BOOK III

UGI UTILITIES, INC. – ELECTRIC DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI ELECTRIC STATEMENT NO. 7 – VICKY A. SCHAPPELL
UGI ELECTRIC STATEMENT NO. 8 – DYLAN W. D'ASCENDIS
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UGI UTILITIES, INC. – ELECTRIC DIVISION
PA P.U.C. NO. 6, SUPPLEMENT NO. 92

DOCKET NO. R-2025-3059430

Issued: March 27, 2026 Effective: June 1, 2026

UGI ELECTRIC STATEMENT NO. 7

VICKY A. SCHAPPELL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059430

UGI Utilities, Inc. – Electric Division

Statement No. 7

Direct Testimony of
Vicky A. Schappell

Topics Addressed: **Capital Planning**

Dated: March 27, 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 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" or the "Company") and the Gas Division ("UGI Gas"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. Please describe your educational background and work experience.

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

Q. What are your responsibilities as 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, Information Technology ("IT"), and the Building and Grounds Departments. I collaborate with the Senior Director – Electric Division, Senior Engineering Managers, and the Senior Director Financial Planning and Analysis to monitor annual capital budget performance and develop strategies to limit variances in capital installations and spending. I also work closely with the President of UGI to develop the overall capital spend and in-service strategy. In this role, I have also prepared testimony, and, supporting exhibits and schedules, and sponsored responses to discovery requests for past rate cases. Also, I am responsible for preparing UGI Electric's Annual Asset Optimization Plan. Additionally, I had an integral role in developing an expanded capital spending monitoring process made necessary by the Company's accelerated capital investment programs.

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

A. Yes. UGI Electric 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 Electric 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 Electric Exhibit VAS-1, I am sponsoring UGI Electric 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 Electric for the FPFTY that is reflected in the proposed rates?

A. The total budgeted plant additions for UGI Electric for the FPFTY is $37,311,000.

Q. As an initial matter, are Transmission plant additions excluded from Pennsylvania distribution service rate base for UGI Electric?

A. Yes, they are. The Company identifies projects that only serve a Transmission plant function as part of its overall capital budgeting process. Projects that are identified as having solely a Transmission purpose are excluded from the distribution rate base presented in this proceeding. Some categories of projects support both the distribution and transmission functions. For these projects, UGI Electric uses an allocation factor to ensure an appropriate portion of the dollars associated with these General and Common plant additions are recovered through distribution rates, while the transmission portion is excluded.

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

A. UGI Electric has four main categories that make up its capital budgets: (1) replacement and betterment of infrastructure, which includes transmission, substation, and distribution assets; (2) growth, including expansion of the transmission and distribution system to support growth; (3) IT; and (4) other capital spending. I will describe each of these categories and the projects associated with them, as well as the total dollars attributable to each category, below.

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

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

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

A. Schedule C-2 is an accounting presentation based on FERC accounts. For purposes of developing Schedule C-2, budgeted dollars in each 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 Electric.

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

A. Yes, I have. UGI Electric Exhibit VAS-2 reflects the Company's plant additions, broken down by 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 Electric Exhibit VAS-2 shows a historical comparison of the total budgeted plant placed in service versus actual plant placed in service additions for the three-year period from fiscal year 2023 through fiscal year 2025. I will describe the Company's performance history, which 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 Electric Exhibit VAS-2 and Schedule C-2.

A. While the forecasted total plant in service figures match for the FTY and FPFTY, there is a difference in the presentation of how UGI Electric Exhibit VAS-2 and Schedule C-2 present plant additions, and it is important to understand how these budget presentations align. Specifically, UGI Electric Exhibit VAS-2 shows how the Company's four individual budget categories constitute the Company's total Plant Additions and how they map into the Distribution and General and Common Plant on Schedule C-2. Exhibit VAS-2 shows that all 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. Because of the small size of the operations at UGI Electric, based on the mix of projects planned for each fiscal year, there might not be spending in each of the budget categories in both of the plant categories.

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

A. When the Company plans for future operations, the Company utilizes a project-based build-up and does not directly budget using 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, 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 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 together.

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

A. Replacement and betterment ("R&B") projects improve, repair or replace existing infrastructure and make up the majority of projects captured in UGI Electric's Long Term Infrastructure Improvement Plan ("LTIIP"). The Company's LTIIP performance is described in the direct testimony of Vince A. DeGuisto (UGI Electric Statement No. 3).

Q. Please describe how the prioritization process is used to evaluate R&B Projects.

A. Projects are prioritized for inclusion in the budget according to the condition of, and risks associated with, existing assets, including those factors affecting safety and reliability. In determining the condition of an existing asset, the Company considers various criteria, including, but not limited to, age, material, performance, inspection and test results, obsolescence, and maintenance costs.

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

A. UGI Electric's LTIIP guides the formulation of the overall R&B capital budget. Within the various program categories of the LTIIP, R&B projects are selected and prioritized in the budget under two key designations: condition-based replacements and reliability enhancements. Condition-based replacements address "aging infrastructure," such as poles, transformers, underground primary cable, open wire secondary, and deteriorated or failed pole-mounted equipment (e.g., switches, reclosers, and capacitors). Reliability enhancement projects are targeted towards addressing known reliability issues or implementing system resiliency strategies. These projects are prioritized based on metrics such as worst-performing feeder circuits and include the creation of inter-substation tie-lines and the deployment of distribution automation devices. Additionally, through its comprehensive inspection and maintenance program, UGI Electric assesses asset conditions to identify and prioritize maintenance issues or trends. The information collected through this hybrid approach is used to schedule projects to mitigate short-term and long-term system impacts. The total anticipated budgeted plant additions associated with R&B projects in the FPFTY is $30,639,000, making up the majority of the capital additions included in this case; these additions are included in Distribution plant additions.

Q. What are growth projects?

A. Growth projects provide new or upgraded electric service to customers and may involve primary overhead and underground line extensions, new or upgraded transformer installations, and associated service enhancements.

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

A. The growth portion of the capital budget is developed using historical trends as well as projections that are informed by known large customers, forecasts of growth projects, counts of residential developments and associated customers, and general construction and development trends in the UGI Electric service territory. The final budget layers in the above components, considering construction timing and the level of confidence in the customer's ability to meet project timelines. The total anticipated budgeted plant additions associated with growth projects in the FPFTY is $3,301,000; 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 that 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, and 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 $4,364,000. Of this amount, $1,931,000 relates to one specific large IT project, Field Services Management ("FSM"). FSM has a planned in-service date of July 2026 as presented in the Company's 2025 Gas Base Rate Case (See the Direct Testimony of Vicky A. Schappell, UGI Gas Statement No. 5)[1], and there are no additional costs included in the FPFTY. The total anticipated budgeted plant additions associated with IT projects in the FPFTY is $1,235,000, 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.

Q. What are Other capital projects?

A. Other capital projects include building-related projects, capital tool purchases, and fleet purchases. Building-related projects include building and land purchases, building improvements/renovations, and furniture purchases. Capital tool projects encompass new tool purchases for field use during capital projects. These tools include pole saws, wire strippers, test equipment, safety tools, and lighting equipment. Fleet purchases are needed to maintain reliable transportation and related apparatus for field employees to perform

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[1] See PAPUC v. UGI Gas, R-2024-3052716 (Recommended Decision issued on August 8, 2025 recommending approval of the Joint Petition for Approval of Settlement of All Issues without modification). No party challenged the Company's FSM and related IT Plan.

their daily functions. These acquisitions include SUVs, pickup trucks, cargo vans, service-body trucks, bucket trucks, and equipment trailers for poles. The total anticipated budgeted plant additions associated with Other projects in the FPFTY is $2,135,000, of which $84,000 is included in Distribution plant additions and $2,051,000 is included in General and Common plant additions.

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

A. The prioritization process for Other capital projects is specific to the need being addressed. Building-related projects are prioritized for inclusion in the budget based on safety, security, regulatory, financial, or strategic needs. Regulatory-driven projects often originate from compliance requirements or certain audit observations. Physical security audits may prompt the installation of fencing, gates, and access controls. Capital tool projects are prioritized for inclusion in the budget according to the useful life of the existing assets. Fleet purchases are prioritized for inclusion in the budget based on age, condition, maintenance costs, and mileage of the existing asset.

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

A. The planned capital for FY2027 includes cost increases in R&B associated with additional and necessary investments in the LTIIP's Circuit Improvement Projects program, related to a dramatic increase in facility upgrades and replacements associated with pole attachment make-ready work required to support recent and material increases in broadband expansion. The actual and projected expenditures in the Modified Second LTIIP reflect the increased scope and complexity of pole attachment make-ready projects that UGI Electric has completed or is expecting to complete within the five-year term of the LTIIP. On September 25, 2025, the Commission issued an Opinion and Order approving the Company's Modified LTIIP. The Company's LTIIP performance is described in the direct testimony of Vince A. DeGuisto (UGI Electric Statement No. 3).

The planned capital for FY2027 also includes an increase in R&B associated with one very large project, the Mine Hollow Substation. The substation will be a 66/13.8kV substation on the eastern edge of UGI Electric's service territory with four (4) new 13kV feeders. The project spans multiple years of spending, and is estimated to go into service in September 2027. This project is described in greater detail in the testimony of Mr. DeGuisto.

Q. How can UGI Electric'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 Electric Exhibit VAS-2, over the past three years, the Company's total budgeted in-service plant additions were $59,709,000, while the total actual in-service plant additions were $66,125,000. Thus, UGI Electric's plant in service as viewed by variance to budget is over 110% ($66,126,000/$59,708,000) over the three-year period. The percentage of plant additions is calculated by dividing the actual plant additions by the budgeted plant additions (Actual / Forecast). This correlation is indicative of the Company's ability to develop a plan for plant additions and reliably execute 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 plant additions align as closely as possible to total plant addition actuals.

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

A. During the Company's capital budget process, which occurs during the summer/fall, a two-year budget is prepared. The first year of the capital budget is the basis for the FTY. The second year is a preliminary budget and is the basis for the FPFTY. During the budget process, project managers estimate the total project costs and budgeted in-service dates at the project level based on the current data available. These estimated in-service dates are the basis for the budgeted plant additions as further discussed in the testimony of UGI Electric witness Amy M. Keller (UGI Electric 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. The Company adjusts its project lists on an annual basis to respond to operational demands, such as the need to reprioritize projects based on emerging service needs or unanticipated equipment condition changes. For example, the Company's annual budget reflects on-going circuit improvement projects focused on remediating conductor clearance violations identified as part of attachment make-ready projects for expanded rural internet access. The number of make-ready projects varies annually depending on requests by the broadband companies that are doing attachment work. UGI Electric does not control the number of project requests it receives in any particular fiscal year. Costs within this program category include UGI Electric costs to bring poles, attachments, and other equipment into compliance with current published safety, reliability and construction standards in advance of work done by the new pole attacher. To the extent the requests for make-ready work are lower than budgeted, the costs would be reallocated back into the budget. As described above, the Company manages its capital budget for any particular year in total. In doing so, the Company will prioritize projects and update associated projections as needed in order to achieve a result which has the greatest likelihood of being on budget for the year in total. UGI Electric has consistently met or exceeded its capital budget projections.

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 for the four budget categories described above. 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 the 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 110.7% of its budget, as mentioned above. Thus, the Company has demonstrated that over a three-year period, it has a documented history of meeting or exceeding its budgeted plant additions. This close correlation between budgeted and actual plant placed in service over the past three years shows that UGI Electric's budget process is very effective at identifying its required plant additions, and UGI Electric'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. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC

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-2025-3059525
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 ELECTRIC

EXHIBIT VAS-2

UGI UTILITIES, INC. - ELECTRIC DISTRIBUTION 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	3 Year Total Budget	3 Year Total Actual
Distribution								
Replacement and Betterment	12,784	12,658	14,112	17,385	13,762	16,220	40,658	46,263
Growth	2,701	2,743	3,609	3,425	6,190	2,837	12,500	9,005
Other	98	973	27	104	71	-	196	1,077
IT	-	390	-	-	-	-	-	390
Subtotal Distribution	15,583	16,764	17,748	20,914	20,023	19,057	53,354	56,735
General and Common Plant								
Replacement and Betterment	-	-	-	10	-	9	-	19
Growth	-	-	-	-	-		-	-
Other	237	7	464	978	2,088	2,878	2,789	3,863
IT	193	896	2,262	951	1,110	3,662	3,565	5,509
Subtotal General and Common Plant	430	903	2,726	1,939	3,198	6,549	6,354	9,391
Total Plant Additions	16,013	17,667	20,474	22,853	23,221	25,606	59,708	66,126
	(1)	**(2)**	**(1)**	**(2)**	**(1)**	**(2)**	**(1)**	**(2)**
Capital Spend as % of Budget	**(2) / (1)**	**110.3%**	**(2) / (1)**	**111.6%**	**(2) / (1)**	**110.3%**	**(2) / (1)**	**110.7%**

Forecasted Performance

Description	FPFTY Budget 2027	FTY Budget 2026
Distribution		
Replacement and Betterment	30,639	19,094
Growth	3,301	3,513
Other	84	27
IT	-	128
Subtotal Distribution	34,024	22,762
General and Common Plant		
Replacement and Betterment	-	-
Growth	-	-
Other	2,051	1,590
IT	1,235	4,235
Subtotal General and Common Plant	3,286	5,825
Total Forecasted Plant Additions	37,310	28,587

UGI ELECTRIC STATEMENT NO. 8

DYLAN W. D'ASCENDIS

UGI Electric Statement No. 8

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

UGI UTILITIES, INC. – ELECTRIC DIVISION

DOCKET NO. R-2025-3059430

Direct Testimony and Exhibit
of
Dylan W. D'Ascendis

<u>List of Topics Addressed</u>

Return on Equity

March 27, 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 I have testified before are identified in Appendix A.

II. PURPOSE OF DIRECT TESTIMONY

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 (the "Commission") with a recommendation regarding UGI Utilities, Inc. – Electric Division's ("UGI Electric" or the "Company") return on common equity ("ROE") for its electric 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-11, 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 Electric the opportunity to earn an ROE of 10.85% 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 10.85% 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%	10.85%	5.89%
Total	100.00%		8.26%

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ROE.

A. My recommended ROE of 10.85% 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 Electric. Using companies of relatively comparable risk as proxies is consistent with the principles of fair rate of return established in the *Hope*[1] 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 thirteen (13) electric utility companies ("Electric 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 Electric 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)	10.43%
Risk Premium Model (RPM)	10.59% - 11.00%
Capital Asset Pricing Model (CAPM)	10.22% - 11.45%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	12.35% - 12.98%
Indicated Range of Common Equity Cost Rates Before Adjustments for Company-Specific Risk	10.22% - 12.98%
Business Risk Adjustment	0.40%
Credit Risk Adjustment	-0.07%
Flotation Cost Adjustment	0.13%
Indicated Range of Common Equity Cost Rates after Adjustment	10.68% - 13.45%
Recommended Cost of Equity	10.85%

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

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 Electric Utility Proxy Group is between 10.22% and 12.98%.

After determining the Electric Utility Proxy Group ROE, one must conduct a relative risk analysis to determine whether additional adjustments to the Electric Utility Proxy Group ROE are warranted to reflect the unique risk of the Company. My relative risk analyses show that adjustments to the Electric Utility Proxy Group indicated range of ROEs are necessary based on the Company's relative size, bond rating, and flotation costs. From the indicated range of ROEs after adjustment from 10.68% to 13.45%, I recommend that the Commission approve a specific ROE of 10.85% 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 10.85%?

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

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[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 must still be sufficient to incentivize allocating 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 is therefore 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.

Although analysts, including ratings agencies, may categorize business risks

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

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 Electric 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 driven 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, are also 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 debt-holder risk measures do not translate directly to risks for common equity.

IV. <u>UGI ELECTRIC AND THE ELECTRIC UTILITY PROXY GROUP</u>

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

A. Yes. UGI Electric provides electric utility service to over 62,900 customers in Luzerne and Wyoming counties in northeastern Pennsylvania through approximately 2,700 miles

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[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.

of transmission and distribution lines and 14 substations. UGI Utilities, Inc. holds an 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: an Electric Utility Proxy Group and a Non-Price Regulated Proxy Group, which is comparable in total risk to the Electric 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.

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

Additionally, a relative risk analysis between the Company and the Electric Utility Proxy Group must be made to determine whether or not explicit Company-specific adjustments need to be made to the Electric Utility Proxy Group's indicated results.

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

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

(i) They were included in the Electric Utility Group (East, Central, or West) of *Value Line's Standard Edition* as of January 30, 2026 ("*Value Line*");

(ii) They have 70% or greater of fiscal year 2024 total operating income derived from, and 70% or greater of fiscal year 2024 total assets attributable to, regulated electric 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 thirteen (13) companies met these criteria:

Table 3: Electric Utility Proxy Group Screening Results

Company	Ticker
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Corporation Inc.	AEP
Edison International	EIX
Entergy Corporation	ETR
Evergy, Inc.	EVRG
FirstEnergy Corporation	FE
IDACORP, Inc.	IDA
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
Portland General Electric Company	POR
Southern Company	SO
Xcel Energy Inc.	XEL

V. CAPITAL STRUCTURE

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

A. UGI Electric'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 ELECTRIC UTILITY PROXY GROUP?

A. As shown on page 2 of Schedule DWD-2, common equity ratios range from 26.94% to 52.01% for fiscal year 2024 for the Electric 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 29.00% and 56.00%.[8]

In addition to comparing the Company's requested common equity ratio with common equity ratios currently maintained by the Electric Utility Proxy Group, I also

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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 14 of Schedule DWD-3.

compared the Company's common equity ratio with the equity ratios maintained by the operating subsidiaries of the Electric Utility Proxy Group. As shown on page 3 of Schedule DWD-2, common equity ratios of the operating utility subsidiaries of the companies in the Utility Proxy Group range from 38.13% to 67.52% for fiscal year 2024, for the Electric 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 Electric Utility Proxy Group.

Q. GIVEN THE RANGE OF EQUITY RATIOS PRESENT WITHIN THE UTILITY PROXY GROUP, IS UGI ELECTRIC'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 Electric 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 to develop its 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 Electric Utility Proxy Group described above. I also applied these same models to 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 a 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 Electric 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

[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.

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 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 January 30, 2026, divided by the average closing market price for the 60 trading days ended January 30, 2026.[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.

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

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 Electric Utility Proxy Group increase 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 ELECTRIC 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 Electric 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	10.40%
Median	10.45%
Average of Mean and Median	10.43%

In arriving at a conclusion for the constant growth DCF-indicated common equity cost rate for the Electric Utility Proxy Group, I relied on an average of the mean and the median results of the DCF, specifically 10.43% applicable to the Electric 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 electric utilities.

Q. PLEASE EXPLAIN THE BASIS OF THE EXPECTED BOND YIELD OF 5.78% 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 second 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 5.29%. 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 0.36%, which represents a recent spread between Aaa-rated corporate bonds and A2-rated public utility bonds.[11] Adding that recent 0.36% spread to the expected Aaa-rated corporate bond yield of 5.29% results in an expected A2-

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

rated public utility bond yield of 5.65%. Since the Electric Utility Proxy Group's average Moody's long-term issuer rating is Baa1, another adjustment to the expected A2-rated public utility bond is needed to reflect the difference in bond ratings. An upward adjustment of 0.13%, which represents two-thirds of a recent spread between A2-rated and Baa2-rated public utility bond yields, is necessary to make the prospective bond yield applicable to a Baa1-rated public utility bond.[12] Adding the 0.13% to the 5.65% prospective A2-rated public utility bond yield results in a 5.78% expected bond yield applicable to the Electric Utility Proxy Group.

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

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (*Blue Chip*)	5.29%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.36%
Adjustment to Reflect the Electric Utility Proxy Group's Average Moody's Bond Rating of Baa1	0.13%
Prospective Bond Yield Applicable to the Electric Utility Proxy Group	5.78%

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 Electric 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

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.

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.

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 <u>Stocks, Bonds, Bills, and Inflation ("SBBI") Yearbook 2023</u> ("<u>SBBI - 2023</u>").[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

[14] <u>SBBI-2023</u>, at 193.

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 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 6.89% 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 estimate 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 January 2026. 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 6.93%.[17]

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[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 January 30, 2026, 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 41%, which translates to an 8.97% annual appreciation, and when added to the average of *Value Line's* median expected dividend yields of 2.15%, equates to a forecasted annual total return rate on the market of 11.12%. The forecasted Moody's Aaa-rated corporate bond yield of 5.29% is deducted from the total market return of 11.12%, resulting in an equity risk premium of 5.83%, 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 18.62%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 5.29% results in a 13.33% 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]

Risk Premium Measure	Implied Equity Risk Premium
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	6.89%
PRPM Analysis on Historical Data	6.93%
Prospective Equity Risk Premium using Total Market Returns from *Value Line Summary & Index* less Projected Aaa Corporate Bond Yields	5.83%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P 500 less Projected Aaa Corporate Bond Yields	13.33%
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 Electric 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 Electric 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 Electric Utility Proxy Group's average blended beta is 0.60, 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 4.69% 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 4.87% 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-4.

Index holding period equity risk premium was calculated by applying the PRPM using the historical monthly equity risk premiums from January 1928 to January 2026 to arrive at a PRPM-derived equity risk premium of 4.21% for the S&P Utility Index.

I then derived expected total returns on the S&P Utilities Index of 12.16% 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 5.65%.[21] This resulted in an equity risk premium of 6.51%. As with the market equity risk premiums, I averaged the four risk premiums to arrive at my utility-specific equity risk premium of 4.94%.

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

Risk Premium Measure	**Implied Equity Risk Premium**
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	4.87%
PRPM Analysis on Historical Data	4.21%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P Utilities Index less Projected A2 Utility Bond Yields	6.51%
Average	4.94%

Q. HOW DID YOU DERIVE AN EQUITY RISK PREMIUM OF 4.79% BASED ON AUTHORIZED ROES FOR ELECTRIC UTILITIES?

A. The equity risk premium of 4.79% 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 1,274 rate cases for electric utilities which were fully litigated during the period from

[21] Derived on line 3, page 1 of Schedule DWD-4.
[22] As shown on page 9 of Schedule DWD-4.

January 1, 1980 through January 30, 2026. It shows the implicit equity risk 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 5.65%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 4.79%.

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

A. The range of equity risk premiums I applied to the Electric Utility Proxy Group is from 4.81% to 5.22%, which is the average of the beta-adjusted equity risk premium for the Electric Utility Proxy Group, the S&P Utilities Index, and the authorized return utility equity risk premium.

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

Equity Risk Premium Measure	Equity Risk Premium
Beta-Adjusted Equity Risk Premium	4.69% - 5.94%
S&P Utilities Index Equity Risk Premium	4.94%
Authorized ROE Equity Risk Premium	4.79%
Average	4.81% - 5.22%

[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.

[24] As shown on page 5 of Schedule DWD-4.

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 10.59% to 11.00% for the Electric 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 Electric Utility Proxy Group	5.78%
Prospective Equity Risk Premium	4.81% - 5.22%
Indicated Cost of Common Equity	10.59% - 11.00%

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 assumes that investors only require 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:

[25] As shown on page 1 of Schedule DWD-4.

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

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 1, below, that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[27]

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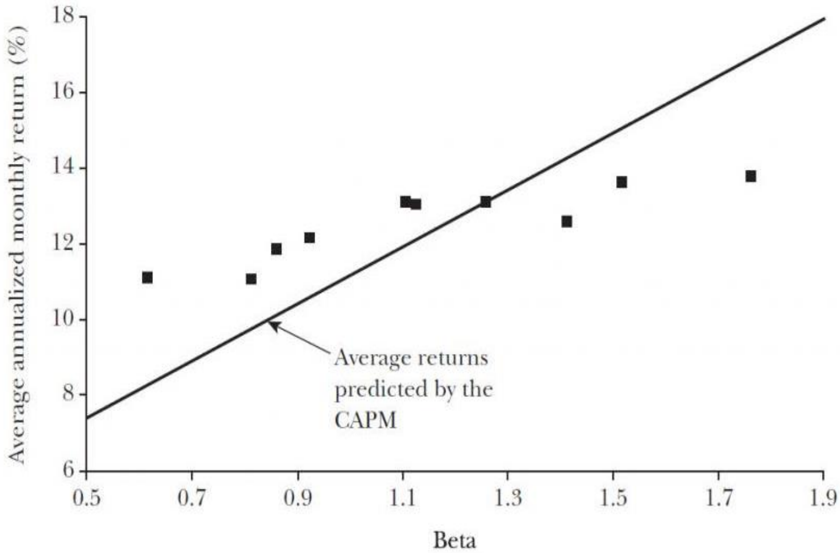
[26] Roger A. Morin, Modern Regulatory Finance (Public Utility Reports, Inc., 2021), at page 223 ("Morin").

[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").

Figure 1: Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003[28]



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.[29]
>
> * * *
>
> 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 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $K = RF + 0.25(RM - RF) + 0.75\,\beta(RM - RF)$[30]

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[28] https://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430.

[29] Morin, at 207.

[30] Morin, at 221.

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).[31]

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.[32]

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. Based on theory and practical research, I have applied both the traditional CAPM and the ECAPM to the companies in the Electric Utility Proxy Group and averaged the results.

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 <u>Modern Portfolio Theory & the Capital Asset Pricing Model</u>:

> 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

[31] Fama & French, at 32.

[32] Fama & French, at 33.

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.[33]

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 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.[34]

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

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

Q. HAVE OTHER JURISDICTIONS CONSIDERED THE ECAPM?

A. Yes, it has been accepted in Alaska, Minnesota, Mississippi, Nevada, New York, and Virginia.[35]

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.

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 Electric Utility Proxy Group at this time.

[35] 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. 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;[36] and (2) the correlation of weekly stock and market index returns.[37]

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

A. As shown in Chart 1, below, the Electric Utility Proxy Group average adjusted beta generally has ranged between 0.60 and 0.80, with some high side exceptions (2007-2008 and 2020-2022) and low side exceptions (2016-2020, second half 2024 – present).

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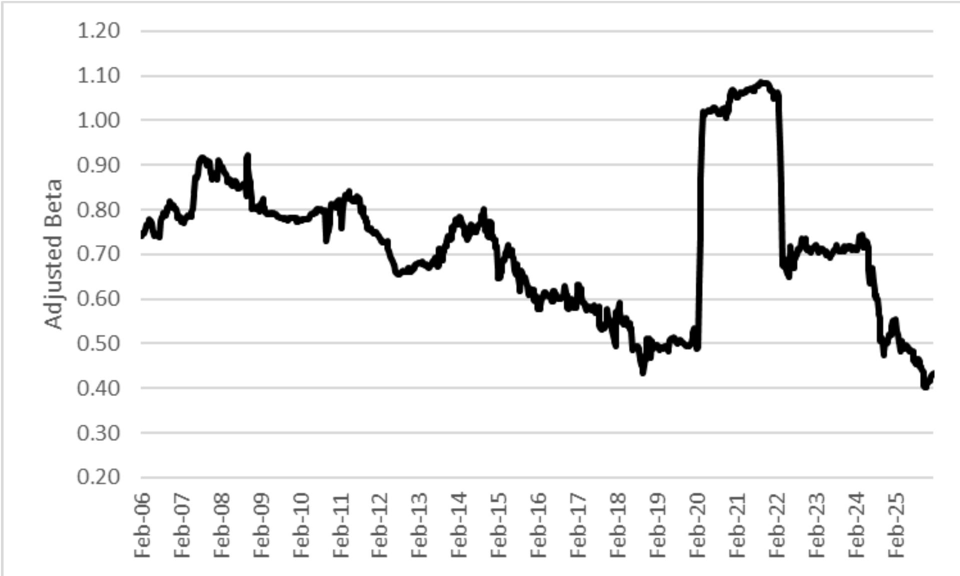
36 A relative volatility greater than 1.0 indicates that particular security is more volatile than the market during that calculation period. A relative volatility below 1.0 indicates that the security has less volatility than the market over that calculation period.

37 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

Chart 1: Bloomberg Adjusted beta for the Electric Utility Proxy Group 2005-Present[38]



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

A. As shown on Chart 2, the Electric 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 Electric Utility Proxy Group and the S&P 500 has varied over the period 2005 – 2026.

[38] Source of Information: Bloomberg Professional Services.

Chart 2: Relative Volatility for the Utility Proxy Group 2005-Present[39]

Chart 3: Correlation of the Utility Proxy Group Relative to the S&P 500 Index 2005-Present[40]

Importantly, as shown on Chart 3, during market distress (i.e., the Great Recession and the COVID-19 pandemic), the correlation of the Electric Utility Proxy Group returns and the S&P 500 returns approached 1.0, showing that utilities, as represented by the Electric Utility Proxy Group, do not possess defensive qualities and should not be

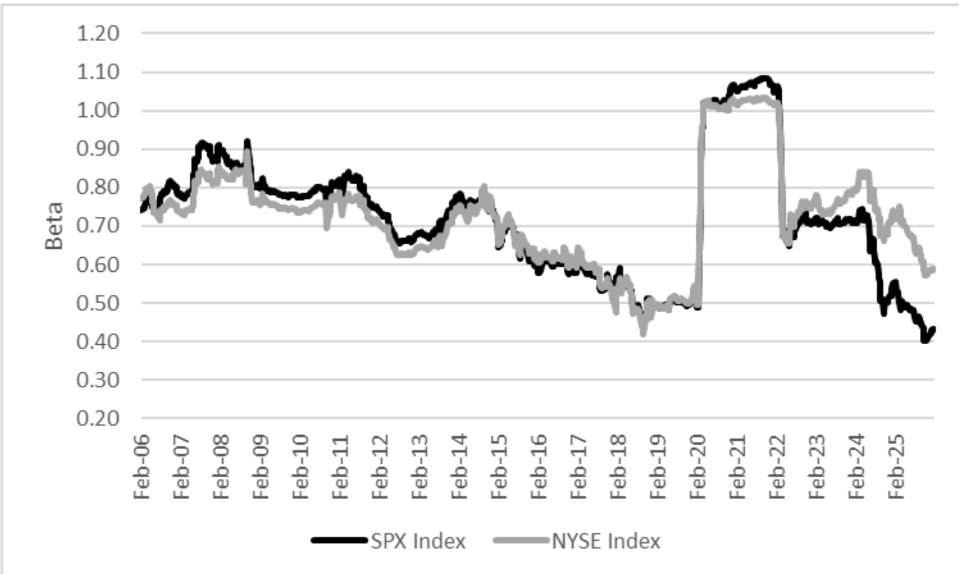
39 Source of Information: S&P Capital IQ.
40 Source of Information: S&P Capital IQ.

considered defensive stocks nor are they safe harbor investments in times of market distress.

Q. DOES THE LOWER CORRELATION OF THE ELECTRIC 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 accurately reflect the risk of the Electric 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 Electric Utility Proxy Group 2005-Present[41]



[41] 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 Electric Utility Proxy Group 2005-Present[42]

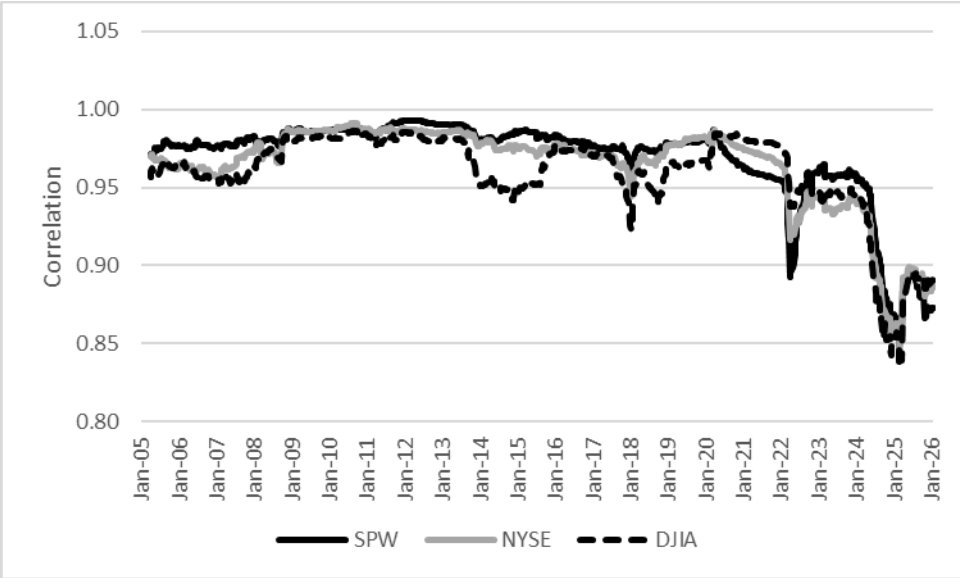
In view of Chart 5, it is clear that the relationship between the S&P 500 and NYSE is dislocated. To determine which index was distorting the risk of the Electric Utility Proxy Group, I compared the S&P 500 returns with those of the NYSE and other market indices.

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 2005-2026 period in the prior charts, which is put forth in Schedule DWD-5 and Chart 6, below:

[42] Source of Information: Bloomberg Professional Services.

Chart 6: Correlation between the S&P 500 Relative to Various Market Indices 2005-Present[43]



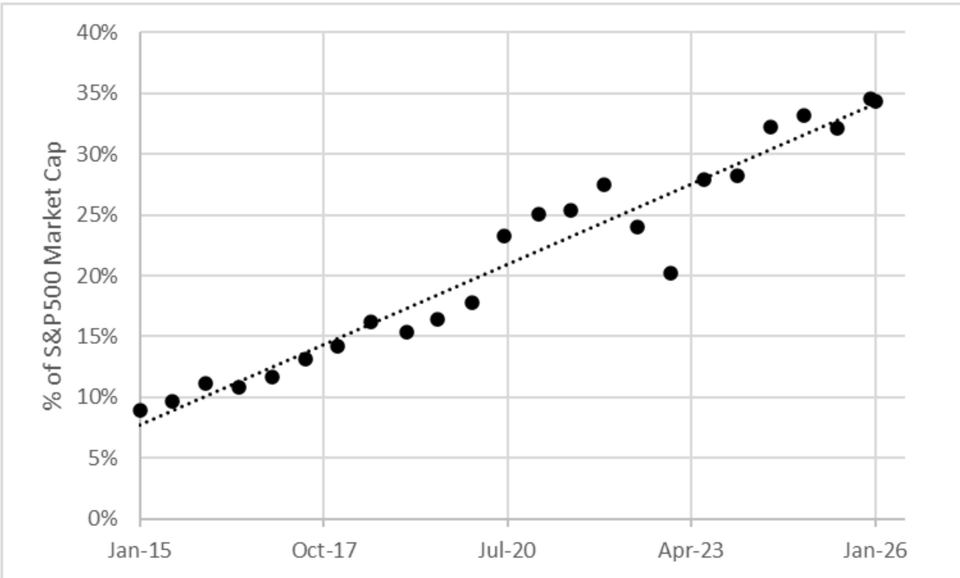
As shown in Chart 6, the two-year rolling correlation between the S&P 500's returns and the other market indices' returns generally ranged between 0.95 and 1.00 for the entire period but has recently dipped below 0.85 for each of the measures, indicating that the relationship between the S&P 500 and the other market indices is 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.

[43] 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"[44] ("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 34.34%, as shown on Chart 7, below:

Chart 7: Magnificent Seven Stocks Percentage of S&P 500 Market Capitalization 2015-Present[45]



Q. DOES THE CONCENTRATION AFFECT THE CALCULATION OF BETA FOR THE ELECTRIC 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 Electric Utility Proxy

[44] 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.

[45] Source of Information: Bloomberg Professional Services.

Group's returns had a **negative** 0.1501 correlation with the Mag7 returns and a **positive** 0.3205 correlation with the rest of the S&P 500, indicating opposite relationships between the Electric Utility Proxy Group and the two subsets of the S&P 500.

Table 10: Correlation between the Electric Utility Proxy Group's Weekly Returns and those of the Magnificent Seven Stocks and the Remaining 493 Component Companies of the S&P 500 January 30, 2026[46]

	Correlation Coefficient 1/30/2026	
	Mag7	Remaining 493
Utility Proxy Group Weekly Returns	-0.1501	0.3205

Given the disconnection of the relationship between the Mag7 and the remaining members of the S&P 500 Index relative to the Electric 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 Electric 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 have also departed from historical benchmarks. Importantly, the NYSE, SPW, and DJIA continue to show high levels of

46 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 of the S&P 500. Looking at the correlations of Electric 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 Electric 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 applications of the CAPM is 4.74%. 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 second 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 4.99% was deducted from the monthly historical total market return of 12.29%, which results in an historical market equity risk premium of 7.31%.[47] 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 7.73%. The PRPM market equity risk premium is 7.74% and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through January 2026.[48]

The *Value Line*-derived forecasted total market equity risk premium is calculated by subtracting the forecasted risk-free rate of 4.74%, discussed above, from the *Value Line* projected total annual market return of 11.12%, resulting in a forecasted total market equity risk premium of 6.38%.

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

48 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 4.74% from the projected total return of the S&P 500 of 18.62%. The resulting market equity risk premium is 13.88%.

When averaged, these five market risk premium measures result in an average total market equity risk premium of 8.61%.

Table 11: Summary of the Calculation of the Market Risk Premium for Use in the CAPM[49]

Market Risk Premium Calculation Method	Market Risk Premium
Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2024)	7.31%
Regression Analysis on Historical Data	7.73%
PRPM Analysis on Historical Data	7.74%
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	13.88%
Average	8.61%

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

A. As shown on pages 1 and 2 of Schedule DWD-6, the average of the mean and median CAPM result using my traditional approach is 10.22%. The average of the mean and median CAPM using only *Value Line* betas is 11.45%. Given the above, a reasonable range of CAPM cost rates is from 10.22% to 11.45%.

[49] 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 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 Electric 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 that is comparable in total risk to the Electric 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 ELECTRIC UTILITY PROXY GROUP?

A. In order to select a proxy group of domestic, non-price regulated companies similar in total risk to the Electric 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 forty-two domestic, non-price regulated firms comparable in total risk to the Electric 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 were:

(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 Electric 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 Electric 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 <u>and</u> 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 Electric Utility Proxy Group, is 11.45%.

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 12.83% to 13.62%. 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 second quarter of 2027, and for the years 2027 to 2031 and 2032 to 2036, is 6.13%.[50] 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 0.18%, 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 A3-rated corporate bond.[51] Subtracting the 0.18% from the 6.13% prospective Baa2-rated corporate bond yield results in a 5.95% expected bond yield applicable to the Non-Price Regulated Proxy Group.

When beta-adjusted risk premiums of 6.88% and 7.66%[52] relative to the Non-Price Regulated Proxy Group are added to the prospective A2-rated corporate bond yield of 5.95%, the indicated range of RPM common equity cost rates is from 12.83% to 13.62%.

Pages 6 and 7 of Schedule DWD-8 contain the inputs and calculations that support my range of indicated CAPM/ECAPM common equity cost rates from 12.46% to 13.21%.

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 ELECTRIC 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 is comparable in total risk to the Electric Utility Proxy Group – are as follows:

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50 *Blue Chip Financial Forecasts*, December 1, 2025 at 14 and January 30, 2026 at 2.

51 As shown on line 2 and explained in note 2, page 3 of Schedule DWD-8.

52 Derived on page 5 of Schedule DWD-8.

Table 12: Summary of Model Results Applied to the Non-Price Regulated Proxy Group[53]

Discounted Cash Flow Model	11.45%
Risk Premium Model	12.83% - 13.62%
Capital Asset Pricing Model	12.46% - 13.21%
Mean	12.25% - 12.76%
Median	12.46% - 13.21%
Average of Mean and Median	12.35% - 12.98%

The average of the mean and median of these models indicates a range of cost rates from 12.35% to 12.98%.

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 10.22% to 12.98%. 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, and the prudence of using multiple cost of common equity models is 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 10.22% and 12.98% is reasonable.

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

VIII. ADJUSTMENTS TO THE COMMON EQUITY COST RATE

Q. IS IT NECESSARY TO CONDUCT A RELATIVE RISK ANALYSIS BETWEEN THE ELECTRIC 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'S SMALLER SIZE RELATIVE TO THE ELECTRIC UTILITY PROXY GROUP COMPANIES INCREASE ITS BUSINESS RISK?

A. Yes. UGI Electric's electric distribution operations are significantly smaller in size relative to the Electric Utility Proxy Group companies, indicating greater relative business risk for the Company because, all else 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 Cost of Capital Navigator: U.S. Cost of Capital Module ("Kroll") 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)[54]

Furthermore, in "The Capital Asset Pricing Model: Theory and Evidence," Fama and French note that size is indeed a risk factor that 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.[55]

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

Also, it is a basic financial principle that the use of funds invested, not the source of funds, gives rise to the risk of any investment.[56] 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)[57]

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

[55] Fama & French, at 25-43.

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

[57] 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 Electric's electric 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 0.40 for my Electric Utility Proxy Group, which means approximately 60% of the Electric 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."[58] Dr. Zepp also noted on

[58] 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."[59]

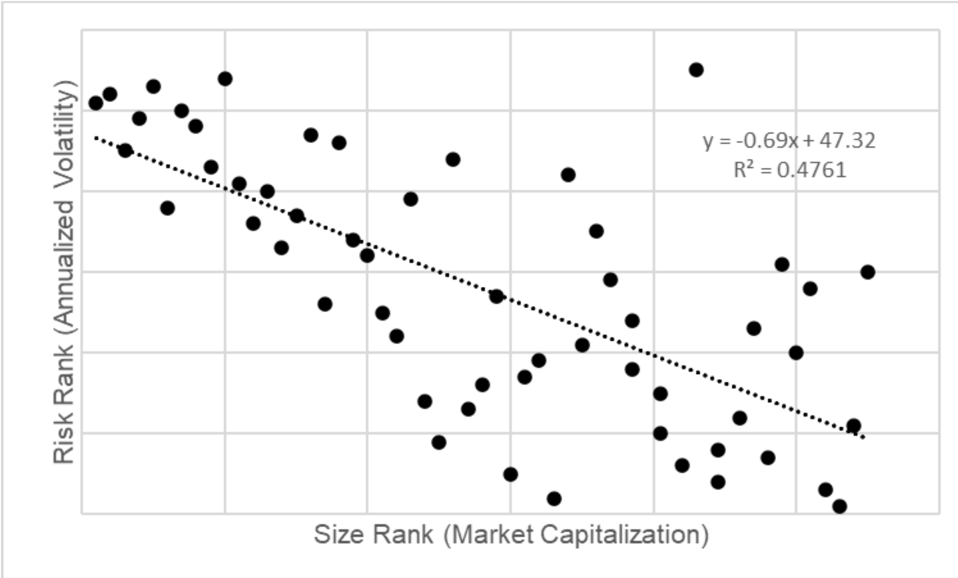
Q. HAVE YOU PERFORMED STUDIES LINKING SIZE AND RISK FOR UTILITY COMPANIES?

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)[60] 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:

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

[60] 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[61]



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.[62] 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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[61] Source: *Value Line*

[62] *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[63]

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 ELECTRIC'S GREATER BUSINESS RISK RELATIVE TO THE ELECTRIC UTILITY PROXY GROUP?

A. Yes. In the absence of other empirical methods, I compared UGI Electric's and the Electric Utility Proxy Group's relative size, as measured by market capitalization on January 30, 2026.

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[63] Source: *Value Line*.

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

	Market Capitalization* ($ Millions)	**Times Greater Than the Company**
UGI Electric	$226.117	
Electric Utility Proxy Group Median	$ 23,964.392	105.98x
*From page 1 of Schedule DWD-9.		

The Company's market capitalization was at $226.117 million as of January 30, 2026, compared with the median market capitalization of the Electric Utility Proxy Group of $23.964 <u>billion</u> as of January 30, 2026. The Electric Utility Proxy Group's market capitalization is 105.98 times the size of UGI Electric's electric distribution operation's market capitalization.

As a result, it is necessary to upwardly adjust the indicated range of common equity cost rates to reflect UGI Electric's significantly 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 Electric Utility Proxy Group with a market capitalization of $23.964 billion falls in the 2nd decile, while UGI Electric's market capitalization of $226.117 million places the Company in the 10th decile. The size premium spread between the 2nd decile and the 10th decile is 4.14%. Even though a 4.14% upward size adjustment is indicated, I conservatively applied a size premium of 0.40% to UGI Electric'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.[64]

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 10.43%, as shown on page 1 of Schedule DWD-3. The standard deviation of those results is 1.15%. Adding the standard deviation to the average of the mean and median DCF result would indicate an ROE of 11.58% for UGI Electric. Given this, my size adjustment should be considered conservative.

B. Credit Risk Adjustment

Q. PLEASE DISCUSS YOUR PROPOSED CREDIT RISK ADJUSTMENT.

A. UGI Electric's long-term issuer rating is A3 from Moody's, which is less risky than the average long-term ratings for the Electric Utility Proxy Group of Baa1 and BBB+, respectively.[65] Hence, a downward credit risk adjustment is necessary to reflect the less risky credit rating, i.e., A3, of UGI Electric relative to the Electric Utility Proxy Group's Baa1 average Moody's bond rating.[66]

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

65 Source of Information: Moody's Investors Service, S&P Capital IQ.

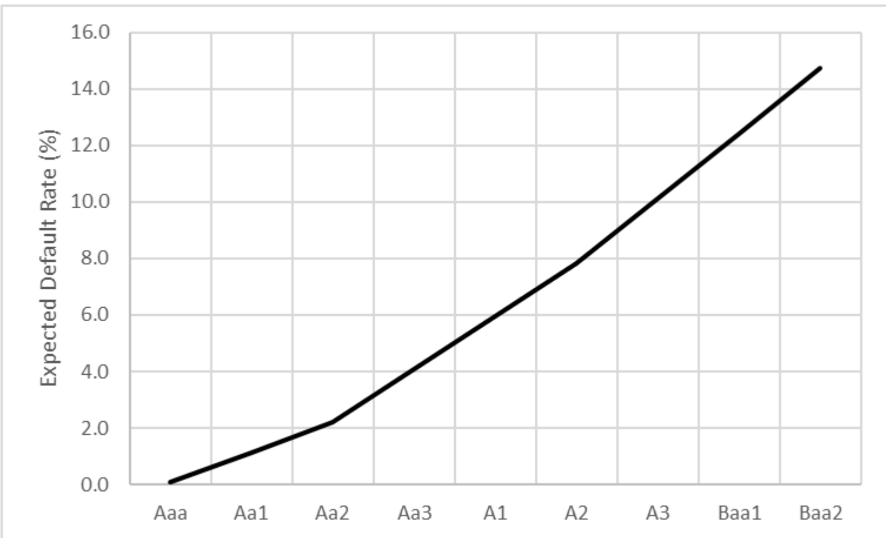
66 As shown on page 3 of Schedule DWD-4.

An indication of the magnitude of the necessary downward adjustment to reflect the lower credit risk inherent in an A3 bond rating is one-third of a recent three-month average spread between Moody's Baa2- and A-rated public utility bond yields of 0.20%, shown on page 2 of Schedule DWD-4, or 0.07%.[67]

Q. WHY IS IT IMPORTANT THAT YOU MAKE A CREDIT RISK ADJUSTMENT?

A. It is important to reflect a company's relative financial risk, as companies with riskier bond ratings have a higher risk of default, and because of that, equity investors would require a higher return on their investment. To illustrate the risk of default related to changes in bond rating, Chart 10 below presents Moody's Idealized Cumulative Expected Default Rates for debt obligations with maturities lasting 30-years based on the respective rating.

Chart 10: Moody's Idealized Cumulative Expected Default Rates Based on Debt Obligations with 30-Year Maturities



As shown in Chart 10, Moody's notes an observable difference in the default rates based on each respective rating. Therefore, even though credit ratings might be similar, the default rates indicate that different ratings equate to different risks.

67 1/3 * 0.20% = 0.07%.

C. 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.

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.[68]

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

[68] Morin, at 329.

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 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.[69] In addition, Morin confirms the need for such an adjustment even when no new equity issuance is imminent.[70] Consequently, it is proper to include a flotation cost 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).[71]

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 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.

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

70 Morin, at 339.

71 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.

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 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.[72]

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 0.13% is required to reflect the flotation costs applicable to the Electric Utility Proxy Group.

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

A. Applying the 0.40% business risk adjustment, -0.07% credit risk adjustment, and the 0.13% flotation cost adjustment to the indicated range of common equity cost rates

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[72] *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).

between 10.22% and 12.98% results in a range of common equity cost rates between 10.68% and 13.45%.

IX. <u>CONCLUSION</u>

Q. WHAT IS YOUR RECOMMENDED ROE FOR UGI ELECTRIC?

A. Given the discussion above and the results of my analytical models, I conclude that an appropriate ROE for the Company is 10.85%.

Q. IN YOUR OPINION, IS YOUR PROPOSED ROE OF 10.85% FAIR AND REASONABLE TO UGI ELECTRIC AND ITS CUSTOMERS?

A. Yes, it is.

Q. IN YOUR OPINION, IS UGI ELECTRIC'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.

UGI ELECTRIC

EXHIBIT DWD-1

Appendix A - Resume and Testimony Listing of:

Dylan W. D'Ascendis, CRRA, CVA
Partner

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 200 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

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MANAGEMENT CONSULTANTS

Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

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

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MANAGEMENT CONSULTANTS

Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

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

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Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

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

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Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

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

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MANAGEMENT CONSULTANTS

Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

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				
UGI Utilities, Inc. – Gas Division	01/26	UGI Utilities, Inc. – Gas Division	Docket No. R-2025-3059523	Return on Equity
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

scottmadden
MANAGEMENT CONSULTANTS

Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
Vicinity Energy Philadelphia, Inc.	04/21	Vicinity Energy Philadelphia, Inc.	Docket No. R-2021-3024060	Rate of Return
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				
Lone Star Transmission, LLC	02/26	Lone Star Transmission, LLC	Docket No. 59245	Rate of Return
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				

scottmadden
MANAGEMENT CONSULTANTS

Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
Atmos Energy Corporation – Mid-Texas Division	11/24	Atmos Energy Corporation – Mid-Texas Division	Docket No. OS-24-00019196	Return on Equity
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 ELECTRIC STATEMENT NO. 9

DARIN T. ESPIGH

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059430

UGI Utilities, Inc. – Electric Division

Statement No. 9

Direct Testimony of
Darin T. Espigh

Topics Addressed: **Taxes and Tax Adjustments**

Dated: March 27, 2026

I. <u>INTRODUCTION AND QUALIFICATIONS</u>

Q. Please state your full name and business address.

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

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

A. I am employed by UGI Corporation ("UGI Corp.") as Senior Manager, Natural Gas Tax Accounting. UGI Corp. is the parent company of UGI Utilities, Inc. ("UGI"). UGI has two operating divisions, the Electric Division ("UGI Electric" or the "Company") and the Gas Division ("UGI Gas"), each of which is 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 return-related filings. Additionally, I maintain the current and deferred income tax accrual and expense accounts, perform tax research, and assist UGI with tax matters as they arise. I also manage UGI's reporting of various tax filings with its local, state, and federal jurisdictions.

Q. Please describe your educational background and work experience.

A. They are set forth in my resume attached as UGI Electric Exhibit DTE-1.

Q. Please describe the purpose of your testimony.

A. I am providing testimony on behalf of UGI Electric. I will explain the Company's *pro forma* tax adjustments to its principal accounting exhibits for the fully projected future test year ending September 30, 2027 ("FPFTY"). I will also explain the tax adjustments made to the results of UGI Electric'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 UGI Electric Exhibits DTE-1 and DTE-2. Together with other Company witnesses, I am sponsoring portions of UGI Electric Exhibit A (Fully Projected), UGI Electric Exhibit A (Future), and UGI Electric Exhibit A (Historic) that pertain to taxes. These exhibits comprise UGI Electric's principal accounting exhibits for the HTY, FTY, and FPFTY. I am also sponsoring certain responses to the Commission's filing requirements and standard data requests. Each response identifies the witness sponsoring it.

II. <u>TAX ADJUSTMENTS</u>

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

A. As explained in the direct testimony of Tracy A. Hazenstab (UGI Electric Statement No. 2), UGI Electric's principal accounting exhibit is UGI Electric Exhibit A (Fully Projected), which includes a presentation for the FPFTY. Section D of UGI Electric Exhibit A (Fully Projected) presents necessary adjustments to budgeted levels of expense items and revenues. The *pro forma* adjustments related to taxes are summarized in Schedules D-31 through D-34. These tax adjustments are used to derive UGI Electric's *pro forma* income at present and proposed rates as set forth in Schedule A-1 of the same exhibit.

UGI Electric Exhibit A (Historic) and UGI Electric Exhibit A (Future) follow the format of UGI Electric Exhibit A (Fully Projected), but reflect data for the HTY and the FTY. This information is provided in accordance with the Commission's filing requirements and provides a basis for comparing UGI Electric's FPFTY claims with actual book results from the HTY and adjusted FTY results. Section D to UGI Electric Exhibit A (Historic), Schedule D-31, and UGI Electric Exhibit A (Future), Schedule D-31 include adjustments that share the same methodology as used in Schedule D-31 of UGI Electric Exhibit A (Fully Projected).

A. TAXES OTHER THAN INCOME TAXES

Q. How was the provision for taxes-other-than-income taxes ("TOTI") determined for the FPFTY?

A. TOTI consists of the Pennsylvania Utility Realty Tax ("PURTA"), the Pennsylvania Gross Receipts Tax, Pennsylvania and Local Use taxes, Social Security taxes, Federal Unemployment tax ("FUTA"), State Unemployment tax ("SUTA") and the Company's assessed contribution to the budgets of the Commission, the Pennsylvania Office of Consumer Advocate, and Pennsylvania Office of Small Business Advocate. TOTI amounts were based on the plan year budget, as adjusted for reasonably known and measurable changes to various payroll taxes as explained by the direct testimony of Ms.

Hazenstab (UGI Electric Statement No. 2). The adjustments are shown on UGI Electric Exhibit A (Fully Projected), Schedule D-31. The net adjustment of ($0.294) million is brought forward to Schedule D-3, page 2.

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 Electric 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 Electric is continuing its practice of normalizing the tax repairs expense deduction for federal tax purposes. For state tax purposes, UGI Electric continues to flow-through the repairs tax benefit over the tax lives of the asset that generated the benefit, which is generally 20 years. The fully adjusted claim for the FPFTY income tax expense is shown on UGI Electric Exhibit A (Fully Projected), Schedule D-1.

Q. Please describe the claim for income taxes shown on Schedule D-1, lines 18 and 19.

A. The calculation of federal and state income taxes can be found on Schedule D-33, lines 13 and 19. This schedule shows the calculation of *pro forma* income taxes for the FPFTY at present and proposed rates. Line 1 shows the revenue at present and proposed rates, while line 2 shows the operating expenses at present and proposed rates from Schedule D-1. Line 3 reflects operating income before debt interest is deducted, by netting line 1 from line 2.

Debt interest expense is synchronized by multiplying the rate base claim from Schedule C-1 by the weighted cost of debt recommended in the direct testimony of Dylan A. D'Ascendis (UGI Electric Statement No. 8) and shown on Schedule B-7. The resulting interest expense on line 6 is subtracted from net income before debt interest to calculate base taxable income on line 7.

In accordance with established Commission practice, lines 8 through 11 of Schedule D-33 reduce the base taxable income, for state tax purposes, by the total difference between accelerated tax depreciation shown on line 8 and the *pro forma* book depreciation shown on line 9. The statutory state corporate net income tax rate was then applied (as further described below in Section F of my testimony) to determine the *pro forma* state income tax expense shown on line 13. Lines 14 through 19 show the federal income tax expense calculation at current and proposed rates, while line 20 sums the state and federal tax expense amounts before application of Deferred Federal and State Income Taxes. At lines 21 through 28, Deferred Federal and State Income Taxes are used to increase the *pro forma* income tax expense at present and proposed rates, with the total calculated amount for income taxes before the application of other adjustments shown on line 29. The amounts of accelerated depreciation, cost of removal, repairs tax deduction, tax basis adjustments to plant, straight line depreciation, and book depreciation used in determining income taxes are summarized on Schedule D-34.

Q. What is the total FPFTY income tax expense for UGI Electric?

A. As shown on Schedule D-33 at line 31, the *pro forma* combined income tax expense at present rates is $0.296 million, and the *pro forma* income tax expense at proposed rates for the FPFTY is $4.555 million. As explained below in Section E of my testimony, this figure is not 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. Did the Company reflect the amortization of Excess Deferred Federal Income Taxes ("EDFIT") resulting from the 2017 Tax Cuts and Jobs Act ("TCJA") in its income tax expense claim?

A. Yes, the Company calculated the amount of the EDFIT to be amortized and flowed back to ratepayers in its FPFTY. This amount is included in the overall federal deferred tax expense calculated on Line 25 of Schedule D-33. The total amortization was approximately $0.232 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 8 reflects the difference in income tax expense for book and tax purposes attributable to the difference between the accelerated tax depreciation and straight-line book depreciation on test year plant balances, net of offsets associated with contributions in aid of construction. Rate base was reduced further by the state regulatory liability associated with UGI Electric's repairs tax method shown on line 6. As the state tax consequence of accelerated depreciation is flowed through, there is no associated state ADIT balance.

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

A. As shown on line 8 of Schedule C-6 and on line 5 of Schedule A-1, the ADIT offset is $27.953 million, which includes an amount related to the repairs tax method explained below in Section D of my testimony.

Q. Does the Company's reduction to rate base include an amount associated with EDFIT?

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

Q. Did the Company calculate its federal ADIT rate base deduction in compliance with the normalization requirements of the Internal Revenue Code?

A. Yes. The Company's calculation properly reflects the pro-rationing concept in accordance with Treasury Regulation 1.167(l)-1(h)(6)(ii) that it must follow for ratemaking purposes to comply with IRS normalization requirements. To qualify for normalization, the IRS requires utilities to pro-rate rate base deductions for ADIT to account for the fact that the Company accrues ADIT for plant additions throughout the year. See UGI Electric Exhibit DTE-2 for the calculation of the pro-rata adjustment.

D. REPAIRS TAX METHOD

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

A. In its tax return for the year ended September 30, 2009, UGI Electric adopted a tax accounting method to expense as repairs certain items capitalized for book purposes in accordance with federal tax regulations. As it did in the Company's previous base rate case at Docket No. R-2022-3037368, UGI Electric chose to normalize its federal income tax expense claim, inclusive of the repairs tax deduction. This difference between accelerated tax depreciation and book depreciation in the calculation of federal tax expense creates ADIT. For state income tax purposes, solely with respect to the repairs tax deduction, UGI Electric chose to flow-through the repairs tax benefit over the tax useful lives of the assets generating the tax deduction. The state ADIT balance associated with the repairs tax deduction is classified as a regulatory liability, as it represents the repairs tax benefit that ratepayers have not yet received. In both the federal and state instances, the ADIT balance amortizes or unwinds over the remaining life of the asset.

As noted previously, the Company reduces rate base by the sum of the federal ADIT balance and the state repair regulatory liability.

E. CONSOLIDATED TAX BENEFITS

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

A. No. The Company's revenue requirement is established based on its stand-alone federal income tax attributes. It is 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. 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 Pennsylvania tax rate change?

A. 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%). 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. Due to the Company's fiscal year ended September 30, when is the annual Pennsylvania tax rate change effective?

A. As provided in Act 53, the annual tax rates are for "*taxable years beginning…on or after the (calendar year) dates set forth"* in the law. As explained in the Company's annual letter at Docket No. M-2022-3037158, since UGI Electric's fiscal year begins on October 1, the reduction in the tax rate for each calendar year is effective on October 1 rather than January 1.

Below is a table detailing the Company's state tax rates based on it's fiscal years beginning October 1 as detailed by the calendar year schedule in Act 53.

Calendar Year	UGI Electric Fiscal Year Beginning	Tax Rates
2023	October 1, 2023	8.99%
2024	October 1, 2024	8.49%
2025	October 1, 2025	7.99%
2026	October 1, 2026	7.49%
2027	October 1, 2027	6.99%
2028	October 1, 2028	6.49%
2029	October 1, 2029	5.99%
2030	October 1, 2030	5.49%
2031	October 1, 2031	4.99%

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

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

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC

EXHIBIT DTE-1

DARIN ESPIGH, CPA

PROFESSIONAL EXPERIENCE

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

Manage the accounting for income taxes in accordance with ASC 740 for Natural Gas business segment. Provide technical accounting guidance and expertise on tax accounting, planning and compliance matters. Oversee and review the preparation of information supporting various regulatory filings. Oversee and review the preparation of various tax related filings. 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 Base Rate Case	Docket No. R-2025-3059523

UGI ELECTRIC

EXHIBIT DTE-2

UGI - Electric 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					$ 27,557
10/31/2026	51	335	91.78%	47	27,604
11/30/2026	69	305	83.56%	58	27,661
12/31/2026	57	274	75.07%	43	27,704
1/31/2027	71	243	66.58%	48	27,752
2/28/2027	56	215	58.90%	33	27,784
3/31/2027	59	184	50.41%	30	27,814
4/30/2027	90	154	42.19%	38	27,852
5/31/2027	67	123	33.70%	22	27,875
6/30/2027	142	93	25.48%	36	27,911
7/31/2027	98	62	16.99%	17	27,928
8/31/2027	273	31	8.49%	23	27,951
9/30/2027	786	1	0.27%	2	**$ 27,953**

UGI ELECTRIC STATEMENT NO. 10

SHERRY A. EPLER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-
3059430

UGI Utilities, Inc. – Electric Division

Statement No. 10

Direct Testimony of
Sherry A. Epler

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

Dated: March 27, 2026

I. INTRODUCTION

Q. Please state your name and business address.

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

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

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

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

A. My current responsibilities related to UGI Electric include: (1) all aspects of tariff and rate administration, including interactions with electric retail suppliers under the Company's electric supplier tariff; and (2) revenue analysis.

Q. Please provide your educational background and professional experience.

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

Q. Have you testified previously before the Pennsylvania Public Utility Commission?

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

Q. Please describe the purpose of your testimony.

A. I will address: (1) the development of sales and revenue for the historic test year ended September 30, 2025 ("HTY"), future test year ending September 30, 2026 ("FTY"), and fully projected future test year ending September 30, 2027 ("FPFTY"); and (2) and certain proposed tariff modifications.

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

A. Yes. Company witness Cynthia S. Fang, Director at Atrium Economics, LLC (UGI Electric Statement No. 11), is sponsoring allocation of the revenue increase and rate design, in addition to her testimony supporting class cost of service, using the projected sales and revenue figures discussed in my testimony. Additionally, Company witness Jessica R. Rogers (UGI Electric Statement No. 1) is sponsoring certain proposed tariff modifications.

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

A. Yes, I am sponsoring the following Exhibits: UGI Electric Exhibit SAE-1 (Resume), UGI Electric Exhibit SAE-2 (10 Year Normal Heating and Cooling Degree Days 2015-2024), UGI Electric Exhibit SAE-3 (UGI Electric Customer Counts), UGI Electric Exhibit SAE-4 (Fully Projected Future Test Year Sales and Revenue Adjustments), UGI Electric Exhibit SAE-5 (Future Test Year Sales and Revenue Adjustments), UGI Electric Exhibit SAE-6 (Historic Test Year Sales and Revenue Adjustments), UGI Electric Exhibit E (Proof of Revenue), and certain portions of UGI Electric Exhibit F (Proposed Tariff). I am also sponsoring certain responses to the Commission's standard filing requirements, as indicated on the matter list accompanying this filing, that were prepared by me or under my direction.

II. TEST YEARS' SALES AND REVENUES

A. Development of FPFTY Sales and Revenues

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

A. FPFTY sales and revenues were developed by annualizing and normalizing the Company's 2027 fiscal year planned sales and revenue budget. Annualized sales were determined by developing sales and revenue adjustments reflective of annual expected use per customer and projected customer counts as of the end of the FPFTY, or September 30, 2027. UGI Electric Exhibit SAE-2 provides the development of the Company's normal degree day values, which are based on the 10-year period 2015-2024. This data was used in normalizing use per customer for degree days. Normal Heating Degree Days ("HDD") and Cooling Degree Days ("CDD") 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.

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

A. A summary of all adjustments made to the 2027 planned budget in order to develop FPFTY sales is shown on UGI Electric Exhibit SAE-4(a). In total, these adjustments reflect a decrease in sales of 15,349,000 kWh, or 1.55%, with a net downward adjustment to margin of $861,000, and a net decrease in revenues of $5,897,000.

Q. Please explain the "Adjustment for Customer Changes" shown on UGI Electric Exhibit SAE-4(b).

A. The "Adjustment for Customer Changes" annualizes customer counts for certain rate classes to anticipated end-of-test-year levels. The Company projects customer growth forward from September 2025 actual levels based on a two-year average growth pattern from year-end September 2023 to year-end September 2024 and from year-end September 2024 to year-end September 2025, as shown in the presented customer rate categories. UGI Electric Exhibit SAE-3 provides the actual historical customer count and illustrates the relatively static nature of the service territory.

Q. How is this adjustment quantified?

A. UGI Electric Exhibit SAE-4(b) provides the calculation of the associated sales and revenue adjustments related to customer count changes and reflects customer count increases for default service customers taking service under Rate R-General, Rate R-Heating, Rate GS-1-Commercial General, and a decrease for Rate GS-4-Commercial General. Adjustments were made to these four rate class categories, as they comprise the majority of customer counts and the largest total margin of dollars for the Company. In total, as reflected on UGI Electric Exhibit SAE-4(a), this adjustment increases sales by 5,363,000 kWh and increases projected revenues by $986,000. The impact to margin is an increase of $300,000.

Q. Please explain the adjustment for "Normalized Use/Customer."

A. As described by witness Vivian K. Ressler (UGI Electric Statement No. 4), the sales-kWh values for the budget were developed using a rolling one-year actual of the sales-kWh for each month for a one-year period ending April 2025. As the associated average degree days for these periods differ from the Company's 10-year period used to define normal degree days for ratemaking purposes, or normal weather, an adjustment is necessary to normalize usage to the Company's stated 10-year normal weather. This adjustment utilizes the variance between the calculated average degree days for the periods utilized for budget development and the Company's 10-year normal degree days to calculate the normalizing adjustments. *See* UGI Electric Exhibit SAE-2 for related degree day data. UGI Electric Exhibit SAE-4(c) shows the calculation of the adjustment of the use per default service customer taking service under Rate R-General, Rate R-Heating, Rate GS-1-Commercial General, and Rate GS-4-Commercial General, respectively. As shown in this exhibit, this adjustment is calculated by applying the heating and cooling sensitivity per degree day to the difference between the calculated average degree days for the periods utilized for budget development and the Company's 10-year normal degree days. In total, as reflected on UGI Electric Exhibit SAE-4(a), this adjustment decreases sales by 20,712,000 kWh and decreases projected revenues by $3,783,000. The impact to margin is a decrease of $1,050,000.

Q **Please explain the adjustment on UGI Electric Exhibit SAE-4(d) "Adjustment for GSR-1."**

A. The "Adjustment for GSR-1" annualizes the revenue from the default service GSR-1 rate based on the December 1, 2025, Residential GSR-1 rate of $0.11211/kWh versus its budgeted level of $0.11470/kWh and Non-Residential GSR-1 rate of $0.10758/kWh versus its budgeted level of $0.11005/kWh. This GSR-1 adjustment decreases projected revenues by $1,731,000 with no impact to margin.

Q **Please explain the adjustment on UGI Electric Exhibit SAE-4(e) "Adjustment for USP."**

A. The Adjustment for USP annualizes the revenue from the UGI Electric Rider C – Universal Service Program ("USP") rider based on the December 1, 2025, USP Rider rate of $0.01868/kWh versus its budgeted level of $0.02121/kWh and updates for the base budget volumes to which the $0.02121/kWh rate is applied. This USP adjustment decreases projected revenues by $1,529,000 with no impact to margin.

Q **Please explain the adjustment on UGI Electric Exhibit SAE-4(f) "Adjustment for STAS."**

A. The "Adjustment for STAS" is the calculated State Tax Adjustment Surcharge ("STAS") on all Revenue adjustments presented in UGI Electric Exhibits SAE-4(b), (c), (d), (e), (g), and (h). This STAS adjustment increases projected revenues by $14,000 with no impact to margin.

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

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 increases revenues by $263,000 with no impact to margin.

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

A. The "Adjustment for DSIC" annualizes the Distribution System Improvement Charge ("DSIC") rate to reflect end of FPFTY conditions. This DSIC adjustment decreases projected revenues by $118,000 and decreases projected margins by $111,000.

B. Development of Sales and Revenue for the FTY and HTY

Q. How were normalized and annualized sales and revenue determined for the FTY ending September 30, 2026?

A. Budgeted sales and revenues served as the starting point for the development of the normalized and annualized FTY sales and revenues summarized on UGI Electric Exhibit SAE-5(a). All of the adjustments that were made in the development of the FPFTY were also made in the development of the FTY, with the exception of the "Adjustment for DSIC." These detailed adjustments are contained in UGI Electric Exhibits SAE-5(b)-(g).

Q. How were normalized and annualized sales and revenue determined for the HTY ended September 30, 2025?

A. Historic sales and revenues served as the starting point for the development of the normalized and annualized HTY sales and revenues shown in summary on UGI Electric

Exhibit SAE-6(a). All of the adjustments that were made in the development of the FPFTY were also made in the development of the HTY, except for the "Adjustment for DSIC."

III. TARIFF MODIFICATIONS

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

A. The Company is revising references to the Supplement Number, Notice Language, Issue and Effective Dates, and page numbers as necessary; in accordance with 52 Pa. Code Chapter 53 standards. Apart from the proposed rate schedule changes (in accordance with this rate case filing), a complete list of tariff modifications can be found in the List of Changes Made by the Supplement section in UGI Gas Exhibit F – Proposed Supplement No. 92 to UGI Electric Tariff No. 6. More significant proposed changes to the tariff include:

- Rule 13, Payment Terms, subsection 13-e, has clarifying language added to explain that Budget Billing will be reviewed and adjusted on a quarterly basis.
- Subsection 13-j was added to specify the acceptable and Applicable Forms of Payment that customers may remit to the Company for payment of public utility service.
- Rider A – The State Tax Adjustment Surcharge was rolled into rates and reset to 0.00%.
- Rider C – Universal Service Program was revised so the CAP credit bad debt and preprogram arrearage 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. Additionally, language has been added to allow the USP Rider to apply on a fully negotiated basis for certain Rate HTP customers allowing

those customers to contribute to Rider USP and otherwise lower USP costs borne by the Company's residential customers.

- Rider G –DSIC was reset to 0.00% in accordance with 66 Pa. C.S. § 1358(b).
- Language has been added to allow the DSIC Rider to apply on a fully negotiated basis for certain Rate HTP customers allowing those customers to contribute to the DSIC rider and otherwise lower DSIC costs borne by the Company's other customers.
- New rates have been added to Rates LED-OL and LED-SL for 300-350 wattage range based on customer interest.
- Clarifying language has been added to multiple lighting rate schedules due to the phase out of certain lights.

Q. Are any other tariff changes being proposed by the Company?

A. The Company has proposed other, less substantive, changes to the tariff that are listed on page 2, List of Changes, of UGI Electric Exhibit F – Proposed Tariff.

Q. Does this conclude your testimony?

A. Yes.

UGI ELECTRIC

EXHIBIT SAE-1

Sherry Epler

Senior Manager, Tariff & Supplier Administration

Work Experience

UGI Utilities, Inc., Denver, PA

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

UGI Utilities, Inc., Reading, PA

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

Education

Bachelor of Science, Accounting, Albright College, 1995

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

Previous testimony provided before the Pennsylvania Public Utility Commission:

Docket No. R-2021-3023618	UGI Electric Base Rate Case
Docket No. R-2021-3030218	UGI Gas Base Rate Case
Docket No. R-2022-3037368	UGI Electric Base Rate Case
Docket No. R-2024-3052716	UGI Gas Base Rate Case
Docket No. R-2025-3059523	UGI Gas Base Rate Case

UGI ELECTRIC

EXHIBIT SAE-2

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

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Average *
Jan	1,268	1,140	992	1,210	1,188	956	1,082	1,271	836	1,027	1,097
Feb	1,309	924	757	824	953	828	1,009	923	803	824	915
Mar	996	623	938	955	872	641	682	728	799	660	789
Apr	446	495	289	628	371	545	424	482	341	382	440
May	94	236	225	87	145	234	217	108	214	108	167
Jun	25	26	41	26	26	28	18	16	50	8	26
Jul	0	0	0	0	0	0	3	0	0	0	0
Aug	0	0	19	0	3	0	0	0	1	17	4
Sep	38	60	94	82	49	95	53	92	109	40	71
Oct	390	352	224	413	302	320	203	401	301	313	322
Nov	509	623	701	812	798	525	737	582	725	601	661
Dec	638	996	1,108	933	961	945	788	991	785	1,040	920
Totals	5,713	5,475	5,388	5,970	5,668	5,117	5,216	5,594	4,964	5,020	5,412

UGI Utilities Inc. - Electric Division
10 Year Normal Cooling Degree Days (2015-2024)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Average *
Jan	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0
Apr	0	1	15	4	7	0	6	2	29	12	8
May	143	69	35	77	32	61	58	73	18	68	63
Jun	153	151	161	117	113	178	201	123	91	208	150
Jul	244	326	244	261	320	377	221	339	273	323	293
Aug	210	290	140	262	196	269	274	284	145	186	226
Sep	134	117	102	119	79	86	74	72	86	50	92
Oct	0	9	37	28	14	5	10	0	12	3	12
Nov	1	0	0	0	0	1	0	8	0	5	0
Dec	0	0	0	0	0	0	0	0	0	0	0
Totals	885	963	734	868	761	977	844	901	654	855	844

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

UGI ELECTRIC

EXHIBIT SAE-3

UGI Utilities Inc. - Electric Division
Customer Counts at Year End September

	Sept 1995	Sept 2017	Sept 2018	Sept 2019	Sept 2020	Sept 2021	Sept 2022	Sept 2023	Sept 2024	Sept 2025	Sept 2026	Sept 2027
Residential Non- Heating	42,920	44,014	44,024	44,104	44,301	44,237	44,253	44,279	44,356	44,488	44,533	44,663
Residential Heating	10,389	10,341	10,372	10,347	10,415	10,448	10,532	10,544	10,583	10,599	10,626	10,667
Commercial Non-Heating	5,872	7,142	7,179	7,239	7,294	7,302	7,292	7,338	7,385	7,349	7,374	7,412
Commercial Heating	585	336	338	337	331	327	329	327	322	326	325	325
Industrial Non-Heating	136	118	118	115	117	121	120	119	118	116	118	118
Industrial Heating	45	35	35	35	35	35	35	35	35	35	35	35
Public St & Hwy Lighting	51	54	53	54	53	53	55	54	54	54	54	54
Other	5	7	7	7	7	7	7	7	7	7	7	7
Sales for Resale	2	3	3	3	3	3	3	3	3	3	3	3
Total	60,005	62,050	62,129	62,241	62,556	62,533	62,626	62,706	62,863	62,977	63,075	63,284

Note: Excludes unmetered Lighting

UGI ELECTRIC

EXHIBIT SAE-4(a) – SAE-4(h)

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

	Sales (000's) MWh	Revenues ($000's)	Margin ($000's)	Reference
Budget 2027	992,290	149,982	52,528	
Adjustment for Customer Changes	5,363	986	300	UGI Electric Exhibit SAE-4(b)
Adjustment for Normalized Use/Customer	(20,712)	(3,783)	(1,050)	UGI Electric Exhibit SAE-4(c)
Adjustment for GSR-1		(1,731)	0	UGI Electric Exhibit SAE-4(d)
Adjustment for USP		(1,529)	0	UGI Electric Exhibit SAE-4(e)
Adjustment for STAS		14	0	UGI Electric Exhibit SAE-4(f)
Adjustment for EEC		263	0	UGI Electric Exhibit SAE-4(g)
Adjustment for DSIC		(118)	(111)	UGI Electric Exhibit SAE-4(h)
Fully Projected Future Test Year 2027	976,941	144,085	51,667	

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

Adjustment for Customer Changes
Rate R General, Rate R Heating, Rate GS-1 Com-Gen, Rate GS-4 Com-Gen
GSR-1 subgroups only

Line #		[1] Rate R General	[2] Rate R Heating	[3] Rate GS-1 Com-Gen	[4] Rate GS-4 Com-Gen	[5] Total
1	Original Budget Customers in FPFTY 2027 (Unadjusted)	44,000	10,478	4,799	1,706	60,983
2	FPFTY 2027 Customers (Fully Adjusted)	44,260	10,560	4,839	1,742	61,401
3	Change in Customers during FPFTY 2027	260	82	40	36	418
4	Total UPC (Unadjusted)-kWh	8,724	16,320	4,940	43,311	73,296
5	Annualization Adjustment for Sales-MWh	2,268	1,338	198	1,559	5,363
6	USP unit rate $/kWh	$ 0.01868	$ 0.01868	$ -	$ -	
7	EEC-Class 1 & Class 2 unit rate $/kWh	$ 0.00181	$ 0.00181	$ 0.00233	$ 0.00233	
8	GSR-1 unit rate $/kWh	$ 0.11211	$ 0.11211	$ 0.10758	$ 0.10758	
9	Distribution unit rate (margin plus GRT) $/kWh	$ 0.05290	$ 0.05290	$ 0.05987	$ 0.03339	
10	Customer Charge rate $/month	$ 10.75000	$ 10.75000	$ 17.00000	$ 18.00000	
11	Total Revenue Adjustment (L12+L13+L14+L15+L16)	$ 454	$ 259	$ 42	$ 231	$ 986
12	USP Adjustment (L5 * L6)	$ 42	$ 25	$ -	$ -	$ 67
13	EEC Adjustment (L5 * L7)	$ 4	$ 2	$ 0	$ 4	$ 11
14	GSR Adjustment (L5 * L8)	$ 254	$ 150	$ 21	$ 168	$ 593
15	Distribution Adjustment (L5 * L9)	$ 120	$ 71	$ 12	$ 52	$ 255
16	Customer Charge Adjustment (L3*12*L10)	$ 34	$ 11	$ 8	$ 8	$ 60
17	Total Margin Adjustment (L15 less GRT+L16)	$ 146	$ 77	$ 19	$ 57	$ 300

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

Adjustment for Usage per Customer
Rate R General, Rate R Heating, Rate GS-1 Com-Gen, Rate GS-4 Com-Gen
GSR-1 subgroups only

Line #		[1] Rate R General	[2] Rate R Heating	[3] Rate GS-1 Com-Gen	[4] Rate GS-4 Com-Gen	[5] Total
1	Heating Sensitivity/HDD/cust (kWh/DD/cust)	$ 1.6999	$ 0.5644	$ 3.1200	$ 0.4490	
2	DD Variance (to 10 Year normal)	(193)	(193)	(193)	(193)	
3	kWh/customer adjustment (L1 * L2)	(328)	(109)	(602)	(87)	
4	Customers FY27 (fully adjusted)	44,260	10,560	4,839	1,742	
5	Normalizing Adj (L3 * L4)/1000 -MWh	(14,521)	(1,150)	(2,914)	(151)	(18,736)
6	Total Revenue unit rate (L7+L8+L9+L10+L11)-$/kWh	$ 0.18550	$ 0.18550	$ 0.16978	$ 0.14330	
7	USP unit rate-$/kWh	$ 0.01868	$ 0.01868	$ -	$ -	
8	EEC-Class 1 & Class 2 unit rate-$/kWh	$ 0.00181	$ 0.00181	$ 0.00233	$ 0.00233	
9	GSR-1 unit rate-$/kWh	$ 0.11211	$ 0.11211	$ 0.10758	$ 0.10758	
10	Distribution unit rate (margin plus GRT)-$/kWh	$ 0.05290	$ 0.05290	$ 0.05987	$ 0.03339	
11	Revenue Adjustment (L5 * L6)	$ (2,694)	$ (213)	$ (495)	$ (22)	$ (3,423)
12	USP Adjustment (L5 * L7)	$ (271)	$ (21)	$ -	$ -	$ (293)
13	EEC Adjustment (L5 * L8)	$ (26)	$ (2)	$ (7)	$ (0)	$ (36)
14	GSR Adjustment (L5 * L9)	$ (1,628)	$ (129)	$ (313)	$ (16)	$ (2,087)
15	Distribution Adjustment (L5 * L10)	$ (768)	$ (61)	$ (174)	$ (5)	$ (1,008)
16	Margin Adjustment (L15 less GRT)	$ (723)	$ (57)	$ (164)	$ (5)	$ (949)
17	Cooling Sensitivity/CDD/cust (kWh/DD/cust)	$ 0.5761	$ 0.6299	$ 1.7746	$ 0.2485	
18	DD Variance (to 10 Year normal)	(48)	(48)	(48)	(48)	
19	kWh/customer adjustment (L17 * L18)	(28)	(30)	(85)	(12)	
20	Customers FY27 (fully adjusted)	44,260	10,560	4,839	1,742	
21	Normalizing Adj (L19 * L20)/1000 -MWh	(1,224)	(319)	(412)	(21)	(1,976)
22	Total Revenue unit rate (L23+L24+L25+L26)-$/kWh	$ 0.18550	$ 0.18550	$ 0.16978	$ 0.14330	
23	USP unit rate-$/kWh	$ 0.01868	$ 0.01868	$ -	$ -	
24	EEC-Class 1 & Class 2 unit rate-$/kWh	$ 0.00181	$ 0.00181	$ 0.00233	$ 0.00233	
25	GSR-1 unit rate-$kWh	$ 0.11211	$ 0.11211	$ 0.10758	$ 0.10758	
26	Distribution unit rate (margin plus GRT)-$/kWh	$ 0.05290	$ 0.05290	$ 0.05987	$ 0.03339	
27	Revenue Adjustment (L21 * L22)	$ (227)	$ (59)	$ (70)	$ (3)	$ (359)
28	USP Adjustment (L21 * L23)	$ (23)	$ (6)	$ -	$ -	$ (29)
29	EEC Adjustment (L21 * L24)	$ (2)	$ (1)	$ (1)	$ (0)	$ (4)
30	GSR Adjustment (L21 * L25)	$ (137)	$ (36)	$ (44)	$ (2)	$ (220)
31	Distribution Adjustment (L21 * L26)	$ (65)	$ (17)	$ (25)	$ (1)	$ (107)
32	Margin Adjustment (L31 less GRT)	$ (61)	$ (16)	$ (23)	$ (1)	$ (101)
33	Total Adjustment Summary-FY27					
34	Normalizing Adj (L5+L21)-MWh	(15,745)	(1,470)	(3,326)	(172)	(20,712)
35	Total Revenue Adjustment (L11+L27)	$ (2,921)	$ (273)	$ (565)	$ (25)	$ (3,783)
36	Total USP Adjustment (L12+L28)	$ (294)	$ (27)	$ -	$ -	$ (322)
37	Total EEC Adjustment (L13+L29)	$ (28)	$ (3)	$ (8)	$ (0)	$ (39)
38	Total GSR Adjustment(L14+L30)	$ (1,765)	$ (165)	$ (358)	$ (18)	$ (2,306)
39	Total Distribution Adjustment(L15+L31)	$ (833)	$ (78)	$ (199)	$ (6)	$ (1,116)
40	Total Margin Adjustment (L16+L32)	$ (784)	$ (73)	$ (187)	$ (5)	$ (1,050)

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

Adjustment for GSR-1

	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
Residential													
Original Budget GSR-1 Rate FPFTY 2027-$/kWh	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	
FPFTY 2027 Annulized GSR-1 Dec 1, 2025 Rate-$/kWh	$0.11211	$0.11211	$0.11211	$0.11211	$0.11211	$0.11211	$0.11211	$0.11211	$0.11211	$0.11211	$0.11211	$0.11211	
GSR-1 Rate Variance	($0.00259)	($0.00259)	($0.00259)	($0.00259)	($0.00259)	($0.00259)	($0.00259)	($0.00259)	($0.00259)	($0.00259)	($0.00259)	($0.00259)	
Total GSR-1 Volumes-MWh	36,802	40,835	62,296	68,000	51,488	48,604	35,160	37,276	43,514	55,414	44,111	31,982	555,481
GSR-1 Revenue Adjustment	($95)	($106)	($161)	($176)	($133)	($126)	($91)	($97)	($113)	($144)	($114)	($83)	($1,439)
Non-Residential													
Original Budget GSR-1 Rate FPFTY 2027-$/kWh	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	
FPFTY 2027 Annulized GSR-1 Dec 1, 2025 Rate-$/kWh	$0.10758	$0.10758	$0.10758	$0.10758	$0.10758	$0.10758	$0.10758	$0.10758	$0.10758	$0.10758	$0.10758	$0.10758	
GSR-1 Rate Variance	($0.00247)	($0.00247)	($0.00247)	($0.00247)	($0.00247)	($0.00247)	($0.00247)	($0.00247)	($0.00247)	($0.00247)	($0.00247)	($0.00247)	
Total GSR-1 Volumes-MWh	8,657	8,628	10,676	12,340	10,254	9,603	8,768	9,179	10,100	11,094	10,354	8,649	118,302
GSR-1 Revenue Adjustment	($21)	($21)	($26)	($30)	($25)	($24)	($22)	($23)	($25)	($27)	($26)	($21)	($292)
Total													
Total GSR-1 Volumes-MWh	45,459	49,462	72,973	80,340	61,741	58,207	43,928	46,455	53,614	66,507	54,465	40,631	673,782
GSR-1 Revenue Adjustment	($117)	($127)	($188)	($207)	($159)	($150)	($113)	($119)	($138)	($171)	($140)	($104)	($1,731)

UGI Utilities, Inc.- Electric Division
Fully Projected Future Period- 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 Budget USP Calculation	$720	$799	$1,219	$1,331	$1,007	$951	$687	$730	$852	$1,084	$863	$625	$10,869
Updated Budget USP Calculation	$702	$780	$1,189	$1,299	$983	$928	$671	$712	$831	$1,058	$842	$610	$10,605
Variance to Original Budget Calculation	($17)	($19)	($30)	($32)	($24)	($23)	($17)	($18)	($21)	($26)	($21)	($15)	($264)
Original Budget USP Rate FPFTY 27 - $kWh	$0.02121	$0.02121	$0.02121	$0.02121	$0.02121	$0.02121	$0.02121	$0.02121	$0.02121	$0.02121	$0.02121	$0.02121	
FPFTY 2027 Annualized USP Dec 1, 2025 Rate-$kWh	$0.01868	$0.01868	$0.01868	$0.01868	$0.01868	$0.01868	$0.01868	$0.01868	$0.01868	$0.01868	$0.01868	$0.01868	
USP Rate Variance-$kWh	($0.00253)	($0.00253)	($0.00253)	($0.00253)	($0.00253)	($0.00253)	($0.00253)	($0.00253)	($0.00253)	($0.00253)	($0.00253)	($0.00253)	
Total Rate R Volumes-MWh	37,121	41,210	62,864	68,628	51,942	49,046	35,451	37,626	43,924	55,924	44,490	32,252	560,479
Total Rate R excl CAP Volumes-MWh	33,116	36,766	56,081	61,223	46,335	43,753	31,624	33,567	39,185	49,888	39,687	28,771	499,996
USP Rate Revenue Variance	($84)	($93)	($142)	($155)	($117)	($111)	($80)	($85)	($99)	($126)	($100)	($73)	($1,265)
Total Revenue Variance	($101)	($112)	($171)	($187)	($142)	($134)	($97)	($103)	($120)	($153)	($121)	($88)	($1,529)

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

Adjustment for STAS

	Unadjusted Budget Revenue Excluding STAS	Customer Adj	UPC Adj	GSR-1	USP	EEC	DSIC Adj	Revised Revenue Excluding STAS	STAS Revenue @ Dec 1, 2025 Rate 0.02%	STAS Revenue @ Budget Rate 0.01%	STAS Adjustment
Residential	$ 114,727	$ 713	$ (3,193)	$ (1,439)	$ (1,529)	168	$ (116)	$ 109,332	$ 22	$ 11	$ 10
Commercial & Industrial	$ 34,603	$ 273	$ (589)	$ (290)	$ -	91	$ (2)	$ 34,085	$ 7	$ 3	$ 3
Public Streets & Highway Lighting	$ 613	$ -		$ (2)	$ -	3	$ 0	$ 614	$ 0	$ 0	$ 0
Other Sales to Public Authorities	$ 20	$ -		$ -	$ -	1	$ 0	$ 21	$ 0	$ 0	$ 0
Sales for Resale	$ 4	$ -		$ -	$ -	0	$ (0)	$ 4	$ 0	$ 0	$ 0
Total	$ 149,967	$ 986	$ (3,783)	$ (1,731)	$ (1,529)	$ 263	$ (118)	$144,056	$ 29	$ 15	$ 14

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

Adjustment for EEC

	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 EEC-Class 1 Rate FPFTY 2027-$/kWh	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	
FPFTY 2027 Annualized EEC-Class 1 Rate Effective Dec 1,2025-$/kWh	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	
EEC-Class 1 Rate Variance-$/kWh	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	
Total EEC-Class 1 Volumes-MWh	37,252	41,343	63,024	68,799	52,072	49,178	35,558	37,750	44,052	56,072	44,633	32,373	562,105
Total EEC-Class 1 Revenue Adjustment	$11	$12	$19	$21	$16	$15	$11	$11	$13	$17	$13	$10	$169
Original Budget EEC-Class 2 Rate FPFTY 2027-$/kWh	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	
FPFTY 2027 Annualized EEC-Class 2 Rate Effective Dec 1,2025-$/kWh	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	
EEC-Class 2 Rate Variance-$/kWh	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	
Total EEC-Class 2 Volumes-MWh	11,831	11,066	14,812	15,539	12,129	12,272	10,922	12,544	13,702	15,105	13,526	11,226	154,676
Total EEC-Class 2 Revenue Adjustment	$13	$12	$16	$17	$13	$14	$12	$14	$15	$17	$15	$12	$172
Original Budget EEC-Class 3 Rate FPFTY 2027-$/kWh	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	
FPFTY 2027 Annualized EEC-Class 3 Rate Effective Dec 1,2025-$/kWh	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	
EEC-Class 3 Rate Variance-$/kWh	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	
Total EEC-Class 3 Volumes-MWh	19,846	22,907	19,585	23,771	26,772	19,069	23,375	21,499	24,214	23,054	26,643	24,776	275,509
Total EEC-Class 3 Revenue Adjustment	($6)	($6)	($5)	($7)	($7)	($5)	($7)	($6)	($7)	($6)	($7)	($7)	($77)
Total EEC Revenue Adjustment	$19	$18	$30	$31	$22	$23	$16	$19	$22	$27	$21	$15	$263

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

Adjustment for DSIC

	Unadjusted Budget DSIC Revenue @5%	Adjusted Budget DSIC Revenue @ 5%	DSIC Revenue Adjustment	GRT on DISC Adjustment	DSIC Margin Adjustment
Residential	$ 2,429	$ 2,314	$ (116)	$ 7	$ (109)
Commercial & Industrial	$ 776	$ 774	$ (2)	$ 0	$ (2)
Public Streets & Highway Lighting	$ 25	$ 25	$ 0	$ (0)	$ 0
Other Sales to Public Authorities	$ 1	$ 1	$ 0	$ (0)	$ 0
Sales for Resale	$ 0	$ 0	$ (0)	$ 0	$ (0)
Total	$ 3,231	$ 3,113	$ (118)	$ 7	$ (111)

UGI ELECTRIC

EXHIBIT SAE-5(a) – SAE-5(g)

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

	Sales (000's) MWh	Revenues ($000's)	Margin ($000's)	Reference
Budget 2026	992,290	148,872	51,484	
Adjustment for Customer Changes	2,682	493	150	UGI Electric Exhibit SAE-4(b)
Adjustment for Normalized Use/Customer	(20,645)	(3,770)	(1,046)	UGI Electric Exhibit SAE-4(c)
Adjustment for GSR-1		(1,731)	0	UGI Electric Exhibit SAE-4(d)
Adjustment for USP		(1,529)	0	UGI Electric Exhibit SAE-4(e)
Adjustment for STAS		14	0	UGI Electric Exhibit SAE-4(f)
Adjustment for EEC		263	0	UGI Electric Exhibit SAE-4(g)
Future Test Year 2026	974,327	142,612	50,588	

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

Adjustment for Customer Changes
Rate R General, Rate R Heating, Rate GS-1 Com-Gen, Rate GS-4 Com-Gen
GSR-1 subgroups only

Line #		[1] Rate R General	[2] Rate R Heating	[3] Rate GS-1 Com-Gen	[4] Rate GS-4 Com-Gen	[5] Total
1	Customers in Test Year 2026 (Unadjusted)	44,000	10,478	4,799	1,706	60,983
2	Future Test Year 2026 Customers (Fully Adjusted)	44,130	10,519	4,819	1,724	61,192
3	Change in Customers during Future Test Year 2026	130	41	20	18	209
4	Total UPC (Unadjusted)-kWh	8,724	16,320	4,940	43,311	73,296
5	Annualization Adjustment for Sales-MWh	1,134	669	99	780	2,682
6	USP unit rate $/kWh	0.01868	0.01868	0.00000	0.00000	
7	EEC-Class 1 & Class 2 unit rate $/kWh	0.00181	0.00181	0.00233	0.00233	
8	GSR-1 unit rate $/kWh	0.11211	0.11211	0.10758	0.10758	
9	Distribution unit rate (margin plus GRT) $/kWh	0.05290	0.05290	0.05987	0.03339	
10	Customer Charge rate $/month	$ 10.75000	$ 10.75000	$ 17.00000	$ 18.00000	
11	Total Revenue Adjustment (L12+L13+L14+L15+L16)	$ 227	$ 129	$ 21	$ 116	$ 493
12	USP Adjustment (L5 * L6)	$ 21	$ 12	$ -	$ -	$ 34
13	EEC Adjustment (L5 * L7)	$ 2	$ 1	$ 0	$ 2	$ 5
14	GSR Adjustment (L5 * L8)	$ 127	$ 75	$ 11	$ 84	$ 297
15	Distribution Adjustment (L5 * L9)	$ 60	$ 35	$ 6	$ 26	$ 127
16	Customer Charge Adjustment (L3*12*L10)	$ 17	$ 5	$ 4	$ 4	$ 30
17	Total Margin Adjustment (L15 less GRT+L16)	$ 73	$ 39	$ 10	$ 28	$ 150

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

Adjustment for Usage per Customer
Rate R General, Rate R Heating, Rate GS-1 Com-Gen, Rate GS-4 Com-Gen
GSR-1 subgroups only

Line #		[1] Rate R General	[2] Rate R Heating	[3] Rate GS-1 Com-Gen	[4] Rate GS-4 Com-Gen	[5] Total
1	Heating Sensitivity/HDD/cust (kWh/DD/cust)	1.6999	0.5644	3.1200	0.4490	
2	DD Variance (to 10 Year normal)	(193)	(193)	(193)	(193)	
3	kWh/customer adjustment (L1 * L2)	(328)	(109)	(602)	(87)	
4	Customers FY26 (fully adjusted)	44,130	10,519	4,819	1,724	
5	Normalizing Adj (L3 * L4)/1000 -MWh	(14,478)	(1,146)	(2,902)	(149)	(18,675)
6	Total Revenue unit rate (L7+L8+L9+L10+L11)-$/kWh	0.1855	0.1855	0.16978	0.14330	
7	USP unit rate-$/kWh	0.01868	0.01868	0.00000	0.00000	
8	EEC-Class 1 & Class 2 unit rate-$/kWh	0.00181	0.00181	0.00233	0.00233	
9	GSR-1 unit rate-$/kWh	0.11211	0.11211	0.10758	0.10758	
10	Distribution unit rate (margin plus GRT)-$/kWh	0.05290	0.05290	0.05987	0.03339	
11	Revenue Adjustment (L5 * L6)	$ (2,686)	$ (213)	$ (493)	$ (21)	$ (3,412)
12	USP Adjustment (L5 * L7)	$ (270)	$ (21)	$ -	$ -	$ (292)
13	EEC Adjustment (L5 * L8)	$ (26)	$ (2)	$ (7)	$ (0)	$ (35)
14	GSR Adjustment (L5 * L9)	$ (1,623)	$ (128)	$ (312)	$ (16)	$ (2,080)
15	Distribution Adjustment (L5 * L10)	$ (766)	$ (61)	$ (174)	$ (5)	$ (1,005)
16	Margin Adjustment (L15 less GRT)	$ (721)	$ (57)	$ (163)	$ (5)	$ (946)
17	Cooling Sensitivity/CDD/cust (kWh/DD/cust)	0.5761	0.6299	1.7746	0.2485	
18	DD Variance (to 10 Year normal)	(48)	(48)	(48)	(48)	
19	kWh/customer adjustment (L17 * L18)	(28)	(30)	(85)	(12)	
20	Customers FY26 (fully adjusted)	44,130	10,519	4,819	1,724	
21	Normalizing Adj (L19 * L20)/1000 -MWh	(1,220)	(318)	(410)	(21)	(1,969)
22	Total Revenue unit rate (L23+L24+L25+L26)-$/kWh	0.1855	0.1855	0.16978	0.14330	
23	USP unit rate-$/kWh	0.01868	0.01868	0.00000	0.00000	
24	EEC-Class 1 & Class 2 unit rate-$/kWh	0.00181	0.00181	0.00233	0.00233	
25	GSR-1 unit rate-$kWh	0.11211	0.11211	0.10758	0.10758	
26	Distribution unit rate (margin plus GRT)-$/kWh	0.0529	0.0529	0.05987	0.03339	
27	Revenue Adjustment (L21 * L22)	$ (226)	$ (59)	$ (70)	$ (3)	$ (358)
28	USP Adjustment (L21 * L23)	$ (23)	$ (6)	$ -	$ -	$ (29)
29	EEC Adjustment (L21 * L24)	$ (2)	$ (1)	$ (1)	$ (0)	$ (4)
30	GSR Adjustment (L21 * L25)	$ (137)	$ (36)	$ (44)	$ (2)	$ (219)
31	Distribution Adjustment (L21 * L26)	$ (65)	$ (17)	$ (25)	$ (1)	$ (107)
32	Margin Adjustment (L31 less GRT)	$ (61)	$ (16)	$ (23)	$ (1)	$ (100)
33	Total Adjustment Summary-FY26					
34	Normalizing Adj (L5+L21)-MWh	(15,699)	(1,464)	(3,312)	(170)	(20,645)
35	Total Revenue Adjustment (L11+L27)	$ (2,912)	$ (272)	$ (562)	$ (24)	$ (3,770)
36	Total USP Adjustment (L12+L28)	$ (293)	$ (27)	$ -	$ -	$ (321)
37	Total EEC Adjustment (L13+L29)	$ (28)	$ (3)	$ (8)	$ (0)	$ (39)
38	Total GSR Adjustment(L14+L30)	$ (1,760)	$ (164)	$ (356)	$ (18)	$ (2,299)
39	Total Distribution Adjustment(L15+L31)	$ (830)	$ (77)	$ (198)	$ (6)	$ (1,112)
40	Total Margin Adjustment (L16+L32)	$ (781)	$ (73)	$ (187)	$ (5)	$ (1,046)

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

Adjustment for GSR-1

	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
Residential													
Original Budget GSR-1 Rate FTY 2026-$/kWh	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	
FTY 2026 Annulized GSR-1 Dec 1, 2025 Rate-$/kWh	$0.11211	$0.11211	$0.11211	$0.11211	$0.11211	$0.11211	$0.11211	$0.11211	$0.11211	$0.11211	$0.11211	$0.11211	
GSR-1 Rate Variance	($0.00259)	($0.00259)	($0.00259)	($0.00259)	($0.00259)	($0.00259)	($0.00259)	($0.00259)	($0.00259)	($0.00259)	($0.00259)	($0.00259)	
Total GSR-1 Volumes-MWh	36,802	40,835	62,296	68,000	51,488	48,604	35,160	37,276	43,514	55,414	44,111	31,982	555,481
GSR-1 Revenue Adjustment	($95)	($106)	($161)	($176)	($133)	($126)	($91)	($97)	($113)	($144)	($114)	($83)	($1,439)
Non-Residential													
Original Budget GSR-1 Rate FTY 2026-$/kWh	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	
FTY 2026 Annulized GSR-1 Dec 1, 2025 Rate-$/kWh	$0.10758	$0.10758	$0.10758	$0.10758	$0.10758	$0.10758	$0.10758	$0.10758	$0.10758	$0.10758	$0.10758	$0.10758	
GSR-1 Rate Variance	($0.00247)	($0.00247)	($0.00247)	($0.00247)	($0.00247)	($0.00247)	($0.00247)	($0.00247)	($0.00247)	($0.00247)	($0.00247)	($0.00247)	
Total GSR-1 Volumes-MWh	8,657	8,628	10,676	12,340	10,254	9,603	8,768	9,179	10,100	11,094	10,354	8,649	118,302
GSR-1 Revenue Adjustment	($21)	($21)	($26)	($30)	($25)	($24)	($22)	($23)	($25)	($27)	($26)	($21)	($292)
Total													
Total GSR-1 Volumes-MWh	45,459	49,462	72,973	80,340	61,741	58,207	43,928	46,455	53,614	66,507	54,465	40,631	673,782
GSR-1 Revenue Adjustment	($117)	($127)	($188)	($207)	($159)	($150)	($113)	($119)	($138)	($171)	($140)	($104)	($1,731)

UGI Utilities, Inc.- Electric Division
Future Period- 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 Budget USP Calculation	$720	$799	$1,219	$1,331	$1,007	$951	$687	$730	$852	$1,084	$863	$625	$10,869
Updated Budget USP Calculation	$702	$780	$1,189	$1,299	$983	$928	$671	$712	$831	$1,058	$842	$610	$10,605
Variance to Original Budget Calculation	($17)	($19)	($30)	($32)	($24)	($23)	($17)	($18)	($21)	($26)	($21)	($15)	($264)
Original Budget USP Rate FY 26-$/kWh	$0.02121	$0.02121	$0.02121	$0.02121	$0.02121	$0.02121	$0.02121	$0.02121	$0.02121	$0.02121	$0.02121	$0.02121	
FTY 2026 USP Dec 1 Rate-$/kWh	$0.01868	$0.01868	$0.01868	$0.01868	$0.01868	$0.01868	$0.01868	$0.01868	$0.01868	$0.01868	$0.01868	$0.01868	
USP Rate Variance-$/kWh	($0.00253)	($0.00253)	($0.00253)	($0.00253)	($0.00253)	($0.00253)	($0.00253)	($0.00253)	($0.00253)	($0.00253)	($0.00253)	($0.00253)	
Total Rate R Volumes-MWh	37,121	41,210	62,864	68,628	51,942	49,046	35,451	37,626	43,924	55,924	44,490	32,252	560,479
Total Rate R excl CAP Volumes-MWh	33,116	36,766	56,081	61,223	46,335	43,753	31,624	33,567	39,185	49,888	39,687	28,771	499,996
USP Rate Revenue Variance	($84)	($93)	($142)	($155)	($117)	($111)	($80)	($85)	($99)	($126)	($100)	($73)	($1,265)
Total Revenue Variance	($101)	($112)	($171)	($187)	($142)	($134)	($97)	($103)	($120)	($153)	($121)	($88)	($1,529)

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

Adjustment for STAS

	Unadjusted Budget Revenue Excluding STAS	Customer Adj	UPC Adj	GSR-1	USP	EEC	Revised Revenue Excluding STAS	STAS Revenue @ Dec 1 Rate	STAS Revenue @ Budget Rate	STAS Adjustment
								0.02%	0.01%	
Residential	$ 113,881	$ 357	$ (3,184)	$ (1,439)	$ (1,529)	168	$ 108,255	$ 22	$ 11	$ 10
Commercial & Industrial	$ 34,348	$ 136	$ (587)	$ (290)	$ -	91	$ 33,698	$ 7	$ 3	$ 3
Public Streets & Highway Lighting	$ 604	$ -	$ -	$ (2)	$ -	3	$ 606	$ 0	$ 0	$ 0
Other Sales to Public Authorities	$ 20	$ -	$ -	$ -	$ -	1	$ 20	$ 0	$ 0	$ 0
Sales for Resale	$ 4	$ -	$ -	$ -	$ -	0	$ 4	$ 0	$ 0	$ 0
Total	$ 148,857	$ 493	$ (3,770)	$ (1,731)	$ (1,529)	$ 263	$142,583	$ 29	$ 15	$ 14

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

Adjustment for EEC

	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 EEC-Class 1 Rate FTY 2026-$/kWh	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	
FTY 20267 Annualized EEC-Class 1 Rate Effective Dec 1,2025-$/kWh	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	
EEC-Class 1 Rate Variance-$/kWh	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	
Total EEC-Class 1 Volumes-MWh	37,252	41,343	63,024	68,799	52,072	49,178	35,558	37,750	44,052	56,072	44,633	32,373	562,105
Total EEC-Class 1 Revenue Adjustment	$11	$12	$19	$21	$16	$15	$11	$11	$13	$17	$13	$10	$169
Original Budget EEC-Class 2 Rate FTY 2026-$/kWh	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	
FTY 2026 Annualized EEC-Class 2 Rate Effective Dec 1,2025-$/kWh	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	
EEC-Class 2 Rate Variance-$/kWh	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	
Total EEC-Class 2 Volumes-MWh	11,831	11,066	14,812	15,539	12,129	12,272	10,922	12,544	13,702	15,105	13,526	11,226	154,676
Total EEC-Class 2 Revenue Adjustment	$13	$12	$16	$17	$13	$14	$12	$14	$15	$17	$15	$12	$172
Original Budget EEC-Class 3 Rate FTY 2026-$/kWh	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	
FTY 2026 Annualized EEC-Class 3 Rate Effective Dec 1,2025-$/kWh	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	
EEC-Class 3 Rate Variance-$/kWh	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	
Total EEC-Class 3 Volumes-MWh	19,846	22,907	19,585	23,771	26,772	19,069	23,375	21,499	24,214	23,054	26,643	24,776	275,509
Total EEC-Class 3 Revenue Adjustment	($6)	($6)	($5)	($7)	($7)	($5)	($7)	($6)	($7)	($6)	($7)	($7)	($77)
Total EEC Revenue Adjustment	$19	$18	$30	$31	$22	$23	$16	$19	$22	$27	$21	$15	$263

UGI ELECTRIC

EXHIBIT SAE-6(a) – SAE-6(g)

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

	Sales (000's) MWh	Revenues ($000's)	Margin ($000's)	Reference
Actual 2025	988,200	146,117	50,101	
Adjustment for Customer Changes	985	161	44	UGI Electric Exhibit SAE-6(b)
Adjustment for Normalized Use/Customer	(16,254)	(3,062)	(823)	UGI Electric Exhibit SAE-6(c)
Adjustment for GSR-1		3,065	0	UGI Electric Exhibit SAE-6(d)
Adjustment for USP		289	0	UGI Electric Exhibit SAE-6(e)
Adjustment for STAS		19	0	UGI Electric Exhibit SAE-6(f)
Adjustment for EEC		242	0	UGI Electric Exhibit SAE-6(g)
Adjusted Historic Test Year 2025	972,930	146,832	49,322	

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

Adjustment for Customer Changes
Rate R General, Rate R Heating, Rate GS-1 Com-Gen, Rate GS-4 Com-Gen
GSR-1 subgroups only

Line #		[1] Rate R General	[2] Rate R Heating	[3] Rate GS-1 Com-Gen	[4] Rate GS-4 Com-Gen	[5] Total
1	Average Effective Customers in Historic Year	44,135	10,516	4,813	1,723	61,187
2	Number of Customers at End of Year	44,144	10,521	4,827	1,741	61,233
3	Change in Customers during Historic Year 2025	9	5	14	18	46
4	Total UPC (Unadjusted)-kWh	8,652	16,297	5,006	42,678	
5	Annualization Adjustment for Sales-MWh	81	78	72	753	985
6	USP unit rate $/kWh	$ 0.02222	$ 0.02222	$ -	$ -	
7	EEC-Class 1 & Class 2 unit rate $/kWh	$ 0.00181	$ 0.00181	$ 0.00233	$ 0.00233	
8	GSR-1 unit rate $/kWh	$ 0.11470	$ 0.11470	$ 0.11005	$ 0.11005	
9	Distribution unit rate (margin plus GRT) $/kWh	$ 0.05290	$ 0.05290	$ 0.05987	$ 0.03339	
10	Customer Charge rate $/month	$ 10.75000	$ 10.75000	$ 17.00000	$ 18.00000	
11	Total Revenue Adjustment (L12+L13+L14+L15+L16)	$ 17	$ 16	$ 15	$ 114	$ 161
12	USP Adjustment (L5 * L6)	$ 2	$ 2	$ -	$ -	$ 4
13	EEC Adjustment (L5 * L7)	$ 0	$ 0	$ 0	$ 2	$ 2
14	GSR Adjustment (L5 * L8)	$ 9	$ 9	$ 8	$ 83	$ 109
15	Distribution Adjustment (L5 * L9)	$ 4	$ 4	$ 4	$ 25	$ 38
16	Customer Charge Adjustment (L3*12*L10)	$ 1	$ 1	$ 3	$ 4	$ 9
17	Total Margin Adjustment (L15 less GRT+L16)	$ 5	$ 5	$ 7	$ 27	$ 44

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

Adjustment for Usage per Customer
Rate R General, Rate R Heating, Rate GS-1 Com-Gen, Rate GS-4 Com-Gen
GSR-1 subgroups only

Line #		[1] Rate R General	[2] Rate R Heating	[3] Rate GS-1 Com-Gen	[4] Rate GS-4 Com-Gen	[5] Total
1	Heating Sensitivity/HDD/cust (kWh/DD/cust)	1.7072	0.5686	3.0959	0.4449	
2	DD Variance (to 10 Year normal)	(193)	(193)	(193)	(193)	
3	kWh/customer adjustment (L1 * L2)	(329)	(110)	(598)	(86)	
4	Customers FY25 (fully adjusted)	44,144	10,521	4,827	1,741	
5	Normalizing Adj (L3 * L4)/1000 -MWh	(14,545)	(1,155)	(2,884)	(149)	(18,733)
6	Total Revenue unit rate (L7+L8+L9+L10+L11)-$/kWh	$ 0.19163	$ 0.19163	$ 0.17225	$ 0.14577	
7	USP unit rate-$/kWh	$ 0.02222	$ 0.02222	$ -	$ -	
8	EEC-Class 1 & Class 2 unit rate-$/kWh	$ 0.00181	$ 0.00181	$ 0.00233	$ 0.00233	
9	GSR-1 unit rate-$/kWh	$ 0.11470	$ 0.11470	$ 0.11005	$ 0.11005	
10	Distribution unit rate (margin plus GRT)-$/kWh	$ 0.05290	$ 0.05290	$ 0.05987	$ 0.03339	
11	Revenue Adjustment (L5 * L6)	$ (2,787)	$ (221)	$ (497)	$ (22)	$ (3,527)
12	USP Adjustment (L5 * L7)	$ (323)	$ (26)	$ -	$ -	$ (349)
13	EEC Adjustment (L5 * L8)	$ (26)	$ (2)	$ (7)	$ (0)	$ (35)
14	GSR Adjustment (L5 * L9)	$ (1,668)	$ (132)	$ (317)	$ (16)	$ (2,135)
15	Distribution Adjustment (L5 * L10)	$ (769)	$ (61)	$ (173)	$ (5)	$ (1,008)
16	Margin Adjustment (L15 less GRT)	$ (724)	$ (57)	$ (162)	$ (5)	$ (949)
17	Cooling Sensitivity/CDD/cust (kWh/DD/cust)	0.5217	0.4887	1.3464	0.1393	
18	DD Variance (to 10 Year normal)	71	71	71	71	
19	kWh/customer adjustment (L17 * L18)	37	35	96	10	
20	Customers FY25 (fully adjusted)	44,144	10,521	4,827	1,741	
21	Normalizing Adj (L19 * L20)/1000 -MWh	1,635	365	461	17	2,479
22	Total Revenue unit rate (L23+L24+L25+L26)-$/kWh	$ 0.19163	$ 0.19163	$ 0.17225	$ 0.14577	
23	USP unit rate-$/kWh	$ 0.02222	$ 0.02222	$ -	$ -	
24	EEC-Class 1 & Class 2 unit rate-$/kWh	$ 0.00181	$ 0.00181	$ 0.00233	$ 0.00233	
25	GSR-1 unit rate-$kWh	$ 0.11470	$ 0.11470	$ 0.11005	$ 0.11005	
26	Distribution unit rate (margin plus GRT)-$/kWh	$ 0.05290	$ 0.05290	$ 0.05987	$ 0.03339	
27	Revenue Adjustment (L21 * L22)	$ 313	$ 70	$ 79	$ 3	$ 465
28	USP Adjustment (L21 * L23)	$ 36	$ 8	$ -	$ -	$ 44
29	EEC Adjustment (L21 * L24)	$ 3	$ 1	$ 1	$ 0	$ 5
30	GSR Adjustment (L21 * L25)	$ 188	$ 42	$ 51	$ 2	$ 282
31	Distribution Adjustment (L21 * L26)	$ 86	$ 19	$ 28	$ 1	$ 134
32	Margin Adjustment (L31 less GRT)	$ 81	$ 18	$ 26	$ 1	$ 126
33	Total Adjustment Summary-FY25					
34	Normalizing Adj (MWh) (L5+L21)	(12,910)	(790)	(2,423)	(132)	(16,254)
35	Total Revenue Adjustment (L11+L27)	$ (2,474)	$ (151)	$ (417)	$ (19)	$ (3,062)
36	Total USP Adjustment (L12+L28)	$ (287)	$ (18)	$ -	$ -	$ (304)
37	Total EEC Adjustment (L13+L29)	$ (23)	$ (1)	$ (6)	$ (0)	$ (31)
38	Total GSR Adjustment(L14+L30)	$ (1,481)	$ (91)	$ (267)	$ (15)	$ (1,852)
39	Total Distribution Adjustment(L15+L31)	$ (683)	$ (42)	$ (145)	$ (4)	$ (874)
40	Total Margin Adjustment (L16+L32)	$ (643)	$ (39)	$ (136)	$ (4)	$ (823)

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

Adjustment for GSR-1

	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
Residential													
Actual GSR-1 Rate FY 25-$/kWh	$0.11064	$0.11064	$0.10637	$0.10637	$0.10637	$0.10637	$0.10637	$0.10637	$0.11470	$0.11470	$0.11470	$0.11470	
HTY 2025 GSR-1 Sep 1, 2025 Rate-$/kWh	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	$0.11470	
GSR-1 Rate Variance	$0.00406	$0.00406	$0.00833	$0.00833	$0.00833	$0.00833	$0.00833	$0.00833	$0.00000	$0.00000	$0.00000	$0.00000	
Total GSR-1 Volumes-MWh	36,795	40,825	62,289	67,970	51,467	48,589	35,149	34,220	43,561	56,088	39,374	37,464	553,793
GSR-1 Revenue Adjustment	$149	$166	$519	$566	$429	$405	$293	$285	$0	$0	$0	$0	$2,812
Non-Residential													
Actual GSR-1 Rate FY 25-$/kWh	$0.11064	$0.11064	$0.10637	$0.10637	$0.10637	$0.10637	$0.10637	$0.10637	$0.11005	$0.11005	$0.11005	$0.11005	
HTY 2025 GSR-1 Sep 1, 2025 Rate-$/kWh	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	$0.11005	
GSR-1 Rate Variance	($0.00059)	($0.00059)	$0.00368	$0.00368	$0.00368	$0.00368	$0.00368	$0.00368	$0.00000	$0.00000	$0.00000	$0.00000	
Total GSR-1 Volumes-MWh	8,116	7,567	18,559	20,920	19,112	(2,401)	7,448	7,842	9,143	11,426	8,196	9,016	124,944
GSR-1 Revenue Adjustment	($5)	($4)	$68	$77	$70	($9)	$27	$29	$0	$0	$0	$0	$254
Total													
Total GSR-1 Volumes-MWh	44,911	48,392	80,848	88,890	70,579	46,188	42,598	42,063	52,704	67,514	47,570	46,480	678,738
GSR-1 Revenue Adjustment	$145	$161	$587	$643	$499	$396	$320	$314	$0	$0	$0	$0	$3,065

UGI Utilities, Inc.- Electric Division
Historic Period- 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
Historic Period FY25 USP Rate -$/kWh	$0.02198	$0.02198	$0.02121	$0.02121	$0.02121	$0.02121	$0.02121	$0.02121	$0.02222	$0.02222	$0.02222	$0.02222	
HTY 2025 USP Sep 1, 2025 Rate-$/kWh	$0.02222	$0.02222	$0.02222	$0.02222	$0.02222	$0.02222	$0.02222	$0.02222	$0.02222	$0.02222	$0.02222	$0.02222	
USP Rate Variance-$/kWh	$0.00024	$0.00024	$0.00101	$0.00101	$0.00101	$0.00101	$0.00101	$0.00101	$0.00000	$0.00000	$0.00000	$0.00000	
Total Rate R Volumes-MWh	37,118	41,209	62,858	68,604	51,931	49,039	35,447	34,497	43,913	56,530	39,663	37,718	558,526
Total Rate R excl CAP Volumes-MWh	33,113	36,764	56,075	61,202	46,326	43,747	31,620	30,770	39,168	50,420	35,375	33,639	498,219
USP Rate Revenue Variance	$8	$9	$57	$62	$47	$44	$32	$31	$0	$0	$0	$0	$289

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

Adjustment for STAS

	Actual Revenue Excluding STAS	Customer Adj	UPC Adj	GSR-1 Adj	USP Adj	EEC Adj	Revised Revenue Excluding STAS	STAS Revenue @ Sep 20 Rate	STAS Revenue @ FY 25	STAS Adjustment
								0.02%		
Residential	$ 109,244	$ 32	$ (2,625)	$ 2,811	$ 289	$ 156	$ 109,909	$ 22	$ 7	$ 14
Commercial & Industrial	$ 35,727	$ 129	$ (437)	$ 251	$ -	$ 80	$ 35,750	$ 7	$ 3	$ 5
Public Streets & Highway Lighting	$ 1,095	$ -		$ 3	$ -	$ 4	$ 1,102	$ 0	$ 0	$ 0
Other Sales to Public Authorities	$ 21	$ -		$ -	$ -	$ 1	$ 22	$ 0	$ -	$ 0
Sales for Resale	$ 20	$ -		$ 0	$ -	$ 0	$ 20	$ 0	$ 0	$ 0
Total	$ 146,107	$ 161	$ (3,062)	$ 3,065	$289	$242	$146,803	$ 29	$ 10	$ 19

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

Adjustment for EEC

	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
Historic EEC-Class 1 Actual Rates FY 25-$/kWh	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00151	$0.00181	
Historic Year 2022 EEC-Class 1 Rate Effective Sept 1, 2025-$/kWh	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	$0.00181	
EEC-Class 1 Rate Variance-$/kWh	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00000	
Total EEC-Class 1 Volumes	37,248	41,335	63,020	68,776	52,058	49,166	35,549	34,601	44,044	56,679	39,772	37,848	560,094
Total EEC-Class 1 Revenue Adjustment	$11	$12	$19	$21	$16	$15	$11	$10	$13	$17	$12	$0	$157
Historic EEC-Class 2 Actual Rates FY 25-$/kWh	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00122	$0.00233	
Historic Year 2022 EEC-Class 2 Rate Effective Sept 1, 2025-$/kWh	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	$0.00233	
EEC-Class 2 Rate Variance-$/kWh	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00111	$0.00000	
Total EEC-Class 2 Volumes	11,745	11,110	14,763	15,687	12,073	12,244	10,918	11,400	13,311	15,592	11,640	12,883	153,366
Total EEC-Class 2 Revenue Adjustment	$13	$12	$16	$17	$13	$14	$12	$13	$15	$17	$13	$0	$156
Historic EEC-Class 3 Actual Rates FY 25-$/kWh	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00042	$0.00014	
Historic Year 2022 EEC-Class 3 Rate Effective Sept 1, 2025-$/kWh	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	$0.00014	
EEC-Class 3 Rate Variance-$/kWh	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	($0.00028)	$0.00000	
Total EEC-Class 3 Volumes	19,846	22,907	19,585	23,771	26,772	19,069	23,375	20,704	22,009	24,649	30,302	21,753	274,741
Total EEC-Class 3 Revenue Adjustment	($6)	($6)	($5)	($7)	($7)	($5)	($7)	($6)	($6)	($7)	($8)	$0	($71)
Total EEC Revenue Adjustment	$19	$18	$30	$31	$22	$23	$16	$17	$22	$27	$16	$0	$242

UGI ELECTRIC STATEMENT NO. 11

CYNTHIA S. FANG

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059430

UGI Utilities, Inc. – Electric Division

Statement No. 11

Direct Testimony

of

Cynthia S. Fang, Director
Atrium Economics, LLC

Topics Addressed:	**Cost of Service**
	Revenue Allocation
	Rate Design

Dated: March 27, 2026

Table of Contents

I. INTRODUCTION

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

A. My name is Cynthia ("Cyndee") S. Fang, and I am employed by Atrium Economics, LLC ("Atrium") as a Director. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

Q. Please describe your professional background and education.

A. I have over 20 years of experience in the energy industry focusing on regulatory, cost recovery and rate design issues. I joined Atrium Economics in December 2024. Before joining Atrium Economics, I was Vice President of Regulatory at NorthWestern Energy. In this role I was responsible for the development and execution of the Company's regulatory strategy in Montana, South Dakota, and Nebraska. I joined NorthWestern Energy in 2021 as the Director of Regulatory Affairs in Montana. Prior to NorthWestern Energy, I held various leadership roles at San Diego Gas & Electric, which included overseeing the Company's electric rate strategy as well as electric forecasting, electric load analysis and research, and origination teams. I began my career in the energy industry as a Public Utilities Rates Analyst at the Minnesota Department of Commerce, Energy Division. I received my Bachelor of Science in Political Economics of Natural Resources from the University of California at Berkley and completed all coursework required for a Ph.D. in Applied Economics at the University of Minnesota, focusing on environmental economics. A copy of my resume is provided as UGI Electric Exhibit CSF-1.

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

A. The purpose of my testimony is to present and support UGI Utilities, Inc. – Electric Division's ("UGI Electric" or the "Company") allocated costs of service study ("ACOSS") for electric distribution services and to explain how the results of that study inform the allocation of the Company's proposed revenue requirement among customer classes and the Company's rate design proposals in this proceeding. The ACOSS presents the updated cost of providing electric distribution service to customers and allocates the Company's cost of service associated with Pennsylvania Public Utility Commission ("Commission") jurisdictional operations to the Company's retail customer classes. My testimony describes the analytical framework used to develop the ACOSS, explains the methodologies used to functionalize, classify, and allocate distribution costs to customer classes, and presents the study results as a cost-based reference for evaluating the Company's proposed revenue apportionment and distribution rate design.

Q. Please summarize the contents of your testimony.

A. My testimony consists of this introduction section and the following five additional sections:

- **Section II** explains the ratemaking guiding principles and discusses how those principles are applied in the development of the Company's ACOSS, revenue apportionment, and rate design.

- **Section III** provides an overview of the ACOSS for electric distribution services, including the analytical process used to functionalize, classify, and allocate distribution plant, expenses, and revenue requirements to customer classes.
- **Section IV** describes the supporting data sources and allocation factors used in the Company's ACOSS for electric distribution services and presents the results as a cost-based reference for evaluating the Company's proposed revenue apportionment and distribution rate design.
- **Section V** discusses how the results of the ACOSS inform the allocation of the Company's proposed electric distribution revenue requirement among customer classes and describes the Company's proposed moderated approach to revenue apportionment.
- **Section VI** presents the Company's rate design proposal for distribution rates to continue to move to more cost-based rate design by increasing customer costs recovered through the customer charge and simplification of distribution rate. This includes:
    - For all customers, a proposal to increase the system charge to be more cost-based;
    - For non-residential customers on Schedules General Service, 5 kW minimum, ("GS-4") and large Power Service ("LP") with demand charges, a proposal to move demand charges to be more cost based; and

- For some non-residential customers on Schedules Flood Control Power Service ("FCP"), GS-4, and LP, a proposal to simplify rates with a transition towards the elimination of the current block structure of demand (\$/kW) and distribution (\$/kWh) charges.

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

A. Yes. I am sponsoring Book VIII, labeled as UGI Electric Exhibit D – Allocated Cost of Service Study (Fully Projected) ("Exhibit D"). Exhibit D contains three sections for which an index is provided on page 2 of Exhibit D. I also am sponsoring portions of Book I, Section 53.51 et seq. of the Commission's Regulations, Part IV-Rate Structure and Cost Allocation.

Q. Would you briefly describe the contents of Exhibit D?

A. Exhibit D provides the information required under 52 Pa. Code § 53.53(a)(3) 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. The studies contained in UGI Electric Exhibit D are based on costs and operating conditions for the fully projected future test year ("FPFTY") ending September 30, 2027.

Exhibit D consists of three sections detailing the process of developing the ACOSS for electric distribution services. The first section includes an introduction, the general purpose and process of the cost-of-service study, as well as an overview of the excel-based fully functional ACOSS model presented in this proceeding. The second section presents the ACOSS development process specific to the Company's electric distribution services, including the Functionalization, Classification, and Allocation of costs. The Allocation section specifically describes the development of Internal and External allocation factors and processes used in the ACOSS for electric distribution services. The last section depicts the results of the cost-of-service studies, including revenue requirement apportionment, comparison of cost of service with revenues under present and proposed rates, and development of rate of return by customer class under present and proposed rates.

Q. Please describe the schedules included in Exhibit D.

A. The following is the list of Schedules included in Exhibit D:

- **Schedule 1 - Account Balances and Allocation Methods** detail the various account inputs and the choices made in the functionalization, classification, and allocation processes.
- **Schedule 2 - Functional Split and Minimum System Study** presents the functionalization of distribution plant into primary and secondary components and the classification of those costs into customer and demand-related portions based on the results of the minimum system study.
- **Schedule 3 - External Allocation Factors** depict the allocation factors utilized within the model developed based on the special studies. The reports outline the

methods and factors used to allocate electric distribution costs among different customer classes.

- **Schedule 4 - Internal Allocation Factors** depict the allocation factors calculated within the ACOSS model based on the relative cost ratios of allocated costs, and present the allocation factor basis in dollars and the resulting allocation factors in percentage terms.
- **Schedule 5 - Comparison of Cost of Service and Rate of Return Under Present and Proposed Rates** compares each customer class's cost of service with revenues under present and proposed rates, illustrating how the proposed revenue apportionment moves classes closer to cost-based levels.
- **Schedule 6 - Summary of Cost of Service and Rate of Return Under Present and Proposed Rates** summarizes, by customer class, the rate base, revenues, expenses, and resulting rates of return under present and proposed rates, including key cost-of-service metrics such as relative rates of return and parity ratios, and the results of the moderation scenario discussed under revenue apportionment.
- **Schedule 7 - Cost of Service Allocation Study Detail by Account** provides a comprehensive breakdown of cost allocation and resulting revenue requirements distribution under the required equal rate of return for all customer classes. This breakdown is categorized by the FERC Account and further segmented by rate class.

- **Schedule 8 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class** summarizes the results of functionalized and classified revenue requirements under required equal rate of return for all customer classes. The report identifies and segregates the costs associated with each function further dividing into categories that reflect how costs are incurred and allocated (classified).

II. GUIDING PRINCIPLES

Q. What guiding principles are considered within the rate making process?

A. There are several principles that guide the ratemaking process that have found broad acceptance in the recognized literature on utility ratemaking and regulatory policy. These principles help inform the allocation of revenues (i.e., assignment of cost responsibility for each rate class) and the rate design for the recovery of costs within each rate class. They 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 and Understandability**: Rates should be simple and understandable for customers.
- **Stability**: 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.
- **Revenue Sufficiency**: Rates should generate enough revenue to cover the utility's costs, including a fair return on investment.

These principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates.[1] Each of these principles plays an important role evaluating UGI Electric's proposals for the apportionment of revenues to customer classes and rate design for the recovery of costs of utility services. In addition, these principles are consistent with Pennsylvania practice and precedent, including the *Lloyd* decision,[2] 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 did you apply these principles in development of the Company's ACOSS?

A. The development of an ACOSS that reflects cost causation is a critical starting point. The ACOSS based on cost causation is an important reference point to provide transparency which helps avoid undue discrimination among customer classes. An ACOSS that reflects cost causation recognizes that customers and customer classes should be assigned responsibility for costs based on how and why those costs are incurred in providing service. Some costs are driven by the number of customers connected to the system, others

[1] James Bonbright et al. Principles of Public Utility Rates, Public Utilities Reports, Inc. 2nd Edition, 1988.
[2] *Lloyd v. Pa. P.U.C.*, 904 A.2d 1010 (Pa. Cmwlth. 2006), *appeal denied*, 591 Pa. 676, 916 A.2d 1104 (2007).

by the capacity required to meet peak demand, and others by energy usage. In the context of electric distribution service, different customer classes place different demands on the various parts of the system.

Q. How does the Company apply these principles when apportioning the identified revenue increase across customer classes?

A. The allocation of customer costs is a controversial issue. Allocation of costs based on cost causation principles helps ensure that costs are assigned in a manner that reflects these differences. The ACOSS evaluates whether cost-based allocations will generate sufficient revenue to cover the costs of serving each customer class, including a fair return on capital (**Revenue Sufficiency**). When a class earns below the system average rate of return, it does not fully cover its costs; when it earns above the average, it subsidizes other classes. Achieving parity of rates of return across classes results in assignment of cost responsibility that reflects the cost of service for each class (**Reflective of Costs**) resulting in reduction in inter-class subsidies (**Fairness**). At times, moderation may be applied when translating cost-of-service results into class revenue responsibilities. This approach allows movement towards more cost-based revenue relationships while recognizing important ratemaking considerations such as rate **Stability**, gradualism, and the management of interclass revenue relationships.

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

A. Rate design that reflects cost causation (**Reflective of Costs**)—using the ACOSS as a reference for customer, demand, and energy charges—enhances **Efficiency and Fairness** and provides a critical reference point for the Company's proposals. Rates that accurately reflect the utility's cost of providing service encourages responsible resource use and conservation, while minimizing cross-subsidies within customer classes. Similar to revenue apportionment, moderation may be needed based on the comparison to current rates. A transition path or gradualism that allows movement towards more cost-based rates may be needed to provide customers **Stability and Understandability**.

III. OVERVIEW OF ALLOCATED COST OF SERVICE STUDY

Q. What are the general purposes and use of the ACOSS in this base rate proceeding?

A. An ACOSS serves two purposes:

(1) Providing the cost-basis for the allocation of the jurisdictional cost of electric distribution service that makes up the total base revenue requirement to the various customer classes (e.g., residential, commercial and industrial) based on their use of the Company's system; and

(2) Providing the cost-based reference for the development of the Company's rate design proposals.

An ACOSS helps guide the allocation of distribution costs to customer classes by estimating the cost of serving each class and the cost-based references for customer charges and demand charges for rate design.

Q. Please describe the general approach used to develop the ACOSS?

A. The Company's ACOSS was developed using a standard, widely accepted cost-based ratemaking framework that consists of functionalization, classification, and allocation. This three-step approach is commonly used in electric utility cost of service studies and is consistent with guidance provided in the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual.[3] The process begins by organizing costs according to the functions they support within the electric distribution system. Those functionalized costs are then classified based on the factors that drive the incurrence of the costs. Finally, classified costs are allocated to customer classes using allocation factors that reflect cost causation and customer usage characteristics. This structured approach provides transparency into how costs flow through the study and ensures consistency between the ACOSS and the Company's underlying revenue requirement.

Q. What are the steps to performing an ACOSS?

A. The ACOSS process consists of three primary steps: cost functionalization, cost classification, and cost allocation. Cost functionalization assigns plant and expenses to the utility functions they support. Cost classification further separates those functionalized costs based on the primary factors that cause them to be incurred. Cost allocation then

[3] National Association of Regulatory Utility Commissioners. (January 1992). Electric Utility Cost Allocation Manual. Washington, D.C. Available for download at: https://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD, Last Accessed March 15, 2026

assigns the classified costs to customer classes using appropriate allocation factors. Each step builds upon the prior step, and all three are necessary to ensure that costs are assigned in a manner consistent with cost causation principles.

Q. Please describe cost functionalization.

A. Cost functionalization is the process of assigning plant and expenses to specific utility functions based on the role those assets and costs play in providing service. For electric distribution service, these functions include substations, primary distribution, secondary distribution, transformation, onsite and metering, and customer accounts and services. Functionalization ensures that costs are grouped according to the part of the system they support. This is important because different customer classes interact with different parts of the system in different ways. Functionalization also provides the foundation for subsequent classification and allocation steps. Indirect costs that support multiple functions, such as general plant and administrative and general expenses, are allocated to functions using internal allocation factors that reasonably reflect how those costs are incurred across the system.

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 system, and (3) the amount of electricity consumed by customers. These classification categories have been identified for purposes of the ACOSS as Customer Costs, Demand Costs, and Energy Costs, respectively.

Q. Please describe the types of costs in the Customer, Demand, and Energy Costs categories.

A. Customer Costs are costs that are driven primarily by the number of customers served and do not vary with usage or demand. Examples include meters, service drops, billing, customer service, and account maintenance.

Demand Costs are driven by the capacity required to serve customer load, particularly during peak periods. These costs are associated with facilities such as substations, transformers, and distribution lines that are sized to meet peak demand measured in kilowatts ("kW").

Energy Costs vary with energy consumption and are driven by the amount of electricity delivered to customers measured in kilowatt hours ("kWh").

Q. What is required to appropriately classify costs as Customer, Demand, and Energy?

A. Proper classification requires an understanding of how the utility system is designed, operated, and used by customers. This includes reviewing engineering characteristics of assets, system planning practices, historical data, and available studies that identify cost drivers. Where facilities serve both customer-connection and load-carrying functions, additional analyses—such as minimum-size or minimum-system studies—are used to distinguish customer and demand components.

Q. Are there generally accepted methods for preparing classification studies for electric utility distribution assets?

A. Yes. The generally accepted methods are set forth in the NARUC Electric Utility Cost Allocation Manual ("NARUC Manual"). The NARUC Manual specifically states[4] that an electric utility's distribution-related facilities are, from a design and operational basis, sized to meet the maximum kW load (demand) requirements of customers. Moreover, the NARUC Manual also states[5] that all distribution costs should be classified as either customer- or demand-related, or a combination of these two factors. To develop a classification of these facilities between a combination of customer- and demand-related costs requires an analysis of relative unit costs for different size facilities (i.e., a minimum system study or zero-intercept study). These studies recognize that distribution assets have a dual purpose – (1) to meet peak demands and (2) to connect customers to the system – and estimate the portion of the utility's investment that is affected by both purposes.

Q. Please describe the cost allocation portion of the ACOSS.

A. The final step is the allocation of each functionalized and classified cost element to the individual customer or rate class. Customers are generally divided into customer classes based on the type and character of services they require. Costs typically are allocated to these customer classes based on factors related to the number of customers, the amount of capacity demanded by customers, and the energy usage of customers. For example, much

[4] Ibid., 96–98.
[5] Ibid., 89

of the plant and equipment cost depends upon the customers' peak demand. These costs are allocated based on the coincident-peak or non-coincident peak demands of the rate class, depending on which characteristic more closely affects cost causation. Other portions of the cost depend upon the number of customers on the system, and these costs are allocated on a customer, or weighted-customer, basis. In addition, certain variable production costs, as well as fuel and purchased power costs, primarily depend upon the amount of energy a customer consumes. These costs are allocated based on the amount of energy consumed, adjusted for losses of energy that occur in the transmission and distribution process.

Q. How does the analysis establish the cost and utility service relationships?

A. Establishing cost and service relationships requires analyzing the utility's system design, operating characteristics, accounting records, and customer usage patterns. This analysis identifies how different customer classes contribute to the need for system assets and services. Understanding these relationships is critical to selecting appropriate classification and allocation methods.

Q. Please explain the term "direct assignment"?

A. Direct assignment refers to assigning costs directly to a specific customer or customer class when those costs are incurred exclusively to serve that customer or class. Direct assignment best reflects cost causation and is used whenever sufficient data are available.

Maximizing the use of direct assignment reduces reliance on more generalized allocation methods.

Q. Please explain the considerations in determining the cost allocation methodologies used to perform an ACOSS.

A. In determining cost allocation methodologies, several considerations are evaluated, including the relationship between costs and cost drivers, consistency with established regulatory practice, availability and quality of data, and the reasonableness and stability of results. The objective is to apply allocation methods that are theoretically sound, practically implementable, and reflective of how costs are incurred in providing service.

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 methodological preferences or guidelines for performing cost studies or designing rates which can influence the proposed cost allocation method utilized by the utility.

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. The objective is to utilize the best available information to produce results that are both reasonable and consistent with cost-causation principles while remaining practical to implement within the utility's existing accounting and data systems.

The availability of detailed operational and engineering data can also influence the development of allocation factors used in the study. When detailed data is available, it can support more refined allocation factors that better reflect the cost drivers associated with providing electric distribution service. Conversely, where certain data is not directly available, reasonable estimates or proxy measures may be used to approximate cost causation relationships. Similarly, when accounting records do not separately identify costs by function or customer class, those costs must be allocated using secondary allocation factors that reflect the most reasonable relationship between the costs incurred and the services provided.

Q. Did the Company make any modifications in the preparation of this case that would impact ACOSS?

A. Yes, as part of its case, and presented by Company witness Sherry A. Epler in UGI Electric Statement No. 10, the Company utilized a 10-year historical average to develop the weather data underlying the use per customer calculation. The ten-year historical average is based on the year ended December 31, 2024. The Company proposes that this 10-year approach 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-2022-3037368 – based on data ending on December 31, 2019. The change in forecast methodology impacts ACOSS and rate design.

IV. UGI ELECTRIC'S ALLOCATED COST OF SERVICE STUDY

Q. Please describe UGI Electric's derivation of its total revenue requirement.

A. The Company's base rates are proposed to recover the base revenue requirement exclusive of the costs recovered in trackers and riders and associated taxes. As explained by Company witness Tracy A. Hazenstab (UGI Electric Statement No. 2), the Company's forecasted revenue requirement for the 12-month period ending September 30, 2027 is $162.7 million. In the setting of retail base rates, a base level of miscellaneous other revenue is treated as a credit. The base retail rates proposed in this proceeding are designed to recover an amount net of these credits; an amount of $161.4 million. The proposed increase to base rate revenues is $17.3 million, which represents an approximate 25.9% increase in margin revenues and 11.9% increase in total revenues.

Q. What is the source of the cost data analyzed in UGI Electric's ACOSS?

A. All cost-of-service data was extracted from the Company's total cost of service (*i.e.*, total revenue requirement) 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 Electric's rate classes structured for the purposes of conducting its ACOSS?

A. For UGI Electric's ACOSS, all tariffed rate classes are included in the ACOSS and are mapped according to the following:

ACOSS Class	**Rate Schedule**
Residential	R
General Service	GS-1 and GS-5
General Service-4	GS-4
Flood Control Power	FCP
Large Power	LP
Lighting	OL, SL, SOL, SSL, MHOL, MHSL, and LED-OL

In addition, the Company maintains tariff Rate Schedule HTP (High Tension Power). Currently, the Company has no customers receiving service under Rate HTP and therefore, there are no cost allocations to this rate schedule included in the ACOSS at this time.

Q. Please explain how UGI Electric's Pennsylvania jurisdictional costs are derived.

A. This filing is based on the investment and expense incurred to provide distribution service to UGI Electric's Pennsylvania jurisdictional customers. Certain costs associated with UGI Electric's provision of transmission service under an open access transmission tariff administered by PJM Interconnection, LLC ("PJM") are recoverable from PJM through an annual formulary revenue requirement filing approved by the FERC. The costs subject to recovery through this FERC-jurisdictional rate mechanism were excluded to identify UGI Electric's Commission-jurisdictional distribution costs. Once UGI Electric completed this assignment, I utilized UGI Electric's cost of service specific to its Pennsylvania-jurisdictional retail customers.

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

A. UGI Electric has selected the Atrium excel based model ("Atrium ACOSS Model") to conduct the ACOSS in this general base rate case. The Atrium ACOSS Model was developed by Atrium on a proprietary basis for its consulting engagements and has been used in multiple jurisdictions. This is the same Atrium ACOSS Model that UGI Electric presented in UGI Electric's last base rate case at Docket No. R-2022-3037368. Further, there are no material differences, in output and format, between the Atrium ACOSS Model used in this case and the past ACOSS models that UGI Electric presented in UGI Electric's 2021 base rate case at Docket No. R-2021-3023618 and 2018 base rate case at Docket No. R-2017-2640058.

Q. Does the methodology utilized in the current cost allocation study and supporting analyses match the method used in UGI Electric's base rate cases at Dockets No. R-2022-3037368, R-2021-3023618, and R-2017-2640058?

A. Yes. The current ACOSS presented with this filing and proposed for use for decisions on the apportionment of the class revenue increases and rate design reflects the same methods utilized in UGI Electric's last three base rate cases.

Q. Did the Commission opine on the appropriateness of these ACOSS methods in these base rate case proceedings?

A. Yes. In the UGI Electric base rate case at Docket No. R-2017-2640058, the Commission explicitly adopted UGI Electric's ACOSS and rejected the alternative proposed by the Office of Consumer Advocate ("OCA"), stating the following in the final order:

> Additionally, as UGI and the OSBA both highlighted, the Commission has affirmed the use of the "minimum system method" as the accepted approach to classify and allocate distribution system costs in several proceedings. See 2012 PPL Order, supra; see also, Pa. PUC v. PPL Electric Utilities Corp., Docket No. R-2010-2161694, (Order entered December 21, 2010) (2010 PPL Order). Further, we find that UGI's ACOSS is consistent with the NARUC Manual and more accurately reflects cost-causation principles than the ACOSS methodology proposed by the OCA.[6]

A. FUNCTIONALIZATION AND CLASSIFICATION OF COSTS

Q. How did you functionalize and classify UGI Electric's Pennsylvania-jurisdictional distribution costs?

[6] *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket Nos. R-2017-2640058, *et al.*, p. 160 (Order entered Oct. 25, 2018).

A. The process started with each of the Company's FERC accounts, which were assigned to a specific function. In some instances, the costs in an account were first split into separate functions or classifications if the costs in the account were incurred to perform more than one function or the costs in an account varied significantly with respect to more than one factor. For example, the accounts for distribution system poles, towers and fixtures, and conductors and conduits were separated into two functions: primary distribution and secondary distribution, based on voltage levels. In addition, these costs were further separated into demand and customer classifications. The functionalization and classification studies are provided in Section I of UGI Electric Exhibit D. It should be noted that the functionalization and classification of distribution plant investments and expenses are based on a detailed analysis of specific UGI Electric plant records and cost data.

Q. How were distribution costs classified between customer-related and demand-related costs?

A. Distribution costs recorded in FERC Accounts 364 (Poles, Towers, and Fixtures), 365 (Overhead Conductors and Devices), 367 (Underground Conductors and Devices), and 368 (Transformers) were classified between customer-related and demand-related components using a Minimum System Study ("MSS"). The purpose of the MSS was to identify the portion of distribution plant investment that is required to provide a basic minimum level of service to each customer, regardless of load. That portion was classified as customer-related. The remaining portion of plant investment, which varies with load and system capacity requirements, was classified as demand-related. Exhibit D, Section

II.2 contains a more comprehensive explanation of the process, including primary and secondary categorization of these assets.

B. COST ALLOCATION

Q. Please describe the cost allocation process.

A. To the extent possible, revenues, operating expenses, and rate base are directly assigned by customer class consistent with the methodology described in Exhibit D, Section II.3. Classified costs are allocated to customer classes using the External and Internal allocation factors described in the study, which are supported by the Company's billing determinants, load research, plant records, and other special studies. External allocation factors rely on observable customer characteristics such as customer counts, peak demand, meter studies, and other supporting studies. Internal allocation factors are derived within the model based on previously allocated plant, expense, and rate base balances to ensure internal consistency in the assignment of common and overhead costs. This approach ensures that the resulting class revenue requirements are grounded in measurable service characteristics and supported by documented study inputs.

Q. What allocation methods were utilized to allocate the costs of demand-related distribution lines and substations?

A. Non-coincident peak ("NCP") demands were used to allocate demand-related distribution line and substation costs because those facilities are planned, designed, and constructed to meet the maximum load imposed on specific portions of the distribution system, rather than the system-wide peak occurring at a single moment in time.

Distribution infrastructure—such as feeders, circuits, and substations—serves localized groups of customers. Each segment of the distribution system must be capable of accommodating the highest load experienced on that segment, regardless of whether that load coincides with the Company's overall system peak. A customer class may reach its maximum demand during periods that are not coincident with the system peak, yet the distribution facilities serving that class must still be sized to reliably meet that maximum requirement. Accordingly, non-coincident peak demand more accurately reflects the cost driver for distribution demand-related investment.

The use of NCP allocators for distribution demand costs is consistent with engineering design standards and established cost-of-service principles, which allocate costs based on the manner in which facilities are utilized and the capacity requirements they must satisfy. By allocating distribution line and substation costs in proportion to each class's maximum load contribution, the study aligns revenue responsibility with the actual drivers of distribution system investment.

Q. What allocation methods were utilized in your studies for customer related costs?

A. Because a significant portion of the distribution system costs are incurred simply to attach a customer to the system and are the same regardless of the amount of energy that the customer might consume, significant portions of the distribution system costs and customer-specific costs are allocated to classes using allocators that are related to the number of customers in the class. However, because there generally is a wide difference between the customer classes in terms of the level of customer-related costs required per customer, many of the allocations of customer-related costs are weighted to reflect the relative differences in the average cost per customer of providing customer-related facilities or services for particular rate classes. Thus, customer-related costs such as meters, service lines, meter reading, billing, and customer service are allocated based on the cost-weighted number of customers in each class. The customer-related allocation factors and the relative-cost weights assigned to each class are shown in Exhibit D, Schedule 3.

Q. How are general and common plant costs allocated?

A. Detailed plant account data for Common Plant were reviewed and categorized as Plant-, Labor. Costs were then allocated using the internal allocation factor derived from the ratio of allocated Operation and Maintenance ("O&M") labor expenses by customer class.

Q. Please describe the method used to allocate the reserve for depreciation and depreciation expenses.

A. Accumulated depreciation was allocated by account in the same manner as their associated plant accounts. Depreciation expense was allocated to classes in proportion to total allocated plant based on the composite plant allocation factor, except for distribution depreciation expense, which also followed the allocation of the associated plant account.

Q. How are distribution-related O&M expenses allocated?

A. In general, these expenses were allocated using the same cost allocation methods applied to the Company's corresponding plant accounts. Distribution-related O&M expenses are incurred to operate and maintain specific plant-in-service accounts. In other words, the existence of particular plant facilities necessitates the incurrence of expenses to operate and maintain those facilities. As a result, the allocation basis used for a given plant account is also used to allocate the related O&M expense account. Where an expense cannot be directly associated with a specific plant account, the ACOSS uses an internal distribution allocator to assign those costs.

Q. How are customer account, service, and sales expenses allocated?

A. Customer account, service, and sales expenses are generally allocated based on the average number of customers in each respective class with the following exceptions: (a) Uncollectible Accounts Expense (FERC Account No. 904) is allocated based on historical write-off experience by customer class, thereby aligning the expense with the classes that give rise to the bad debt risk; (b) Customer Records and Collection Expenses related to the Universal Service Program (FERC Account No. 903), and (c) Miscellaneous Customer Service & Informational Expenses related to Energy Efficiency & Conservation (FERC Account No. 910). Expenses in FERC Account Nos. 903 and 910 are allocated using account-specific allocation factors.

Q. How are taxes other than income taxes allocated?

A. In the ACOSS, taxes other than income taxes were allocated based on the specific cost drivers associated with each tax category. Taxes were classified according to the assessment basis established for each type of tax, such as payroll, property, or functional relationship. Payroll-related taxes were allocated based on labor expenses, while property taxes were allocated based on total plant investment.

Q. How are income taxes allocated?

A. Income taxes are allocated to each customer class using a rate base allocator. This reflects the principle that, under a uniform rate of return framework, income taxes are proportional to the return earned on rate base.

C. ACOSS RESULTS

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

A. Table 1 below presents a summary of the Company's ACOSS that can be reviewed in Schedule 6 of Book IX, UGI Electric Exhibit D. These results provide cost-based guidelines for evaluating class revenue levels and interclass subsidies. Additionally, Schedule 6 summarizes each class's earned rate of return under current rates, the revenues currently being collected, the allocated cost of service at equal rate of return, and the revenue adjustments necessary to bring class revenues into alignment with their respective cost responsibilities.

Table 1 - Summary Results of the Company's ACOSS ($000)[7]

Customer Classes	Current Revenues	Current Class Revenue to Total	Cost to Serve	Class Cost to Serve to Total	Class Revenue (Deficiency)/ Excess	Percentage Change to Cost to Serve
Residential	$ 109,152	75.76%	$ 128,324	79.52%	$ (19,172)	17.56%
General Service	5,258	3.65%	6,786	4.21%	$ (1,528)	29.06%
General Service-4	13,973	9.70%	12,814	7.94%	$ 1,159	-8.29%
Flood Control Power	21	0.01%	23	0.01%	$ (2)	11.88%
Large Power	13,858	9.62%	11,830	7.33%	$ 2,028	-14.63%
Lighting	1,823	1.27%	1,591	0.99%	$ 232	-12.73%
Subtotal	**$ 144,085**	**100.00%**	**$ 161,368**	**100.00%**	**$ (17,283)**	12.00%
Other Revenues	$ 1,304		$ 1,304		$ -	
Total System	**$ 145,388**		**$ 162,672**		**$ (17,283)**	11.89%

Table 1 presents the revenue deficiency/excess for each rate class and the class rate of return on the net rate base at present rates. The revenue deficiency/excess for each rate class shows revenue increases or decreases necessary to get the classes to their cost to serve. Regarding rate class revenue levels, the ACOSS results show that the Residential, General Service, and Flood Control Power rate classes are being charged rates that recover less than their indicated costs of service; whereas rates for other rate classes provide for recovery of more than the indicated costs of serving these other rate classes. In other words, to set each classes' revenues equal to their cost to serve indicated in the ACOSS the Residential, General Service, and Flood Control Power rate classes require an increase in revenues, while General Service-4, Large Power, and Lighting require a decrease in revenues.

Additionally, Table 2 below provides helpful insights into the Company's financial metrics such as the current Rate of Return and corresponding Relative Rate of Return and

[7] See Exhibit D, Schedule 6, lines 18, line 58, and line 59. Other Revenues is the sum of lines 13 and 14 shown at line 57. General Service includes GS-1 and GS-5.

current Revenue to Cost Ratio with the corresponding Parity Ratio at the class-level and system-level, where system-level is defined as the aggregation of all customer classes.

Table 2 - Current Rate of Return and Revenue to Cost Ratio[8]

Customer Classes	Current Rate of Return	Relative Rate of Return	Current Revenue to Cost Ratio	Current Parity Ratio
Residential	0.32%	0.09	0.85	0.95
General Service	0.42%	0.12	0.78	0.87
General Service-4	16.10%	4.70	1.09	1.22
Flood Control Power	7.42%	2.17	0.90	1.00
Large Power	20.02%	5.84	1.17	1.31
Lighting	16.36%	4.78	1.15	1.28
Total System	3.43%	1.00	**0.89**	1.00

The Current Rate of Return shows the return each class is earning under existing rates compared to the Company's overall system return. The Relative Rate of Return expresses that relationship on a normalized basis, where 1.00 indicates parity with the system average. Similarly, the current Revenue-to-Cost Ratio compares each class's present revenues to its allocated cost of service at an equalized rate of return. A ratio of 1.00 reflects revenue-cost alignment, while values above or below 1.00 indicate over- or under-recovery, respectively. The corresponding Parity Ratio provides the same alignment measure in index form. Together, these metrics indicate whether a class is contributing revenues above or below its cost responsibility and provide guidance for evaluating interclass revenue relationships.

[8] See Exhibit D, Schedule 6, line 29 and line 31. General Service includes GS-1 and GS-5.

Q. How do the ACOSS results provide guidelines for rate design, both among and within rate classes?

A. The ACOSS results provide cost-based guidelines for evaluating both interclass revenue relationships and the design of rates within each class. At the class level, the revenue-to-cost ratios indicate whether existing rates recover more or less than a class's indicated cost of service. Where a class is under- or over-recovering relative to its allocated costs, rate adjustments can be considered to move class revenues closer to cost responsibility and bring class rates of return nearer to the system average rate of return. In this way, overall rate levels are better aligned with the cost of providing service.

Within each rate class, the classified and allocated costs developed in the ACOSS provide useful information for establishing the appropriate balance among customer, demand, and energy charges. Schedule 8 of Exhibit D summarizes the Company's functionalized revenue requirement on a per-customer and per-unit of billed demand basis for each rate class, which supports the development of rates that reflect the underlying cost structure of service.

V. <u>UGI ELECTRIC'S REVENUE APPORTIONMENT</u>

Q. Please summarize the guidance the Company's proposed ACOSS provides for revenue apportionment to the customer classes.

A. In development of the Company's ACOSS, the analysis begins with cost-based references. Proposals to allocate the base revenue requirement based on cost causation are designed to produce results that are reflective of costs and fair, such that cost assignment aligns with how costs are incurred. Moderation may be applied when translating cost-of-service results into class revenue responsibilities in order to promote rate stability, provide gradualism in the movement towards more cost-based relationships, and maintain rates that are understandable to customers. This framework provides transparency to cost responsibility across customer classes and potential cross subsidies between customer groups. To determine the potential need for moderation of the Company's proposed allocation to customer classes, two boundary reference points are used:

- <u>Equalized Rate of Return</u>: Revenue apportionment to customer classes to achieve an equalized rate of return for each class, that is, revenues allocated to the customer class are equal to its cost of service. While under this scenario, each customer class pays their share of cost of service (resulting in apportionment that achieves **Fairness** and is **Reflective of Costs**), different customer classes can experience different increases due to the variations between a class's current revenue versus its cost of service, resulting in potential issues with **Stability** and **Simplicity and Understandability**.
- <u>Equal Percent Increase by Class</u>: Revenue apportionment to customer classes is on an equal percent basis, that is, if revenue in total increases by 12.0%, then the increase to each customer class is 12.0%. Under this scenario, all customer groups will receive the same increase resulting in high **Simplicity and Understandability**, however the results may perpetuate cross-subsidies across customer groups, resulting in revenue assignment that is not **Reflective of Costs**.

Tables 3 and 4 below present respectively these two reference points, Equalized Rate of Return and Equal Percent Increase by Class, for class apportionment.

Table 3: Revenue Apportionment – Equalized Rate of Return

	Current			Equalized Rate of Return			
Customer Classes	Revenues	% Allocation	Parity Ratio	Revenue Allocation	% Allocation	Parity Ratio	% Change from Current
Residential	$ 109,152	75.76%	0.95	$ 128,324	79.52%	1.00	17.56%
General Service	5,258	3.65%	0.87	6,786	4.21%	1.00	29.06%
General Service-4	13,973	9.70%	1.22	12,814	7.94%	1.00	-8.29%
Flood Control Power	21	0.01%	1.00	23	0.01%	1.00	11.88%
Large Power	13,858	9.62%	1.31	11,830	7.33%	1.00	-14.63%
Lighting	1,823	1.27%	1.28	1,591	0.99%	1.00	-12.73%
Total	**$ 144,085**	**100.00%**	**1.00**	**$ 161,368**	**100.00%**	**1.00**	**12.00%**

Table 3 presents the class apportionment of revenues required to achieve equalized rates of return by customer class. This condition is reflected by a revenue-to-cost ratio, or parity ratio, of 1.00, where revenues assigned to each class fully recover that class's cost of service. The updated ACOSS results indicate an overall system revenue increase of 12.0%. Apportioning this increase across customer classes to achieve an equalized rate of return results in class revenue changes ranging from a decrease of 14.6% (more than 26 percentage points below the system average increase) to an increase of 29.1% (more than double the system average increase). These results illustrate the extent to which current class revenues differ from cost-based levels.

Table 4: Revenue Apportionment – Equal Percent Increase by Class

	Current			Equal Percent by Class			
Customer Classes	Revenues	% Allocation	Parity Ratio	Revenue Allocation	% Allocation	Parity Ratio	% Change from Current
Residential	$ 109,152	75.76%	0.95	$ 121,957	75.58%	0.95	11.73%
General Service	5,258	3.65%	0.87	6,020	3.73%	0.89	14.50%
General Service-4	13,973	9.70%	1.22	15,598	9.67%	1.21	11.63%
Flood Control Power	21	0.01%	1.00	26	0.02%	1.13	26.25%
Large Power	13,858	9.62%	1.31	15,575	9.65%	1.31	12.39%
Lighting	1,823	1.27%	1.28	2,193	1.36%	1.38	20.29%
Total	**$ 144,085**	**100.00%**	**1.00**	**$ 161,368**	**100.00%**	**1.00**	**12.00%**

Table 4 presents the class apportionment under an equal percentage increase by customer class. The apportionment of the required revenue increase based on an equal percentage increase of 12.0% across all customer classes results in customer class parity ratios ranging from 0.89 for the General Service class to 1.38 for the Lighting class. Under this approach, existing differences between current revenues and cost of service are maintained, as each class receives the same proportional increase regardless of its current parity ratio.

Q. Does the Company propose any moderation to revenue apportionment?

A. Yes. While the ACOSS provides a benchmark for allocating revenues based on a cost of service, the Company recognizes that moving immediately to equalized rates of return across customer classes could result in significant changes in allocated revenues for certain classes. This is particularly true where a utility has a small customer base; the customer base is largely within one rate class, and the largest rate classes are well below the cost of service. Therefore, the Company has moderated the revenue apportionment to balance cost-of-service principles with considerations of gradualism and customer impacts. As such, UGI Electric is not proposing either of the two previously discussed methodologies.

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

A. Under the Company's proposal, the overall revenue increase of 12.0% is distributed across the customer classes in a manner that moves classes closer to their cost of service while avoiding the larger revenue shifts that would occur under a fully equalized rate of return approach. As shown in Table 5, the proposed class revenue changes range from 2.24% for the General Service-4 class to 22.47% for the General Service customers[9], compared to the larger increases and decreases that would result from strictly equalizing class rates of return.

The resulting parity ratios under the Company's proposal range from 0.95 for the General Service class to 1.20 for the Large Power class, representing an improvement relative to current levels while maintaining reasonable rate stability across customer classes.

Table 5 – Proposed Revenue Apportionment[10]

	Current			Proposed			
Customer Classes	**Revenues**	**% Allocation**	**Parity Ratio**	**Revenue Allocation**	**% Allocation**	**Parity Ratio**	**% Change from Current**
Residential	$ 109,152	75.76%	0.95	$ 124,535	77.17%	0.97	14.09%
General Service	5,258	3.65%	0.87	6,440	3.99%	0.95	22.47%
General Service-4	13,973	9.70%	1.22	14,286	8.85%	1.11	2.24%
Flood Control Power	21	0.01%	1.00	23	0.01%	1.00	11.88%
Large Power	13,858	9.62%	1.31	14,189	8.79%	1.20	2.39%
Lighting	1,823	1.27%	1.28	1,894	1.17%	1.19	3.92%
Total	**$ 144,085**	**100.00%**	**1.00**	**$ 161,368**	**100.00%**	**1.00**	**12.00%**

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 moves customer classes closer to their respective cost-of-service levels while maintaining reasonable rate stability across classes. As shown in Table 5, the current parity ratios range from 0.87 for the General Service class to 1.31 for the Large Power class. Under the Company's proposal, the parity ratios move closer to unity for all classes and range from 0.95 for the General Service, which includes GS-1 and GS-5, to 1.20 for the Large Power class.

[9] General Service customers include customers in GS-1 and GS-5.
[10] General Service includes GS-1 and GS-5.

In particular, classes that are currently recovering less than their cost of service move closer to parity. For example, the General Service increases from a parity ratio of 0.87 to 0.95, and the Residential class increases from 0.95 to 0.97. At the same time, classes that are currently recovering more than their cost of service move closer to parity as well. The Large Power class decreases from 1.31 to 1.20, and the Lighting class decreases from 1.28 to 1.19.

Overall, the Company's proposed revenue apportionment represents a balanced approach that improves alignment with cost-of-service results while moderating the magnitude of revenue shifts among customer classes.

Q. What does Table 6 show regarding the Company's proposed revenue apportionment?

A. Table 6 compares the relative rate of return by customer class under current revenues and under the Company's proposed revenue apportionment. The table presents each class's rate of return on net rate base and the corresponding relative rate of return, which measures each class's return relative to the Company's overall system rate of return of 1.00. A relative rate of return below 1.00 indicates that a class is recovering less than the system average return, while a value above 1.00 indicates that the class is recovering more than the system average.

As shown in Table 6, the Company's proposal moves the relative rates of return for all classes closer to the system average, thereby improving alignment with cost-of-service results while moderating the magnitude of the changes across customer classes. For example, the Residential class increases from a relative rate of return of 0.09 under current revenues to 0.81 under the proposal, and the General Service class increases from 0.12 to 0.77. At the same time, classes that are currently recovering substantially more than the system average move closer to unity, such as Large Power, which decreases from 5.84 to 2.08, and Lighting, which decreases from 4.78 to 1.74. Overall, the Company's proposal improves the alignment between revenues and cost of service while maintaining reasonable rate stability across customer classes.

Table 6 - Comparison of Relative Rate of Return by Rate Class[11]

Customer Classes	Current Rate of Return On Net Rate Base	Current Relative Rate of Return	Proposed Rate of Return on Net Rate	Proposed Relative Rate of Return	Percent Change
Residential	0.32%	0.09	6.72%	0.81	80%
General Service	0.42%	0.12	6.38%	0.77	74%
General Service-4	16.10%	4.70	14.10%	1.71	81%
Flood Control Power	7.42%	2.17	8.07%	0.98	102%
Large Power	20.02%	5.84	17.22%	2.08	78%
Lighting	16.36%	4.78	14.35%	1.74	80%
Total Company	**3.43%**	**1.00**	**8.26%**	**1.00**	

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

A. Table 7 summarizes the current and proposed interclass subsidies and the reduction in subsidies resulting from the Company's proposed revenue apportionment. As shown in the table, the proposal substantially reduces the magnitude of cross-subsidies among customer classes.

[11] See Exhibit D, Schedule 6, lines 29-30 and lines 73-74.

Table 7 - Comparison of Present and Proposed Subsidies ($000)[12]

Customer Classes	Current Class Subsidy	Proposed Class Subsidy	Reduction in Subsidy
Residential	(6,251)	(3,788)	2,463
General Service	(489)	(347)	142
General Service-4	2,621	1,473	1,148
Flood Control Power	4	0	4
Large Power	3,591	2,359	1,232
Lighting	524	303	220

The reduction occurs across all classes. For example, the subsidy received by the Residential class decreases from $6.3 million to $3.8 million, while the subsidy received by the General Service, which includes GS-1 and GS-5, decreases from $0.5 million to $0.3 million. At the same time, subsidies provided by other classes are also reduced. For instance, the subsidy provided by the General Service-4 class decreases from $2.6 million to $1.5 million, and the subsidy provided by the Large Power class decreases from $3.6 million to $2.4 million. The proposal also results in no subsidy associated with the Flood Control Power class.

Overall, the Company's proposal significantly reduces cross-subsidies while maintaining a moderated transition toward cost-based revenue responsibility.

VI. UGI ELECTRIC'S RATE DESIGN PROPOSALS

Q. Please describe the present rate structure for UGI Electric customers.

A. UGI Electric currently provides electric distribution service under several rate schedules that apply to different customer classes based on usage characteristics and service

[12] See Exhibit D, Schedule 6, line 40 and line 66. Reduction in Subsidy = Absolute difference between Proposed Subsidy and Current Subsidy.

requirements. The principal customer classes and rate schedules addressed in this proceeding include Residential ("R"), General Service ("GS-1" and "GS-5"), General Service-4 ("GS-4"), Flood Control Power ("FCP"), Large Power ("LP"), and Lighting service. These rate schedules establish the distribution charges applicable to customers receiving service from the Company.

Under the present rate structure, most customer classes are billed through a combination of a monthly customer charge and a volumetric distribution charge, with the volumetric charge generally applied on a flat per-kilowatt-hour basis. Larger commercial and industrial customers receiving service under Schedules GS-4 and LP are also subject to demand charges, reflecting the impact of their peak demand on the distribution system. These demand charges are structured using two-block demand rates, while volumetric charges for these classes are structured using three-block or four-block declining block energy rates. Table 8 summarizes the key elements of the present rate design by customer class.

Table 8 - Current Rate Design by Customer Class[13]

Rate Schedule	Customer Charge	Demand Charge	Volumetric Charge
Schedule R	Yes	No	Flat rate
Schedule GS1	Yes	No	Flat rate
Schedule GS5	Yes	No	Flat rate
Schedule FCP	Yes	No	Flat rate
Schedule GS4	Yes	2-block rate	3-block rate
Schedule LP	Yes	2-block rate	4-block rate

[13] As described later in this testimony, while Schedules FCP and LP do not have customer charges identified in the tariff, the current rate design creates a minimum bill impact that functions similar to a customer charge.

Q. Please describe the Company's rate design proposals.

A. UGI Electric's proposed rate design reflects an effort to better align rates with the underlying cost of providing electric distribution service while moderating bill impacts to customers. The proposal also considers the results of the Company's cost-of-service study and the gradual transition toward a cost-based rate structure, while moving toward simpler and more streamlined rate structures. The Company's rate design proposals to move towards rate that are more **Reflective of Costs** will result in rates that will better ensure customers contribute a more representative portion of their fair share of utility cost of service (**Fairness**) and promote more efficient use of resources (**Efficiency**). In addition, the Company proposes various rate design changes to **Simplify** and improve **Understandability** of its current rates. The Company proposes the following key changes to the current rate design.

First, the Company proposes increasing the customer charge for all rate schedules with current customer charges and establishing a customer charge for Rate LP in order to better reflect the fixed costs associated with providing electric distribution service. A significant portion of distribution system costs are customer related or fixed and do not vary directly with short-term customer usage. Increasing the customer charge, or adding a customer charge, improves cost alignment by recovering a greater portion of these fixed costs through fixed charges rather than through volumetric rates. The proposed increases in customer charges are accompanied by compensating adjustments to volumetric distribution rate components, all else equal. The move to more cost-based customer charges and the compensating decrease in volumetric charges will provide customers with greater month-to month bill stability. In addition, while lower system charges and higher energy rates may provide customers with the incentive to save energy through energy efficiency and conservation, overstated energy rates will provide an inefficient price signal that overvalues energy efficiency and conservation.

Second, for non-residential customers on Schedules GS-4 and LP with demand charges, the Company proposes to move demand charges to be more cost based. Distribution system costs are either customer related or demand related. Similar to the Company's proposal to move towards more cost-based customer charges, increasing the demand charge improves cost alignment by recovering a greater portion of demand related costs through demand charges rather than through volumetric rates. The proposed increases in demand charges are accompanied by compensating adjustments to volumetric distribution rate components, all else equal. The Company does not propose to introduce any demand charges for customer groups that currently do not have demand charges in this proceeding.

Third, for non-residential customers on Schedules FCP, General Service-4 and Large Power, the Company proposes to begin transitioning away from the current block rate structures for distribution and demand charges by moderating or eliminating existing blocks. Currently, FCP has a block rates structure for its distribution charges, and GS-4 and LP have a block rate structure for demand charges and distribution charges. Such structures are generally not aligned with cost-of-service principles because the marginal cost of providing distribution service does not vary with changes in usage or demand and can be overly complex. The Company's proposal moderates or eliminates the existing block structures by adjusting demand and energy charges in a manner that moves rates toward a more cost-reflective structure while moderating potential bill impacts.

In addition, the Company's proposed changes will **Simplify** and improve **Understandability** of rates**:**

- More consistent definition of fixed monthly charges to be customer charges.
- Reduction and/or elimination of block rates for demand charges and/or volumetric distribution rates.

Q. Are there any rate design proposals for Lighting customers?

A. No. The Company does not propose any changes to rate design for Lighting. Lighting rates will adjust to reflect changes in cost of service as an equal percent change to all distribution rate components equal to the class average change.

Q. Please describe what you mean by a cost-based rate structure.

A. A cost-based rate structure is informed by the ACOSS and consists of:

- A **fixed monthly customer charge** for the recovery of Customer-related costs that vary based on the number of customers served rather than the amount of utility service supplied.
- A **demand charge** for the recovery of Demand/capacity costs that vary with the demand on various parts of the system.

- A **volumetric rate** for the recovery of Energy/usage costs that vary based on the quantity of electricity consumed.

Often times volumetric rates recover all remaining costs of utility services not recovered through customer or demand changes when customer and demand charges are below cost-based levels.

Q. Why is a cost-based rate structure beneficial?

A. A cost-based rate design is one that aligns the rates customers see for energy services with the utility's cost of service, making them **Reflective of Costs** (rates should reflect the cost of providing service to different customer classes). This also promotes **Efficiency** (rates should promote the efficient use of resources and encourage conservation while avoiding undue restriction of economic use) and **Fairness** (rates should be fair to all customer classes, avoiding undue discrimination). The transition to cost-based rates must be balanced and take into consideration current rates to ensure proposed rates meet customer needs for **Simplicity and Understandability** (rates should be simple and understandable for customers) and **Stability** (rates should provide bill stability for customers and revenue stability for the utility).

Q. How do cost-based rates promote fairness?

A. A cost-based rate design ensures that all customers pay their fair share of energy services received and avoids intraclass cost-shifts when prices don't reflect cost of service.

Q. Are there any additional considerations made to the determination of a cost-based customer charge?

A. For the purposes of developing customer related costs for a residential customer charge, the Commission has previously provided additional guidance regarding costs eligible for recovery through a residential customer charge. This guidance excludes certain costs identified as customer related in the ACOSS and limits eligible costs for recovery through a residential customer charge to be costs associated with meters and services and related O&M expenses, meter reading and billing and collection expenses, meter data management systems, and related employee benefits, administrative and general expenses. The unit cost value used as a reference for development of a cost-based residential customer charge presented in this testimony reflects these adjustments.

Q. Are the Company's fixed monthly customer charges currently cost-based?

A. No. It is important to recognize that any revenue not recovered through the fixed monthly customer charge must be recovered through other delivery rate components, such as demand or volumetric charges. All else equal, an increase in the customer charge would result in a compensating decrease in other delivery rate components.

The Company's ACOSS provides cost-based reference levels for customer charges. Table 9 compares current customer charges with these cost-based levels. As shown in the table, current customer charges recover only a small portion of customer-related costs for most rate schedules. Except for Schedule LP, current customer charges recover less than 40 percent of the customer-related costs identified in the ACOSS.

Table 9 - Comparison of Current and Cost-based Customer Charges[14]

Rate Schedule	Current	Cost-Based	% of Cost-based	% Change from Current
Schedule R	$10.75	$28.48	37.7%	164.9%
Schedule GS1	$17.00	$56.90	29.9%	234.7%
Schedule GS5	$10.75	$56.90	18.9%	429.3%
Schedule FCP	$6.03	$54.30	11.1%	800.5%
Schedule GS4	$18.00	$64.82	27.8%	260.1%
Schedule LP	$135.80	$147.03	92.4%	8.3%

Currently the Schedule LP identifies the following charges:

- No customer charge;
- A three-block demand charge that includes one price for the first 100 kW of billing demand, another for the next 400 kW of billing demand, and then a third price for demand over 500 kW of billing demand; and
- A four-block declining volumetric distribution charge that includes one rate for the first 100 hours use of billing demand, a second rate for the next 200 hours use of billing demand but not more than 200,000 kWh, a third rate for the next 200 hours use of billing demand but not more than 200,000 kWh, and a fourth rate for usage above that identified as Excess.

However the charge for the first 100 kW or less per month is applied as a customer charge, that is, as a fixed dollar amount per month, rather than a demand charge, $/kW within a given month. Under this pricing structure, customers are effectively paying a customer charge of $135.80 a month and a zero demand charge for the first 100 kW. For the purposes of this testimony, the fixed component is presented as a customer charge.

[14] See Exhibit D, Schedule 8, line 63. Cost-based for Residential is explained below in connection to Table 11.

In addition, currently the Schedule FCP identifies the following charges:

- No customer charge;
- A two-block distribution charge that includes one price for the first 100 kWh of billing demand, another for all additional kWh.

However the charge for the first 100 kWh or less per month is applied as a customer charge, that is, as a fixed dollar amount per month, rather than a volumetric distribution charge, $/kWh within a given month. Under this pricing structure, customers are effectively paying a customer charge of $6.03 a month and a zero volumetric charge for the first 100 kWh. For the purposes of this testimony, this fixed component is treated as a customer charge.

Q. What is the Company's proposal for customer charges?

A. As presented in Table 9 above, current customer charges are well below cost-based levels, recovering only a fraction of customer-related costs identified in the cost-of-service study. The Company seeks to continue moving rates toward levels that are more **Reflective of Costs**. To support this objective, the Company proposes to increase the customer charge for several rate schedules, as summarized in Table 10. These proposed increases move the customer charges closer to the cost-based reference levels while maintaining reasonable customer bill impacts. In addition, the Company's proposal also seeks to **Simplify** and improve **Understandability** by introducing more consistent definition and application of customer charges across rate schedules.

Table 10 - Customer Charge Proposals

Rate Schedule	Current	Cost-Based	% of Cost-based	Proposed	Proposed % of Cost-based	% Change from Current
Schedule R	$10.75	$28.48	37.7%	$22.00	77.2%	105%
Schedule GS1	$17.00	$56.90	29.9%	$30.00	52.7%	76%
Schedule GS5	$10.75	$56.90	18.9%	$30.00	52.7%	179%
Schedule FCP	$6.03	$54.30	11.1%	$13.50	24.9%	124%
Schedule GS4	$18.00	$64.82	27.8%	$45.00	69.4%	150%
Schedule LP	$135.80	$147.03	92.4%	$150.00	102.0%	10%

In developing proposed rates, the Company moderated the movement toward cost-based levels to maintain gradualism and mitigate bill impacts. In addition, the Company selected administratively practical charge levels that are easy to implement and communicate to customers. As a result, certain proposed customer charges may slightly exceed or remain below the calculated cost-based levels.

Q. Please describe why an increase in the customer charge to be more cost-based is important.

A. First, as reflected above, increasing or establishing the customer charge to be more cost-based ensures customers contribute a more representative portion of their fair share of system costs. Second, increasing customer charges also improves bill stability. Third, while lower customer charges and higher energy rates may provide customers with the incentive to save energy through energy efficiency and conservation, overstated energy rates will provide an inefficient price signal that overvalues energy efficiency and conservation. Further, the overall customer bill, inclusive of supply pricing done on a purely volumetric basis, will continue to send adequate and appropriate price signals to consumers on the value of conservation without interfering with cost causation principles in the design of the distribution rates.

Q. Please describe the additional rate changes proposed for Schedule FCP.

A. Currently under Schedule FCP, as discussed above, customers pay a fixed monthly distribution charge for the first 100 kWh or less per month per installed pump and pay a volumetric distribution charge of any additional kWh over that first 100 kWh. In addition to the movement towards more cost-based rates with an increase in the fixed monthly charge, the Company proposes to redefine this as a customer charge to improve **Simplicity** and **Understandability**. In addition, the Company proposes a flat volumetric distribution charge be applied to all usage in the month. Schedule FCP's current, cost-based, and proposed charges are presented in Table 11.

Table 11 - Rate Design Schedule FCP

Description	Current	Cost-based	Proposed	%age of Cost-based	% change from current
Customer Charge ($/mo)	$ 6.03	$ 54.30	$ 13.50	25%	124%
Distribution Charges ($/kWh)	$ -	$ 0.02603	$ 0.03128		
First 100 kW	$ -	$ 0.02603	$ 0.03128		
Over 100 kW	$ 0.02733	$ 0.02603	$ 0.03128		

Q. Please describe the additional rate changes proposed for Schedule GS-4.

A. Currently under Schedule GS-4, customers pay a declining 2-block demand charge and a declining 3-block volumetric distribution charge. In addition to an increase in the customer charge, the Company proposes to move from a 2-block demand charge to a flat demand charge be applied to all demand and to move from a 3-block volumetric distribution charge to a flat volumetric distribution charge be applied to all usage in the month. Schedule GS-4's current, cost-based, and proposed charges are presented in Table 12.

Table 12 - Rate Design Schedule GS-4

Description		Current	Cost-based	Proposed	%age of Cost-based	% change from current
Customer Charge ($/mo)	$	18.00	$64.82	$45.00	69%	150%
Demand Charges ($/kW)	$	-	$6.58	$3.75	57%	100%
First 20 kW	$	3.59				4%
Over 20 kW	$	2.20				70%
Distribution Charges ($/kWh)	$	-	$ 0.01092	$ 0.02624		
First 200 hours of demand	$	0.03399				
Next 300 hours of demand	$	0.02142				
All over 500 hours of demand	$	0.01785				

Q. Please describe the additional rate changes proposed for Schedule LP.

A. Currently under Schedule LP, customers pay a fixed monthly distribution charge for the first 100 kW or less per month and demand charges for any demand greater than the first 100 kWh. UGI Electric is proposing to establish a clear customer charge for Schedule LP that would slightly increase the effective customer charge associated with the first 100 kW in usage. The Company's proposal includes renaming the current monthly fixed charge to be a customer charge and introduces a non-zero demand charge to demand less than 100 kW. In addition, the Company proposes to collapse the current declining block demand charges applicable to the next 400 kW and to kW over 500 to a single demand charge, thereby moving from the current 3-block demand charge to a 2-block demand charge. Further the Company proposes to move from a 4-block volumetric distribution charge to a flat volumetric distribution charge that would be applied to all usage in the month. Schedule LP's current, cost-based, and proposed charges are presented in Table 13.

Table 13 - Rate Design Schedule LP

Description	Current	Cost-based	Proposed	%age of Cost-based	% change from current
Customer Charge ($/mo)	$ 135.80	$147.03	$150.00	102%	10%
Demand Charges ($/kW)	$ -	$7.78	$ -		
First 100 kW	$ -		$2.50	32%	100%
Next 400 kW	$ 0.94		$5.00	64%	432%
Over 500 kW	$ 0.69				625%
Distribution Charges ($/kWh)	$ -	$ 0.00112	$ 0.01125		
First 100 hours of demand	$ 0.02506				
Next 200 hours of demand	$ 0.01809				
Next 200 hours of demand	$ 0.01656				
All over 500 hours of demand	$ 0.01555				

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

A. Yes. UGI Electric Exhibit E – Proof of Revenue, sponsored by Company witness Epler, presents a detailed comparison of present and proposed rates and revenues for each of UGI Electric's rate classes.

VII. CONCLUSION

Q. Please summarize your conclusions and recommendations for UGI Electric's ACOSS, class revenues, and rate design.

A. My conclusions and recommendations are as follows:

- The Commission should accept the results of the Company's ACOSS as a realistic reflection of cost causation and the design and operating characteristics of the Company's distribution system.
- The Commission should accept the results from the Company's ACOSS as a guide to evaluate and set UGI Electric's class revenues and rate design in this proceeding. The Company's ACOSS has been developed using a standard, transparent, and widely accepted cost-of-service framework. The study adheres to established cost-causation principles and reflects the guidance set forth in the NARUC Manual. The ACOSS provides a reasonable and supportable allocation of costs to customer classes based on how those costs are incurred to provide service. The results identify the relative cost responsibility of each class, measure current revenue-to-cost relationships, and quantify the adjustments necessary to align revenues with allocated costs under an equalized rate of return framework. As noted above, the Commission previously approved the methods employed by UGI Electric in prior base rate proceedings.
- The Commission should accept the Company's proposed apportionment of revenues to its rate classes because the Company has exercised sound regulatory judgment by proposing a moderated approach that moves classes toward cost while maintaining rate stability and gradualism. This approach appropriately balances the principles of cost causation, fairness, stability, and revenue sufficiency.

- The Commission should approve the rate design proposed by the Company because it reasonably balances key rate design objectives I presented earlier in my testimony, including (1) achieving fair and equitable rate levels that are reflective of the cost to serve; (2) avoiding undue discrimination between and within rate classes; (3) developing rates that are stable and understandable; (4) creating economically efficient pricing for delivery service; (5) encouraging conservation and efficient use; (6) recovering the revenue requirement in a manner that maintains revenue stability and minimizes year-to-year under- or over-collections, and (7) simplifying and improving the understandability of rates.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC

EXHIBIT CSF-1

CYNDEE FANG

Experienced industry leader with over 20 years of experience who strives to engage others to conceive, create, and execute practical solutions to the most challenging problems. Expert witness with extensive experience and understanding of utility regulatory process including expertise in regulatory strategy and rate design.

EDUCATION

University of Minnesota, Ph.D. (ABD), Applied Economics

University of California, Berkeley, B.S., Political Economics of Natural Resources

YEARS EXPERIENCE

20+

RELEVANT EXPERTISE

Expert Witness, Allocated Cost of Service & Rate Design , Regulatory Strategy

PROFESSIONAL HISTORY

ATRIUM ECONOMICS

DIRECTOR, 2024

- Expert witness focused on the following areas of expertise:
    - Regulatory Policy & Strategy;
    - Alternative Regulatory Mechanisms & Cost Recovery;
    - Allocation of Cost of Service; and
    - Rate Design.

NORTHWESTERN ENERGY

VICE PRESIDENT - REGULATORY; 2021 - 2024

- Oversaw the Company's regulatory activities in Montana, South Dakota, and Nebraska.
- Developed and executed a regulatory strategy to advance a more constructive regulatory framework to meet the Company's strategic needs.
- Established an in-house cost of service and rate design team.
- Developed and executed a strategy for Montana rate reviews to advance a more constructive regulatory framework.

SAN DIEGO GAS AND ELECTRIC

ENERGY SUPPLY - ORIGINATION & PORTFOLIO DESIGN MANAGER; 2020 – 2021

- Lead the portfolio design of Electric & Fuel Procurement (E&FP), as SDG&E right-sizes portfolio, with market analytics that inform and guide the long-term strategy including daily optimization activities and forward-looking planning efforts.
- Lead all competitive procurement of renewable energy and conventional resources beyond one year to fulfill SDG&E's energy and resource capacity needs.

FORECASTING, RESEARCH & ANALYTICS – MANAGER OF ENERGY RESEARCH & ANALYSIS; 2018 – 2020

- Lead and oversee load forecasting, research and analysis teams to ensure the advancement of data-driven decision making in support of the Company's strategic needs including the advancement of operational improvements to better address changing California energy policies. Key areas of focus include impacts of customer adoption of advanced technology (PV, EV) and analysis of COVID impacts.
- Development of collaborative internal stakeholder processes to ensure alignment on Company direction regarding electric sales forecast. Key areas of focus include identification of key drivers and CCA expansion.
- Establishment of collaborative relationships with external stakeholders to support the advancement of the Company's strategic objectives related to the sales forecast.

RATES AND PRICING – MANAGER OF CUSTOMER PRICING; 2017 – 2018

- Oversight of all aspects of the pricing policy to meet the strategic needs of SDG&E and ensure fair and equitable rates for SDG&E’s 1.4 million electric customers.
- Development, advocacy and implementation of the Company’s rate strategy, including the development of regulatory filings to advance this strategy.
- Development of collaborative internal stakeholder processes to ensure alignment on Company direction regarding electric rates.
- Establishment of collaborative relationships with external stakeholders to support the advancement of the Company’s rate strategy needs to include representing the Company as a witness in regulatory proceedings and lead settlement negotiations.

RATE STRATEGY AND ANALYSIS MANAGER; 2015 – 2017
ELECTRIC RATES MANAGER; 2010 – 2015
PRINCIPAL/REGULATORY ECONOMIC ADVISOR; 2006 - 2010

MINNESOTA DEPARTMENT OF COMMERCE

PUBLIC UTILITIES RATES ANALYST; 2003 - 2006

- Development of the position of the Minnesota Department of Commerce on matters related to energy policy and presentation before the Minnesota Public Utilities Commission
- Implementation of Minnesota’s Renewable Energy Objective, including the establishment of the Minnesota Renewable Energy Tracking System and compliance review of utility filings (integrated resource plans, certificate of need)

REGULATORY EXPERIENCE

Alternative Regulatory Mechanisms

- Consideration of the Formula Rate Mechanism Tariff Revision Designated as TA 353-4 *on behalf of ENSTAR Natural Gas Company, LLC of Alaska* (Docket No. U-25-013)

- 2022 Montana Rate Review (Docket No. 2022.07.078) - Witness: Priority Regulatory Mechanisms proposing new revenue adjustment mechanisms and redesign of existing mechanisms https://www.northwesternenergy.com/docs/default- source/default-document-library/billing-and-payment/2022-montana-rate-review/08-fang- direct-testimony-regulatory-policy.pdf
- PCIA Reform (A.17-04-018) - Joint Application of Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company for Approval of the Portfolio Allocation Methodology for All Customers – *Cost Recovery and Rate Design witness for SDG&E*
- Establishment of Tree Mortality Non-Bypassable Charge (TM-NBC) (A.16-11-005) Application to Establish Non-Bypassable Charge ("NBC") for Above-Market Costs Associated with Tree Mortality Power Purchase Agreements ("Tree Mortality") in Compliance with Senate Bill 859 and Resolution E-4805 – *Cost Recovery and Rate Design witness for SDG&E*
- SDG&E's Wildfire Expense Memorandum Account (WEMA) Proceeding (A.15-09-010) – *Cost Recovery witness*
- Establishment of Cost Allocation Mechanism (CAM) (A.11-05-023) - SDG&E's Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power – *Cost Recovery and Rate Design witness*

Affordability

- Affordability Rulemaking – R.18-07-006: Order Instituting Rulemaking to Establish A Framework and Processes for Assessing the Affordability of Utility Service – *SDG&E lead*
- Residential Essential Use Study – A.19-11-019: Joint Utility Proposal for the Study to Identify Electric Essential Usage for Residential Customers – *SDG&E lead*
- A.17-10-007: SDG&E 2019 General Rate Case – *rebuttal witness addressing affordability*
- Residential TOU Exclusions Pursuant to Section 745 – R.12-06-013: To ensure residential customers defaulting to TOU do not experience unreasonable hardship under TOU rates – *Rate Design Policy witness*

Allocated Cost of Service and Rate Design

- 2022 Montana Rate Review (Docket No. 2022.07.078) - Witness: Allocated Cost of Service and Rate Design presenting the Company's moderation proposals to allocated cost of service and rate design for customers https://www.northwesternenergy.com/docs/default-source/default-document-library/billing- and-payment/2022-montana-rate-review/31-fang-acos-rd-direct-testimony.pdf
- SDG&E General Rate Case Phase 2 Application for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design - *Rate Design and Policy Witness*

Rate Design

Time-Variant Pricing and Residential Default Time-of-Use

- Petition for Approval of (1) Time of Use ("TOU") and Critical Peak Pricing ("CPP") Rates and (2) Modification of the TOU Summer Period for the CPP Pilot Program, and (3) CEI South's Rate RS-CPP Tariff *on behalf of Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South* (Cause No. 46263)
- Application of San Diego Gas & Electric Company for Authority to Update Electric Rate Design Regarding Residential Default Time-Of-Use Rates and Fixed Charges (A.17-12-013)
- Residential Rate Reform (R.12-06-013) - SDG&E's Application in response to Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations – *multiple phases*
- SDG&E's 2016 General Rate Case Phase 2 Proceeding (A.15-04-012) - includes proposal to update TOU periods
- SDG&E's 2015 Rate Design Window Filing (A.14-01-027) – includes proposal to update TOU periods and residential baseline

Innovative Rate Design and Emerging Technologies

- SDG&E's Electric Vehicle Grid Integration (VGI) Pilot Program (A.14-04-014) – *Rate Design Policy and Cost Recovery witness*
    - SDG&E was recognized as the 2020 Investor-Owned Utility of the Year by Smart Electric Power Alliance (SEPA) for its "Power Your Drive" program and the innovative VGI rate, an hourly dynamic grid integrated rate. https://sepapower.org/knowledge/2020-sepa-power-players- award-winners/
- Net Energy Metering Reform (R.14-07-002) - SDG&E Application in response to Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering
- Application of SDG&E for Authority to Implement Priority Review and Standard Review Proposals to Accelerate Widespread Transportation Electrification (A.17-01-020) – *Rate Design Policy and Cost Recovery witness*

Economic Development Rates

- Application of San Diego Gas & Electric Company for Authority to Implement Rate Relief and Increase Spend in Support of the San Diego Unified Port District's Energy Management Plan (A.17-09-005) – *Cost Recovery and Rate Design witness*
- Application of SDG&E for Authority to Implement Economic Development Rates (A.17-02-008) – *Cost Recovery and Rate Design witness*

Cost Recovery

- Assessment of Potential Gas LDC Capital Transition Costs and Analysis of Depreciation and Alternative Cost Recovery Approaches for Pathways to Commonwealth Decarbonization Goals *on behalf of Massachusetts Gas Local Distribution Companies (National Grid; Eversource Energy; Berkshire Gas Company; Liberty Utilities; Unitil)*

- Strategic Targeted Pipe Replacement Plan *on behalf of Washington Gas and Light Company of the District of Columbia* (Formal Case No. 1179) – *rebuttal witness responding to parties on risk of stranded assets and stranded costs*
- SONGS Decommissioning (A.14-12-007) Joint Application of SDG&E and SCE for 2014 SONGS Units 2 & 3 Decommissioning Cost Estimate and related Decommissioning – *Cost Recovery witness*
- SDG&E General Rate Case Application for Authority to Update its Electric and Gas Revenue Requirements and Base Rates - *Cost Recovery and Rate Design witness; multiple years*
- ERRA Trigger (A.17-05-012) Expedited Application of San Diego Gas & Electric Under the Energy Resource Recovery Account Trigger Mechanism
- SDG&E's Energy Resource Recovery Account (ERRA) Forecast Application for the recovery of costs associated with electric procurement – *Cost Recovery and Rate Design witness, multiple years*

SELECTED PUBLICATIONS / PRESENTATIONS

Panelist at Critical Consumer Issue Forum (CCIF)

- Critical Consumer Issues Forum (CCIF) 14th Annual Kickoff Forum in Collaboration at 2023 NARUC Annual Meeting; Topic: "Exploring Rate Design & Other Regulatory Tools: Maximizing Grid Value & the Customer Experience."
- "Navigating the Challenges & Opportunities of Today's Regulatory Landscape" https://criticalconsumerissuesforum.com/wp-content/uploads/CCIF-2023-Navigating-Regulatory- Landscape-Report.pdf
- "The Customer-Centered Clean Energy Transition: Balancing Technology, People & the Planet"

Presenter/Instructor ad EEI Advanced Rate School at University of Wisconsin Public Utility Institute (WPUI); July 2021.

Advanced Workshop in Regulation and Competition – Annual Western Conference held by Center for Research in Regulated Industries, of Rutgers Business School, Rutgers University

- "Zen and the Art of Rate Design" – Webinar sponsored by Center for Research in Regulated Industries, of Rutgers Business School, Rutgers University, January 13, 2021 – Link to webinar Zen and the Art of Rate Design [nam02.safelinks.protection.outlook.com]
- Member of Western Conference Organizing Committee from 2015-2022.
- Author/Co-author and Presenter as well as chair/discussant – multiple years.
    - 2022 – "Residential Time of Use Rates…and how one utility got there"
    - 2019 – "A Modern Rate Architecture for California's Future"
    - 2017 – "Solar Adoption and Customer Consumption in the Residential Sector"
    - 2016 – "Solar Adoption and Customer Demand in the Residential Sector"
    - 2014 - "Revisiting Rate Structure Reform to Meet a Low Carbon Future"
    - 2013 - "Unbundling – A Needed Fix for Residential Rate Design"
    - 2012 - "Rate Structure Reform to Meet a Low Carbon Future"

"Residential Time of Use…and what it took to get there" Presentation at EPRI's Rates Working Group (September 2020)

Discussant for 2020 POWER Conference– Session: Retail Rate Design (April-May 2020, Energy Institute at Haas School of Business, University of California, Berkeley) - Link to 2020 POWER Conference https://haas.berkeley.edu/energy-institute/events/power-conference/past-power-conferences/2020- power-conference/

Panelist at CEC Workshop on Scope of Load Management Rulemaking (January 2020) - Link to workshop https://www.energy.ca.gov/event/workshop/2020-01/commissioner-workshop-scope-load-management-rulemaking-19-oir-01

Presentation at Advanced Rate Design Strategy Workshop hosted by Hawaiian Electric (July 2019) - Link to workshop https://www.hawaiianelectric.com/clean-energy-hawaii/grid-modernization- technologies/advanced-rate-design-strategy

Panelist at Forth Roadmap Conference 2019 – Session: Rate Design to Accelerate Transportation Electrification (June 2019) - Link to Roadmap 12 http://roadmapforth.org/program/

"A Modern Rate Architecture for California's Future" by Margot Everett (PG&E), Cynthia Fang (SDG&E), Andre Ramirez (SCE), and Jude Schneider (SCE); Public Utilities Fortnightly, Vol 156, No. 12; November 1, 2018.

"SDG&E's Design of Grid Integrated Rates" at Panelist at CEC Workshop: CA Vehicle-Grid Integration Roadmap (October 2018) - Link to workshop information https://www.energy.ca.gov/programs-and- topics/programs/california-vehicle-grid-integration-roadmap-update/past-workshops-and

Panelist at CPUC ZEV Rate Design Forum 2018: California Public Utilities Commission forum to review and evaluate electric rate designs that could support the state's zero-emission vehicle goals established by Governor Jerry Brown's executive order B-48-18: having 5 million light-duty zero-emissions vehicles on the road by 2030. (June 2018) - Link to CPUC ZEV Rate Design Forum 2018 https://www.cpuc.ca.gov/energy/electricrates/

Panelist at CPUC Rate Design Forum on Demand Charges and Advanced Rate Designs (December 2017) - Link to CPUC Electric Rate Forum 2017 https://www.cpuc.ca.gov/General.aspx?id=6442455548

Presentations at Utility of the Future Rate Group sponsored by Economics Incorporated

- "COVID 19 Impacts – Some Early Insights" (May 2020)
- "A Customer-Focused Alternative to Pricing" (November 2019)
- "SDG&E's Design of Real Time Pricing and Other Dynamic Rates" (April 2017)

UGI ELECTRIC STATEMENT NO. 12

BRIAN J. MEILINGER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2025-3059430

UGI Utilities, Inc. – Electric Division

Statement No. 12

Direct Testimony of
Brian J. Meilinger

Topics Addressed:
Universal Service Programs
Strategic Initiatives
Low-Income Customer Counts

Dated: March 27, 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" or the "Company") and the Gas Division ("UGI Gas"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC"). 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 Electric Exhibit BJM-1.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of UGI Utilities, Inc. – Electric Division ("UGI Electric" 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 Electric has undertaken to make sure that its customers have access to affordable utility service. Customer affordability is a core focus at UGI Electric. This is evident from the success of the Company's many customer programs, as well as the Company's commitment to voluntarily increase its annual donation to Operation Share from the current $117,423 per year up to $150,000 per year for the next three years (FY27, FY28, and FY29). 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 $150,000 annually to Operation Share for the next three years; and (3) provides data regarding the Company's low-income customer counts.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes, I am sponsoring UGI Electric Exhibit BJM-1, which provides a list of the proceedings in which I have testified.

II. UNIVERSAL SERVICE PROGRAMS

Q. Does UGI Electric 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 Electric submits a USECP every five years for the Commission's review and approval.

Q. Did UGI Electric 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 Electric proposing any changes to its USECP as a part of this base rate proceeding?

A. No. However, UGI Electric intends to update its USECP with the $150,000 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 electric heating customers, maximum monthly CAP payments are set at 6% of income for customers with household incomes between 0-50%, 8% of income for customers with household incomes between 51-100% FPIG, and 9% of income for customers with household incomes between 101-150% FPIG. CAP participants with no income are placed on the monthly minimum payment, which is $30 for electric heating service and $15 for non-heating electric 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 25%, or 6,000 kWh for UGI Electric general customers and 12,788 kWh for UGI Electric heating customers. 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.

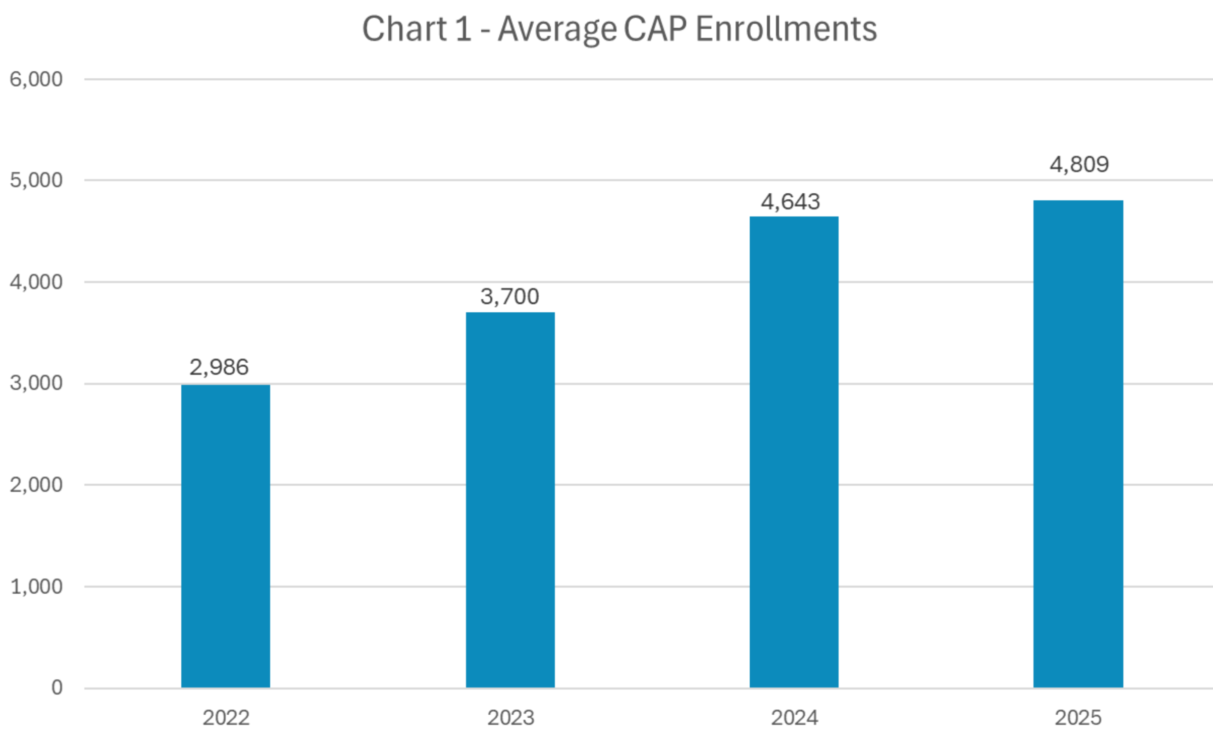
Q. Has the Company's CAP helped low-income customers afford their utility bills?

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 4,809 customers, which represents a 4% increase over 2024, and a 61% increase over the 2022 CAP average enrollment of

2,986. Please see Chart 1 below for details regarding the growth in UGI Electric 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. As a result of the 2023 UGI Electric Base Rate Case settlement (Paragraph 60(d)), the Company undertook an effort to auto-enroll non-shopping customers who received LIHEAP in the prior 12 months into the Company's CAP. This initiative led to 173 customers being enrolled in 2024 and 214 customers being enrolled in 2025. In order to continue promoting the availability of the CAP, the Company continued with its twice-a-year marketing campaigns to self-certified customers who had not yet gone through the Company's income verification process, as well as to LIHEAP recipients who were not currently enrolled in CAP, with a call to action to enroll in CAP.

Q. How has CAP worked to make participating customers' bills more affordable?

A. In 2024, the Company provided its CAP customers with approximately $1.1 million of Pre-Program Arrearage ("PPA") forgiveness and $6.2 million CAP Shortfall, and in 2025, $1.2 million and $7.4 million, respectively. The PPA component of CAP benefits customers by providing arrearage forgiveness over a 36-month period if customers continue to make timely, full monthly CAP payments. For instance, a customer entering CAP with $2,500 in arrears 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 who incurs a usage-based bill calculated at $150 would not be responsible for the entire bill amount, just the $50.

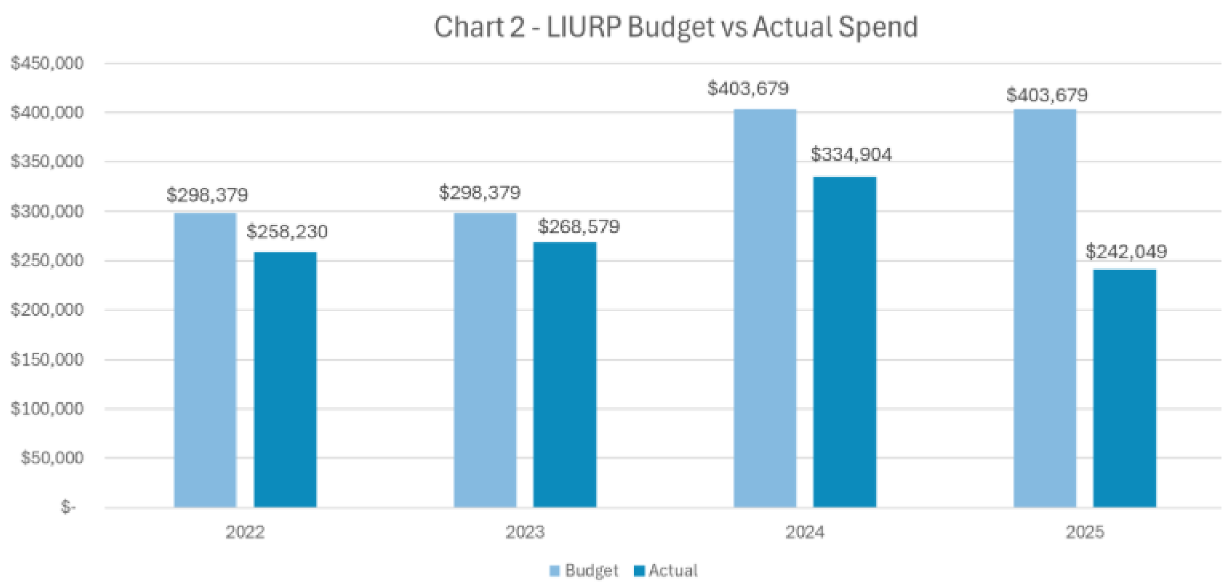
Q. What are the Company's plans to continue building upon the growth in CAP customer enrollments?

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 who are not currently enrolled in CAP. In addition, social media posts, website landing page graphics, and text messages to subscribed customers periodically focus on the benefits of CAP.

Q. How has the Company's LIURP helped customers?

A. The Company has utilized four CBOs for its LIURP. Since 2022, UGI Electric has had mixed results in utilizing its LIURP budget, as shown below.

- 2022: 87% of budget utilization
- 2023: 90% of budget utilization
- 2024: 83% of budget utilization
- 2025: 60% budget utilization



These results are primarily due to issues with some CBOs not being able to fully utilize their agreed-upon budgets. In one particular instance, a CBO that did not perform to contracted spending levels in 2025 had its 2026 budget reduced, and the funds were reallocated to higher performing CBOs.

Furthermore, UGI Electric has received feedback from some CBOs that certain jobs are being deferred due to the presence of asbestos and mold or other issues that are preventing the customer from moving forward with the LIURP job.

Q. What are the reasons for the increased variance to the LIURP budget?

A. During the 2022-2025 timeframe, the Company's CBOs completed 231 LIURP jobs, or an average of 58 per year. In 2024, the budget was increased by $105,300, or 35% from the prior year, to comply with the 2023 UGI Electric BRC Settlement, Paragraph 59(a), which increased the total LIURP budget to accommodate 20 additional baseload and 10 additional heating jobs annually. Feedback from CBOs indicates that it will be challenging for UGI Electric to utilize its full LIURP budget in 2026 and beyond.

Q. Has the Company's Operation Share Program helped customers?

A. Yes. During the 2022-2025 timeframe, the Company issued nearly 1,600 Operation Share grants for $515,036 to low-income customers. As part of the UGI Electric 2023 Base Rate Case settlement, Paragraph 58, the Company increased its Operation Share budget by $30,000 from $87,423 to $117,423.

Q. Has UGI Electric undertaken any additional voluntary efforts to support its low-income customers?

A. Yes. In November 2025, in response 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 for electric customers to $177,923 for Fiscal Year 2026 and provided additional low-income assistance.

Q. Are there other programs available to payment troubled customers?

A. Yes. In addition to the UGI Electric 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 that 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. For the 2025-2026 LIHEAP season, the Company was recently made aware that the season has been extended until May 8. UGI Electric 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 Electric 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.[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 facilitated approximately 7,200 grants for nearly $2.4 million, which was instrumental in assisting low-income customers in maintaining and/or restoring Electric service as well as facilitating emergency furnace repair or replacement. For the 2025-2026 LIHEAP season, which had a delayed start date of early December, the Company has already facilitated the processing of 898 grants for $279,990 as of early February 2026.

[1] https://dced.pa.gov/programs/weatherization-assistance-program-wap/.

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 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 maximum of $600 up to $900 to help maintain the customer's service as active. For this initiative, the grant issued was equal to the total arrearage, up to a maximum of $900. There were 490 Operation Share grants totaling approximately $90,000 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.
  - Customers who received LIHEAP in the prior season were offered streamlined enrollment in 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) who 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) who 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 overtime to provide additional assistance to customers who may have been impacted by the Government Shutdown. Highlights are summarized below:

- 559 Operation Share grants, totaling $128,483, were issued in November and December 2025. This can be compared to 45 grants for $14,562 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. Related to the UGI Electric 2023 Base Rate Case settlement, the Company has undertaken several initiatives to assist with customer enrollment in Universal Service Programs. First, the Company increased its Operation Share annual funding commitment from $87,423 to $117,423. Second, the annual LIURP budget was increased by $105,300 to accommodate

20 additional baseload and 10 additional heating jobs annually. Third, the Company expanded access to the LIURP from a prior maximum of 150% of FPIG to 200% of FPIG (up to 20% of total budget), which enables a larger population of customers to be eligible for weatherization services. Fourth, the Company solicited customers via email and direct mail who self-reported Level 1 income in the prior 12 months for enrollment in the Company's CAP twice a year. Fifth, the Company undertook a very time-consuming and manual process to auto-enroll and recertify customers for CAP. The auto-enrollment initiative was focused on customers who received LIHEAP but were not yet enrolled in CAP. This initiative was an "opt out" campaign, which means that customers must contact UGI Electric if they do not want to be auto enrolled. 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 Electric 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. For instance, in February 2026, the Company solicited 110 Electric customers for enrollment in CAP via email or direct mail and is still compiling the results of this effort to determine how many are interested in enrolling in 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 $150,000 annually to Operation Share in Fiscal Years 2027, 2028, and 2029. This multi-year commitment reflects an increase of more than 25% to the Company's contribution to Operation Share. The additional funds will provide substantial assistance to low- and moderate-income customers with income levels up to 250% FPIG.

IV. CONFIRMED LOW INCOME CUSTOMER COUNTS

Q. Did UGI Electric 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 USRs were affected by unintentional data inconsistencies, which increased the number of customers included.

Q. Has UGI Electric 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 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 were required to thoroughly vet and cleanse the data, 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 in 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."

Q. How many confirmed low-income customers does UGI Electric have?

A. As of February 11, 2026, the Company had 9,511 confirmed low-income customers. This figure represents customers who have self-certified their income, participated in the Company's CAP, Operation Share, or LIURP, where income was verified to be at below 150% FPIG, as well as those customers who have received LIHEAP in the prior 12 months.

Of the 9,511 Confirmed Low Income customers referenced above, UGI Electric has 6,434 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.

V. <u>CONCLUSION</u>

Q. Does this conclude your testimony?

A. Yes, it does.

UGI ELECTRIC

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
UGI Utilities, Inc. Gas Division Base Rate Increase Filing: Docket No. R-2025-3059523

Education

Master of Business Administration in Finance - Saint Joseph's University, Philadelphia, PA
Bachelor of Arts in Economics & Business Administration - Ursinus College, Collegeville, PA