394	$13,593	$10,792	$0	$0	$0	$0	$0	$0	$0	$51,422
Check	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for MFC

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
Actual PGC Rate HTY	$4.5259	$4.5259	$5.6281	$5.6281	$5.6281	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	
September HTY PGC Rate	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	$6.6061	
PGC Rate Variance	$2.0802	$2.0802	$0.9780	$0.9780	$0.9780	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Total PGC Volumes-Rate R	1,916	3,983	7,697	9,968	7,832	4,770	2,913	1,294	730	656	753	620	
Total PGC Volumes-Rate N	641	1,461	2,931	3,931	3,203	1,936	1,169	580	339	326	326	328	
Total PGC Volumes	2,556	5,444	10,628	13,898	11,035	6,706	4,082	1,875	1,069	982	1,079	947	60,302
Rate R %	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	
Rate N %	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	
MFC Rate R Adj Rate	$0.0472	$0.0472	$0.0222	$0.0222	$0.0222	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
MFC Rate N Adj Rate	$0.0092	$0.0092	$0.0043	$0.0043	$0.0043	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Rate R Revenue Variance	$90	$188	$171	$221	$174	$0	$0	$0	$0	$0	$0	$0	
Rate N Revenue Variance	$6	$13	$13	$17	$14	$0	$0	$0	$0	$0	$0	$0	
Total Revenue Variance	$96	$201	$183	$238	$188	$0	$0	$0	$0	$0	$0	$0	$907

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for USP

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
Actual HTY USP Rate	$0.4693	$0.4693	$0.5770	$0.5770	$0.5770	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	
September HTY USP Rate	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	$0.6257	
USP Rate Variance	$0.1564	$0.1564	$0.0487	$0.0487	$0.0487	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Total Rate R Volumes	2,184	4,545	8,802	11,414	8,967	5,458	3,327	1,479	843	761	865	718	49,362
Total Rate R excl CAP Volumes	2,084	4,338	8,403	10,897	8,561	5,210	3,176	1,411	805	727	826	686	47,123
USP Rate Revenue Variance	$326	$678	$1,314	$1,704	$1,339	$815	$497	$221	$126	$114	$129	$107	$7,370
Total Revenue Variance	$326	$678	$1,314	$1,704	$1,339	$815	$497	$221	$126	$114	$129	$107	$7,370

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for GPC

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	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	(76)	(106)	(143)	(159)	(144)	(139)	(119)	(78)	(109)	(72)	(72)	(90)	(1,308)
Revenue Variance	($5)	($7)	($9)	($10)	($10)	($9)	($8)	($5)	($7)	($5)	($5)	($6)	($86)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MMCF)		(366)
$/MCF		$6.00
Excess Take Revenue/Margin	$	(2,199)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for STAS

		Unadjusted 2025 TOTAL		@-0.12% Adjusted 2025 TOTAL		Revenue Adjustment Total
Residential-Non Htg	$	(10)	$	(10)	$	0
Residential-Heating	$	(797)	$	(770)	$	27
Residential-RT	$	(70)	$	(68)	$	2
Total R/RT	$	(877)	$	(848)	$	29
Commercial-Non Htg	$	(11)	$	(11)	$	0
Commercial- Htg	$	(220)	$	(212)	$	8
Industrial	$	(10)	$	(10)	$	0
Com/Ind NT	$	(86)	$	(83)	$	3
Total N/NT	$	(327)	$	(315)	$	12
Total DS	$	(63)	$	(62)	$	1
Total LFD	$	(84)	$	(83)	$	1
Total XD-F	$	-	$	-	$	-
Total Interruptible	$	-	$	-	$	-
Grand Total	$	(1,351)	$	(1,308)	$	43

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for EEC Rider

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
Original Budget HTY R/RT Rate	$0.2001	$0.2001	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	
HTY R/RT Rate	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	
R/RT Rate Variance	($0.0193)	($0.0193)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
R/RT Rate Volumes	2,184	4,545	8,802	11,414	8,967	5,458	3,327	1,479	843	761	865	718	49,362
R/RT Revenue Adjustment	($42)	($88)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($130)
Original Budget FTY N/NT Rate	$0.0277	$0.0277	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	
HTY N/NT Rate	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	
N/NT Rate Variance	$0.0084	$0.0084	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
N/NT Rate Volumes	1,317	2,731	5,244	6,917	5,568	3,408	2,231	1,139	813	745	752	742	31,608
N/NT Revenue Adjustment	$11	$23	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$34
Original Budget FTY DS Rate	$0.0978	$0.0978	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	
HTY DS Rate	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	
DS Rate Variance	($0.0090)	($0.0090)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
DS Rate Volumes	543	836	1,385	1,722	1,385	966	678	418	300	286	309	321	9,149
DS Revenue Adjustment	($5)	($8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($12)
Original Budget FTY LFD Rate	$0.0049	$0.0049	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	
HTY LFD Rate	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	
LFD Rate Variance	$0.0297	$0.0297	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
LFD Rate Volumes	2,078	2,123	2,659	3,098	2,472	2,329	2,011	1,720	1,553	1,513	1,578	1,621	24,754
LFD Revenue Adjustment	$62	$63	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$125
Total Revenue Adjustment	$26	($9)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16

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) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	16.0	22,934	366,944
Rate R	15.9	19,178	305,721
Rate RT	16.3	3,756	61,223

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	82.3	611,318	50,311,471
Rate R	82.7	533,332	44,119,383
Rate RT	79.4	77,986	6,192,088
Rate RT Total	76.5	81,742	6,253,311

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	363.6	4,584	1,666,742
Rate N	238.9	3,081	736,180
Rate NT	485.4	1,480	718,392
Rate DS	9,224.8	23	212,170

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	526.2	65,162	34,288,244
Rate N	322.4	45,429	14,644,522
Rate NT	674.9	18,631	12,574,062
Rate DS	6,415.3	1,102	7,069,661
Rate Commercial NT Total	661.0	20,111	13,292,454

Industrial

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	2,341.6	1,249	2,924,658
Rate N	655.6	613	401,902
Rate NT	2,053.9	456	936,578
Rate DS	8,812.1	180	1,586,178
Rate NT Total	691.8	20,567	14,229,032
Rate DS Total	6,795.4	1,305	8,868,009

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

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	16.0	23,545	376,720
Rate R	15.9	19,789	315,497
Rate RT	16.3	3,756	61,223

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	82.5	605,094	49,920,255
Rate R	83.0	527,108	43,728,167
Rate RT	79.4	77,986	6,192,088
Rate RT Total	76.5	81,742	6,253,311

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	363.6	4,606	1,674,742
Rate N	239.8	3,103	744,179
Rate NT	485.4	1,480	718,392
Rate DS	9,224.8	23	212,170

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	526.2	64,941	34,171,954
Rate N	321.4	45,208	14,528,893
Rate NT	674.9	18,631	12,574,062
Rate DS	6,414.7	1,102	7,068,999
Rate Commercial NT Total	661.0	20,111	13,292,454

Industrial

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	2,341.6	1,260	2,950,416
Rate N	719.1	625	449,431
Rate NT	2,053.9	456	936,578
Rate DS	8,739.7	179	1,564,406
Rate NT Total	691.8	20,567	14,229,032
Rate DS Total	6,783.4	1,304	8,845,576

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	16.0	24,144	386,304
Rate R	15.9	20,447	326,043
Rate RT	16.3	3,697	60,261

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	82.7	597,939	49,449,555
Rate R	83.2	519,287	43,204,587
Rate RT	79.4	78,652	6,244,969
Rate RT Total	76.6	82,349	6,305,230

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	363.6	4,603	1,673,651
Rate N	231.0	3,094	714,839
Rate NT	485.4	1,486	721,304
Rate DS	10,326.4	23	237,507

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	526.2	64,781	34,087,762
Rate N	307.6	44,978	13,835,770
Rate NT	674.9	18,687	12,611,856
Rate DS	6,846.0	1,116	7,640,136
Rate Commercial NT Total	660.9	20,173	13,333,161

Industrial

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	2,341.6	1,276	2,987,882
Rate N	1,184.8	673	797,359
Rate NT	2,053.9	447	918,093
Rate DS	8,156.6	156	1,272,430
Rate NT Total	691.1	20,620	14,251,254
Rate DS Total	7,065.7	1,295	9,150,073

UGI GAS

EXHIBIT SAE-8

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

Notes:
1/ Storage Trip Cost ($/mcf) 0.1690

2/ Weekend Load Reduction Factor (%) 13.4%

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 - 0.134)) * WE
WD = 1.15 * 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 - 0.134)) + 2] * WE] / 7
7.75 * WE / 7
Step 2 WE = 0.90 * 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/(1-0.134)) - 2) * WE] - (3 * AVERAGE)
3.75 * WE - (3 * AVERAGE)
0.38 * AVERAGE

EQ #4 **Unit Cost Calculation ($/mcf)**
= [(Wkly Imbalance) / (7 * AVERAGE)] * STORAGE TRIP COST
= [(0.38 x Average) / (7 x AVERAGE)] x 0.169
0.05 x 0.169
0.0085

EQ #5 **Per Unit of Demand Calculation ($/mcf per month)**
= Unit Cost Demand x 20 days
= 0.0085 x 20
0.1700

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 Oct 2024 through Sep 2025
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)	1.4940	(A)
2/	Anticipated Average Monthly Imbalance %	0.9401%	(B)
3/	Load Factors & MBS Rate Calculation		

Rate	Load Factor	
DS	27.7%	(C)
LFD	58.6%	(C)
XD Firm	57.5%	(C)
Transportation System Average	51.4%	(D)

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

Rate	MBS Rate ($/mcf)	
DS	0.0198	(E)
LFD	0.0113	(E)
XD Firm	0.0116	(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 Oct 2024 through Sep 2025
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	$	22,053,717		
Allocator 1/			93.47%	6.24%
Uncollectible Revenue Requirement			$ 20,612,599	$ 1,376,805
Total Proposed Revenue			$ 869,313,264	$ 292,438,718
MFC % 2/			2.37%	0.47%

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. 11

JOHN D. TAYLOR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 11

Direct Testimony

of

John D. Taylor, Managing Partner
Atrium Economics, LLC

Topics Addressed:	**Cost of Service** **Revenue Allocation** **Rate Design** **Weather Normalization Adjustment**

Dated: January 28, 2026

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I. WITNESS IDENTIFICATION AND BACKGROUND

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

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

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting testimony on behalf of UGI Utilities, Inc. – Gas Division's ("UGI Gas" or the "Company") Gas Base Rate Case.

Q. What is the purpose of your testimony in this proceeding?

A. I prepared and am sponsoring UGI Gas's fully allocated cost of service study ("ACOSS"), which is found in UGI Gas Exhibit D. The ACOSS determines the embedded costs of serving UGI Gas's distribution customers associated with the Pennsylvania Public Utility Commission ("Commission") jurisdiction. I also support the apportionment, or allocation, of the class revenue increase, and the Company's rate design proposal. Finally, I am supporting the Company's Weather Normalization Adjustment ("WNA") proposal.

Q. Please describe your educational background and professional experience.

A. UGI Gas Exhibit JDT-1 contains background information summarizing my education, presentation of expert testimony, and other industry-related activities.

Q. Please summarize the content of your testimony.

A. My testimony consists of this introduction section (I) and the following six additional sections: (II) Purpose and Principles of Cost Allocation, (III) UGI Gas's Allocated Cost of Service Study, (IV) Principles of Sound Rate Design, (V) UGI Gas's Class Revenues, (VI) UGI Gas's Rate Design, and (VII) WNA Mechanism.

Q. Mr. Taylor, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Book IX, labeled as UGI Gas Exhibit D – Allocated Cost of Service Study (Fully Projected) ("Exhibit D"). Exhibit D contains three sections for which an index is provided on page 2 of Exhibit D. Also, I am sponsoring portions of Book I and Book II, Section 53.53 et seq. of the Commission's Regulations, Part IV-Rate Structure and Cost Allocation. Related to the WNA proposal, I'm sponsoring the following exhibits:

- UGI Gas Exhibit JDT-2, Normal Heating Degree Days Report;
- UGI Gas Exhibit JDT-3, WNA Data Report; and
- UGI Gas Exhibit JDT-4, WNA Mechanism Policy Factors.

II. ALLOCATED COST OF SERVICE STUDY OVERVIEW

Q. What is the general purpose and use of an ACOSS in regulatory proceedings?

A. The purpose of an ACOSS is to allocate the gas distribution utility's overall fully projected future test year ("FPFTY") costs to the various classes of service in a manner that reflects the relative costs of providing service to each class. An ACOSS represents an analysis of which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop the ACOSS results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more rate classes, or the cost of providing multiple products to the same rate class, use the same facilities and the use by one rate class precludes the use by another rate class.

In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of gas throughput, while variable costs change directly with changes in gas throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains, service lines, meters, and regulators.

Finally, the ACOSS provides different contributions to the development of economically efficient rates and the cost responsibility by rate class. This is accomplished through analyzing costs and assigning each rate class its proportionate share of the utility's total revenues and costs within the test year. The results of these studies can be utilized to determine the relative cost of service for each rate class to help determine the individual class revenue responsibility and provide guidance with rate design. Using the cost information per unit of demand, customer, and commodity developed in the ACOSS to understand and quantify the allocated costs in each rate class is a useful step in the rate design process to guide the development of rates.

Q. Is the preparation of an ACOSS an exact science?

A. No. The fundamental purpose of an ACOSS is to aid in the design of rates to be charged by identifying all of the capital and operating costs incurred by a utility to provide service to all of its customers and then assigning or allocating those costs to individual rate classes based on how those rate classes cause the costs to be incurred. The allocation of costs using an ACOSS is a practical requirement of utility regulation since rates are based on the cost of service for the utility under a cost-based regulatory model. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers, with such return on being reflective of a fair rate of return. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing revenues that equate to the level of the revenue requirement.

Q. Is there a guiding principle that supports the appropriate allocation of costs?

A. Yes, a fundamental foundational principle, cost causation, should be followed to produce accurate and reasonable results. Cost causation addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs, so the analysis results in an appropriate allocation of the utility's total revenue requirement among the various rate classes. In other words, the costs assigned or allocated to particular customers should be those costs that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service.

Q. How do you establish the cost and utility service relationships?

A. An important element in the selection and development of a reasonable ACOSS methodology is the establishment of relationships between customer requirements, load profiles, and usage characteristics on the one hand and the costs incurred by the company in serving those requirements on the other hand. To accomplish this, I reviewed UGI Gas's expense and plant accounts, operational data, usage information, and conducted interviews with UGI Gas employees. The details and data gathered provided information on the key factors that cause the costs to vary and supported studies of the relative costs of providing facilities and services for each rate class. From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for the utility's plant and expense elements.

Q. What are the steps to performing an ACOSS?

A. A three-step analysis of the utility's total operating costs must be undertaken to establish each customer class's cost responsibility. The three steps that are the basis to conduct an ACOSS are (1) cost functionalization, (2) cost classification, and (3) cost allocation.

Q. Please describe cost functionalization.

A. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. UGI Gas's primary functional cost categories associated with natural gas distribution services include gas supply, storage, transmission, distribution, and customer. Indirect costs that support these functions, such as general plant and administrative and general expenses, are allocated to functions using allocation factors related to plant and/or labor ratios, i.e., internal allocation factors.

Q. Please describe cost classification.

A. The second step, cost classification, further separates the functionalized plant and expenses according to the primary factors that determine the amount of costs incurred. These factors are: (1) the number of customers; (2) the need to meet the peak demand requirements that customers place on the gas distribution system; and (3) the amount of gas consumed by customers. These classification categories have been identified for purposes of the ACOSS as: (1) customer costs; (2) demand costs; and (3) commodity costs, respectively.

Q. Please describe the types of costs contained in the customer, demand, and commodity costs categories.

A. Customer-related costs are incurred to attach a customer to the gas distribution system, meter any gas usage, and maintain the customer's account. Customer costs are a function of the number of customers served by the utility and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with minimum size distribution mains, services, meters, regulators, customer service, and accounting expenses.

Demand or capacity related costs are associated with plant that is designed, installed, and operated to meet maximum hourly or daily gas flow requirements, such as the utility's transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity related component of cost relative to UGI Gas's requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity because they vary with the amount of gas volumes purchased by UGI Gas for its customers.

Q. Please describe the cost allocation process.

A. The final step is to allocate each functionalized and classified cost element to the individual rate class. Costs are typically allocated on customer, demand, commodity, or revenue allocation factors. From a cost-of-service perspective, the best approach is a direct assignment of costs where costs are incurred by a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by rate class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the way customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics. These meters have different costs based on size and type. Therefore, differences in the cost of meters are reflected by using a different average meter cost for each class of service. Notably, UGI Gas has performed direct assignment analysis of its most competitive negotiated rate customers who receive service under Rate XD, and those direct assignment results are reflected in the ACOSS presented in UGI Gas Exhibit D.

Q. Are there factors that can influence the overall cost allocation framework utilized by a gas utility when performing an ACOSS?

A. Yes. First, the fundamental and underlying philosophy applicable to all cost studies pertains to the concept of cost causation for purposes of allocating costs to customer groups. Cost causation addresses the question – which customer or group of customers causes the utility to incur particular types of costs? To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers. The factors that can influence the cost allocation used to perform an ACOSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility.

Q. Why are these considerations relevant to conducting UGI Gas's ACOSS?

A. It is important to understand these considerations because they influence the overall context within which a utility's cost study is conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the utility's gas system design and operations and understanding the regulatory environment in the state the utility operates in as it pertains to cost of service studies and gas ratemaking issues.

Q. How does the availability of data influence an ACOSS?

A. The structure of the utility's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by operating unit or geographic region, and the types of load data available.

Q. How do state regulatory policies affect a utility's ACOSS?

A. State regulatory policies and requirements prescribe whether there are any historical precedents used to establish utility rates in the state. Specifically, state regulations and past precedents set forth the methodological preferences or guidelines for performing cost studies or designing rates which can influence the proposed cost allocation method utilized by the utility.

III. UGI GAS'S ALLOCATED COST OF SERVICE STUDY

Q. Please describe the Atrium Model used in conducting the ACOSS filed in this proceeding.

A. UGI Gas has selected the Atrium excel based model ("Atrium ACOSS Model") to conduct the ACOSS in this general base rate case. Atrium developed the Atrium ACOSS Model on a proprietary basis for its consulting engagements, and it has been used in multiple jurisdictions. This is the same model I sponsored in the Company's last base rate case at Docket No. R-2024-3052716.

Q. Please describe the process of performing UGI Gas's ACOSS presented in this filing.

A. The detailed process description of UGI Gas's ACOSS analysis is presented in Exhibit D, providing a full scope of the process including the development of allocation factors that support various cost of service studies presented in this proceeding as discussed below.

Q. Please discuss the content of Exhibit D.

A. Exhibit D provides the information required under 52 Pa. Code § 53.53(a)(1) and, in particular, Exhibit A - Gas Utilities, by providing a cost of service study that fully distributes the Pennsylvania jurisdictional costs of providing retail distribution service to the various rate classes at both present and proposed rates. See 52 Pa. Code § 53.53(a)(1), Exhibit A.

Exhibit D consists of three sections detailing the process of developing the ACOSS. Section I – Introduction includes an introduction, the general purpose and process of the ACOSS, as well as an overview of the excel-based fully functional ACOSS model presented in this proceeding. Section II – UGI Gas's Cost of Service Procedures presents the ACOSS development process specific to the Company, including the Functionalization, Classification, and Allocation of costs. The Allocation section (Section II.3) describes all internal and external allocation factors and the allocation processes used in the ACOSS. The last section, Section III – UGI Gas's Cost of Service Results depicts the results of the ACOSS, including revenue requirement apportionment, comparison of cost of service with revenues under current and proposed rates, and development of rate of return by customer class under current and proposed rates.

Q. Please describe the content and schedules included in Exhibit D.

A. Exhibit D contains a narrative description of the ACOSS procedures, provides details on the allocation factors, and contains the following Schedules:

- Schedule 1 – Summary of Cost of Service and Rate of Return Under Current and Proposed Rates
- Schedule 2 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
- Schedule 3 - Cost of Service Allocation Study Detail by Account
- Schedule 4 - Account Balances and Allocation Methods
- Schedule 5 - External Allocation Factors
- Schedule 6 - Internal Allocation Factors

Q. What was the source of the cost data analyzed in UGI Gas's ACOSS?

All cost-of-service data was extracted from the Company's total cost of service (*i.e.*, total revenue requirement) and schedules contained in this general rate case filing for the FPFTY ending September 30, 2027. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company and information provided by Company personnel.

Q. How are UGI Gas's rate classes structured for the purposes of conducting its ACOSS?

A. For UGI Gas's ACOSS, I included six rate classes:

- Rate R - General Service – Residential & Residential Transportation
- Rate N - General Service – Non-Residential & Non-Residential Transportation
- Rate DS - Delivery Service
- Rate LFD - Large Firm Delivery Service
- Rate XD Firm - Extended Large Firm Delivery Service
- Rate IS - Interruptible Service

Q. Do you propose any modification to the current customer classes?

A. No. I am not proposing any modifications to the existing customer classes. The current class structure aligns with the Company's approved tariff schedules and is consistent with the configuration adopted in the Company's most recent general rate case, Docket No. R-2024-3052716.

Q. How did you classify and allocate the cost of distribution mains?

A. I classified distribution mains as 100% demand related and allocated their costs in two steps. First, a portion of the costs was directly assigned to Rate XD Firm based on an analysis provided by the Company. Second, I allocated the remaining balance using the Average and Excess ("A&E") method.

Q. Please describe the methodology used for the costs directly assigned to the XD customers.

A. For each customer, a distribution system analysis is performed to determine which assets (including footage, diameter, material type, and vintage year) of the distribution system are utilized to serve each Rate XD customer. Using the Company's plant records, the costs and footage for these assets are summarized based on the footage assigned to the customer as a percentage of the total footage for that asset. A portion of this cost is allocated to each Rate XD customer based on the customer's throughput on that asset as a percent of the asset total. The calculated costs for all assets assigned to each Rate XD customer are summed to determine that customer's directly allocated costs. These customer-level costs are then summed across all Rate XD customers to develop the direct assignment for the Rate XD class.

Q. Please describe the A&E method.

A. The A&E method allocates costs based on a combination of average usage and peak usage levels. This method is used to allocate costs on both the consistent usage (average demand), and the additional capacity needed during peak times (excess demand). The average demand is determined by the average daily throughput volumes per customer class. The excess demand represents the additional capacity needed to meet the peak demand or maximum usage levels for each customer class. These two factors are weighted based on the system load factor, which is the ratio of average demand to peak demand for the entire system. This factor determines the proportion of costs attributed to average daily usage versus peak capacity requirements.

Q. Can you explain the system load factor and its significance in this method?

A. The system load factor is calculated as follows:

Load Factor = Average Daily Throughput ÷ Peak Day Demand

It indicates the efficiency of the system's utilization. A higher load factor suggests that demand is relatively stable, reducing the need for excess capacity. This metric helps balance the cost allocation between average usage and peak demand. UGI Gas's firm service load factor for the FPFTY is 40.53%, which is the system load factor excluding interruptible load. Therefore, the allocation assigns 40.53% of the costs to average daily usage and 59.47% to peak demand.

Q. Why is the interruptible load excluded from the load factor calculations?

A. Interruptible load is excluded from the load factor calculations because it does not contribute to the system's peak day demand, which is a critical driver of infrastructure. In addition, interruptible customers are not assigned any excess load. Interruptible customers agree to reduce or halt their gas usage during periods of high demand, meaning they do not place the same capacity requirements on the distribution system as firm customers. Including interruptible load would misrepresent the true cost drivers and unfairly allocate costs to customers who do not rely on guaranteed peak capacity.

Q. Has the A&E method been approved by the Commission?

A. Yes. The A&E method was approved by the Commission in PECO Energy Company's rate case at Docket No. R-2020-3018929.

Q. Did you consider other classification or allocation methods?

A. Yes. I considered the customer/demand classification method and the Peak and Average ("P&A") allocation method. However, the Commission has not traditionally recognized the customer component of gas mains, which means the customer/demand classification method is not consistent with past Commission orders.[1] The P&A allocation method has also been evaluated for use in past Pennsylvania rate cases and applies a fixed 50/50 weighting instead of relying on the system load factor.

Q. How do the allocation results differ between the A&E method and the P&A method for UGI Gas in this case?

A. The allocation results for each method are presented below in Table 1. The A&E method allocates a higher percentage of costs to Rate R (46.8% vs. 44.7%) and Rate N (31.6% vs. 28.9%), reflecting its reliance on the system load factor. On the other hand, the P&A method allocates a higher percentage of costs to Rate LFD (15.4% vs. 11.7%) and Interruptible (4.3% vs. 3.5%), due to its 50/50 weighting of average demand within the peak portion. These differences illustrate how the P&A method allocates more costs to

[1] *Pa. PUC, et al. v. Columbia Gas of Pennsylvania, Inc.,* Docket No. R-2020-3018835 (Order entered February 19, 2021), p. 217.

higher-load factor customers than the A&E method, despite those customers having more efficient use of the system.

Table 1 – Comparison of Mains Allocators of the Company's ACOSS

	Rate R	Rate N	Rate DS	Rate LFD	Interruptible
A&E	46.8%	31.6%	6.4%	11.7%	3.5%
P&A	44.7%	28.9%	6.7%	15.4%	4.3%

Q. Does UGI Gas's ACOSS include gas commodity costs?

A. Yes. The gas costs reflected in the ACOSS correspond to gas cost revenues that have a neutral impact on the study's results, resulting in a net-zero effect.

Q. Please summarize the results of the Company's ACOSS.

A. Table 2 below presents a summary of the Company's ACOSS that can be reviewed in Schedule 1 of Book IX, UGI Gas Exhibit D. The ACOSS shows an overall revenue requirement of $1,234.7 million and a resulting deficiency of $99.4 million. The revenue deficiency/excess for each rate class shows revenue increases or decreases necessary to get the classes to their cost to serve.

Table 2 - Summary Results of the Company's ACOSS ($000)[2]

Customer Classes	Current Revenues	Cost to Serve	Class Revenue (Deficiency)/ Excess	Percentage Change to Cost to Serve	Current Rate of Return	Current Revenue to Cost Ratio	Current Parity Ratio
Rate R	$ 794,595	$ 895,723	$ (101,128)	12.7%	5.2%	0.89	0.96
Rate N	269,032	292,438	(23,405)	8.7%	6.5%	0.92	0.99
Rate DS	36,024	34,197	1,827	-5.1%	9.3%	1.05	1.14
Rate LFD	58,792	54,870	3,922	-6.7%	9.6%	1.07	1.16
Rate XD Firm	39,155	26,027	13,128	-33.5%	17.0%	1.45	1.56
Rate IS	22,953	16,665	6,288	-27.4%	14.3%	1.37	1.48
Total Base	**1,220,551**	**1,319,920**	**(99,369)**	**8.1%**	**6.5%**	**0.93**	**1.00**
Other Revenues	14,131	14,131	-				
Total Company	**1,234,682**	**1,334,051**	**(99,369)**				

The ACOSS shows that Rate R and Rate N classes are being charged rates that recover less than their indicated costs of service, whereas rates for other rate classes provide for recovery of more than the indicated costs of serving these other rate classes. In other words, to set each classes' revenues equal to their cost to serve indicated in the ACOSS, Rate R and Rate N would require an increase in revenues, while all other classes would require a decrease. Additionally, Table 2 provides helpful insights into UGI Gas's class financial metrics, such as the current Rate of Return and corresponding Relative Rate of Return and Current Revenue to Cost Ratio with the corresponding Parity Ratio.

Q. Have you prepared more detailed reports of UGI Gas's ACOSS results?

A. Yes, additional details are included in Exhibit D. Schedule 4 "Account Balances and Allocation Methods" of Exhibit D includes revenue requirement information by FERC account provided by UGI Gas and shows assigned functions, categories, and allocation factors. Schedule 3 "Cost of Service Allocation Study Detail by Account" of Exhibit D

[2] See Exhibit D, Schedule 1, lines 13, 52, 57, 24, 26, and 27.
Percent Change = Class Revenue (Deficiency)/Sufficiency ÷ Current Revenues

presents the resulting allocations by customer class of UGI Gas's proposed revenue requirement based on the results of the computations included in the ACOSS.

IV. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the rate design principles utilized in developing the Company's rate design proposals.

A. The rate design principles below draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates.[3] Each of these principles plays an important role in analyzing the rate design proposals of UGI Gas and provides a roadmap that helps guide utilities and regulators when considering how to achieve utility rates that are fair, efficient, practical, and reasonable. The foundation of rates should include:

- Fairness: Rates should be fair to all customer classes, avoiding undue discrimination.
- Efficiency: Rates should promote the efficient use of resources and encourage conservation while avoiding undue restriction of economic use.
- Simplicity: Rates should be simple and understandable for customers.
- Stability/Gradualism: Rates should provide bill stability for customers and revenue stability for the utility.
- Reflective of Costs: Rates should reflect the cost of providing service to different customer classes.

[3] James Bonbright et al. Principles of Public Utility Rates, Public Utilities Reports, Inc. 2nd Edition, 1988.

- Revenue Sufficiency: Rates should generate enough revenue to cover the utility's costs, including a reasonable return on investment.

In addition, these principles are consistent with Pennsylvania practice and precedent, including the *Lloyd* decision,[4] where the Commonwealth Court indicated that cost of service is the "polestar" of ratemaking but that other factors, including those listed above, can be considered as well.

Q. How are these principles translated into the design of rates?

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures within rate classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter the process. In other words, both quantitative and qualitative information are evaluated before reaching a final rate design determination. Out of necessity, the rate design process must be, in part, influenced by judgmental evaluations.

V. UGI GAS'S REVENUE APPORTIONMENT

Q. Please describe the approach used by UGI Gas to allocate its proposed $99.4 million revenue increase among its customer rate classes.

A. UGI Gas's proposed allocation of the revenue increase is informed by the results of the ACOSS and reflects a deliberate effort to move all rate classes closer to the overall system

[4] *Lloyd v. Pa. P.U.C.*, 904 A.2d 1010 (Pa. Cmwlth. 2006), *appeal denied*, 591 Pa. 676, 916 A.2d 1104 (2007).

rate of return, thereby reducing the subsidies that currently exist between classes. This approach is consistent with long-standing regulatory practice and precedent, including the *Lloyd* decision and the Commission's Order on remand approving the settlement in that case.

The benchmark option evaluated under UGI Gas's proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost for each class was equal to 1.00. This is shown above in Table 2 where the changes in each classes' revenues would be set to their deficiency or surplus. It was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue, given the large increase required to move some classes to parity. After discussions with the Company, the increase proposed in this case was allocated based on a desire to move toward full parity over time while addressing issues of gradualism. To accomplish this, the Company first reflected the slight rate decreases for competitively negotiated classes XD and IS in the mechanics of the calculations, resulting from incorporating the current Distribution System Improvement Charge ("DSIC") rider into base rates. Second, Rate N was assigned an increase to move them to parity, equivalent to 1.18 times the system increase. Finally, Rates DS and LFD were assigned increases that correct approximately two-thirds of the class's over-earning relative to the system-average rate of return. While there are various yardsticks used to measure the degree of movement toward cost of service, the Company evaluated two metrics: (1) the percentage movement towards the system rate of return; and (2) the reduction in the subsidies occurring between classes. In addition, the Company's proposal results in keeping the residential average monthly bill increase under

$10, and with these considerations, the Company is proposing the revenue changes shown in Table 3 below.

Table 3 – Proposed Class Revenue Apportionment
Base Distribution Margin ($000)[5]

Customer Classes	Current Revenues	Proposed Revenues	Proposed Revenue Change	Proposed Percentage Change	Proposed Rate of Return	Proposed Revenue to Cost Ratio
Rate R	$ 794,595	$ 869,272	$ 74,677	9.4%	7.4%	0.97
Rate N	269,032	$ 292,418	23,386	8.7%	8.2%	1.00
Rate DS	36,024	$ 36,732	708	2.0%	9.4%	1.07
Rate LFD	58,792	$ 59,528	736	1.3%	9.4%	1.08
Rate XD Firm	39,155	$ 39,090	(64)	-0.2%	16.4%	1.44
Rate IS	22,953	22,879	(73)	-0.3%	13.7%	1.37
Total Base	**$ 1,220,551**	**$ 1,319,920**	**$ 99,369**	**8.1%**	**8.2%**	**1.00**

Q. To what degree does the Company's proposed revenue apportionment move the classes toward their cost of service?

A. The Company's proposed revenue apportionment results in the reduction of the existing rate subsidies and excesses among the Company's rate classes, moving classes toward the overall system rate of return. From a class cost of service standpoint, this type of class movement and reduction in class rate subsidies is desirable, as it brings class revenues and rates closer to the indicated cost of service for each rate class.

Table 4 below compares the current and proposed rates of returns and parity ratios. The Company's proposal moves the return for all rate classes closer to the Company's proposed return. Likewise, parity ratios move closer to the desired 1.0 level.

[5] See Exhibit D, Schedule 1, lines 10, 52, 58, 61, 70, and 72.

Table 4 - Comparison of Relative Rate of Return by Rate Class
Base Distribution Margin ($000)[6]

Customer Classes	Current Revenues	Proposed Revenues	Current Return	Proposed Return	Current Parity Ratio	Proposed Parity Ratio
Rate R	$ 794,595	$ 869,272	5.2%	7.4%	0.96	0.97
Rate N	$ 269,032	$ 292,418	6.5%	8.2%	0.99	1.00
Rate DS	$ 36,024	$ 36,732	9.3%	9.4%	1.14	1.07
Rate LFD	$ 58,792	$ 59,528	9.6%	9.4%	1.16	1.08
Rate XD Firm	$ 39,155	$ 39,090	17.0%	16.4%	1.56	1.44
Rate IS	$ 22,953	$ 22,879	14.3%	13.7%	1.48	1.37
Total Base	**$ 1,220,551**	**$ 1,319,920**	**6.5%**	**8.2%**	**1.00**	**1.00**

Q. To what degree does the Company's proposed revenue apportionment decrease the existing subsidies between rate classes?

A. Table 5 below summarizes the current subsidies, proposed subsidies, and the reduction in subsidies for all customer classes resulting from the Company's proposed revenue apportionment.

Table 5 - Comparison of Current and Proposed Subsidies ($000)[7]

Customer Classes	Current Class Subsidy	Proposed Class Subsidy	Reduction in Subsidy
Rate R	$ (34,867)	$ (26,451)	$ 8,416
Rate N	(23)	(20)	3
Rate DS	4,965	2,535	2,430
Rate LFD	9,160	4,658	4,502
Rate XD Firm	13,654	13,063	590
Rate IS	7,112	6,215	897
Total Company	$ -	$ -	$ -

[6] Exhibit D, Schedule 1, lines 10, 52, 24, 70, 27, and 73.
[7] See Exhibit D, Schedule 1, lines 35 and 63. Reduction in Subsidy = Absolute difference between Proposed Subsidy and Current Subsidy.

VI. UGI GAS'S RATE DESIGN

Q. Please summarize the rate design changes UGI Gas has proposed in this rate proceeding.

A. In general, UGI Gas's rate design strategy is to make incremental movements toward reflecting the Company's relative cost of serving each rate class to provide natural gas distribution service to those customers. UGI Gas has proposed the following rate design changes to its current tariff schedules:

- Rate R – Increase in the monthly customer charge from $16.25 to $23.00, with the remaining proposed increase to be recovered in the volumetric charge.
- Rate N – Increase in the monthly customer charge from $36.42 to $39.00, with the remaining proposed increase to be recovered in the volumetric charge.
- Rate DS – Increase in the monthly customer charge from $300 to $353, with the remaining proposed increase to be recovered in the volumetric charge.
- Rate LFD – Increase in the volumetric charge from $1.3831 per Mcf to $1.4173 per Mcf.
- Rate XD Firm – Decrease equivalent to the DSIC rider amount.
- Rate IS – Decrease equivalent to the DSIC rider amount.

Q. Has the Company prepared a detailed comparison of the Company's current and proposed rates and resulting revenues by rate class?

A. Yes. UGI Gas Exhibit E – Proof of Revenue, sponsored by Company witness Sherry A. Epler, Statement No. 10, presents a detailed comparison of current and proposed revenues for each of UGI Gas's rate classes.

Q. What billing determinants were used to develop the Company's proposed base rates in this proceeding?

A. Consistent with the Settlement Agreement approved by the Commission in Docket Nos. R-2024-3052716 et al., the Company evaluated the use of a ten-year historical period and determined that a ten-year historical average of heating degree days ("HDDs") ending December 31, 2024, is a more appropriate basis for both base-rate billing determinants and WNA calculations. In support of this conclusion, I am sponsoring the Normal Heating Degree Days Report in UGI Gas Exhibit JDT-2, which evaluates long-term weather trends and normalization alternatives and recommends adoption of a ten-year historical average to reflect more recent weather conditions. Specifically, this analysis was undertaken pursuant to the settlement agreement approved by the Commission on September 11, 2025, at Docket Nos. R-2024-3052716, et al. which established the following requirement:

> UGI Gas will include in its filing a report and recommendation on the use of a rolling ten-year historical average period to be used to calculate its normal heating degree day amounts for purposes of the WNA, as well as the use of a ten-year historical average period for purposes of determining projected sales and billing determinants in base rates. (p.12)

As set forth in UGI Gas Exhibit JDT-2, the Company proposes that the 10-year normals be updated in conjunction with each future rate case filing. This would replace the Company's current practice, wherein it used 15 years of weather data updated every five years, with the last update – the one that supported the rates established in Docket R-2024-3052716 – based on data ending on December 31, 2019.

Q. What factors drove the change in billing determinants in this case compared to prior rate cases?

A. Two primary factors contributed to the change in billing determinants in this case. First, as I just described, in the prior proceedings, the Company relied on a fifteen-year historical average ending in 2019. Under the Company's current methodology, it was required to update its normal weather in this proceeding. Updating that methodology alone, by advancing the fifteen-year period to include more recent data, would have replaced approximately one-third of the historical observations with newer years that generally reflect lower heating degree days. As a result, even without a change to a ten-year historical average of HDDs, normalized billing determinants would have declined due to the inclusion of warmer recent weather.

Second, in compliance with the Settlement Agreement, the Company evaluated and ultimately is proposing the use of a ten-year historical average ending December 31, 2024. As demonstrated in Exhibit JDT-2, a ten-year period more closely aligns with observed recent weather patterns and the long-term downward trend in heating degree days, while avoiding the overstatement of heating demand that can occur when older, colder years remain embedded in the normalization period.

Q. How does the ACOSS support the proposed increases to customer charges?

A. Atrium's ACOSS model allows for developing the total revenue requirement by functions and classifications. As such, we can see directly the revenue requirement associated with the customer classification and the respective functions that form this revenue requirement. Table 6 below provides the information related to the current and proposed customer charges for Rates R, N, and DS, compared to the customer-related unit cost per customer per month.

Table 6 - Customer Charge Current, Proposed, and ACOSS Unit Cost Results ($)[8]

Customer Classes	Current Basic Facilities Charge	Proposed Basic Facilities Charge	Customer Related Unit Cost	Demand and Customer Related Unit Cost
Rate R	16.25	23.00	54.03	79.04
Rate N	36.42	39.00	70.69	224.16
Rate DS	300.00	353.00	542.90	2,201.57

As seen in the above table, the proposed increases in customer charges are still under the customer-related unit cost identified in the ACOSS. These include the customer portion of distribution facilities, as well as customer service and billing costs.

Q. Can you please discuss the results in Table 6 above within the context of the Company's proposed customer charges and past Commission precedent?

A. Yes, past Commission precedent defines customer-related costs for inclusion in a customer charge as costs associated with meters and services and related operations and maintenance ("O&M") expenses, meter reading and billing and collection expenses, meter data management systems, and related employee benefits, administrative and general expenses. The Company is proposing a Rate R customer charge of $23.00, which is below the $54.03 within Table 6 above, and represents meter reading, customer service, and

[8] See Exhibit D, Schedule 2, lines 118 and 119.

billing and collection expenses. These are all costs historically allowed by the Commission in a customer charge. Taking into consideration past precedent in Pennsylvania and given the results of the ACOSS as shown in Table 6 above, the Company is proposing to move the Rate R customer charge to $23.00. Similarly, the Company is proposing customer charge increases to Rate N and Rate DS that are still well below the customer related unit cost for these rates.

Q. Why are setting customer charges more in alignment with the fixed cost of service an important outcome of ratemaking?

A. These proposed customer charges help to reduce customer bill volatility, alleviate a significant portion of the instability in the Company's margin recovery, are fair to customers, are easily understood, convey more appropriate price signals with respect to recovery of fixed utility costs, benefit low-income customers that have higher than average use, and are not regressive in application to low-income customers who may have little control over their use of energy and are negatively impacted when recovering more costs in volumetric charges.

Establishing higher monthly fixed charges helps to equalize the contribution each customer within a class makes towards recovery of the fixed costs attributable to this class. This method of cost recovery is preferable to including such costs in the volumetric charges, which has the effect of causing some customers to pay too much while others pay too little. The customer charges provide for recovery of a portion of the Company's fixed costs, which are incurred solely because of the existence of customers connected to the system. These costs, such as the expense of reading meters and billing, occur regardless of whether natural gas is used and are not related to demands placed on the system. The proposed customer charge increases will also help to ensure the Company's recovery of a greater portion of its fixed costs of providing service. Inasmuch as costs are not related to usage, they should be recovered, to the extent possible, through a tariff mechanism that does not depend upon volumetric billing.

In terms of understandability, customers easily recognize fixed cost charges and are used to these pricing structures in their everyday lives. Because these costs do not vary with the customer's usage, it is perfectly understandable that the charge should not vary as well.

Q. Please expand on why an increase in the Rate R customer charge would benefit low-income customers.

A. There is often a common misconception that low-income customers are low-usage customers. This is not a correct characterization of low-income customers on the Company's system who are indeed higher-use customers. According to the Company's historical residential customer billing data[9], the average use for confirmed low-income customers not enrolled in the Customer Assistance Program ("CAP")[10] is 86.7 Mcf/year.

[9] Based on three full years (2022, 2023 and 2024) of residential customer billing data. This dataset included individual monthly usage levels for each customer, along with key identifying attributes that enabled segmentation of the residential class for comparative purposes.

[10] Customers with Confirmed Low-Income indicator as of January 2025. Confirmed Low Income indicator is applied when a customer provides proof of income and is subsequently enrolled in CAP, participated in Low Income Usage Reduction Program ("LIURP"; 200% Federal Poverty Income Guidelines ("FPIG")) or received an Operation Share grant (250% FPIG) or a Low Income Home Energy Assistance Program ("LIHEAP") grant (150% FPIG) within prior 12 months.

This is 14% higher than the average of the Company's residential non-low-income customer use of 76.0 Mcf/year.

Also, all else being equal, higher customer charges necessitate lower variable charges. The collection of costs through fixed or volumetric charges is only the means of collecting the revenue to cover costs for a specific customer class. The amount of total revenue that must be recovered does not change. Higher usage customers pay more when more fixed customer costs are embedded in the volumetric rates. This creates a social equity concern, as customers who can afford to reduce their usage through energy efficiency investments can decrease their bills by making such investments, while those customers who cannot afford to make energy efficiency investments will see increases in their bills. Examples of those who could possibly afford to reduce their usage include higher-income households who can undertake more expensive energy efficiency measures. While some environmental advocates may prefer that households stop using natural gas altogether, families still use gas as an economic energy source for basic human needs such as keeping themselves warm, cooking, and caring for themselves.

Further, recovering fixed costs in volumetric charges places regressive burdens on low-income households who have to make decisions to reduce their gas usage, which impacts their quality of life. Families use gas as an economic energy source for basic human needs such as keeping themselves warm, to cook, and care for themselves. For many households, particularly low-income customers, a substantial portion of natural gas consumption reflects non-discretionary usage necessary to meet basic human needs and cannot be meaningfully reduced through "just use less" through price signals, absent the ability to invest in more efficient equipment or building improvements.

Lastly, considerations relating to the intersection of income and rate design would be amiss if they did not include discussions relating to UGI Gas's low-income programs. UGI Gas has available a continuum of low-income targeted programs, beyond CAP, including facilitating Low-Income Home Energy Assistance Program ("LIHEAP"), and offering Low-Income Usage Reduction Program ("LIURP") and weatherization assistance, as well as Operation Share to address customers experiencing economic hardship.

Q. Have you conducted an analysis of the difference between the current $16.25 monthly residential customer charge and the proposed $23.00 a month charge on low-income customers?

A. Yes. Table 7 compares the amount a confirmed non-CAP low-income customer with an average usage of 86.7 Mcf/year would pay between the customer charge and the volumetric charge under the Company's proposal (Scenario A) of increasing the monthly customer charge to $23.00, and Scenario B, which keeps the monthly customer charge unchanged at $16.25.

Table 7 – Comparison of Annual Charges for Average CAP Customer[11]

Average LI Customer (non-CAP)	Scenario A	Scenario B	B - A	% change
Customer Charges	$ 276.00	$ 195.00	$ (81.00)	-41.5%
Distribution Charges	592.61	680.78	$ 88.18	13.0%
Total Annual Charges	**$ 868.61**	**$ 875.78**	$ 7.18	0.8%

The comparison shows that while the Company's proposal increases the annual customer charges by $81.00 or 41.5%, the increase is offset by the $88.18 or 13.0% lower distribution charges. In other words, by not changing the current customer charge, customers may face higher overall costs because of the increase in distribution charges. This suggests that any policy or pricing adjustment leading to keeping the customer charge unchanged would shift more costs to the variable distribution component, increasing the financial burden on low-income customers, close to 1%, over a year. As previously stated, a volumetrically weighted rate design conveys improper price signals to customers because it recovers fixed costs through the volumetric components of the utility's rate structure. When this undesirable situation exists, it can: (1) increase revenue variability due to factors beyond the utility's ability to influence; (2) fail to account for cost differences between and within customer classes; (3) promote inefficient use of the utility's system; and (4) needlessly inflate bills in the winter months. The important policy point in this discussion is that it makes no economic sense to send the wrong economic price signals to all customers in order to supposedly benefit a small subset of low-income

[11] Scenario A uses a monthly customer charge of $23.00 and distribution charges of $6.8383/Mcf, as proposed by the Company. Scenario B uses the current monthly customer charge of $16.25 and distribution charges of $7.8558/Mcf, which would be necessary to recover Rate R's proposed revenue.

customers. It is far more efficient to address the issues of low-income customers directly through programs and assistance, such as the Company's CAP.

VII. WNA MECHANISM

Q. What is the Company's proposal regarding WNA in this proceeding?

A. UGI Gas is requesting the Commission to extend the current WNA pilot mechanism for an additional five (5) years after its current expiration in October 2027. This request follows the settlement agreement approved by the Commission on September 11, 2025, at Docket Nos. R-2024-3052716, et al. which established the following:

> UGI Gas's WNA Pilot will end on October 31, 2027, unless affirmatively extended or otherwise permitted by Commission order. Should UGI Gas request a continuation or modification of the WNA for the period on or after November 1, 2027, it may file a stand-alone Petition or incorporate into a base rate proceeding to be filed no later than January 31, 2026. (p.12)

Q. Has the Commission recently approved similar WNA mechanisms?

A. Yes. For example, in its most recent Final Order in the Columbia Gas of Pennsylvania ("Columbia") case, issued in December 2025, the Commission explicitly approved the continuation of Columbia's WNA mechanism "to allow it a reasonable opportunity to earn up to its Commission-authorized revenue requirement."[12]

[12] Pa. PUC v. Columbia Gas of Pa., Inc., Docket No. R-2024-3067174, Final Order at 301 (Dec. 4, 2025).

Q. Has the Company complied with the WNA stipulations from the settlement agreements in prior rate cases?

A. Yes. As mentioned above, I am sponsoring the Normal Heating Degree Days Report in UGI Gas Exhibit JDT-2, which supports utilizing a 10-year weather history, and was agreed upon in Docket No. R-2024-3052716, et al. In addition, as explained by Company witness Brian J. Meilinger, UGI Gas Statement No. 12, the Company has reviewed the WNA Pilot communication materials, and it has expanded its reporting as agreed upon in Docket No. R-2024-3052716, et al. Lastly, UGI Gas Exhibit JDT-3 provides the WNA data requested by the parties in the settlement agreements in Dockets No. R-2021-3030218 and No. R-2024-3052716.[13]

Q. How does the use of a ten-year historical average for billing determinants relate to the Company's WNA?

A. The use of a ten-year historical average serves a consistent and complementary role in both base-rate development and WNA operation. Base rates are established using billing determinants normalized to the same ten-year weather baseline against which actual weather will later be compared under the WNA. Maintaining this consistency ensures that the WNA functions as intended by adjusting revenues solely for deviations between actual weather and the normalized weather assumptions embedded in rates.

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[13] The Company has filed five reports with the Commission since November 30, 2023, containing WNA data from April 2023 through October 2025. These reports are available at https://www.puc.pa.gov/pcdocs/1807398.pdf, https://www.puc.pa.gov/pcdocs/1835933.pdf, https://www.puc.pa.gov/pcdocs/1857431.pdf, https://www.puc.pa.gov/pcdocs/1885030.pdf, and https://www.puc.pa.gov/pcdocs/1904492.pdf

As explained in Exhibit JDT-2, using different weather baselines for rate-setting and WNA calculations could introduce misalignment and unintended over or under recovery. By applying the same ten-year historical average for both purposes, the Company preserves methodological integrity and ensures that customers and the Company are treated fairly when weather conditions differ from normal.

Q. Does the use of a ten-year historical average eliminate the need for a WNA?

A. No. While a ten-year historical average better reflects recent weather conditions, actual heating degree days will continue to vary from year to year in ways that cannot be predicted with certainty. Accordingly, the WNA remains an important mechanism to address year-to-year weather variability by reconciling revenues to the normalized assumptions used to set rates, thereby protecting both customers and the Company from the financial effects of abnormal weather.

Using a ten-year historical average also improves the definition of "normal" weather by placing greater weight on more recent conditions. As a result, deviations between actual weather and normalized assumptions are expected to be smaller, on average, than under a longer historical period that includes older, less representative data. This improved alignment is expected to reduce the magnitude of WNA surcharges or credits over time, while preserving the WNA's role in addressing unavoidable weather variability.

Q. Please describe the Company's proposed WNA.

A. After adopting the modifications to the current WNA pilot pursuant to the Commission-approved settlement at Docket No. R-2024-3052716, UGI Gas's WNA mechanism functions as follows:

i) It adjusts the usage in customer bills based on deviations from normal weather, as measured by Heating Degree Days ("HDDs"), by comparing actual HDDs ("AHDDs") to normal HDDs ("NHDDs") based on a 15-year weather history.

ii) It includes a 3% deadband, meaning no adjustment is made unless the weather deviates by more than ±3% from normal. This prevents minor weather variations from triggering bill changes and ensures that adjustments occur only when there are material deviations.

iii) It applies to Residential (excluding CAP customers) and Small Commercial classes.

iv) It applies during the heating season months of October through April. By excluding non-heating season usage and focusing on the weather-sensitive portion of consumption, the mechanism is carefully targeted and limited in scope. Specifically, the WNA no longer applies in May.

Q. Why is a WNA mechanism necessary for UGI Gas's rate structure?

A. UGI Gas's current rate design recovers significant fixed costs through volumetric charges. Weather-driven usage swings can cause under-recovery in warm winters and over-recovery in cold winters. The WNA stabilizes this to provide the Company a reasonable opportunity to recover its authorized revenue requirement while protecting customers from additional charges in colder than normal winters.

Q. Can you elaborate on the relationship between fixed costs and usage-based recovery in UGI Gas's current rate design?

A. UGI Gas's current rate design recovers a significant portion of its fixed costs, such as infrastructure, maintenance, and administrative expenses, through volumetric charges based on customer usage. Because revenues are recovered through volumetric rates established using billing determinants that reflect normal weather conditions, periods of warmer-than-normal weather result in lower-than-expected gas usage and corresponding under-recovery of fixed costs, even though those costs do not vary with consumption. Conversely, colder-than-normal weather can lead to over-recovery. This mismatch creates volatility for both customers and the utility. The WNA mechanism helps address this by normalizing revenues to reflect normal weather conditions, ensuring that fixed costs are recovered more consistently with what was authorized by the Commission when it approved current rates.

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 current rates, approximately 72% of base rate distribution revenues for Rate R is recovered through the volumetric distribution charge. For Rate N, approximately 81% of base rate distribution revenue is recovered through the volumetric distribution charge. This clearly indicates that even though UGI Gas's distribution costs are fixed, there is a risk of over- or under-recovery, for the vast majority of costs, resulting in the need for the WNA.

Q. Are there alternative rate designs which more closely align fixed cost recovery with distribution charges and minimize potential under- and over-recovery due to weather?

A. Yes. Straight-Fixed-Variable ("SFV") rate design would accomplish that goal.

Q. How would a transition toward a SFV rate design help mitigate under- and over-recovery risks?

A. A transition to a SFV rate design would reduce UGI Gas's reliance on usage-based charges to recover fixed costs. Under the current structure, a significant portion of fixed costs, such as infrastructure and maintenance, are recovered through volumetric rates, making revenues highly sensitive to weather-driven consumption changes. SFV shifts recovery of fixed costs to a fixed monthly charge, ensuring that these costs are collected consistently regardless of seasonal usage fluctuations. This approach mitigates under-recovery risks during mild winters and over-recovery during colder-than-normal periods, providing greater revenue stability and aligning cost recovery with cost causation principles.

Q. How does UGI Gas's proposed WNA align with the factors the Commission may consider when evaluating this alternative ratemaking mechanism?

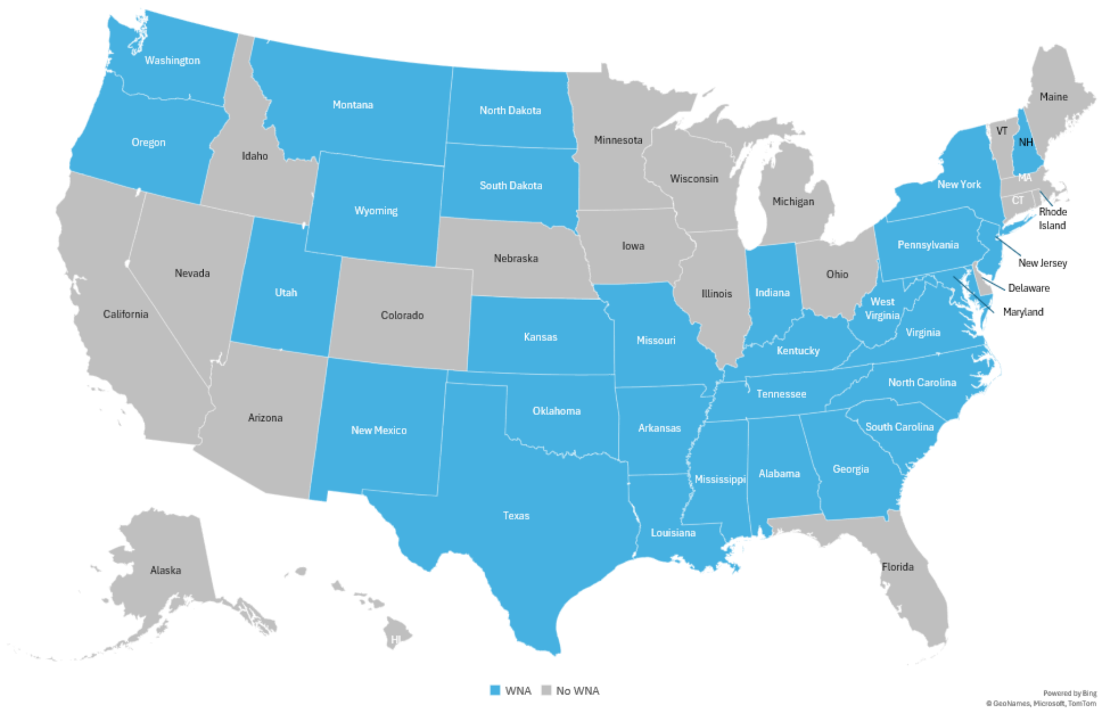
A. Exhibit JDT-4 details how UGI Gas's proposed WNA aligns with each of the fourteen items identified within the Statement of Policy as outlined by the Commission in the alternative rate making Docket No. M-2015-2518883. However, it is important to note that the Statements of Policy language[14] suggests that the Commission intends to consider these elements, but not all of them may be relevant or deemed required in order to determine whether a proposal is just and reasonable.

Q. Are WNAs common alternative ratemaking mechanisms in the utility industry?

A. Yes. WNA mechanisms are widely used across the United States to stabilize customer bills and utility revenues during weather conditions that deviate from normal. The map that follows shows that 29 states with a total of 67 gas utilities have adopted similar mechanisms.

[14] "the Commission may consider, among other relevant factors, the following:" Docket M-2015-2518883 PA Bulletin Dated July 1, 2020 (https://www.puc.pa.gov/pcdocs/1633016.pdf)

Figure 1 – WNA in the United States



Q. Why should the Commission approve the continuation of UGI Gas's WNA pilot?

A. The continuation of UGI Gas's WNA pilot is reasonable because it supports the Company's ability to recover its Commission-authorized revenue requirement, which is based on prudently planned, just and reasonable costs incurred to provide safe and reliable service. In its most recent decision in Columbia's case, issued on December 2025, the Commission has recognized the role of weather normalization mechanisms in addressing weather-related revenue volatility by allowing the continuation of Columbia's WNA pilot. Further, as designed, the Company has already taken into consideration and adopted many modifications intended to provide greater transparency and more protections to customers, as well as reasonable limitations previously supported by the parties and the Commission. For these reasons, UGI Gas's proposed WNA should be approved as filed.

VIII. CONCLUSION

Q. Please summarize your conclusions and recommendations for UGI Gas's ACOSS, class revenues, and rate design.

A. I recommend that the Commission approve the following:

- The Company's proposed ACOSS, as a realistic reflection of cost causation and the design and operating characteristics of the Company's distribution system, and as a guide to evaluate and set UGI Gas's class revenues and rate design in this proceeding.
- The Company's proposed apportionment of revenues to its rate classes, because it reasonably balances the various criteria that the Company considered in the revenue apportionment process and moves classes towards their cost to serve.
- The rate design proposed by the Company, including the proposed customer charge increases, because it reasonably balances key rate design objectives I presented earlier in my testimony, including: (1) achieving fair and equitable rate levels that are reflective of the cost to serve; (2) avoiding undue discrimination between and within rate classes; (3) developing rates that are stable and understandable; (4) creating economically efficient pricing for delivery service; (5) encouraging conservation and efficient use; and (6) recovering the revenue requirement in a manner that maintains revenue stability and minimizes year-to-year under- or over-collections.
- The Company's proposal to extend the WNA pilot program through October 2032, along with alignment in the use of a 10-year period for defining normal weather for

the WNA, sales and billing determinants in this case, which address weather-driven revenue fluctuations, as the alternative ratemaking mechanism to recovering distribution fixed costs through a fixed charge.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT JDT-1

John D. Taylor

MANAGING PARTNER

Mr. Taylor has experience with a wide range of costing, ratemaking, and regulatory activities for gas and electric utilities. He has testified numerous times on these and other issues for clients across North America. He has extensive experience with costing and pricing rates and services, regulatory planning and strategy development, revenue recovery and tracking mechanisms, merger and acquisitions analysis, new product and service development, affiliate transaction reviews, line extension policies, market assessments, litigation support, and organizational and operations reviews. He has testified on numerous occasions as an expert witness on costing and ratemaking related issues on behalf of utilities before federal, state, and provincial regulatory bodies and has extensive experience in evaluating and implementing innovative ratemaking approaches and rate design concepts.

He has also testified on return on equity, electric vehicle and battery storage programs, time-of-use rates, and the appropriate use of statistical analysis during audit testing. Mr. Taylor has led engagements relating to gas supply planning and the review of midstream transportation and storage capacity resources. He has worked as the market monitor for New England ISO's capacity market, supported the negotiation of PPAs, and supported feasibility and prudence studies of generation investments. He has also been involved in selling generating assets and distribution companies, supporting due diligence efforts, financial analyses, and regulatory approval processes.

Mr. Taylor received a master's degree in Economics from American University and holds a bachelor's degree in Environmental Economics from the University of North Carolina at Asheville.

EDUCATION

M.A., Economics, American University

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

YEARS EXPERIENCE

18

RELEVANT EXPERTISE

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

His consulting career includes Managing Partner with Atrium Economics, LLC; Principal Consultant – Advisory & Planning with Black & Veatch Management Consulting, LLC; Senior Project Manager & Principal of Concentric Energy Advisors, Inc.; and CEO of Nova Data Testing, Inc. Mr. Taylor started his career working on Capitol Hill working with NGOs that were seeking Public Private Partnerships with the Federal Government, World Bank, and International Monetary Fund to pursue various projects in developing countries.

EXPERT WITNESS TESTIMONY PRESENTATION

UNITED STATES:

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

CANADA:

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

REPRESENTATIVE EXPERIENCE

RATE DESIGN AND REGULATORY PROCEEDINGS

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

- Lead expert and witness for class costs of service studies across North America and worked on dozens of other class cost of service and rate design projects for other lead witnesses.
- Developed WNA mechanism for a gas utility including back casting results and supporting expert witness testimony and exhibits.

- Developed revenue requirement model to comply with a new performance-based formula ratemaking process for a Midwest electric utility.
- Supported the development of time of use rates, demand rates, economic development rates, load retention rates, and line extension policies.
- Analyzed and summarized allocation methodology for a shared services company.
- Assessed the reasonableness of costs through various benchmarking efforts.
- Led the effort to collect and organize plant addition documentation for six Midwest utilities associated with the state commission’s audit of rate base.
- Supported lead-lag analyses and testimonies.
- Analyzed customer usage profiles to support reclassification of rate classes for a gas utility.
- Helped conduct a marginal cost analysis to support rate design testimony.

LITIGATION SUPPORT AND EXPERT TESTIMONY

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

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

TRANSACTION EXPERIENCE

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

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

FINANCIAL ANALYSIS AND MARKET RESEARCH

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

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

UGI GAS

EXHIBIT JDT-2

UGI Utilities, Inc. – Gas Division
Before The Pennsylvania Public Utility Commission
Normal Heating Degree Days Report

Normal Heating Degree Days ("NHDDs") Report and Recommendation

This report and recommendation was prepared in compliance with item D.58.e of the Settlement Agreement in Docket Nos. R-2024-3052716, et al., which established the following:

> (…) UGI Gas will include in its filing a report and recommendation on the use of a rolling ten-year historical average period to be used to calculate its normal heating degree day amounts for purposes of the WNA, as well as the use of a ten-year historical average period for purposes of determining projected sales and billing determinants in base rates.

I. Use of a ten-year historical average NHDD for base-rate billing determinants

Based on the analysis prepared by Atrium Economics of historic HDD data from 1975–2024, shown in Figure 1,[1] adopting a ten-year historical average is recommended. The long-term regression line demonstrates a persistent downward trend in HDDs, reflecting a period of ongoing warming over the last several decades, and provides useful directional context for evaluating normalization alternatives. Compared with 15-year average normals from two different recent periods (2005–2019[2] and 2010–2024) utilized by UGI Gas, the 10-year normal (2015–2024) more closely aligns with the current climate trajectory and the most recent observed weather patterns. Importantly, the 10-year historical average produces results that are closely aligned with the central tendency implied by the regression trend.

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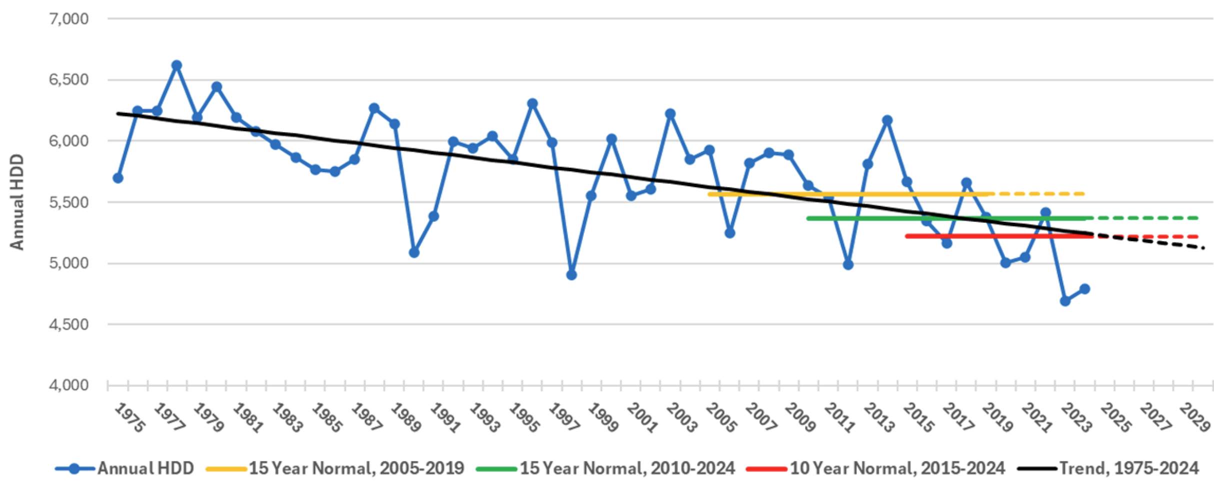
[1] Based on the composite average for the UGI Gas distribution system which is calculated as the weighted average of HDD data for the following weather stations: Wilkes-Barre/Scranton International Airport (KAVP) 22.2%, Bradford Regional Airport (KBFD) 16.3%, Reading Regional Airport (KRDG) 15.2%, Harrisburg International Airport (KMDT) 15.2%, Lancaster Airport (KLNS) 15.2%, Allentown Lehigh Valley International Airport (KABE) 15.2%, and Clearfield–Lawrence Airport (KFIG) 0.7%. The 50-year dataset utilized was obtained from AccuWeather.

[2] Period used to set NHDDs in the prior rate case for billing determinants as well as initial WNA NHDDs.

UGI Utilities, Inc. – Gas Division
Before The Pennsylvania Public Utility Commission
Normal Heating Degree Days Report

Figure 1 – Historic Annual HDD & Normalization Alternatives[3]



Using a longer period may overstate heating demand and inflate projected sales, leading to normalized usage assumptions that are not reflective of the conditions that customers are likely to experience during the fully projected future projected test year ("FPFTY") period. Therefore, a ten-year historical normal is more appropriate, more current, and more consistent with the observed trend of warming weather.

II. Use of a rolling ten-year historical average for WNA NHDD

Although the analysis above supports the conclusion that a ten-year average better represents recent warming trends, applying a rolling ten-year average specifically for WNA calculations is not recommended unless the same rolling approach is also used to determine base-rate billing determinants.

If base rates are set using a fixed ten-year normal (e.g., 2015–2024) while WNA calculations later transition to a different rolling ten-year period (e.g., 2016–2025), the WNA would compare actual weather to a baseline inconsistent with the rate-setting baseline. This misalignment could result in over- or under-correction relative to the assumptions embedded in customer rates, which

[3] Chart interpretation for grayscale / black-and-white printing:

- Annual HDD values are shown by the solid line with circular markers.
- The trend (1975–2024) is shown by a smooth solid line that slopes downward from left to right.
- The shorter horizontal reference lines near the right side of the chart are explained as follows:
    - The highest horizontal line corresponds to the 15-year normal for 2005–2019.
    - The middle horizontal line corresponds to the 15-year normal for 2010–2024.
    - The lowest horizontal line corresponds to the 10-year normal for 2015–2024.

is contrary to the WNA's objective of reconciling actual weather to the same normalized weather conditions used in establishing base rates.

Maintaining a consistent HDD baseline for both functions aligns with the overarching utility ratemaking "matching principle," which requires that the utility align revenue requirements and billing determinants within the same period and under the same assumptions when setting rates.[4] Therefore, rather than using a rolling period or defining a fixed frequency for recalculation, the Company recommends recalculating the NHDD ten-year average based on the most recently completed ten-year period that ended during the historic test year ("HTY"). In this case, that would be the ten-year period ending December 31, 2024.

III. Conclusion

In accordance with item D.58.e of the Settlement Agreement in Docket Nos. R-2024-3052716, et al.:

- It is recommended that the Company adopt a ten-year historical average HDD for determining projected sales and billing determinants in base rates, as the Figure 1 graph clearly demonstrates that a ten-year period reflects recent warming trends and closely tracks the directional signal indicated by the long-term regression analysis making it a reasonable and supportable normalization period.
- It is not recommended to adopt a rolling ten-year historical average for WNA calculations unless the Commission also intends to adopt the use of a rolling period for base-rate normalization between rate cases. Using different normals for rate-setting and WNA reconciliation could introduce inconsistency and unintended outcomes.

This approach maintains methodological integrity, aligns with observed weather trends, and complies with the Settlement's reporting requirements.

[4] National Regulatory Research Institute, *Future Test Years: Evidence from State Utility Commissions*, Report No. 13-10, at 5 (Oct. 2013), available at https://pubs.naruc.org/pub/FA86C105-05F5-9766-BC78-29829AC50361

UGI GAS

EXHIBIT JDT-3

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2022 NOV	2022 DEC	2023 JAN	2023 FEB	2023 MAR	2023 APR	2023 MAY
R/RT and N/NT	Total Number of Bills	657,848	690,784	702,630	637,189	757,679	644,611	723,767
R/RT and N/NT	Number of Bills with WNA	494,845	335,446	609,400	605,793	709,079	588,357	503,561
R/RT and N/NT	Billed WNA Volume Adj (ccf)	3,349,172	2,246,101	13,453,826	24,268,267	20,479,847	9,423,352	1,105,684
R/RT and N/NT	Billed WNA Revenue Adj ($)	$ 1,536,159	$ 1,021,184	$ 6,152,516	$ 10,999,357	$ 9,194,818	$ 4,311,784	$ 487,940
R/RT	Total Number of Bills	591,744	621,058	631,171	573,017	680,249	580,105	650,634
R/RT	Number of Bills with WNA	447,992	301,310	550,669	547,010	639,251	532,148	455,315
R/RT	Billed WNA Volume Adj (ccf)	2,153,568	1,439,549	8,647,924	15,124,980	12,723,261	6,098,146	566,866
R/RT	Billed WNA Revenue Adj ($)	$ 1,080,819	$ 716,506	$ 4,334,131	$ 7,543,041	$ 6,319,132	$ 3,049,904	$ 283,485
N/NT	Total Number of Bills	66,104	69,726	71,459	64,172	77,430	64,506	73,133
N/NT	Number of Bills with WNA	46,853	34,136	58,731	58,783	69,828	56,209	48,246
N/NT	Billed WNA Volume Adj (ccf)	1,195,604	806,552	4,805,902	9,143,287	7,756,586	3,325,206	538,818
N/NT	Billed WNA Revenue Adj ($)	$ 455,340	$ 304,678	$ 1,818,385	$ 3,456,316	$ 2,875,687	$ 1,261,880	$ 204,455

Data Presented By Calendar Month

Region	Reporting Item	2022 NOV	2022 DEC	2023 JAN	2023 FEB	2023 MAR	2023 APR	2023 MAY
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	692	987	1,166	998	858	447	181
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	594	982	846	800	791	341	206
UGI Gas - North	Calendar Month - Normal Heating Degree Days	837	1,130	1,313	1,154	1,027	605	303
UGI Gas - North	Calendar Month - Actual Heating Degree Days	725	1,088	1,001	878	942	459	299
UGI Gas - South	Calendar Month - Normal Heating Degree Days	632	905	1,066	911	744	365	130
UGI Gas - South	Calendar Month - Actual Heating Degree Days	555	933	775	701	673	273	129
UGI Gas - West	Calendar Month - Normal Heating Degree Days	781	1,067	1,230	1,056	896	498	220
UGI Gas - West	Calendar Month - Actual Heating Degree Days	712	1,102	948	823	876	423	249

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2022 NOV	2022 DEC	2023 JAN	2023 FEB	2023 MAR	2023 APR	2023 MAY
R/RT and N/NT	Bill Count Total	661,595	682,807	699,952	639,135	760,059	640,522	722,158
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	495,114	263,607	612,172	607,639	710,022	583,773	246,153
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	74.8%	38.6%	87.5%	95.1%	93.4%	91.1%	34.1%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	21,005	60,755	243	92	531	311	247,613
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	3.2%	8.9%	0.0%	0.0%	0.1%	0.0%	34.3%
R/RT and N/NT	Bill Count without WNA Charges/Credits	145,476	358,445	87,537	31,404	49,506	56,438	228,392
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	22.0%	52.5%	12.5%	4.9%	6.5%	8.8%	31.6%

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2023 JUN	2023 JUL	2023 AUG	2023 SEP	2023 OCT	2023 NOV	2023 DEC
R/RT and N/NT	Total Number of Bills	679,115	672,095	750,421	666,627	712,202	673,107	669,970
R/RT and N/NT	Number of Bills with WNA	5,354	72	5	15	211,543	456,224	460,215
R/RT and N/NT	Billed WNA Volume Adj (ccf)	(18,930)	723	(1,020)	1,221	568,839	2,700,175	4,775,793
R/RT and N/NT	Billed WNA Revenue Adj ($)	$ (7,892)	$ 22	$ (393)	$ 454	$ 258,355	$ 1,280,999	$ 2,267,281
R/RT	Total Number of Bills	610,673	604,474	673,177	598,915	640,299	605,796	602,536
R/RT	Number of Bills with WNA	4,668	64	1	14	187,839	412,231	413,761
R/RT	Billed WNA Volume Adj (ccf)	(6,314)	(1,522)	36	(99)	324,373	1,828,070	3,242,561
R/RT	Billed WNA Revenue Adj ($)	$ (3,158)	$ (790)	$ 10	$ (50)	$ 164,836	$ 946,337	$ 1,678,848
N/NT	Total Number of Bills	68,442	67,621	77,244	67,712	71,903	67,311	67,434
N/NT	Number of Bills with WNA	686	8	4	1	23,704	43,993	46,454
N/NT	Billed WNA Volume Adj (ccf)	(12,616)	2,245	(1,057)	1,320	244,467	872,105	1,533,232
N/NT	Billed WNA Revenue Adj ($)	$ (4,735)	$ 812	$ (402)	$ 504	$ 93,519	$ 334,662	$ 588,432

Data Presented By Calendar Month

Region	Reporting Item	2023 JUN	2023 JUL	2023 AUG	2023 SEP	2023 OCT	2023 NOV	2023 DEC
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	35	3	10	96	376	692	987
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	51	0	5	107	320	724	786
UGI Gas - North	Calendar Month - Normal Heating Degree Days	104	42	65	202	523	837	1,130
UGI Gas - North	Calendar Month - Actual Heating Degree Days	111	8	32	159	407	773	843
UGI Gas - South	Calendar Month - Normal Heating Degree Days	11	0	2	54	306	632	905
UGI Gas - South	Calendar Month - Actual Heating Degree Days	6	0	0	47	261	647	728
UGI Gas - West	Calendar Month - Normal Heating Degree Days	54	13	26	147	453	781	1,067
UGI Gas - West	Calendar Month - Actual Heating Degree Days	80	1	18	144	408	691	763

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2023 JUN	2023 JUL	2023 AUG	2023 SEP	2023 OCT	2023 NOV	2023 DEC
R/RT and N/NT	Bill Count Total	0	0	0	0	727,098	668,042	663,445
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	0	0	0	0	184,540	431,193	470,364
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	0.0%	0.0%	0.0%	0.0%	25.4%	64.5%	70.9%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	0	0	0	0	55,602	7,234	3,747
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	0.0%	0.0%	0.0%	0.0%	7.6%	1.1%	0.6%
R/RT and N/NT	Bill Count without WNA Charges/Credits	0	0	0	0	486,956	229,615	189,334
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	0.0%	0.0%	0.0%	0.0%	67.0%	34.4%	28.5%

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2024 JAN	2024 FEB	2024 MAR	2024 APR	2024 MAY	2024 JUN	2024 JUL
R/RT and N/NT	Total Number of Bills	724,592	681,980	682,512	725,300	721,146	679,265	734,574
R/RT and N/NT	Number of Bills with WNA	681,099	645,482	646,595	664,738	586,262	30,534	499
R/RT and N/NT	Billed WNA Volume Adj (ccf)	17,463,903	19,299,656	25,201,442	10,508,920	6,187,180	451,727	(15,683)
R/RT and N/NT	Billed WNA Revenue Adj ($)	$ 8,167,157	$ 9,077,681	$ 11,847,340	$ 4,906,085	$ 2,918,063	$ 199,054	$ (6,443)
R/RT	Total Number of Bills	651,291	613,382	613,650	652,736	648,873	611,382	660,330
R/RT	Number of Bills with WNA	614,798	583,134	583,894	601,058	531,639	27,271	314
R/RT	Billed WNA Volume Adj (ccf)	10,942,912	12,481,667	16,251,546	6,519,900	4,057,503	191,750	(2,927)
R/RT	Billed WNA Revenue Adj ($)	$ 5,664,520	$ 6,461,106	$ 8,412,549	$ 3,375,181	$ 2,100,742	$ 99,280	$ (1,548)
N/NT	Total Number of Bills	73,301	68,598	68,862	72,564	72,273	67,883	74,244
N/NT	Number of Bills with WNA	66,301	62,348	62,701	63,680	54,623	3,263	185
N/NT	Billed WNA Volume Adj (ccf)	6,520,991	6,817,989	8,949,897	3,989,020	2,129,677	259,977	(12,756)
N/NT	Billed WNA Revenue Adj ($)	$ 2,502,636	$ 2,616,575	$ 3,434,791	$ 1,530,905	$ 817,321	$ 99,773	$ (4,895)

Data Presented By Calendar Month

Region	Reporting Item	2024 JAN	2024 FEB	2024 MAR	2024 APR	2024 MAY	2024 JUN	2024 JUL
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	1,166	1,031	858	447	181	35	3
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	1,026	860	648	378	111	8	0
UGI Gas - North	Calendar Month - Normal Heating Degree Days	1,313	1,193	1,027	605	303	104	42
UGI Gas - North	Calendar Month - Actual Heating Degree Days	1,133	920	754	474	157	56	8
UGI Gas - South	Calendar Month - Normal Heating Degree Days	1,066	941	744	365	130	11	0
UGI Gas - South	Calendar Month - Actual Heating Degree Days	944	771	559	304	82	1	0
UGI Gas - West	Calendar Month - Normal Heating Degree Days	1,230	1,091	896	498	220	54	13
UGI Gas - West	Calendar Month - Actual Heating Degree Days	1,052	879	675	420	141	36	2

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2024 JAN	2024 FEB	2024 MAR	2024 APR	2024 MAY	2024 JUN	2024 JUL
R/RT and N/NT	Bill Count Total	731,791	680,203	676,080	730,279	728,083	0	0
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	688,451	643,676	639,931	666,340	587,492	0	0
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	94.1%	94.6%	94.7%	91.2%	80.7%	0.0%	0.0%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	508	3	369	899	175	0	0
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%
R/RT and N/NT	Bill Count without WNA Charges/Credits	42,832	36,524	35,780	63,040	140,416	0	0
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	5.9%	5.4%	5.3%	8.6%	19.3%	0.0%	0.0%

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2024 AUG	2024 SEP	2024 OCT	2024 NOV	2024 DEC	2025 JAN	2025 FEB
R/RT and N/NT	Total Number of Bills	728,175	669,948	751,839	652,863	690,188	742,545	647,127
R/RT and N/NT	Number of Bills with WNA	128	(2)	288,385	559,418	427,644	415,714	426,511
R/RT and N/NT	Billed WNA Volume Adj (ccf)	(6,104)	(4,027)	1,723,324	8,405,258	2,957,527	(3,100,199)	(3,255,501)
R/RT and N/NT	Billed WNA Revenue Adj ($)	$ (2,527)	$ (1,704)	$ 795,006	$ 3,968,165	$ 1,388,659	$ (1,431,770)	$ (1,513,534)
R/RT	Total Number of Bills	653,863	603,292	674,662	588,776	621,163	667,793	582,802
R/RT	Number of Bills with WNA	39	(4)	259,212	508,986	385,192	373,211	384,270
R/RT	Billed WNA Volume Adj (ccf)	(1,295)	(1,207)	996,923	5,538,982	1,887,330	(1,812,212)	(1,975,349)
R/RT	Billed WNA Revenue Adj ($)	$ (675)	$ (621)	$ 516,234	$ 2,868,153	$ 977,916	$ (937,443)	$ (1,022,233)
N/NT	Total Number of Bills	74,312	66,656	77,177	64,087	69,025	74,752	64,325
N/NT	Number of Bills with WNA	89	2	29,173	50,432	42,452	42,503	42,241
N/NT	Billed WNA Volume Adj (ccf)	(4,809)	(2,820)	726,400	2,866,276	1,070,197	(1,287,987)	(1,280,152)
N/NT	Billed WNA Revenue Adj ($)	$ (1,852)	$ (1,082)	$ 278,772	$ 1,100,013	$ 410,743	$ (494,327)	$ (491,302)

Data Presented By Calendar Month

Region	Reporting Item	2024 AUG	2024 SEP	2024 OCT	2024 NOV	2024 DEC	2025 JAN	2025 FEB
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	10	96	376	692	987	1,166	998
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	19	48	315	627	1,030	1,266	999
UGI Gas - North	Calendar Month - Normal Heating Degree Days	65	202	523	837	1,130	1,313	1,154
UGI Gas - North	Calendar Month - Actual Heating Degree Days	43	79	406	681	1,061	1,364	1,103
UGI Gas - South	Calendar Month - Normal Heating Degree Days	2	54	306	632	905	1,066	911
UGI Gas - South	Calendar Month - Actual Heating Degree Days	6	25	244	516	912	1,173	891
UGI Gas - West	Calendar Month - Normal Heating Degree Days	26	147	453	781	1,067	1,230	1,056
UGI Gas - West	Calendar Month - Actual Heating Degree Days	25	74	388	655	1,021	1,310	1,019

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2024 AUG	2024 SEP	2024 OCT	2024 NOV	2024 DEC	2025 JAN	2025 FEB
R/RT and N/NT	Bill Count Total	0	0	766,628	629,649	703,828	730,792	653,438
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	0	0	323,925	546,068	319,684	32,920	22,900
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	0.0%	0.0%	42.3%	86.7%	45.4%	4.5%	3.5%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	0	0	1,074	38	107,240	386,799	388,472
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	0.0%	0.0%	0.1%	0.0%	15.2%	52.9%	59.5%
R/RT and N/NT	Bill Count without WNA Charges/Credits	0	0	441,629	83,543	276,904	311,073	242,066
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	0.0%	0.0%	57.6%	13.3%	39.3%	42.6%	37.0%

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2025 MAR	2025 APR	2025 MAY	2025 JUN	2025 JUL	2025 AUG	2025 SEP
R/RT and N/NT	Total Number of Bills	716,321	709,895	709,872	713,760	735,660	705,888	701,197
R/RT and N/NT	Number of Bills with WNA	522,521	637,555	484,433	19,813	57	18	(25)
R/RT and N/NT	Billed WNA Volume Adj (ccf)	9,366,210	12,277,590	6,286,389	45,793	(12,712)	(2,385)	(3,696)
R/RT and N/NT	Billed WNA Revenue Adj ($)	$ 4,406,295	$ 5,750,700	$ 2,950,691	$ 21,098	$ (5,680)	$ (1,002)	$ (1,347)
R/RT	Total Number of Bills	644,559	639,457	638,553	642,608	661,589	635,194	631,059
R/RT	Number of Bills with WNA	470,537	576,765	439,236	17,805	9	18	(20)
R/RT	Billed WNA Volume Adj (ccf)	6,060,757	7,757,939	4,018,315	20,549	(10,066)	(1,113)	(2,077)
R/RT	Billed WNA Revenue Adj ($)	$ 3,137,726	$ 4,016,147	$ 2,080,248	$ 11,410	$ (4,836)	$ (514)	$ (1,075)
N/NT	Total Number of Bills	71,762	70,438	71,319	71,152	74,071	70,694	70,138
N/NT	Number of Bills with WNA	51,984	60,790	45,197	2,008	48	-	(5)
N/NT	Billed WNA Volume Adj (ccf)	3,305,453	4,519,651	2,268,074	25,244	(2,646)	(1,272)	(1,619)
N/NT	Billed WNA Revenue Adj ($)	$ 1,268,569	$ 1,734,552	$ 870,443	$ 9,688	$ (844)	$ (488)	$ (272)

Data Presented By Calendar Month

Region	Reporting Item	2025 MAR	2025 APR	2025 MAY	2025 JUN	2025 JUL	2025 AUG	2025 SEP
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	858	447	181	35	3	10	96
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	667	425	219	31	3	43	38
UGI Gas - North	Calendar Month - Normal Heating Degree Days	1,027	605	303	104	42	65	202
UGI Gas - North	Calendar Month - Actual Heating Degree Days	748	496	318	61	18	116	175
UGI Gas - South	Calendar Month - Normal Heating Degree Days	744	365	130	11	0	2	54
UGI Gas - South	Calendar Month - Actual Heating Degree Days	553	318	114	15	0	11	8
UGI Gas - West	Calendar Month - Normal Heating Degree Days	896	498	220	54	13	26	147
UGI Gas - West	Calendar Month - Actual Heating Degree Days	698	464	268	39	1	65	87

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2025 MAR	2025 APR	2025 MAY	2025 JUN	2025 JUL	2025 AUG	2025 SEP
R/RT and N/NT	Bill Count Total	709,220	714,780	708,205	0	0	0	0
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	535,815	638,314	465,363	0	0	0	0
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	75.5%	89.3%	65.7%	0.0%	0.0%	0.0%	0.0%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	26	2,067	8,174	0	0	0	0
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	0.0%	0.3%	1.2%	0.0%	0.0%	0.0%	0.0%
R/RT and N/NT	Bill Count without WNA Charges/Credits	173,379	74,399	234,668	0	0	0	0
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	24.4%	10.4%	33.1%	0.0%	0.0%	0.0%	0.0%

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2025 OCT
R/RT and N/NT	Total Number of Bills	762,059
R/RT and N/NT	Number of Bills with WNA	281,147
R/RT and N/NT	Billed WNA Volume Adj (ccf)	803,710
R/RT and N/NT	Billed WNA Revenue Adj ($)	$ 374,502
R/RT	Total Number of Bills	684,790
R/RT	Number of Bills with WNA	253,447
R/RT	Billed WNA Volume Adj (ccf)	497,914
R/RT	Billed WNA Revenue Adj ($)	$ 257,422
N/NT	Total Number of Bills	77,269
N/NT	Number of Bills with WNA	27,700
N/NT	Billed WNA Volume Adj (ccf)	305,796
N/NT	Billed WNA Revenue Adj ($)	$ 117,080

Data Presented By Calendar Month

Region	Reporting Item	2025 OCT
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	341
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	398
UGI Gas - North	Calendar Month - Normal Heating Degree Days	473
UGI Gas - North	Calendar Month - Actual Heating Degree Days	530
UGI Gas - South	Calendar Month - Normal Heating Degree Days	279
UGI Gas - South	Calendar Month - Actual Heating Degree Days	309
UGI Gas - West	Calendar Month - Normal Heating Degree Days	429
UGI Gas - West	Calendar Month - Actual Heating Degree Days	469

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2025 OCT
R/RT and N/NT	Bill Count Total	770,361
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	225,621
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	29.3%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	83,898
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	10.9%
R/RT and N/NT	Bill Count without WNA Charges/Credits	460,842
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	59.8%

UGI GAS

EXHIBIT JDT-4

UGI Utilities, Inc. – Gas Division
Before The Pennsylvania Public Utility Commission
WNA Mechanism Policy Factors

#	Statement of Policy	Company's Response
1	How the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.	UGI Gas's 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. The Company 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 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 a rate design that affords the Company the opportunity to recover all fixed costs in a fixed monthly charge, the WNA mechanism better aligns distribution revenues with cost causation principles.
2	How the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.	While the WNA mechanism does not directly alter customer usage patterns or system peak demand, it plays an important enabling role in the efficient utilization of the Company's gas distribution capacity. Gas system capacity is designed to meet peak-day requirements driven by weather-sensitive load. Traditional volumetric recovery exposes the Company to revenue volatility when conservation, or efficiency efforts reduce throughput, even though peak-driven infrastructure costs remain largely unchanged. By stabilizing revenues, the WNA mechanism removes disincentives to support peak-reflective rate design and conservation initiatives that can moderate peak demand growth. Over time, this alignment supports more efficient use of existing system capacity while preserving the Company's ability to make prudent investments necessary to maintain safe and reliable service.
3	Whether the ratemaking mechanism and rate design reflect the level of demand associated with the	Customer specific usage factors corresponding to their individual demand is continually updated through the WNA formula and reflects the level of demand associated with the customer's anticipated consumption levels. In this proceeding, the Company is also proposing to set Normal Heating Degree Days using a 10-year

UGI Utilities, Inc. – Gas Division
Before The Pennsylvania Public Utility Commission
WNA Mechanism Policy Factors

#	Statement of Policy	Company's Response
	customer's anticipated consumption levels.	average rather than a 15-year average, which more accurately captures recent warming trends. Using a more current weather baseline ensures that the WNA formula better aligns normalized usage with customers' anticipated consumption levels under today's climate conditions. Please refer to UGI Gas Exhibit JDT-2.
4	How the ratemaking mechanism and rate design limit or eliminate interclass and intraclass cost shifting.	UGI Gas's WNA is applied on a customer-specific basis and is designed to be revenue-neutral within each customer class, such that it does not create or exacerbate cross-subsidization either within or across classes.
5	How the ratemaking mechanism and rate design limit or eliminate disincentives for the promotion of efficiency programs.	The Company's WNA only addresses variations due to weather and does not affect customers' ability to pursue energy efficiency measures. 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	How the ratemaking mechanism and rate design impact customer incentives to employ efficiency measures and distributed energy resources.	Customers retain strong incentives to reduce usage because the commodity and other charges remain volumetric. The proposed WNA does not eliminate these price signals, so lower usage still results in lower bills.
7	How the ratemaking mechanism and rate design impact low-income customers and support consumer assistance programs.	In accordance with the Settlement Agreement in Docket Nos. R-2024-3052716, et al., the current WNA mechanism does not apply to low-income customers enrolled in the Company's Customer Assistance Program ("CAP").
8	How the ratemaking mechanism and rate design impact customer rate stability principles.	The American Gas Association Gas Rate Fundamentals book (Pages 152 – 156) states: "The goal of stability recognizes historical relationships among customers in terms of the proportion of system costs each customer group bears. Stability leads to a policy of gradualism in rate changes if substantial increases (or decreases) are

UGI Utilities, Inc. – Gas Division
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#	Statement of Policy	Company's Response
		called for in the context of a single rate case. Changes in gas utility pricing policy should be imposed gradually so that customers can adjust and any adverse impacts on the customers' operation are minimized." The WNA mechanism provides customers with more stable annual bills and directly mitigates volatility in their monthly costs. Customers would pay for the costs assigned to the volumetric base rate in the most recent rate case and customers would not pay more or less than that amount (outside of any established WNA deadband) solely because the actual weather for the month the customers are billed is different than the weather used to determine the rate design of the volumetric base rate.
9	How weather impacts utility revenue under the ratemaking mechanism and rate design.	The Company's WNA adjusts customers' bills due to variations from normal weather during the heating season months of October through April, and it mitigates the revenue effect of weather on the original rate design of the volumetric base rate (outside of any established deadband). 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	How the ratemaking mechanism and rate design impact the frequency of rate case filings and affect regulatory lag.	The WNA does not impact the Company's rate case frequency nor it effects regulatory lag.
11	If or how the ratemaking mechanism and rate design interact with other revenue sources (e.g., surcharges).	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 April. 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.

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#	Statement of Policy	Company's Response
12	Whether the alternative ratemaking mechanism and rate design include appropriate consumer protections.	UGI Gas's WNA includes several consumer protections to ensure fairness and transparency, as follows: a. No Over-Recovery of Revenue: The WNA mechanism operates with a deadband and outside of the deadband the WNA results 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. b. No Cross-Subsidization: The WNA is customer-specific. c. Regulatory Oversight: The WNA is subject to Commission review and regulatory reporting requirements to ensure compliance with approved revenue stabilization objectives and to protect consumers from unintended rate impacts. d. Customer Transparency and Education: UGI Gas has reviewed the WNA Pilot communication materials, and it has expanded its reporting as agreed upon in Docket No. R-2024-3052716 settlement. Please refer to the direct testimony of Company witness Meilinger, UGI Gas Statement No. 12, for details.
13	Whether the alternative ratemaking mechanism and rate design are understandable to consumers.	The WNA is not a new concept to the regulated utility industry and similar versions have been successfully implemented by other Pennsylvania natural gas distribution companies. The WNA tariff provides detailed information to the customer of how the mechanism would work and the adjustments are displayed separately on bills and the Company maintains a detailed FAQ related to the WNA on its website, ensuring transparency. As indicated above, UGI Gas has reviewed the WNA Pilot communication materials, and it has expanded its reporting as agreed upon in Docket No. R-2024-3052716 settlement. Please refer to the direct testimony of Company witness Meilinger, UGI Gas Statement No. 12, for details.
14	How the ratemaking mechanism and rate design will support improvements in utility reliability.	The proposed WNA targets the revenue requirement that would have been already subject to scrutiny and approved by the Commission, meaning that its prudency and reasonableness would have been reviewed and deemed appropriate to support reliability driven

UGI Utilities, Inc. – Gas Division
Before The Pennsylvania Public Utility Commission
WNA Mechanism Policy Factors

#	Statement of Policy	Company's Response
		initiatives. The proposed WNA would help minimize the volatility of the recovery of these costs.

UGI GAS STATEMENT NO. 12

BRIAN J. MEILINGER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 12

Direct Testimony of
Brian J. Meilinger

Topics Addressed:	**Universal Service Programs** **Strategic Initiatives** **Low-Income Customer Counts** **Weather Normalization Adjustment** **("WNA") Communications Revisions**

Dated: January 28, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Brian J. Meilinger. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed, and what is your current position?

A. I am employed by UGI Utilities, Inc. ("UGI") as Director, Customer Programs & Public Relations. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric") and the Gas Division ("UGI Gas" or the "Company"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC"). In this role, I am responsible for directing the Company's Energy Efficiency & Conservation, Universal Service, Community Relations, and Public Relations Departments.

Q. What is your educational and professional background?

A. I graduated from Ursinus College with a B.A. in Economics & Business Administration and Saint Joseph's University with an MBA in Finance. I started my employment with UGI in 2012. My full resume is attached as UGI Gas Exhibit BJM-1.

Q. On whose behalf are you testifying in this proceeding?

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

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to explain the significant efforts that UGI Gas has undertaken to make sure that its customers have access to affordable utility service. Customer affordability is a core focus at UGI Gas. This is evident from the success of the Company's many customer programs, as well as the Company's commitment to voluntarily donate $1 million annually per year for the next three years (FY27, FY28, and FY29) to Operation Share. I will discuss these efforts in greater detail below.

Q. How is your direct testimony organized?

A. My direct testimony (1) describes how UGI's Universal Service Programs have helped customers afford their utility bills, (2) provides an overview of strategic initiatives to drive increased customer participation in Universal Service Programs and address customer affordability concerns, including the Company's commitment to donate $1 million annually to Operation Share for the next three years; (3) provides data regarding the Company's low-income customer counts, and (4) addresses the Company's compliance with paragraph 58(a) of the Joint Petition for Approval of Settlement of All Issues at Docket No. R-2024-3052716 ("2025 Settlement") regarding Weather Normalization Adjustment ("WNA") pilot communications.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes, UGI Gas Exhibit BJM-1 provides a list of the proceedings in which I have testified.

II. UNIVERSAL SERVICE PROGRAMS

Q. Does UGI Gas have a Universal Service and Energy Conservation Program ("USECP")?

A. Yes. The USECP is a comprehensive plan that covers the Company's universal service programs. In accordance with the Commission's Universal Service and Energy Conservation Reporting Requirements at 52 Pa. Code §§ 54.71 – 54.78 and §§ 62.1 – 62.8, UGI Gas submits a USECP every five years for the Commission's review and approval.

Q. Did UGI Gas recently file its USECP for the five-year period January 1, 2026, through December 31, 2030?

A. Yes. The Company filed its 2026-2030 USECP on April 1, 2025, at Docket Nos. M-2025-3054362 and M-2025-3054366. The parties submitted comments on October 6, 2025, and reply comments on November 10, 2025.

Q. Is UGI Gas proposing any changes to its USECP as a part of this base rate proceeding?

A. No. However, UGI Gas intends to update its USECP with the $1 million donation to Operation Share through 2029 as described in my testimony.

Q. Can you please provide an overview of the Company's USECP?

A. The Company offers four programs under its USECP that assist low income customers: (1) Customer Assistance Program ("CAP"); (2) the Hardship Fund (i.e., Operation Share); (3) Low Income Usage Reduction Program ("LIURP"); and (4) the Customer Assistance Referral and Evaluation Services ("CARES").

CAP provides discounted monthly bills and arrearage forgiveness for low-income customers at or below 150% Federal Poverty Income Guidelines ("FPIG"). CAP payments are calculated based on a percentage of a customer's monthly income, also known as a Percentage of Income ("PIP") amount, or a CAP participant's average monthly bill, if lower. For gas heating customers, maximum monthly CAP payments are set at 4% of income for customers with household incomes between 0-50%, and 6% of income for customers with household incomes between 51-150% FPIG. CAP participants with no income are placed on the monthly minimum payment which is $25 for gas heating and $15 for non-heating gas service.

Operation Share provides grants of up to $600 for eligible customers with household incomes up to 250% FPIG who are having difficulty paying their bill. In special circumstances, the Company may provide exceptions to the maximum grant amount of $600. In order to qualify for a grant, the following criteria must be met:

- Customer must have a residential account with their premise being the customer's primary residence;
- The customer must have an active heating or non-heating account;
- A customer must not have received the maximum Operation Share grant amount in the prior 12 months, unless in situations of special circumstance as determined by the Company;
- A customer must have an outstanding balance;
- A customer must provide proof of identification and adequate information to demonstrate the inability to pay their bill;
- Customers whose service has been terminated must contact the UGI Credit Department to discuss their options as Community Based Organizations ("CBOs") cannot provide benefits on an inactive account.

The Company's LIURP offers weatherization services to low-income customers with household incomes up to 200% FPIG. To qualify, a customer must have above average annual usage, defined as exceeding the average residential threshold by 30%, or 877 CCF. Additionally, a customer must not have received LIURP in the prior 7 years and must have twelve months of continuous service.

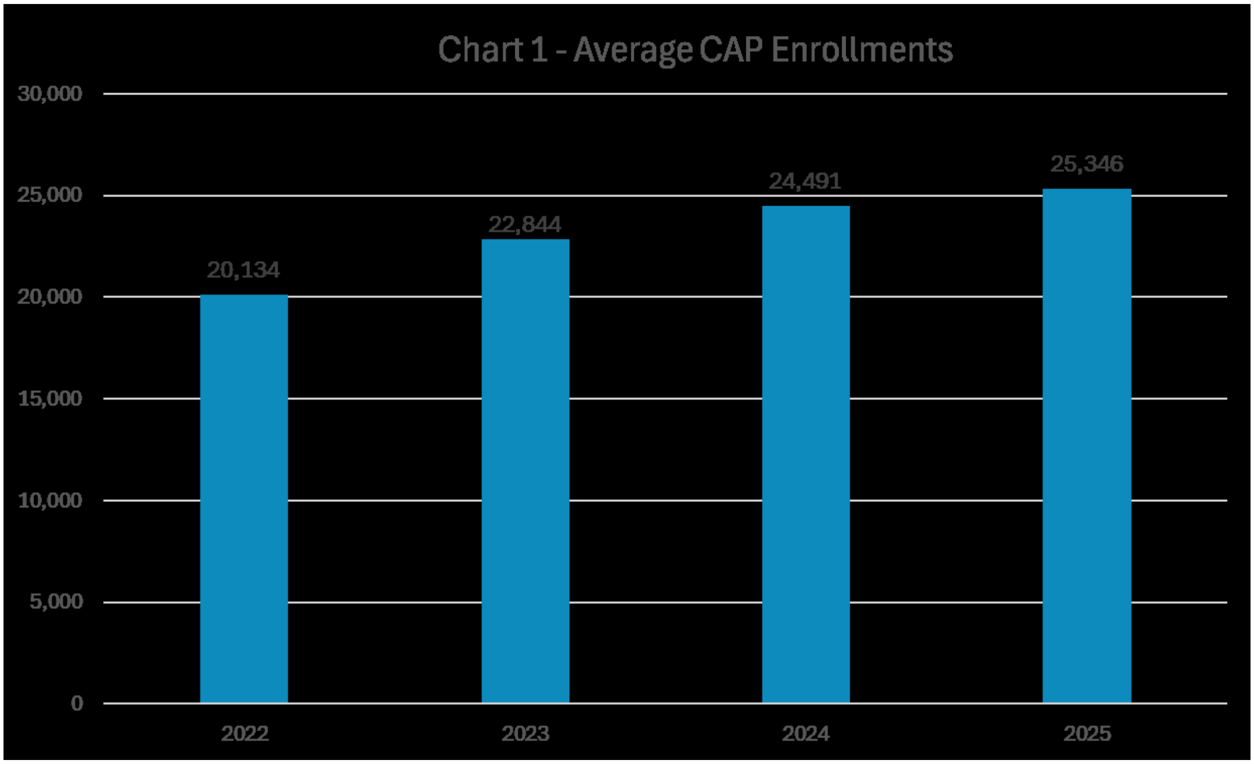
CARES offers customers referral services to other community support programs which may include, but are not limited to LIHEAP, budget counseling, State Weatherization, Office of Aging, etc. There are no income requirements to participate in CARES.

Q. Has the Company's CAP helped low-income customers afford their utility bills?

A. Yes. The Company's CAP has performed well both in terms of increasing customer enrollments and helping make customers' bills more affordable.

Q. How has the Company's CAP enrollment increased from prior years?

A. The Company's average CAP enrollment for 2025 was 25,346 customers, which represents a 3% increase over 2024, and a 26% increase over 2022 CAP average enrollment of 20,134. Please see Chart 1 below for details regarding the growth in UGI Gas CAP enrollments since 2022.



The significant growth in CAP enrollments is a direct result of the Company's efforts to reach as many low-income customers as possible. For instance, the Company undertook a project to assess, identify, and engage with low-income customers in 2023-2024. The Company utilized the services of Experian to help identify potential low-income customers and then performed targeted marketing via email and direct mail with a call to action to visit the Company's CAP landing page to screen for program eligibility. This campaign resulted in approximately 780 customers enrolling in CAP.

Q. How has CAP worked to make customers' bills more affordable?

A. In 2024, the Company provided its CAP customers with approximately $3.8 million of Pre-Program Arrearage ("PPA") forgiveness and $10.6 million CAP Shortfall and in 2025, $3.7 million and $15.9 million respectively. The PPA component of CAP is a benefit to customers, as it provides arrearage forgiveness over a 36-month time period if customers continue making timely and in full monthly CAP payments. For instance, a customer entering CAP with $2,500 of arrearage would have $69.44 ($2,500/36) forgiven each month assuming the customer continues making monthly CAP payments in full. CAP Shortfall is another significant benefit, as customers are not responsible for monthly costs incurred above the CAP bill. For example, a CAP customer on the Percent of Income Plan with a $50 per month CAP bill that incurs a usage-based bill calculated at $150, would not be responsible for the entire bill amount, just the $50.

Q. What are the Company's plans to continue building upon the growth in CAP customer enrollments?

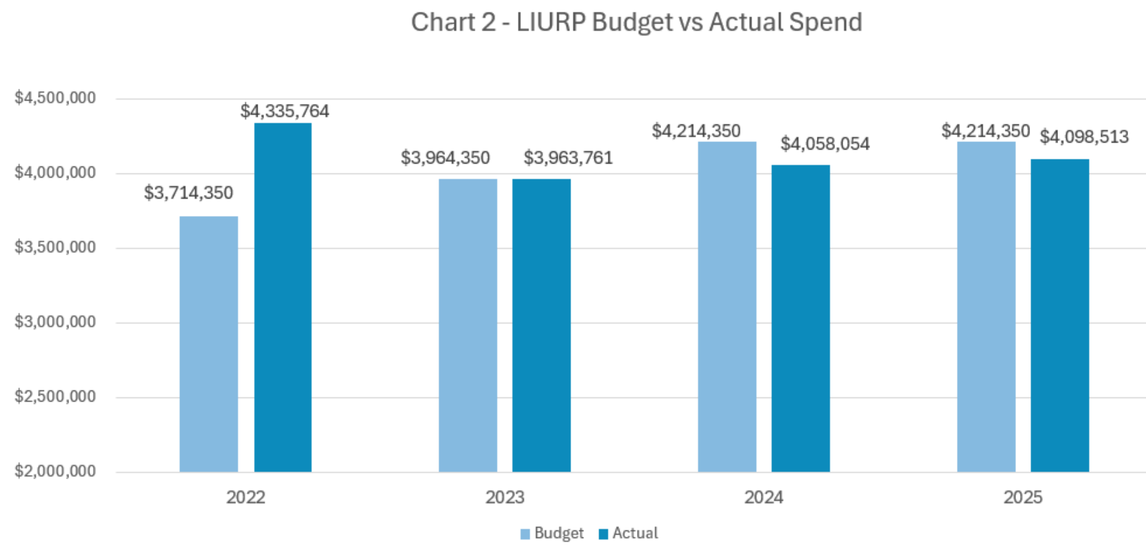
A. The Company continues to focus on increasing customer enrollment in CAP through its marketing efforts that include ongoing general outreach efforts throughout the year and twice a year personalized outreach via email and direct mail to customers who are self-certified low income and to LIHEAP recipients that are not currently enrolled in CAP. The Company is also continuing its Low Income Customer Assessment and Outreach Pilot through 2028 as further described in section III below.

Q. How has the Company's LIURP helped customers?

A. The Company has successfully partnered with 15 weatherization CBOs and contractors to maximize its PUC-approved budgets. Since 2022, the following results were achieved which indicate that UGI Gas has been highly effective at achieving spending to budget:

- 2022: 117% of budget utilization (rollover of unspent budget from prior year)
- 2023: 100% of budget utilization

- 2024: 96% of budget utilization
- 2025: 97% budget utilization



During the 2022-2025 timeframe, the Company's weatherization contractors completed 2,133 LIURP jobs, or an average of 533 per year. As part of the 2025 Settlement, Paragraph 60(a), the Company has agreed to increase its budget effective January 1, 2026, by $1,000,000 from $4,214,350 to $5,214,350 with any unspent budget rolling over to the next year wherein it will make best efforts to spend it within the first six months of the following year. In addition, UGI Gas will comply with the final order issued in the LIURP rulemaking proceeding at Docket No. L-2016-2557886.

Q. Has the Company's Operation Share Program helped customers?

A. Yes. During the 2022-2025 timeframe, the Company has issued nearly 12,000 Operation Share grants for approximately $4.2 million to customers needing assistance. Furthermore, as part of the UGI Gas 2025 Settlement, Paragraph 62(a), the Company increased its Operation Share commitment by $500,000 from $584,500 to $1,084,500 and was permitted to increase the annual budget reallocation limitation across the geographic footprint of its former three rate districts from 5% to 50% (Paragraph 62(b)). Collectively, these settlement provisions provide an increased budget and greater flexibility to reallocate budgets and avoid stranded funding by region, which has occurred in the past.

Q. Has UGI Gas undertaken any additional voluntary efforts to support its low-income customers?

A. Yes. In November 2025, in an attempt to offset impacts to low-income customers due to LIHEAP funding delays resulting from the Federal Government shutdown, the Company made a one-time supplemental donation of $500,000, allocated between the Gas and Electric Divisions, to Operation Share for Fiscal Year 2026. I describe the LIHEAP funding delay in greater detail below. This additional donation brought UGI's contribution to Operation Share to more than $1.5 million for Fiscal Year 2026.

Q. Are there other programs available to assist payment-troubled customers?

A. Yes. In addition to the UGI Gas Universal Service Programs, there are external programs to support payment-troubled customers. These state and federally funded programs include, but are not limited to:

- The Low Income Home Energy Assistance Program ("LIHEAP") provides energy grants which help customers restore and/or maintain service, as well as repair or replace broken heating equipment. The LIHEAP season typically runs from November 1 through April 1. However, in some years, the season is extended pending funding availability. UGI Gas receives a weekly customer voucher file from the Department of Human Services ("DHS") which contains details of the grant amounts, typically up to a maximum of $1,000 per customer, who have gone through DHS's income verification processes and are determined to be at or below 150% FPIG. UGI Gas then applies these grant amounts to customer accounts.

- The Pennsylvania Weatherization Assistance Program (“WAP”) reduces energy costs and increases comfort while ensuring homes are healthier and safer. WAP services include a variety of measures that are provided (when necessary) to allow the safe and effective installation of weatherization measures. It also provides client education on the proper use and maintenance of the installed weatherization measures and ways to reduce energy waste. The average expenditure per household is $7,669 depending on the results of a home audit.[1]

Q. How much assistance has LIHEAP provided over the past three seasons?

A. Over the prior three LIHEAP seasons (2022/2023, 2023/2024, 2024/2025) the Company has facilitated approximately 109,000 grants for nearly $32 million. This funding has been instrumental in assisting low-income customers in maintaining and/or restoring natural gas service as well as emergency furnace repair or replacement. For the 2025-2026 LIHEAP season that had a delayed start date of early December, the Company has already facilitated the processing of approximately 10,106 grants for $2.6 million.

Q. What actions did the Company take to help offset the customer impacts that could have resulted from the delay in LIHEAP launching for the 2025/2026 season?

A. In addition to the proactive $500,000 supplemental Operation Share Company contribution mentioned earlier, the Company’s efforts described below were designed to provide additional assistance to customers and minimize terminations during the delay in LIHEAP funding until the program resumed in December 2025.

Active Income Verified Low-Income Customers (150% FPIG):

- Effective November 1, 2025, UGI temporarily suspended field terminations for non-payment for CAP customers. The Company also worked to maximize any available Operation Share grants to assist with arrears. If an Operation Share grant had already been applied during the year, consistent with its USECP, the Company provided a one-time Operation Share grant in excess of the individual

[1] https://dced.pa.gov/programs/weatherization-assistance-program-wap/.

maximum of $600 to help maintain the customer's service as active. For this initiative, if a customer was behind in CAP payments totaling $900 or less, the maximum grant issued was $900. There were 2,703 Operation Share grants for approximately $598,000 issued to customers in need during the month of November.

- Effective November 1, 2025, UGI temporarily suspended field terminations of active customers in arrears who received LIHEAP within the last 12 months and were not enrolled in CAP. The Company continued its Dunning notices during this timeframe to encourage customers to contact the Company and enroll in a Universal Service Program.
  - The Company actively solicited these customers via auto dialer and by email requesting they immediately contact UGI to enroll in CAP to keep service active.
  - For these customers that received LIHEAP in the prior season, they were offered streamlined enrollment into CAP and did not have to provide proof of income to enroll.

Inactive Income Verified Low-Income Customers (150% FPIG & Already Terminated for Non-Payment):

- For inactive income verified low-income customers (150% FPIG) that contacted the UGI Call Center about their service that had been terminated for non-payment, UGI representatives reviewed options with the customer about enrolling in CAP. If the customer agreed to and was qualified to enroll in CAP, their service was reconnected, and an Operation Share grant was applied to their account. For inactive income verified low-income CAP customers (150% FPIG) that contacted the UGI Call Center about their service that was terminated for non-payment, the Company applied an Operation Share grant to their account to help offset their arrears and turn service back on.

Q. What impacts did these actions have in November and December 2025?

A. The success of the Company's efforts during the November and December 2025 timeframe was substantial. Company representatives worked approximately 250 hours of overtime to provide additional assistance to customers who may have been impacted by the Government Shutdown. Highlights are summarized below:

- 421 confirmed low income customers were enrolled in CAP and either reconnected or not terminated;
- 3,450 Operation Share grants, totaling $905,233 were issued in November and December 2025. This can be compared to 332 grants for $110,201 during this same time period in 2024.

III. STRATEGIC INITIATIVES

Q. What actions has the Company undertaken to maximize customer enrollment in Universal Service Programs?

A. As part of the 2025 Settlement, the Company implemented several noteworthy changes to its Universal Service Programs. First, the Company increased its LIURP budget substantially by $1,000,000 or approximately 24% from $4,214,350 in calendar year 2025 to $5,214,350 in calendar year 2026. For any unspent LIURP budget, those funds will rollover to the next year to be utilized within the first six months of the following year to the extent possible. Second, the Company substantially increased its Operation Share contribution by $500,000 or approximately 86% from $584,500 in Fiscal Year 2025 to $1,084,500 in Fiscal Year 2026 and added increased flexibility to reallocate program funding from a previous maximum of only 5% to now 50% of funding between the Company's former rate districts to minimize underspending and to assist customers in need. Third, the Company is undertaking expanded outreach efforts in 2026 through additional in person Winter Assistance Relief Mobilization ("WARM") events held at targeted locations each year, with a minimum of 6 events in Lancaster, 4 events in Wilkes Barre, and 3 events in Williamsport. Each year thereafter, the Company will target a minimum of three new cities within its service territory as set forth in its tariff, which will be identified in consultation with its Universal Service Advisory Committee. Furthermore, the Company began engaging with various Mayor's offices throughout the UGI Gas service territory to provide the Company's Universal Service brochure in an effort to promote awareness of the Company's low-income assistance programs. Locations for outreach include Allentown, Bethlehem, Easton, Harrisburg, Hazleton, Lancaster, Lock Haven, Pottsville, Reading, Scranton, Wilkes-Barre, and Williamsport. Fourth, the Company is continuing its Low Income Customer Assessment and Outreach Pilot as agreed to in the UGI Gas 2025 Settlement (Paragraph 61(a)) with an annual budget not to exceed $120,000. The purpose of this Pilot is to engage in additional outreach to the Company's estimated low-income customers up to 150% FPIG identified by third-party consumer credit reporting agency Experian. UGI Gas intends to utilize email, direct mail, and digital ads for targeted marketing to these customers. Customers will be directed to a landing page where they can learn more about the process to pursue enrollment in the Company's CAP. Fifth, UGI Gas has adopted the PUC Common Application Form as of December 2025. Finally, the Company has been participating in the DHS data sharing process and has been analyzing this data and evaluating methods to use this information to further promote the availability of the UGI Gas Universal Service Programs. Examples include outreach to data sharing participants who have not yet enrolled in CAP, as well as utilizing the data sharing file to recertify customers for CAP.

Q. What does UGI intend to do to further address affordability concerns for its customers?

A. UGI recognizes the importance of supporting the affordability of utility bills for its low-income customers. That is why the Company is committing to contribute $1,000,000 annually to Operation Share in Fiscal Years 2027, 2028, and 2029. This multi-year commitment is unprecedented in the Company's history and will provide substantial assistance to low and moderate income customers with income levels up to 250% FPIG.

IV. <u>CONFIRMED LOW-INCOME CUSTOMER COUNTS</u>

Q. Did UGI previously identify inconsistencies with regulatory reporting of confirmed low-income customer counts on prior Universal Service Reports ("USR")?

A. Yes. During the 2025 UGI Gas Base Rate Case, it was discovered that the Company had inadvertently reported self-certified low-income customers up to 250% FPIG on prior USR filings; however, the Company should have reported only those customers up to 150% FPIG. Therefore, the Company's confirmed low-income customer counts on prior USR were affected by unintentional data inconsistencies that increased the number of customers included.

Q. Has UGI Gas taken steps to ensure that its internal tracking of the "confirmed low-income" designation for Universal Service Reporting and USECP purposes has become more accurate?

A. Yes. In 2025, the Company made information technology ("IT") system enhancements to ensure that future Universal Service Reports will include self-certified low-income customers up to 150% FPIG, not 250% FPIG as was previously reported in prior years.

This enhancement includes leveraging a more suitable data source, which directly supports the reporting questions being asked. However, significant time and effort to thoroughly vet and cleanse the data was required, which could not be achieved retrospectively. As a result, the 2025 USR confirmed low-income count may result in an overstatement of confirmed low-income counts. The Company anticipates that the confirmed low income counts that will be included on the 2026 Universal Service Report and filed in April 2027, will accurately reflect self-certified low-income customers up to 150% FPIG. Importantly, the Company's definition of "Confirmed Low Income" is now consistent with the PUC's regulations at 52 Pa. Code § 62.2, which defines a "confirmed low-income residential account" to include "[a]ccounts where the NGDC has obtained information that would reasonably place the customer in a low-income designation. This information may include receipt of LIHEAP funds, self-certification by the customer, income source or information obtained in § 56.97(b) (relating to procedures upon ratepayer or occupant contact prior to termination)." However, 52 Pa. Code § 62.2 also defines a "low-income customer" as "[a] residential utility customer whose gross household income is at or below 150% of the Federal poverty guidelines. Gross household income does not include the value of food stamps or other noncash income."[2]

Q. How many confirmed low-income customers does UGI Gas have?

A. As of November 30, 2025, the Company had 68,867 confirmed low-income customers. This figure represents customers who have self-certified their income, participated in the

[2] https://www.pacodeandbulletin.gov/Display/pacode?file=/secure/pacode/data/052/chapter62/s62.2.html&d=reduce

Company's CAP, Operation Share, or LIURP, where income was verified to be at or below 150% FPIG, as well as those customers who have received LIHEAP in the prior 12 months. Of the 68,867 Confirmed Low Income customers referenced above, UGI Gas has 38,499 customers who have gone through the Company's income verification process, have been verified at or below 150% FPIG, and are eligible to participate in a Universal Service Program.

Regarding estimated low-income customers at or below 150% FPIG, as part of the 2026-2030 USECP filing supplemental data request[3] from the PUC, the Company reported 143,404 estimated low-income customers. This figure was developed in accordance with the PUC's Bureau of Consumer Services specified methodology, which derived the estimated number of low income customers by calculating the number of UGI Gas customers in each county of its service territory multiplied by the 2019-2023 American Community Survey 5 Year Estimates census data provided by the Bureau of Consumer Services for that county. However, this calculation methodology may overstate the estimated low-income customer counts due to the census percentages of low-income customers by county which does not necessarily correlate to UGI Gas' customer demographics. By comparison, the Company's Low Income Customer Assessment and Outreach Pilot[4] undertaken with Experian, identified an estimated low-income population of 98,785 customers at or below 150% FPIG in the fall of 2023. The Experian estimate uses actual demographic income data of UGI customers and identifies significantly less customers, at only 68% of the estimated low income customer count of 143,404.

[3] August 25, 2025, response at Docket No. M-2025-3054362

[4] UGI Gas 2022 Base Rate Case settlement paragraph 46(a).

Therefore, UGI Gas's estimated low-income customer counts based on census and published in the USR should be considered an over estimation and referenced with caution.

V. <u>WNA COMMUNICATIONS REVISIONS</u>

Q. Has the Company provided revisions to its communication materials as required in its 2025 Gas Rate Case Settlement?

A. Yes. Consistent with the Settlement requirements, the Company shared draft materials with the required parties, including updates to the Weather Normalization webpage on its public facing website and a new customer letter. The customer letter provides an individualized explanation of charges or credits for a specific billing month. As specified in the 2025 Settlement, the Company solicited feedback from interested USAC members and the statutory parties. All edits were consolidated and distributed, with suggestions either incorporated into the materials or feedback provided explaining why they were not included. A final meeting was held with the statutory parties to address any concerns regarding feedback. Approximately twenty website updates were completed in December 2025, including creation of a new FAQ page, and seven revisions were made to the customer letter which will be available in fiscal year 2026.

VI. <u>CONCLUSION</u>

Q. Does this conclude your testimony?

A. Yes, it does.

UGI GAS

EXHIBIT BJM-1

Brian J. Meilinger
Director – Customer Programs & Public Relations

Work Experience

UGI Utilities, Inc.

2025 – Present	Director – Customer Programs & Public Relations
2021 – 2025	Sr. Manager – Customer Programs & Community Relations
2015 – 2021	Manager – Energy Efficiency & Conservation Programs
2012 – 2015	Sr. Analyst – Financial Planning & Analysis

Previous Testimony

UGI Utilities, Inc. Gas Division Base Rate Increase Filing: Docket No. R-2024-3052716

Education

Master of Business Administration in Finance - Saint Joseph's University, Philadelphia, PA
Bachelor of Arts in Economics & Business Administration - Ursinus College, Collegeville, PA