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. 1 – CHRISTOPHER R. BROWN
UGI ELECTRIC STATEMENT NO. 2 – STEPHEN F. ANZALDO
UGI ELECTRIC STATEMENT NO. 3 – ERIC W. SORBER
UGI ELECTRIC STATEMENT NO. 4 – VIVIAN K. RESSLER
UGI ELECTRIC STATEMENT NO. 5 – PAUL R. MOUL

UGI UTILITIES, INC. – ELECTRIC DIVISION
PA P.U.C. NO. 6, SUPPLEMENT NO. 26
PA P.U.C. NO. 2S, SUPPLEMENT NO. 2

DOCKET NO. R-2021-3023618

Issued: February 8, 2021 **Effective: April 9, 2021**

UGI ELECTRIC STATEMENT NO. 1

CHRISTOPHER R. BROWN

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3023618

UGI Utilities, Inc. – Electric Division

Statement No. 1

Direct Testimony of
Christopher R. Brown

Topics Addressed:	**Overview of Testimony and Witnesses** **Need for Rate Relief** **UGI Electric's COVID-19 Response** **Electric Distribution System Investments** **UGI-1 Initiative and UNITE Systems Modernization** **Management Performance**

Dated: February 8, 2021

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

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

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

A. I am employed by UGI Utilities, Inc. ("UGI") as its Vice President and General Manager of Rates and Supply.

Q. Please briefly describe your responsibilities in that capacity.

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

Director of Operations for the UGI Gas South Region. In my current role, I report directly to the Chief Regulatory Officer.

Q. What is your educational and professional background?

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

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

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

Q. Are you sponsoring any exhibits in this proceeding?

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

II. OVERVIEW OF TESTIMONY AND PRESENTATION OF WITNESSES

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

A. My testimony addresses several points. First, I present an overview of my testimony and the Company's list of witnesses in this proceeding, including an outline of the testimony subjects covered by each witness. Second, I summarize the rate filing, including a brief explanation of the reasons for rate relief. Third, I will address the Company's efforts to provide relief to customers impacted by the COVID-19 Pandemic. Fourth, I discuss the

Company's proposed investments to enhance the Company's service and offerings to its customers, namely an Electric Vehicle ("EV") Program that will promote and provide EV charging infrastructure in the Company's service territory, and an investment in battery storage technology to provide increased and targeted reliability on the Company's distribution system. Fifth, I will address the Company's UGI-1 Initiative and UGI Next Information Technology Enterprise ("UNITE") Systems Modernization. Lastly, I will summarize the evidence of UGI Electric's successful management performance.

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

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

Stephen F. Anzaldo (UGI Electric Statement No. 2) serves as Director of Rates & Regulatory Planning for UGI Electric. He addresses UGI Electric's budgeting process; operating revenues and expenses; compliance with Section 1301.1 of the Public Utility Code; and the revenue requirement model supporting the Company's proposed rate increase (UGI Electric Exhibit A (Fully Projected)). Mr. Anzaldo also sponsors the revenue requirement models for the future and historic periods, UGI Electric Exhibit A (Future) and UGI Electric Exhibit A (Historic), respectively.

Eric W. Sorber (UGI Electric Statement No. 3) is Vice President and General Manager of the UGI Electric Division. Mr. Sorber is responsible for developing and implementing business unit strategies and long-term strategic infrastructure investment plans. Mr. Sorber provides an overview of UGI Electric's operations; reliability and safety record; capital planning; operational response to the COVID-19 Pandemic; proposed battery storage project; and proposed vehicle charging station installations.

Vivian K. Ressler (UGI Electric Statement No. 4) serves as Senior Manager of Sarbanes Oxley Controls ("SOX"), Plant Accounting, and Accounts Payable for UGI Electric. Ms. Ressler will explain UGI Electric's accounting processes. Ms. Ressler will present UGI Electric's rate base claim in this proceeding and address the accounting for the projected plant additions, retirements, and depreciation in the Company's claim. Ms. Ressler also provides testimony on the Company's request for Commission approval to capitalize pre-implementation development costs for Information Technology ("IT") systems. Lastly, Ms. Ressler will present the Company's claim for a regulatory asset for certain costs incurred due to the COVID-19 Pandemic during the year ended September 30, 2020 and will present the Company's claim for recovery of future COVID-19 related costs.

Paul R. Moul (UGI Electric Statement No. 5) is Managing Consultant of P. Moul & Associates, Inc. Mr. Moul presents expert testimony supporting the Company's claimed capital structure, cost of debt, cost of common equity, and overall fair rate of return. Schedules and workpapers supporting Mr. Moul's findings are set forth in UGI Electric Exhibit B.

John D. Taylor (UGI Electric Statement No. 6) is a Managing Partner of Atrium Economics LLC. Mr. Taylor prepared and sponsors the Company's fully-allocated cost of service study used in this case to develop the allocated class costs of service ("ACOSS"), which is found in UGI Electric Exhibit D. The ACOSS allocates the Company's cost of service associated with Commission jurisdictional operations to the Company's retail customer classes. Mr. Taylor also supports the apportionment of the class revenue increase and the Company's rate design proposals. Lastly, Mr. Taylor's testimony addresses the Company's investments in: (1) the EV Program to underpin the development of EV charging infrastructure and EV adoption within the Company's distribution system; and (2) a battery storage project to provide targeted reliability improvements and provide the Company with first-hand operating experience with this technology.

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

Sherry A. Epler (UGI Electric Statement No. 8) serves as Senior Manager – Tariff & Supplier Administration at UGI. Ms. Epler addresses and sponsors the Company's proof of revenues as presented in UGI Electric Exhibit E - Proof of Revenue. Ms. Epler's testimony also presents and supports the supporting sales and revenue adjustments for certain tariff customer classes. Ms. Epler is sponsoring UGI Electric Exhibit F, which is

Supplement 26 to UGI Electric Pa. P.U.C. No. 6 ("Tariff No. 6"). Ms. Epler provides a summary of the proposed changes to the tariff rules, regulations, and rate schedules included in UGI Electric's Tariff No. 6, and changes to the Choice Supplier Tariff, which is incorporated into UGI Electric's Tariff No. 2S, Supplement No. 2. Among these changes, Ms. Epler will discuss changes to the Company's High Tension Power Service tariff rate ("Rate HTP").

Nicole McKinney (UGI Electric Statement No. 9) is Senior Manager Natural Gas Tax Accounting for UGI Corporation and oversees the preparation of state and federal tax data, returns, and tax-related regulatory filings for UGI Electric. Ms. McKinney addresses various tax issues, including the Company's claim for federal and state income taxes, taxes other than income taxes, the calculation of the accumulated deferred income taxes ("ADIT") offset to rate base, the repairs allowance, and the calculation of a hypothetical consolidated tax savings adjustment as required by Section 1301.1 of the Public Utility Code, 66 Pa. C.S. § 1301.1.

III. NEED FOR RATE RELIEF

Q. Please discuss the Company's proposed rate relief request and provide an overview of the Company's proposals in this proceeding.

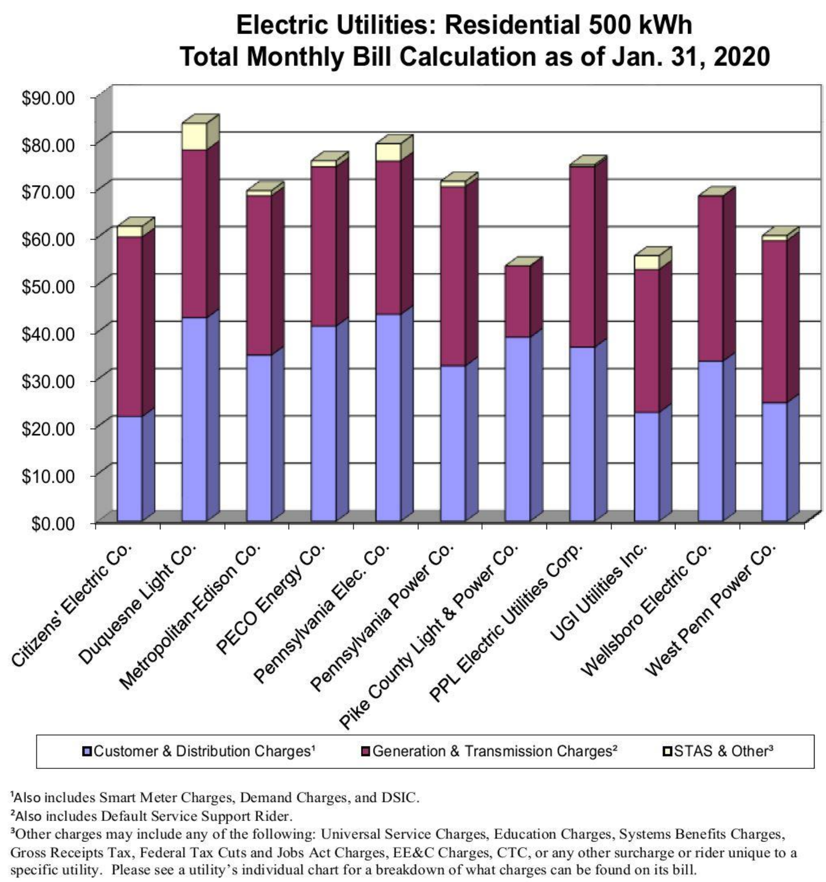
A. UGI Electric is requesting an increase in its annual base rate operating revenues of $8.7 million, or 10.0 percent on a total revenue basis, with a proposed effective date of April 9, 2021. This is the Company's first general base rate case filing since its 2018 rate case at

Docket No. R-2017-2640058. The base rate increase requested in this filing is based on the use of a Fully Projected Future Test Year ("FPFTY") ending September 30, 2022.

Q. How do UGI Electric's current rates compare with other Pennsylvania electric utilities?

A. A comparison of average residential electric bills, shown in Figure 1 below, illustrates that UGI Electric's current residential distribution rates are the second lowest of all the electric distribution companies ("EDCs") in the Commonwealth.[1]

<u>Figure 1.</u>



[1] From 2020 Rate Comparison Report, Pennsylvania Public Utility Commission, July 15, 2020. Available at https://www.puc.pa.gov/General/publications_reports/pdf/Rate_Comparison_Rpt2020.pdf

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

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

Table 1. Average Monthly Bill Impact

Average Electric Customer Bill Impact

	Average Usage	Total Monthly Bill Impact Current	Proposed	Increase (Decrease)	Total
Residential	1,000 kWh	$110.18	$123.83	$13.65	12.4%
Small Commercial	1,000 kWh	$120.40	$135.62	$15.22	12.6%
Industrial	50,000 kWh	$3,931.30	$3,897.36	($33.94)	(0.9%)

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

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

A. The Company's current rates do not provide it with a reasonable opportunity to earn a fair rate of return on its investments made to serve the public in the provision of safe and reliable electric distribution service. Specifically, as reflected in UGI Electric Exhibit A

(Fully Projected), Schedule A-1, the Company's operations are projected to produce an overall return on rate base of just 3.24%, which equates to a return on common equity of only 2.28%, for the twelve months ending September 30, 2022. As explained by Company witness Paul R. Moul (UGI Electric Statement No. 5), these returns are not adequate based on applicable financial data and the risks confronted by UGI Electric. Unless UGI Electric receives the requested rate relief, those returns will continue to decline, deny the Company an opportunity to earn a fair and reasonable rate of return, and jeopardize the Company's ability to attract the capital needed to make the system investments necessary to support and ensure continued system reliability, safety, and customer service performance.

IV. UGI ELECTRIC'S COVID-19 RESPONSE

Q. Please describe how the COVID-19 Pandemic has affected UGI Electric's provision of service to its customers.

A. Since March 6, 2020, when Pennsylvania Governor Wolf issued a Proclamation of Disaster Emergency,[2] followed by a March 15, 2020 Executive Order implementing widespread closures of non-life-sustaining businesses and work from home directives, UGI Electric has had to adapt its operations, accounting, and customer outreach to respond to the enduring COVID-19 Pandemic. In the intervening months, the Governor's office has issued a number of subsequent orders - most recently, the Limited Time Mitigation Order issued December 10, 2020.[3] In addition to the order issued by the Governor's office, the Commission issued Emergency Orders on March 13, 2020, March 20, 2020, and October 13, 2020 modifying the Commission's policies and procedures in response to COVID-19.

[2] https://www.pema.pa.gov/Governor-Proclamations/Pages/default.aspx

[3] https://www.governor.pa.gov/wp-content/uploads/2020/12/20201210-TWW-Limited-Time-Mitigation-Order.pdf

Q. How did these orders from the Governor and the Commission affect Company operations?

A. The operational impact of the COVID-19 Pandemic will be discussed in more detail by Mr. Sorber. However, I would briefly state that in response to the Pandemic, the Company transitioned as much of its workforce to work remotely as possible and adopted numerous policies to ensure the safety of its employees and customers as well as maintain the ongoing safe and reliable operation of the distribution system.

Q. Did the Company undertake any efforts to assist customers impacted by the economic effects of the COVID-19 Pandemic?

A. Yes. Consistent with the Commission's March 13, 2020 Emergency Order, the Company ceased service terminations, but also quickly adopted policies to protect customers affected by the COVID-19 Pandemic. Beginning March 18, 2020, the Company ceased removing customers from its Customer Assistance Plan ("CAP") for failure to recertify and instructed Community Based Organizations to accept telephonic "signatures" for CAP program authorizations. On March 24, 2020, the Company began waiving all late payment charges. On May 21, 2020, UGI Utilities, Inc. filed a petition to modify its consolidated Universal Service and Energy Conservation Plan ("USECP") to implement a pre-pandemic proposal to reduce maximum-tiered monthly Percent-of-Income payments ("PIPs") required of its CAP customers.[4] The Company's PIP petition would update the USECP to reflect the Commission's revisions to the CAP Policy Statement at 52 Pa. Code § 69.261 et seq. This

[4] *Petition for Amendment of UGI Universal Service and Energy Conservation Plan for January 1, 2020 – December 31, 2025*, Docket Nos. M-2019-3014966 and P-2020-3019196. As of the date of this testimony, this petition remains pending before the Commission.

petition, once approved, will result in greater benefits to UGI Electric's customers. The Company also made changes to its Low Income Usage Reduction Program ("LIURP") to provide additional funding of up to $500 per LIURP job in instances where the LIURP contractor incurs documented COVID-19 related costs, such as costs for COVID-19 Pandemic-related personal protective equipment. The Company also expanded eligibility under its Operation Share grant program to 250% of the federal poverty limit ("FPL") and increased the maximum grant size from $400 to $600.

Q. Were these changes accompanied by any additional communication efforts by the Company?

A. Yes. The Company launched an extensive information and outreach campaign associated with its COVID-19 response consisting of a COVID-19 Response webpage, resource pages for residential and commercial customers, bill inserts, website-embedded customer-assistance program videos, Zoom webinars, Facebook advertising, informational emails, and direct mail letters and postcards.

Q. Are there further efforts that the Company believes are warranted in light of the continuing impact of the COVID-19 Pandemic?

A. Yes. The Company recently filed a petition with the Commission to enact an Emergency Relief Program ("ERP") for its electric customers with an enrollment period consistent with that of Phase II of the UGI Gas ERP, pending Commission approval at Docket No. P-2021-3023839. The cornerstone of this program is the provision of grants to customers who can demonstrate they have suffered an economic impact due to COVID-19. The initial successful Phase I of the UGI Gas ERP terminated on December 31, 2020, and a proposed Phase II would support enrollment running from February 1, 2021 – April 30, 2021.

Q. Which customers will be eligible for the UGI Electric ERP?

A. As described in the UGI Electric ERP petition, residential customers and commercial customers receiving service under Rates R, GS-1, GS-4, and GS-5 are potentially eligible if they can demonstrate a COVID-related impact.

Q. Please provide an overview of the benefits that are included in the Company's ERP.

A. Under the UGI Electric ERP, a residential customer enrollee that is in arrears will be eligible for the lesser of a maximum grant of $400 or an amount equal to 25% of the customer's applicable balance. Residential customers who are not in arrears but who have experienced a hardship associated with COVID-19 and who have income at or below 300% of the Federal Poverty Income Guidelines will receive a grant up to $200. Lastly, small business customers impacted by COVID with an applicable past due balance shall be provided a long-term deferred payment arrangement that lasts for no less than eighteen (18) months.

V. ELECTRIC DISTRIBUTION SYSTEM INVESTMENTS

Q. Is the Company proposing any new programs to enhance its distribution system offerings in this proceeding?

A. Yes, the Company has two initiatives that are designed to take advantage of, and promote technology to provide better service to its customers. One of these is the Company's proposed EV initiative to facilitate the development of the charging infrastructure needed for the adoption of EVs within the Company's service territory through both third-party owned and Company-owned EV charging stations. The second initiative is the Company's adoption of battery storage technology to provide targeted improvements to electric system reliability.

Q. Please provide an overview of the EV charging initiatives.

A. The EV initiatives are supported in the direct testimony of UGI Electric witnesses Mr. Sorber (UGI Electric Statement No. 2) and Mr. Taylor (UGI Electric Statement No. 6). These initiatives are designed to support and promote the expanded growth of EVs within the Company's service territory by promoting electric vehicle charging infrastructure build-out and expanded access to EV charging infrastructure through three Company-owned DC Fast Charge ("DCFC") charging stations; and by creating Company investment allowances for make-ready infrastructure through changes to the Company's service and supply system extension tariff rules. The EV program will begin to address notable shortfalls in available EV charging infrastructure within the Company's service territory, increase awareness of the benefits of EVs, provide charging station availability and visibility, and provide information on the impact and use of new charging infrastructure on the distribution grid. As described further by Mr. Taylor, the intent of UGI Electric's EV program in furthering the adoption of EVs is consistent with that of programs offered by Duquesne Light Company ("DLC") and PECO Energy Company ("PECO") approved by the Commission at Dockets R-2018-3000124 and R-2018-3000164 respectively. The UGI

Electric program is most similar to that of DLC in that the Company would own EV charging stations.

Q. Why has the Company decided to propose an EV program at this time?

A. As discussed in the testimony of Mr. Taylor, market trends indicate that EV adoption is no longer limited to a fringe market, but rather is being embraced by a larger segment of the general public. However, as testified to by Mr. Taylor, UGI Electric's service territory currently has no known publicly available EV charging stations, either Level 2 or DCFC. Without sufficient EV charging stations, there will be reluctance by consumers to embrace EVs. The essential need for EV charging station infrastructure is identified in the Pennsylvania DEP's *EV Roadmap* report, as discussed in Mr. Taylor's testimony, and is also outlined as a key area of focus at the federal level, with President Biden's plan calling for 500,000 EV charging stations throughout the nation. UGI Electric is attempting to address the vacuum within its service territory by developing three Company-owned charging stations to support EV charging expansion. Service at these charging stations will be provided via Rate EV-C. At the same time, UGI Electric wishes to encourage the private sector's development of EV charging stations within its service territory and has therefore proposed revisions to its tariff to facilitate EV infrastructure. Mr. Sorber will also testify about the current absence of EV charging stations in UGI Electric's service territory, the anticipated location of these stations, the construction timeline, and the Company's anticipated terms of use for the stations once completed.

Q. Please provide an overview of the battery storage project.

A. UGI Electric is planning a reliability-focused project to install and interconnect a utility-owned, small-scale, 1.25 MWh energy storage battery into the primary distribution system. The Company is implementing this technology as a targeted option to enhance resiliency and service in parts of the distribution system with experienced reliability issues. Mr. Sober's testimony provides further detail on the overall cost and benefits of this battery storage project as well as the criteria used to identify the Company's installation site.

Q. Are there any other factors that render battery storage an attractive technology project for the Company to pursue at this time?

A. Yes. As noted in the testimony of Mr. Sorber, a battery storage project will provide the Company with important first-hand experience with battery technology and its integration into the distribution system and allow design, planning, and monitoring to be validated in a real world application. This project will also allow system operating processes and procedures to be appropriately developed and integrated into the overall daily operations of the distribution system, including those focused on safety.

Q. Are the Company's proposed investments in both EV charging infrastructure and battery storage prudent investments?

A. Yes. The investments the Company is proposing in this proceeding are prudent and embrace technology that is quickly gaining a foothold in our society and in electric distribution systems. I would note that Chairman Brown Dutrieuille issued statements in support of EV infrastructure buildout, and the Commission has itself recently opened a proceeding on the utilization of storage resources as electric distribution assets at Docket No. M-2020-3022877, which speaks to the timeliness of the Company's investment in such technology and to the need for such projects to provide first-hand experience to EDCs within the Commonwealth.

VI. UGI-1 INITIATIVE INCLUDING UNITE SYSTEMS MODERNIZATION

Q. Please describe UGI-1 and UNITE.

A. UGI-1 is a Company-wide improvement initiative focusing on people, tools, and processes that continues UGI Electric's history of pursuing excellent performance. The Company is building on its past focus on distribution system modernization by taking advantage of newer technologies, equipping employees for future success, and improving organizational communication. The centerpiece of UGI-1 is UNITE, a multi-phased project to identify and address business and technology opportunities for improvement. The Company has completed multiple UNITE phases to date and is presently engaged in a current-state analysis review of the Company's asset management processes.

Q. What are improvements that UGI Electric has already derived from UNITE?

A. Phase I of UNITE replaced UGI's Customer Information Systems ("CIS") in September 2017. Since then, UGI has seen a 52% increase in electronic payments, and customers with portal profiles have increased by 69%. These statistics indicate improved customer experience and a lessening of the customer effort needed to access information and services. The upwards trend of electronic payment adoption can be seen in Figure 2. As seen in Figures 3 and 4, after a brief post-implementation period, during which the

Company adapted and fine-tuned its new CIS, the Company now provides better customer service with respect to certain customer service metrics, including grade of service (calls answered within 30 seconds), than prior to the CIS implementation.

Phase II of UNITE, which went live in July 2019, replaced the Company's Enterprise Resource Planning system and introduced SAP's Fieldglass solution for contractor billing. Fieldglass will be implemented beginning in 2021 for UGI Electric. Phase IIIa of UNITE, the Enterprise Performance Management ("EPM") project, went live in October 2020 and implemented the PowerPlan Capital Budgeting and Forecasting solution integrated with the Company's Enterprise Resource Planning and PowerPlan Fixed Asset and Tax systems. PowerPlan provides imbedded lifecycle governance for approving and monitoring capital projects; improved visibility of capital expenditure requests and authorized capital projects; detailed forecasting for more accurate tracking of ongoing capital projects; and improved data analytics for making timely and optimal capital decisions.

Figure 2. Combined Electronic Payments (#/Month) Rolling 3 Months Pre CIS Go-Live (Sept. 2017) through Dec. 2020

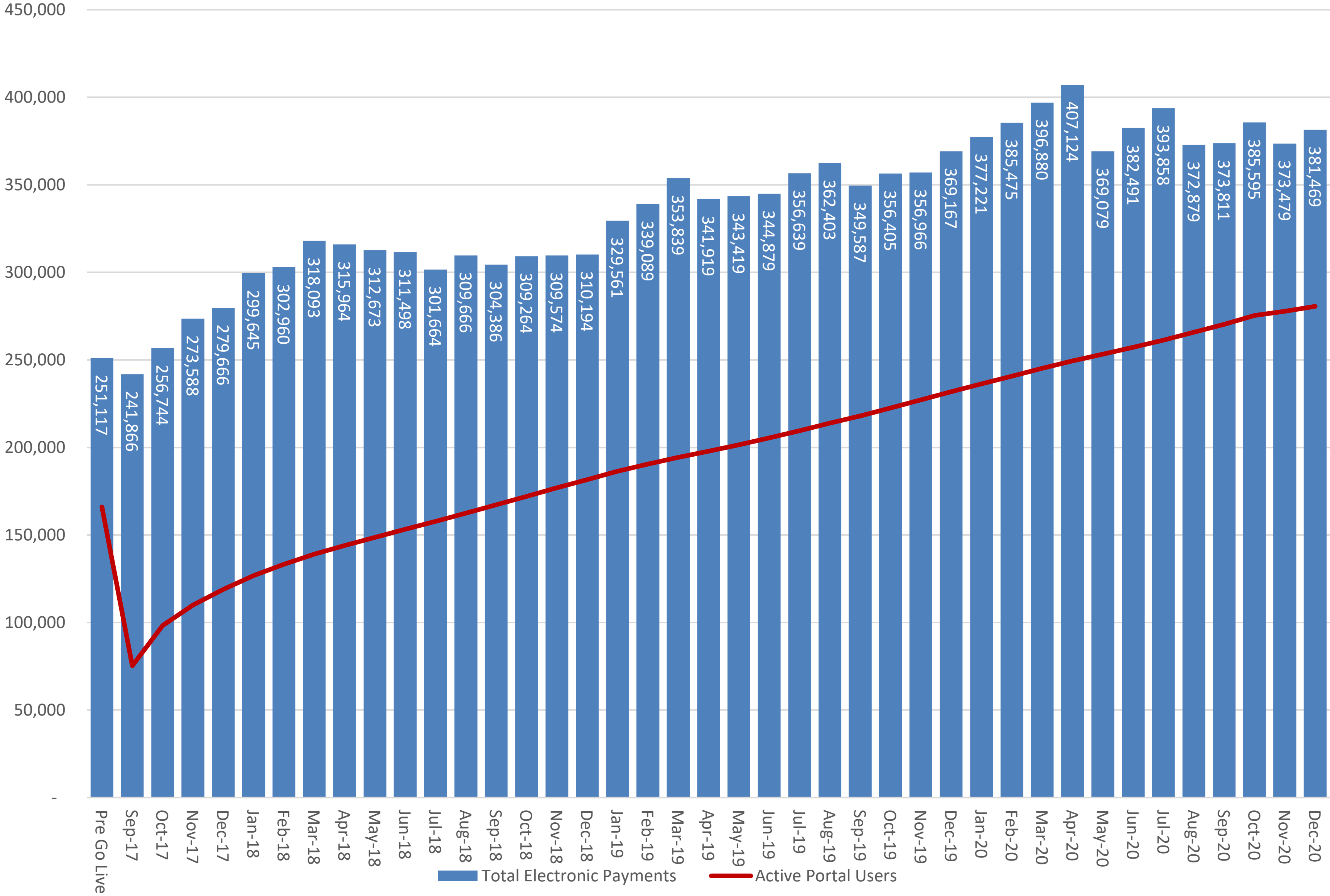


Figure 3. Combined Customer Service Performance - Grade of Service
Rolling 12-Month Average from August 2017 through December 2020

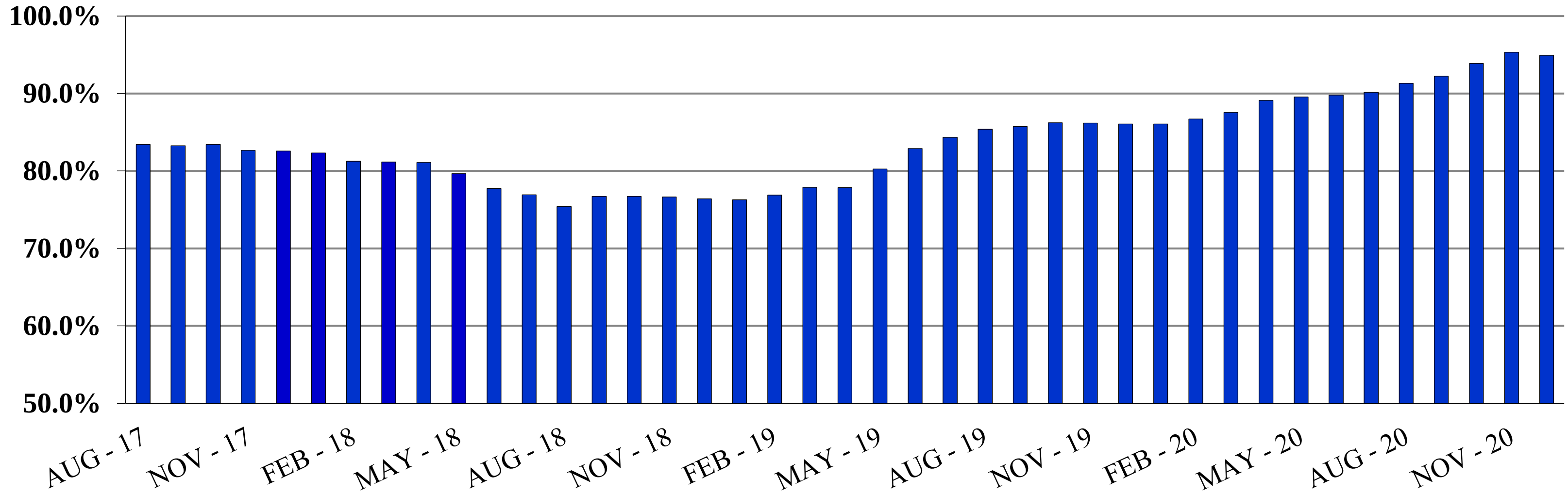


Figure 4. Combined Customer Service Metrics at a Glance

	Pre SAP/2017	FY 2018	FY 2019	FY 2020	FYTD 2021
Customer Satisfaction - Metrix Matrix* (Scale = 1 to 10)	8.9	9.0	9.0	9.2	9.2
Self Service Utilization Rate (Portal / ePayment)	35% / 36%	23% / 50%	31% / 55%	38% / 60%	40% / 63%
Metrix Matrix* First Contact Resolution	NA	89%	89%	90%	90%
Metrix Matrix* Net Promoter Score±	NA	79	80	84	85
ForeSee Contact Center Customer Effort (% Customers Indicating High Effort)	NA	22%	20%	16%	16%

*Metrix Matrix UGI New Accounts Phone Survey (New Meter Sets & Move Requests)
±An index ranging from -100 to 100 that measures the willingness of customers to recommend the Company to others.

Q. Please describe the current state analysis of the asset management processes.

A. The current state analysis is a key element of UNITE's current Enterprise Asset Management ("EAM") project, a multi-year, multi-phase project with the end goal of a new EAM and supporting applications. In early 2021, the Company will be kicking off the EAM's asset data collection phase, which focuses on the identification, standardization, and capture of asset data information across UGI.

Q. What processes are being evaluated in this current state analysis for UGI Electric?

A. Specific electric processes within the scope of this current state analyses include: replacement, reinforcement, and extension projects; service installations; as-built tracking and traceability; record corrections; critical updates; new and upgraded substations; system improvements (including right of way relocations); distribution infrastructure replacements (wire, pole, conductors); transmission switching; street lights; inspection and maintenance; system restoration; fault indicators; third-party poles; vegetation management; and facility locates.

Q. What process and system-related improvements does UGI Electric expect to derive from the current UNITE EAM initiative?

A. The current state analysis on process documentation will feed into the design for a new EAM to leverage the same tools for similar processes that occur across UGI. One goal will be eliminating paper-based processes and providing automation to improve reliability and streamline operations. With respect to systems, the new EAM will be integrated with a consolidated gas and electric Geographic Information System ("GIS"), and other systems, such as CIS and Enterprise Resource Planning discussed above. The EAM will be a central repository for housing, analyzing, and accessing UGI assets and managing full asset lifecycle information. The benefits derived from the EAM implementation will include, among others, improved data quality; better facility tracking and traceability; tools for ensuring ongoing regulatory compliance; a standard dispatching and mobility solution for field work; enhanced work management capabilities; mapping upgrades and automated facility as-builts; and improved risk management capabilities for guiding future betterment decisions. While the Company is at the beginning phase of its multi-year EAM project, the foundational work being performed at this stage will ensure a solid platform upon which to create a comprehensive and integrated EAM framework.

Q. What will be the focus of the UNITE EAM initiative in the FPFTY?

A. Following on the heels of the current state analysis, the Company will be focused on data validation, which will include fieldwork needed to reconcile historical maps and records with modern GIS data.

VII. MANAGEMENT PERFORMANCE AND RECOGNITION

Q. Has the Company claimed any increase in its return on equity in this proceeding for its strong management effectiveness?

A. The Company's claim in this case is fully supported and warranted in support of ongoing activities related to the provision of safe and reliable electric distribution service for all customers. However, in recognition of the impact of the current COVID-19 Pandemic, the Company has excluded a management performance adder from its return on equity calculation in this case. The COVID-19 Pandemic has had broad impacts on the economy generally and within the Company's service territory specifically. Given the additional burdens now faced by portions of UGI Electric's customer base, the Company believes not claiming an addition to return on equity is appropriate as a good corporate citizen and consistent with the Company's management goals of supporting local communities in meaningful ways.

Q. What is the value to UGI Electric's customers by not claiming a management performance adjustment to the claimed return on equity?

A. The exclusion of a 20 basis point adjustment on the Company's return on equity calculation lowers the Company's requested increase in this case by over $200,000.

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

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

- <u>The UGI Electric Emergency Relief Program</u> – As discussed above, UGI Electric has filed for approval to implement a very similar ERP to that of UGI Gas to assist customers impacted by the COVID-19 Pandemic and expand access to universal services.
- <u>High standards for electric reliability</u> – UGI Electric has historically performed above the Commission-established Benchmark levels for maintaining service reliability. While extensive storm-related outages affected these metrics in 2018 and 2019, 2020

has seen a return to historically high indicators of reliability for UGI Electric. For rolling 12 months ending third quarter calendar year 2020, UGI Electric achieved Customer Average Interruption Duration Index ("CAIDI"), System Average Interruption Frequency Index ("SAIFI"), and System Average Interruption Duration Index ("SAIDI") index levels that were 2%, 42%, and 42% better than Benchmark levels, respectively. Preliminary 4th quarter 2020 data for UGI Electric demonstrates a continued positive improvement over 2019 metrics.

- <u>Meeting long-term infrastructure improvement targets</u> – On November 25, 2020, UGI Electric filed an Annual Asset Optimization Plan documenting the progress of its voluntary Long-Term Infrastructure Improvement Plan ("LTIIP"). As described in the testimony of Mr. Sorber, despite the operational challenges of the COVID-19 Pandemic, the Company, in many respects, has met or exceeded its LTIIP goals in the first three years of its five-year LTIIP. The elements of the LTIIP and the Company's progress on critical infrastructure replacement programs that enhance safety and reliability are further explained in Mr. Sorber's testimony.
- <u>An Energy Efficiency and Conservation Plan</u> – Though UGI Electric is exempt from the larger EDCs' requirement to have an energy efficiency and conservation plan ("EE&C Plan") under Act 129, the Company has voluntarily operated an EE&C Plan since 2012. UGI Electric's EE&C Plan provides education and incentives to UGI Electric customers to encourage the efficient use of electricity and incents smart appliance purchase decisions. On March 14, 2019, the Commission entered an Order approving the Company's five-year Phase III EE&C Plan, which began on June 1, 2019. In UGI Electric's most recent EE&C program year, June 1, 2019 – May 31,

2020, the UGI Electric EE&C Plan issued $764,661 in rebates to residential and commercial customers and achieved savings of 10,669,000 kWh, resulting in 7,543 metric tons of CO_2 avoided.[5]

- Enhanced customer-service offerings and continued IT system replacements – As discussed previously in my testimony, the Company's investments in IT through the UNITE initiative have promoted customer self-service through the Company's web portal, increased electronic payments, and improved the customer experience. UNITE has also improved the Company's accounting processes and is poised to do the same with the Company's asset management systems.
- Electric vehicle support – As discussed previously, UGI Electric is proposing a comprehensive EV program in this filing to support and promote the expanded growth of EVs within the Company's service territory by the targeted development and encouragement of EV charging initiatives within the Company's tariff, which support EV charging infrastructure build-out.
- A safety focus – Safety is a fundamental imperative at UGI Electric. The Company continues to implement safety improvements working towards meeting the elevated standards of Occupational Safety and Health Administration's ("OSHA") Voluntary Protection Program compliance. The Company is expanding its successful UGI Making a Difference Safety Incentive Program. This year will also see the production of a 5-year Safety Management Plan as part of the Company's Safety Culture Transformation Program. These and other safety initiatives are further discussed by Mr. Sorber in his testimony.

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

- Low Rates – As noted earlier in my testimony, UGI Electric's residential rates are second-lowest in the Commonwealth. These low rates have provided significant value for UGI Electric's customers for years. Even with the full amount of the proposed rate increase, UGI Electric's residential distribution rates will still be among the lowest.
- Community support – UGI Electric supports a variety of projects that benefit communities throughout this service territory, such as American Red Cross blood drives, the Commission on Economic Opportunity Thanksgiving food drive, the Luzerne County Head Start Angel Tree Christmas gift for children project, and the United Way of Wyoming Valley Christmas in July Food Drive, book drive, and Day of Caring events. UGI invests more than $1.5 million annually to support education improvement programs, including $250,000 in the overlapping UGI Electric and UGI Gas service territories. These programs support pre-K, childhood literacy and enhanced "STEM" (science, technology, engineering, and math) curriculum in elementary schools, fund technical training programs for high school students, and provide support and mentoring for women and minority engineering school students.

The above-described initiatives, as well as those described by the other witnesses, demonstrate UGI Electric's commitment to, and focus on, providing and improving its provision of safe, reliable, and quality distribution services to its customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC

EXHIBIT CRB-1

CHRISTOPHER R. BROWN

VICE PRESIDENT AND GENERAL MANAGER, RATES AND SUPPLY

UGI Utilities, Inc.

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

Amerigas Propane, Inc.

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

UGI Utilities, Inc.

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

Education

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

Previous testimony provided before the Pennsylvania Public Utility Commission:

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

UGI ELECTRIC STATEMENT NO. 2

STEPHEN F. ANZALDO

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3023618

UGI Utilities, Inc. – Electric Division

Statement No. 2

Direct Testimony of
Stephen F. Anzaldo

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

Dated: February 8, 2021

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Stephen F. Anzaldo. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

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

A. I am employed by UGI Utilities, Inc. ("UGI") as Director, Rates and Regulatory Planning. 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 Director, Rates and Regulatory Planning?

A. I have overall responsibility for UGI Gas and UGI Electric rate and regulatory filings before federal and state regulatory commissions, as well as the central coordination of regulatory planning. In this capacity, I report directly to the Vice President and General Manager of Rates and Supply of UGI. On behalf of the Rates Department, I am responsible for budgeting/financial planning for UGI Electric, which is a joint effort of the Rates Department (preparing the revenue and margin budgets) and the Financial Planning and Analysis Department (preparing the operating and capital budgets).

Q. What is your educational background?

A. I received an undergraduate degree in Accounting from St. Joseph's University and a Master's Degree in Business Administration from St. Joseph's University. I am also a Certified Public Accountant in the Commonwealth of Pennsylvania.

Q. Please describe your professional experience.

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

Q. Have you testified previously before this Commission?

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

II. PURPOSE OF TESTIMONY

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

A. I am providing testimony on behalf of UGI Electric in support of the Company's proposed revenue requirement. First, I will explain UGI Electric's budgeting processes (Part III). Next, I will present UGI Electric's ratemaking presentations for the historic test year ended September 30, 2020 ("HTY"), future test year ending September 30, 2021 ("FTY") and the fully projected future test year ending September 30, 2022 ("FPFTY"), including its principal accounting exhibits, operating expenses claims, and certain *pro forma* adjustments (Part IV). The Company's rate proposal in this case is predicated on its FPFTY exhibit. I will also address the Company's compliance with Act 40 of 2016 (Part V).

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. In addition to UGI Electric Exhibit SFA-1 mentioned above, I am sponsoring Exhibit SFA-2, which provides the summary statements of Operating Income before Income Taxes of the Company on a FERC and PUC jurisdictional basis for the HTY, FTY and FPFTY. I am also sponsoring the principal accounting exhibits UGI Electric Exhibit A (Fully Projected), Exhibit A (Future) and Exhibit A (Historic). Other Company witnesses present testimony in support of various portions of these exhibits, including rate base (Vivian R. Ressler, UGI Electric Statement No. 4), fair rate of return (Paul R. Moul, UGI Electric Statement No. 5), depreciation expense (John F. Wiedmayer, UGI Electric Statement No. 7), operating revenue (Sherry A. Epler, UGI Electric Statement No. 8), and tax adjustments (Nicole M. McKinney, UGI Electric Statement No. 9). I am further sponsoring the Company's responses to the Commission's filing requirements and standard data requests where my name is indicated as the sponsoring witness.

III. OVERVIEW OF PRINCIPAL ACCOUNTING EXHIBITS

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

A. UGI Electric Exhibit A (Fully Projected) provides the calculation of the revenue requirement and serves as the principal accounting exhibit for the FPFTY ending September 30, 2022. It includes rate base claims, operating expenses claims, and certain *pro forma* adjustments. The FPFTY information is derived from UGI Electric's operating and capital budgets for the 12 months ending September 30, 2022. UGI Electric Exhibit A (Future) is the principal accounting exhibit for the FTY ending September 30, 2021, including certain *pro forma* adjustments. The FTY information is derived from UGI

Electric's operating and capital budgets for the 12-month period ending September 30, 2021. UGI Electric Exhibit A (Historic) is the principal accounting exhibit for the HTY ended September 30, 2020, with appropriate ratemaking adjustments. The HTY information is derived from the book accounting data for the 12-months ended September 30, 2020. The FTY and HTY schedules are provided as a comparative benchmark with the FPFTY claim, which as explained above is the basis for UGI Electric's proposed revenue increase.

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

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

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

- <u>Section A</u> summarizes UGI Electric's requested rate base, revenues, and expenses at present rates and the calculation of its requested revenue increase.
- <u>Section B</u> includes basic accounting data extracted primarily from UGI Electric's financial, accounting, operating and capital budgets, and other records. This data includes a balance sheet, a statement of net operating income and test year revenues, a schedule of expense items by cost element, and a tax expense calculation. Also

included are schedules showing UGI Electric's embedded cost of debt, year-end capital structure and overall claimed rate of return.

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

Q. What information is included in UGI Electric Exhibits A (Future) and A (Historic)?

A. UGI Electric Exhibits A (Historic) and A (Future) follow the format of UGI Electric Exhibit A (Fully Projected), but reflect data for the fiscal year ended September 30, 2020, and the fiscal year ending September 30, 2021, respectively. This information is provided to comply with the Commission's filing requirements and provides a basis for comparing our FPFTY claims with actual and projected results from the HTY and FTY.

Q. What are the data sources for the UGI Electric Exhibit A (Future) and UGI Electric Exhibit A (Historic)?

A. This data is derived from UGI Electric's books and records, and capital and operating budgets. UGI Electric Exhibit A (Future) is based on adjusted budgeted data for the fiscal year ending September 30, 2021. UGI Electric Exhibit A (Historic) is based on adjusted experienced data for the fiscal year ended September 30, 2020.

IV. <u>BUDGETING PROCESS</u>

Q. Please explain UGI Electric's budgetary preparation and approval process.

A. UGI Electric's fiscal year begins on October 1 and ends on September 30 of the following year. Preparation of the UGI Electric Operating Budget for the subsequent fiscal year begins during the spring, *i.e.*, the budget for the October 1, 2020 through September 30, 2021 fiscal year was prepared in the spring of 2020.

The revenue portion of the budget is a joint effort between the Marketing, Operations, and Rates Departments. The Marketing and Operations Departments provide customer growth and attrition information by customer class along with specific large commercial and industrial sales and revenue budget projections. The Rates Department develops normalized usage per customer for core customer classes, annualized sales and total revenues (as further explained in the direct testimony of UGI Electric witness Ms. Epler (UGI Electric Statement No. 8)). The number of customers by customer class is determined using a wide range of factors, including trends in usage, the level of applications and inquiries for service from existing customers, new construction, and shifts in type of residence and customer mix. Usage per customer is developed by reviewing the long-term usage trends and current and anticipated levels of operation. The budgeted number of customers and usage per customer are combined to produce monthly budgeted sales. The revenue budget is calculated by applying tariff rates for each customer class to budgeted sales, plus an adjustment for unbilled revenue. The sales and revenue budget is then reviewed with and approved by senior management.

Concurrently, the expense portion of the Operating Budget is prepared. Operating and maintenance expenses are developed by each functional manager based upon review of trends, monthly expenditure patterns, and new or changed programs. Employee levels are reviewed, and appropriate staffing levels are set for the upcoming fiscal year. The direct expense portion of the Operating Budget is submitted for review and approval by senior management. UGI Electric's direct expenses are then consolidated with allocated expenses from shared administrative and general functions within UGI and from other affiliated companies providing shared services to UGI Electric to develop the budgeted Statement of Operations. Allocated expenses in the Statement of Operations include functions such as accounting, rates, electric supply, human resources, information systems, payroll, and remittance processing, which are performed in accordance with PUC-approved methods of allocation and affiliated interest arrangements or agreements.

The final Operating Budget is then submitted to the President of UGI for his review and approval, and to the Company's Board of Directors for its review and approval. Each element of the UGI Electric Operating Budget is formulated by personnel with responsibilities specific to each aspect of the operation. The first and primary use of the Operating Budget is as a working tool for the management and planning of the business.

Operating personnel in each functional area prepare a detailed list of capital projects. Each project is identified, described and justified along with a breakdown of the costs associated with it. These projects are presented to senior management, which reviews them in terms of priority, capital availability, and strategic alignment with the operating budget. After due consideration, the Capital Budget is set and presented, along with the Operating Budget, to senior management in a series of review meetings. Additional information concerning the factors considered in establishing the UGI Electric Capital Budget is provided in the direct testimony of Eric W. Sorber (UGI Electric Statement No. 3).

The UGI Electric Capital Budget is prepared in conjunction with the Operating Budget. With the passage of Act 11 of 2012, UGI Electric has also instituted a process for establishing an Operating Budget and Capital Budget for an additional fiscal year in the future, *i.e.*, the FPFTY. This process is the same as outlined above; however, the starting point for the additional year is the FTY budget. The FTY revenue budget is based on normalized weather conditions, per customer usage trends, and projections concerning growth in numbers of customers. Similarly, FTY budget expense amounts are adjusted for salary and personnel increases, known program changes and expense needs. For the capital budget, known capital projects are included based on the process described above, and also described in the Mr. Sorber's testimony (UGI Electric Statement No. 3). Additional assumptions are made for emergent new business opportunities and other operating and capital expenditures based on past experience and current trends.

Q. Please explain how expenses from affiliated companies are allocated to develop the budgeted Statement of Operations.

A. UGI Electric incurs costs for services provided by UGI Corp., and other affiliated companies, in accordance with affiliated interest arrangements authorized by the Commission. UGI also allocates or assigns costs between UGI Electric and UGI Gas. All costs which can be identified as pertaining exclusively to an operating unit are billed directly to that unit. Those costs which cannot be directly associated with the operation of an individual operating unit are allocated to the various companies benefiting from the service. Allocations are done by a methodology applicable to the cost (*e.g.*, budgeted time allocations, number of employees, etc.) or, if no one methodology is specific to the cost, by a formula referred to as the Modified Wisconsin Formula ("MWF"). The MWF achieves an equitable distribution of common expenses based on the relative activity and size of each operating unit to the total of all operating units, which benefit from the respective activities. Activity is measured by total revenues and total operating expenses and size is measured by tangible net assets employed (excluding acquisition goodwill).

Q. How is this budget information used to support UGI Electric's requested revenue increase?

A. This budget information is the starting point for UGI Electric's claims and is adjusted as appropriate to reflect new information gained since the completion of the budgeting process and through application of other appropriate ratemaking principles. Total UGI Electric system rate base and components of operating income are assigned and/or allocated between the FERC and PUC jurisdictions, and the proposed revenue increase is determined on a PUC jurisdictional basis. Revenue in the amount of $8.371 million related to transmission revenue was excluded from this filing. In addition, expenses related to the transmission operations were also adjusted and excluded from this filing. Please see UGI Electric Exhibit SFA-2, pages 1 through 3, for the summary statements of PA Jurisdictional Operating Income before Federal and State Income Taxes, which will tie to Schedule D-2, Column 2, for the test periods presented.

V. REVENUE REQUIREMENTS FOR THE FULLY PROJECTED FUTURE TEST YEAR

Q. How is your discussion of UGI Electric's FPFTY revenue requirement presentation organized?

A. In Section IV.A, I present a summary of UGI Electric's FPFTY revenue requirement. In Section IV.B, I discuss UGI Electric's proposed rate base. In Section IV.C, I explain the determination of UGI Electric's revenues and operating expenses, depreciation, and income taxes.

A. FULLY PROJECTED FUTURE TEST YEAR REVENUE REQUIREMENT

Q. How were the *pro forma* revenue increase and revenues at proposed rates established?

A. This calculation is shown at a summary level on Schedule A-1, column 3 of UGI Electric Exhibit A (Fully Projected). Lines 1-8 summarize the *pro forma* measure of value (rate base). Lines 9-18 show *pro forma* revenues at present rates, *pro forma* expenses, taxes at present rates, *pro forma* net operating income at present rates, and the calculated rate of return at present rates. Lines 19-22 show the increase in net operating income required to permit UGI Electric to earn its required overall rate of return of 7.57%. Application of the

Gross Revenue Conversion Factor ("GRCF") on line 23 establishes the revenue increase shown on line 24 needed to generate that net operating income. Column 4 of Schedule A-1 shows the level of the revenue increase and the increase in expenses associated with the revenue increase. Column 5 of Schedule A-1 shows the revenue, expenses, and rate base at proposed rates, as well as the resulting rate of return of 7.57%.

Q. What is the overall requested increase in revenue?

A. The overall requested increase in revenue is $8.709 million. This represents the difference between the *pro forma* FPFTY revenue requirement of $95.774 million and the annual level of operating revenues of $87.065 million under existing rates. These figures are shown on line 12 of Schedule A-1 of UGI Electric Exhibit A (Fully Projected).

B. REVENUES AND EXPENSES

Q. How were revenues at present rates determined?

A. Revenues at present rates were determined by adjusting the budgeted revenues to reflect the anticipated change in the number of customers, the projected change in existing customer usage, and other *pro forma* normalizing adjustments. The net effect of these adjustments is shown in UGI Electric Exhibit A (Fully Projected), Schedule D-5, and is discussed in the direct testimony of Sherry A. Epler (UGI Electric Statement No. 8).

Q. Please provide an overview of UGI Electric's principal accounting exhibits relative to operating expense claims.

A. UGI Electric's principal accounting exhibit is UGI Electric Exhibit A (Fully Projected), which includes a presentation for the FPFTY ending September 30, 2022. Section D of

UGI Electric Exhibit A (Fully Projected) presents UGI Electric's claims and necessary adjustments to budgeted levels of expense items and revenues. The *pro forma* adjustments related to expense are summarized in Schedules D-3 and D-6 through D-34. These expense adjustments are used, in part, to derive UGI Electric's *pro forma* income at present and proposed rates as set forth in Schedule D-1.

UGI Electric Exhibits A (Historic) and A (Future) follow the format of UGI Electric Exhibit A (Fully Projected) but reflect data for the appropriate test years ending September 30, 2020 and 2021, respectively. This information is provided in an effort to comply with the Commission's filing requirements and provides a basis for comparing our FPFTY claims with prior results.

1. Summary

Q. Please describe Schedule D-1 of UGI Electric Exhibit A (Fully Projected).

A. Schedule D-1 presents a summary income statement that includes UGI Electric's claimed electric revenues, expenses, and taxes at present and proposed rate levels. The direct testimony of Sherry A. Epler (UGI Electric Statement No. 8) addresses the presentation of *pro forma* revenues, adjustments thereto, and the supporting schedules. Schedule D-1 also shows the proposed revenue increase of $8.709 million on line 5 in column 2.

Q. What is the level of net income at proposed rates?

A. As shown on column 3, line 20, this amount is $9.980 million. This represents a $5.708 million increase from the level under current rates (i.e., $4.272 million), as shown on line 20 in column 1 of Schedule D-1.

Q. Please describe Schedule D-2.

A. Schedule D-2 shows the development of the various line items found on Schedule D-1. Column 2 contains the Company's budgeted level of revenues and expenses for the 12-month period ending September 30, 2022. Column 3 shows adjustments to the column 2 figures, where applicable, to reflect various annualization and/or normalization adjustments. Column 4 is the sum of columns 2-3. The amount of the revenue increase and related expenses are shown in column 5 with the resulting revenues and expenses at proposed rates shown in column 6.

Q. Are there schedules showing the derivation of the adjustments shown in Schedule D-2, column 3?

A. Yes. The derivation of the various column 3 revenue adjustments in Schedule D-2 is included in UGI Electric Exhibit A (Fully Projected) in summary fashion on Schedule D-3, page 1, lines 1-14, and then listed by individual adjustment on Schedule D-5. Customer charge and distribution rate revenue adjustments for each customer class are shown on Schedule D-5, lines 1-6. Electric Cost revenue adjustments for each customer class are shown on lines 7-12 and details of other revenue adjustments are shown on lines 14-17. Details for each revenue adjustment are shown in Schedules D-5 (including supporting Schedule D-5A) and D-6, which are discussed in the direct testimony of witness Ms. Epler (UGI Electric Statement No. 8). Regarding *pro forma* expenses, the derivation of the various adjustments are summarized individually on pages 1 and 2 of Schedule D-3, lines 17-26 and lines 45-55. The details for these adjustments are found in Schedules D-5 through D-31.

2. Operating Expense

Q. How were the claimed operating expenses for the FPFTY determined?

A. *Pro forma* FPFTY expenses are based on the PUC jurisdictional budgeted level of expenses as a starting point. The budgeted data, by FERC account, was then adjusted in accordance with Commission precedent and generally accepted ratemaking principles to reflect a normal, ongoing level of operations. Schedules supporting those adjustments are found in UGI Electric Exhibit A (Fully Projected), Section D.

Q. Does UGI Electric budget its operating expenses by FERC account?

A. Yes, it does. UGI Electric budgets its operating expenses both by FERC account and by cost element, such as payroll, employee benefits, rent, etc. UGI Electric uses historic data as a basis for the distribution of expenses to each FERC account. This is shown in Schedule B-4 and is the starting point to determine the FPFTY adjusted operating expenses shown on Schedule D-3.

Q. Were each of the *pro forma* adjustments reflected on Schedule D also charged to an appropriate FERC account?

A. Yes. Each *pro forma* adjustment was calculated based on the appropriate cost element and then distributed to FERC accounts directly or by using the ratio used to distribute the budgeted cost for that element.

Q. Does Schedule D-3 depict the *pro forma* expense adjustments using FERC accounts?

A. Yes. These *pro forma* expense adjustments are presented by major FERC account category. These adjustments are also shown in the Section D summary schedules.

Q. Please discuss the Salaries and Wages ("S&W") adjustment shown on Schedule D-7.

A. Schedule D-7 shows a $57,000 increase to budgeted salaries and wages to reflect end of FPFTY operating conditions. This adjustment annualizes payroll expense and is distributed among the various cost accounts. Page 2 shows the development of this adjustment.

Q. Please describe the annualization adjustment.

A. This adjustment annualizes the effect of wage increases for unionized, exempt and non-exempt employees that will take place during the FPFTY. Schedule D-7, page 2, line 2, reflects the increased percentages for each classification of employee. Lines 3 through 5 indicate the percentage of the year for which the salaries and wages increases are not reflected in the budget.

Q. How did you determine the split of the budgeted salaries among the various employee classifications shown on Schedule D-7?

A. The split of the budgeted salaries among the various classifications shown on Schedule D-7, page 1, was determined using the allocations of labor and headcount for Operating and Maintenance expense in the budget. These employee groupings are the same groupings utilized in developing the labor budget. These categories were used in UGI Electric's budgeting process for the operating expense portion of salaries and wages.

Q. Please discuss Schedule D-10, which shows an adjustment to Rate Case Expense.

A. Lines 1 through 3 show the rate case expense UGI Electric expects to incur in this case, in the amount of $839,500.[1] That amount is then normalized over a two-year period in the amount of $419,750 per year, reflecting the expected period between this case and a future base rate case filing. The rate case expense is incurred in the FTY, however, the FTY does not include any rate case expense related to this proceeding. The FPFTY budget includes a rate case expense in the amount of $338,000, representing one-year of normalized expense. This results in an increase in the level of rate case expense for the FPFTY from the budgeted amount of $338,000 as shown on line 5. Therefore, rate case expense was increased by $81,750 to reflect a normal annual level of rate case expense. We believe that UGI Electric will make regular rate case filings going forward, given the significant capital investments it has undertaken in accordance with its PUC-approved Long-Term Infrastructure Improvement Plan.

Q. What is the nature of the two adjustments being shown in Schedule D-11 for Uncollectible Accounts Expense?

A. The first adjustment in Schedule D-11, $382,000, adjusts the budgeted uncollectible accounts expense to reflect a longer-term average charge-off ratio. Lines 1 through 4 of Schedule D-11 develop this adjustment by showing a ratio that represents the three-year average rate of uncollectible accounts expense for the fiscal years 2018 to 2020. The baseline amount for 2020 is $1.015 million and excludes $1.013 million recorded as a COVID-19 regulatory asset as of September 30, 2020 (as further discussed in the direct

[1] By way of comparison, the rate case expense in UGI Electric's last base rate case totaled $868,967.

testimony of Ms. Ressler (UGI Electric Statement No. 4)). This ratio is used to adjust the amount of uncollectible expense in the budget to conform to the three-year average for the charge-offs. The resulting 1.557 percent ratio shown on line 4 in column 5 is applied on line 7 to the *pro forma* revenues at present rates to calculate the *pro forma* uncollectible accounts expense of $1.347 million shown in column 4 on line 7. This results in an increase in the level of uncollectible accounts expenses for the FPFTY from the budgeted amount of $965,000 as shown on line 5. The 1.557 percent figure is then applied to determine the level of uncollectible accounts expense at *pro forma* proposed rates through the gross revenue conversion factor, as shown in column 3, line 10 of Schedule D-35.

The second adjustment in Schedule D-11 represents the amortization of the regulatory asset balance $1.013 million over a two-year amortization period. The $1.013 million is based on the uncollectible accounts reserve needed in excess of the $1.015 million uncollectible expense built into rates (from the 2018 Electric Rate Case, Docket No. R-2017-2640058). This results in an increase in the level of uncollectible accounts expense for the FPFTY in the amount of $507,000 as shown on line 11. The total increase in the uncollectible account expense for the FPFTY is $888,000 as shown on line 12.

Q. Please discuss Schedule D-12, which shows an adjustment in the amount of $220,000 for COVID-19 costs.

A. Lines 1 through 6 summarize the COVID-19 expenses UGI Electric incurred through November 30, 2020 in the amount of $514,000 net of the portion allocated to Transmission Operations. Line 8 provides the amount of estimated savings (related to COVID-19) net of the portion allocated to Transmission Operations, $74,000, for a net expense in the amount of $440,000. That net amount, recorded as a regulatory asset, is then normalized over a two-year period in the amount of $220,000 per year, reflecting the expected period between this case and a future base rate case filing. This adjustment is discussed further in the direct testimony of Ms. Ressler (UGI Electric Statement No. 4).

Q. Please explain the adjustment shown on Schedule D-14.

A. The adjustment shown on Schedule D-14 in the amount of $53,000 is designed to reflect an update of estimated pension expense prepared after the budget was finalized. The updated estimate is based on a more recent calculation and reflects the cash to be contributed to the plan in the FPFTY. The amounts reflected in the calculation for the pension adjustment include those directly attributable to the UGI Electric pension in addition to the portion of the UGI Corp. and UGI's pension expense that is included in the expenses allocated to UGI Electric. A portion of this adjustment has been allocated to Transmission Operations and is excluded from the revenue claim in this proceeding.

Q. The next adjustment on Schedule D-15 shows a $45,000 cost item for Interest on Customer Deposits at line 1. Please discuss.

A. Under the Company's tariff, the Company is required to pay interest on Customer Deposits it holds in accordance with other requirements of its tariff. As this is a typical business expense, the Company has added this amount to its expense claim that is otherwise not reflected in the Company's operations budget. It is calculated by using the 13-month average level of customer deposits anticipated for the FPFTY ($1.197 million) times the required interest rate (3.75 percent) anticipated for the FPFTY, as published by the Pennsylvania Department of Revenue and required under the Company's tariff.

Q. Please discuss the *pro forma* adjustment on Schedule D-16 for Universal Service expense.

A. This adjustment in the amount of $764,000 normalizes the amount of Universal Services Program ("USP") expense recovered through the Company's USP Rider based on the level of the Universal Service Rider charge effective at the time of the Company's filing in this proceeding. The USP Rider recovers the Company's Customer Assistance Program ("CAP") Credits, Pre-Program Arrearages, third party administrator expense, LIURP expense, and administrative costs associated with its Project Share program. The Company's claim represents the ongoing normalized level of costs based on anticipated levels of CAP program participation. This adjustment increases the Company's budgeted expense by $764,000 to align the Company's current Universal Service Rider charge. As the USP Rider is a fully reconcilable rider, the USP adjustment assures that expenses related to the existing rider are aligned with revenues and no impact related to USP flows through to the revenue requirement calculation. Please see the direct testimony of Ms. Epler (UGI Electric Statement No. 8) for additional discussion of the Universal Service Rider.

Q. Please explain the adjustment on Schedule D-17.

A. This adjustment, in the amount of $314,000, is due to a Gross Receipts Tax adjustment and is based on total revenues for the *pro forma* test year at present rates plus other operating revenues reduced by the uncollectible expense. The Gross Receipts Tax rate applied to this amount is 5.9%.

Q. Please explain the adjustment on Schedule D-18.

A. This adjustment, in the amount of ($2.987) million, is to adjust the Power Supply Expense for the normalized and annualized use per customer. This adjustment is designed to decrease power supply expense (net of Gross Receipts Tax) in order to match power supply revenue at current December 1, 2020 Generation Supply Revenue ("GSR") levels and remove any potential distribution base rate impacts related to 1307(e) power cost recovery. Corresponding revenue adjustments are discussed in the direct testimony of Ms. Epler (UGI Electric Statement No. 8).

Q. Please discuss the *pro forma* adjustment on Schedule D-19 for Energy Efficiency and Conservation program expenses.

A. This adjustment in the amount of $1.135 million is needed to reflect the incremental expense related to the Company's Energy Efficiency and Conservation ("EE&C") program. The first part of the adjustment shown on Line 3 reflects a $1.121 million cost increase related to the Company's EE&C program to reflect the updated 2022 program costs, which are higher than budgeted program costs. The second part of the adjustment reflects an additional expense adjustment in the amount of $14,000 reflected on Line 5. As with the USP Rider adjustment discussed earlier in my testimony, this adjustment aligns the amount of EE&C expense with the EE&C Rider charge (based on the level of the EE&C Rider charges effective at the time of the Company's filing in this matter). As the EE&C Rider is a fully reconcilable rider, the EE&C adjustment assures that expenses related to the existing rider are aligned with revenues and no impact related to EE&C flows through to the revenue requirement calculation. The Company's Phase III EE&C program received PUC approval at Docket No. M-2018-3004144.

3. Depreciation Expense

Q. How was the level of depreciation expense for the FPFTY determined?

A. UGI Electric's depreciation study is set forth in UGI Electric Exhibit A (Fully Projected) and shows the determination of *pro forma* depreciation expense. This study uses the FPFTY ending September 30, 2022 plant in service and the applicable depreciation rates, service lives, and procedures. A summary of the budgeted depreciation expense and adjustments thereto is found in UGI Electric Exhibit A (Fully Projected), Schedule D-21, and is further explained in the direct testimony of John F. Wiedmayer (UGI Electric Statement No. 7).

Q. Please describe the depreciation expense adjustments shown on Schedule D-21.

A. UGI Electric witness John F. Wiedmayer (UGI Electric Statement No. 7.) presents the depreciation analysis that serves as the foundation of the depreciation adjustment. The adjustment for depreciation expense of $440,000 set forth on Schedule D-21, column 3, line 48, is designed to annualize budgeted FPFTY depreciation expense to calculate an entire year's worth of depreciation on plant in service as of the end of the FPFTY. This schedule also shows an increase to the net negative salvage amortization of $15,000. The total annualized depreciation expense for the FPFTY, net of costs charged to clearing accounts and net salvage amortization, is $340,000 as shown on Schedule D-3, page 2, column 10, line 53.

4. Taxes other than Income Taxes

Q. Please describe the taxes other than income adjustments shown on Schedule D-31.

A. Schedule D-31 contains the details for taxes other than income adjustments. The adjustment to the Public Utility Realty Tax ("PURTA") in the amount of $4,000 on line 1 provides for a pro forma tax expense of $60,000. The valuation is based on the 2019 Revised Notice of Determination dated August 19, 2020 for UGI. The total PURTA liability per this notice is $872,363 with 9.31% allocated to the Electric operations resulting in the amount of $81,217. An additional allocation of 26.1612% is made to transmission operations in the amount of $21,247, resulting in a pro forma expense of $59,970. Line 2 provides an adjustment to the Gross Receipts tax in the amount of $314,000 and this amount is supported by the calculation on Schedule D-17 as discussed above. The adjustments to the payroll tax expenses on lines 4-6 are calculated by multiplying the ratio of tax expense to payroll expense included in the FPFTY budget by the amount of the payroll adjustment derived in Schedule D-7 to produce an adjustment to the amount of social security, Federal Unemployment Tax ("FUTA") and State Unemployment Tax ("SUTA") expense in the amount of $4,000. The calculation of these adjustments is shown in more detail on Schedule D-32.

Q. What is the purpose of Schedule D-35?

A. Schedule D-35 shows the calculation of the Gross Revenue Conversion Factor used on Schedule A-1 to calculate the level of revenues required to achieve the net operating income required to generate the rate of return supported by the direct testimony of Mr. Moul (UGI Electric Statement No. 5). These additional revenues are required to recognize that uncollectible accounts expense vary with the level of revenue, and to recognize the Gross Receipts Tax and additional state and federal income taxes attributable to the proposed rate increase.

VI. <u>PA ACT 40 REQUIREMENTS</u>

Q. Mr. Anzaldo, are you familiar with Section 1301.1 of the Pennsylvania Public Utility Code, which is otherwise known as PA Act 40 of 2016?

A. Yes, I am. The legislation, among other things, eliminated the use of consolidated tax savings adjustments for setting rates for public utilities in Pennsylvania. It requires a public utility to demonstrate that it shall use at least 50 percent of what otherwise would have been the revenue requirement associated with a consolidated tax savings adjustment to support reliability or infrastructure related to the rate-base eligible capital investment and the other 50 percent shall be used for general corporate purposes. My understanding is predicated in part on the advice of counsel.

Q. Has the Company calculated what would have been the ratemaking level of a consolidated tax savings adjustment for UGI Electric prior to the enactment of Section 1301.1 of the Public Utility Code?

A. Yes, Company witness Ms. McKinney presents such a calculation in her testimony (UGI Electric Statement No. 9), wherein she determines that the amount of consolidated tax savings applicable to UGI Electric would have been $26,000. Applying the gross revenue conversion factor to that amount of tax expense results in a revenue requirement of $39,510.

Q. Does the Company's rate case claim in this case support the conclusion that it is using at least 50 percent of that revenue requirement amount (associated with a consolidated tax savings adjustment) to support reliability or infrastructure related capital investments?

A. Yes, as included in Schedule C-2 and as discussed in the direct testimony of Mr. Sorber (UGI Electric Statement No. 3), UGI Electric's *pro forma* capital additions for reliability or infrastructure projects in the FTY is $9.697 million and for the FPFTY is $14.074 million. This expenditure level is greater than 50% of the amount of what would have been the consolidated tax savings adjustment under prior ratemaking principles.

Q. Does the Company's rate case claim in this case support the conclusion that it is using at least 50 percent of that revenue requirement amount to support general corporate purposes?

A. Yes. The Company's general corporate purpose expense will also exceed 50% of the tax benefit resulting from elimination of the consolidated tax adjustment. Indeed, the Company anticipated an operating expense budget of more than $81 million in operating expenditures to be used to render electric distribution service; 50 percent of the consolidated tax adjustment revenue requirement would equate to only $19,755.

Q. Is the Company's presentation in this filing consistent with the Commission's and the Commonwealth Court's treatment of PA Act 40 of 2016?

A. Yes. The Company's presentation in this filing is consistent with the Commission's determination on PA Act 40 in the UGI Electric 2018 Base Rate Proceeding at Docket No. R-2017-2640058, and the Commonwealth Court's order affirming the Commission's order on appeal.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC

EXHIBIT SFA-1

Stephen F. Anzaldo
Director – Rates and Regulatory Planning

Work Experience

2015 – current	Director – Rates and Regulatory Planning UGI Utilities, Inc., Denver, PA
2011 – 2013	Director – FP&A, Mid-Atlantic Region American Water Works Company, Inc., Hershey, PA
2009 – 2011	Vice President - Finance Pennsylvania American Water Inc., Hershey, PA
2006 – 2009	Treasurer Aqua America Inc., Bryn Mawr, PA
2004 – 2006	Assistant Treasurer Aqua America Inc., Bryn Mawr, PA
1996 – 2003	Accounting Manager Trigen-Philadelphia Energy Corp., Philadelphia., PA
1991 – 1996	Financial Planning Manager Trigen-Philadelphia Energy Corp., Philadelphia., PA
1985 – 1991	Corporate Accountant General Waterworks Corporation, King of Prussia, PA
1983 – 1985	Certified Public Accountant Cogen, Sklar, Levick & Company, Bala Cynwyd, PA
1981 - 1983	Certified Public Accountant Morris J. Cohen & Company, Philadelphia, PA

Previous Testimony

UGI Electric Default Service Plan:	Docket Nos. P-2016-2543523, G-2016-2543527
UGI Electric Base Rate Case:	Docket No. R-2017-2640058
UGI Electric DSIC Petition:	Docket No. P-2017-2619834
UGI Gas Base Rate Case:	Docket No. R-2018-3006814
UGI Gas Base Rate Case	Docket No. R-2019-3015162
UGI Electric Default Service Plan:	Docket Nos. P-2020-3019907, G-2020-3019908

Education

MBA - Finance from St. Joseph's University, 1998
B.S. in Accounting from St. Joseph's University, 1981
Certified Public Accountant - Commonwealth of Pennsylvania

UGI ELECTRIC

EXHIBIT SFA-2

UGI UTILITIES, INC. - ELECTRIC DIVISION
($000s)

	AS OF SEPTEMBER 30, 2020		
	TOTAL T&D OPERATIONS	LESS: FERC JURISDICTIONAL	PA PUC JURISDICTIONAL
Operating Revenues:			
Electric Revenues	$ 83,911	$ -	$ 83,911
Other Electric Revenues	7,386	6,686	700
Total Operating Revenues	91,297	6,686	84,611
Operating Expenses:			
Operation and Maintenance Expenses			
Power Production Expenses	42,749	-	42,749
Transmission Expenses	2,749	2,749	-
Distribution Expenses	8,164	-	8,164
Customer Accounts Expenses	5,294	-	5,294
Customer Service & Informational Expenses	1,504	-	1,504
Sales Expenses	(43)	-	(43)
Administrative and General Expenses	9,549	2,151	7,398
Total Operation and Maintenance Expenses	69,966	4,900	65,066
Depreciation and Amortization Expenses	7,199	1,286	5,913
Taxes Other Than Income Taxes	6,074	161	5,913
Total Operating expenses Prior To Federal & State Income Taxes	83,239	6,347	76,892
Operating Income Prior To Federal & State Income Taxes	$ 8,058	$ 339	$ 7,719

UGI UTILITIES, INC. - ELECTRIC DIVISION
($000s)

	AS OF SEPTEMBER 30, 2021		
	TOTAL T&D OPERATIONS	LESS: FERC JURISDICTIONAL	PA PUC JURISDICTIONAL
Operating Revenues:			
Electric Revenues	$ 85,840	$ -	$ 85,840
Other Electric Revenues	9,003	7,973	1,030
Total Operating Revenues	94,843	7,973	86,870
Operating Expenses:			
Operation and Maintenance Expenses			
Power Production Expenses	44,156		44,156
Transmission Expenses	2,974	2,974	-
Distribution Expenses	10,401	-	10,401
Customer Accounts Expenses	5,912	-	5,912
Customer Service & Informational Expenses	1,097	-	1,097
Sales Expenses	65	-	65
Administrative and General Expenses	9,432	2,124	7,308
Total Operation and Maintenance Expenses	74,037	5,098	68,939
Depreciation and Amortization Expenses	7,553	1,161	6,392
Taxes Other Than Income Taxes	5,780	187	5,593
Total Operating expenses Prior To Federal & State Income taxes	87,370	6,446	80,924
Operating Income Prior To Federal & State Income Taxes	$ 7,473	$ 1,527	$ 5,946

UGI UTILITIES, INC. - ELECTRIC DIVISION
($000s)

	AS OF SEPTEMBER 30, 2022		
	TOTAL T&D OPERATIONS	LESS: FERC JURISDICTIONAL	PA PUC JURISDICTIONAL
Operating Revenues:			
Electric Revenues	$ 86,371	$ -	$ 86,371
Other Electric Revenues	9,401	8,371	1,030
Total Operating Revenues	95,772	8,371	87,401
Operating Expenses:			
Operation and Maintenance Expenses			
Power Production Expenses	44,166		44,166
Transmission Expenses	3,062	3,062	-
Distribution Expenses	10,580	-	10,580
Customer Accounts Expenses	5,994	-	5,994
Customer Service & Informational Expenses	1,115	-	1,115
Sales Expenses	67	-	67
Administrative and General Expenses	9,701	2,185	7,516
Total Operation and Maintenance Expenses	74,685	5,247	69,438
Depreciation and Amortization Expenses	8,006	1,232	6,774
Taxes Other Than Income Taxes	5,807	193	5,614
Total Operating expenses Prior To Federal & State Income taxes	88,498	6,672	81,826
Operating Income Prior To Federal & State Income Taxes	$ 7,274	$ 1,699	$ 5,575

UGI ELECTRIC STATEMENT NO. 3

ERIC W. SORBER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3023618

UGI Utilities, Inc. – Electric Division

Statement No. 3

Direct Testimony of
Eric W. Sorber

Topics Addressed:	**System Operations**
	System Reliability and Safety
	Capital Planning
	Operational Responses to COVID-19
	Tariff Changes to Rate HTP
	Battery Storage Project
	Electric Vehicle Charging Stations

Dated February 8, 2021

I. <u>INTRODUCTION</u>

Q. Please state your name and business address.

A. My name is Eric W. Sorber. My business address is One UGI Center, Wilkes Barre, Pennsylvania 18711.

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

A. I am employed by UGI Utilities, Inc. ("UGI") as the Vice President and General Manager of UGI's Electric Division. 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 EWS-1 to my testimony.

Q. What are your responsibilities as Vice President and General Manager of UGI Electric?

A. As Vice President and General Manager of UGI Electric, I am responsible for developing and implementing business unit strategies, including emerging technologies. I also provide leadership for engineering, operations, and technical services functions for UGI Electric to improve overall system reliability and modernize the electric system. I report directly to the President of UGI and assist him with budgeting and capital planning for UGI Electric. I am also responsible for developing the long-term strategic infrastructure investment plans for UGI Electric. Under my direction is the UGI Electric engineering and operations staff, which is accountable for five major areas: (1) distribution and construction; (2) transmission and standards; (3) substations; (4) planning and compliance; and (5) safety.

Q. Have you testified previously before this Commission?

A. Yes. I testified before this Commission in UGI Electric's 2018 Base Rate Case proceeding at Docket No. R-2017-2640058.[1] I also testified in UGI Electric's Distribution System Improvement Charge ("DSIC") proceeding at Docket No. P-2017-2619834.[2]

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Electric. In my testimony, I will address the following topics related to UGI Electric's: (1) system operations; (2) reliability and safety initiatives; (3) capital planning; (4) operational response to the COVID-19 Pandemic; (5) tariff changes related to Rate High Tension Power ("HTP") service; (6) proposed battery storage project; and (7) proposed electric vehicle ("EV") charging station installations.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring UGI Electric Exhibits EWS-1 through EWS-3. I am also sponsoring certain responses to the Commission's standard filing requirements as indicated on the master list accompanying this filing.

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[1] *See Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058, et al. (Order entered Oct. 25, 2018).

[2] *See Petition of UGI Utilities, Inc. – Electric Division for Approval of a Distribution System Improvement Charge*, Docket No. P-2017-2619834 (Order entered Dec. 19, 2019).

II. SYSTEM OPERATIONS

Q. Please provide an overview of UGI Electric's operations.

A. UGI Electric provides electric service to approximately 62,000 customers in Luzerne and Wyoming Counties within a service territory encompassing approximately 410 square miles. UGI Electric owns, operates, and maintains over 1,200 circuit miles of overhead and underground primary distribution lines; 13 distribution substations; and 51 distribution circuits. In addition to distribution facilities, UGI Electric owns and operates one Bulk Electric System substation, 16.5 miles of double circuit 230 kilovolt ("kV") transmission lines, and 126 miles of 66 kV transmission lines. UGI Electric is a member of PJM Interconnection LLC ("PJM"), which is a regional transmission organization, and sits on the PJM Transmission Owners Agreement-Administrative Committee.

The costs associated with owning and operating UGI Electric's substation and transmission facilities at 66 kV and above are recovered through the Company's transmission formula rates set under the regulatory jurisdiction of the Federal Energy Regulatory Commission ("FERC"). The costs associated with those facilities are excluded from UGI Electric's claim in this proceeding.

Q. How many operations centers support the UGI Electric service territory?

A. UGI Electric's main office location is at One UGI Center in Wilkes Barre, which houses the bulk of the Company's electric employees, including operations management, engineering, clerical, and a number of field personnel. UGI Electric also maintains a combined warehouse and linemen service location in Forty Fort as well as a substation service center in Hanover Township. Further, UGI Electric's System Operations control center is located in Edwardsville, Pennsylvania.

Q. How does UGI Electric staff its operations?

A. As of September 30, 2020, UGI Electric had a total of 75 direct full-time positions. Of these, 26 are union employees. In addition, UGI Electric benefits from management and support services provided by its parent company UGI Corp. (e.g., insurance, finance and accounting, human resources, legal, treasury operations, information technology, communications, and corporate governance). Moreover, UGI's employees provide various management and support services to both of the Company's Electric and Gas Divisions (e.g., finance and accounting, payroll, supply, rates, purchasing, fleet, marketing, administrative duties, customer service, credit and collection, and information technology).

Q. Has UGI Electric added any new operations staff positions since September 30, 2020?

A. Yes. The Company is adding six new electric positions for FY2021 to address increased workloads and to maintain safe and reliable distribution service in several critical areas. These additional positions are planned for staggered filling between FY2021 and FY2022. These additions will increase salary and wages by an estimated $488,325 in FY2021 and $678,106 in FY2022. These incremental positions include:

- 2 Engineers;
- 1 Emergency Preparedness & Business Continuity Coordinator;
- 1 Sr. Analyst System Operations;
- 1 Electric Budget Coordinator; and
- 1 Second Shift Trouble-Man.

The two distribution engineers will address increased capital workload and technology initiatives. The Long-Term Infrastructure Improvement Plan ("LTIIP"),[3] combined with other capital programs aimed at improving system reliability, safety, adding capacity, and replacing aging infrastructure, have accelerated capital project workloads across the service territory. This pace is expected to continue, and additional engineering resources are critical to ensure these projects are designed and executed in-line with accelerated replacement and improvement goals. In addition, UGI Electric has expanded its investments in Distribution Automation ("DA") technology (i.e., "smart" devices that provide remote monitoring and control of field devices, particularly automatic circuit reclosers). UGI Electric has already installed 53 three-phase devices during the LTIIP period and will install at least 50 more over the next five years. This technology serves as a baseline for more advanced capabilities (i.e., Fault Location, Sectionalizing, and Restoration ("FLSR") systems) that will improve customer reliability. The newly added engineering resources will continue this build-out and support the long-term operational effectiveness of these initiatives.

The Emergency Preparedness & Business Continuity Coordinator will manage the drafting and updating of procedures and policies, development of training materials, and preparation of instructions for emergency preparedness. The coordinator's responsibilities will include pandemic planning, business continuity planning, storm restoration procedures and training, storm response best practices, mutual assistance coordination and onboarding, and public safety outreach, including first responders.

[3] See *Petition of UGI Utilities Inc., - Electric Division for Approval of its Long Term Infrastructure Improvement Plan,* Docket No. P-2017-2619834 (Order entered Dec. 31, 2017).

The Sr. Analyst System Operations position is currently being filled and will add a much-needed resource to the System Operations Department. This department operates the UGI Electric Transmission and Distribution system, including normal and storm-related activities (e.g., emergency response, dispatch, de-energizing lines and equipment, administering PJM requirements, and managing critical systems). Specifically, the Sr. Analyst System Operations position will primarily support all aspects of the Outage Management System ("OMS"). This position will be responsible for operator training, ongoing maintenance and development, and customer facing applications, such as the UGI Electric outage map (which customers can access online). This position also will support the adoption of a new OMS system discussed later in my testimony. Finally, this employee will serve as a backup to the Company's Supervisory Control and Data Acquisition ("SCADA") administrator and support the overall function of the System Operations Department by assisting with storm restoration efforts.

The Budget Coordinator position was filled on December 7, 2020. This employee supported the recent implementation of the utility-wide capital budget and forecasting system (i.e., PowerPlan). This system provides greater oversight to the entire capital process from budget creation to project closeout.

The final incremental position is the Second Shift Trouble-Man. This journeyman lineman position will be scheduled to cover the 3 pm – 11 pm period. Lineman coverage during this time period does not exist today and is handled via callouts after 7 pm. This new shift will increase on-property coverage during these time periods and provide for faster dispatch and response times to system emergencies.

III. SYSTEM RELIABILITY AND SAFETY INITIATIVES

A. SYSTEM RELIABILITY

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

A. The distribution system consists of thirteen 66 kV to 13.8 kV substations that source 51 distribution circuits and over 1,200 miles of primary distribution lines. A typical three-phase primary distribution circuit ("backbone") provides the main source for each load area, extending outward with additional radial single and two-phase lines serving primarily residential customers. Particularly in areas where load is served by a single transformer substation, inter-substation tie-lines are available to support load switching if equipment failures or main line distribution failures occur. Typical wood pole construction serves as the primary method for extending the distribution system throughout the UGI Electric service territory. Approximately 88% of the total primary distribution system consists of aerial/overhead facilities.

Q. Please describe UGI Electric's system reliability performance?

A. UGI Electric Exhibit EWS-2 provides an historical view of UGI Electric's system reliability. UGI Electric has historically demonstrated consistently excellent or good system reliability based on its frequency of achieving PUC benchmark metrics and being above PUC standard metrics. As shown in UGI Electric Exhibit EWS-2, however, the Company did not meet its PUC benchmark metrics during 2018 and 2019. This was primarily due to storm/weather related events. In particular, 2018 was UGI Electric's most challenging year and corresponds to the wettest year in Pennsylvania history. Moreover, six of the seven largest reliability events that UGI Electric experienced in 2018 were storm/weather related.[4] For 2019, five of the nine largest reliability events that UGI Electric experienced were also storm/weather related with one qualifying for major event exclusion. Moreover, while UGI Electric had two reportable events in 2019, it is helpful to add context by noting that UGI Electric only had four reportable events spanning the entire 26-year period from 1993-2018.

While the Company's reliability metrics have improved in 2020 with improved weather, climate conditions driving the significant weather-related events experienced in 2018 and 2019 may become more common or persistent. In response, UGI Electric continues accelerating efforts in critical areas, including robust vegetation management practices and LTIIP replacement and betterment projects. Additionally, as discussed below, to address aging distribution assets and their associated risks to reliability and safety, UGI Electric has implemented targeted repair and replacement programs for key assets, such as wood poles, distribution substation transformers, and underground residential primary cable. UGI Electric is further acting to deploy newer technology, such as battery storage, as proposed herein, as part of its continued focus on reliability and resiliency improvement efforts.

Q. Please describe UGI Electric's LTIIP.

A. UGI Electric, like other utilities, faces an aging infrastructure challenge affecting its distribution system components. The Company's key replacement programs are reflected in its LTIIP, which was approved by Opinion and Order of the Commission entered on December 21, 2017, at Docket No. P-2017-2619834. The LTIIP continues the Company's

[4] A large event includes: (1) the largest amount of customer minutes interrupted; (2) one single outage case; or (3) a series of cases caused by a single weather-related event.

recent focus on accelerated infrastructure repair and replacement, including several infrastructure and technology-based reliability programs (e.g., accelerated underground cable and wood pole replacements, DA, enhanced feeder sectionalizing, and primary substation tie-line additions). These programs address significant long-term reliability factors. The LTIIP also removes aging portions of the system (prior to failure) and replaces them with newer equipment and materials that are designed and installed using modern construction specifications and standards.

The LTIIP achieves a significant acceleration of infrastructure replacements over those installed during the Company's baseline period (i.e., 2012-2015). Specifically, UGI Electric's current LTIIP is a five-year program running from 2018 through 2022, which increases projected capital expenditures by approximately $22.2 million during the term of the LTIIP over the level of investments made during the baseline period. It provides the Company's plans for accomplishing accelerated infrastructure repair, improvement, and replacement activities through 2022.

Through the first three program years, UGI Electric has identified, repaired, improved, and replaced its distribution infrastructure on an accelerated basis, consistent with its obligations and commitments as described in the LTIIP. The Company remains on track to meet its cumulative program targets by 2022. As can be expected each year, variances occur between individual program estimates and actuals for a number of reasons. These reasons include but are not limited to: (1) when projects are placed in-service; (2) how critical reliability projects are prioritized; and (3) what customer demands and external influences, such as the COVID-19 pandemic, occurred. However, for the most part, UGI Electric has met or exceeded its individual annual program goals, including those for wood pole replacements, major system improvement projects, underground cable replacements, and installation of distribution automation devices.

Q. Please describe the Company's key LTIIP programs.

A. The Company's LTIIP programs were developed to make strategic infrastructure replacements while prioritizing reliability initiatives. Critical infrastructure replacement programs that enhance safety and reliability, include: (1) wood pole replacements; (2) distribution substation transformer replacements; and (3) underground cable replacements. UGI Electric has over 45,000 wood poles on the distribution system with an average age of 40 years. The Company relies on an inspection and treatment program to extend the life of these poles and to identify necessary replacements. Prior to 2014, historical inspection reject rates were low (typically less than 1%), resulting in less than 30 pole replacements/reinforcements per year. Subsequent inspections years, however, showed a significant increase in the reject rate and a corresponding increase in pole replacements and reinforcements. Given the increased reject rate and the age of the distribution pole inventory, UGI Electric began an accelerated replacement initiative in 2016 targeting 150 to 200 poles per year, specific to the inspection program. This pole replacement program was included in the approved LTIIP. Through fiscal year 2020 of the LTIIP, UGI Electric replaced over 600 wood poles across the system. The Company currently has a three-year average reject rate of 5.8%.

A second major replacement program in the LTIIP targets substation transformers. UGI Electric has twenty-one 66 kV to 13.8 kV transformers directly serving customer load. Over the course of the last three fiscal years, UGI Electric replaced three distribution transformers at key substations, all of which were over 40 years old. These transformers are a major component of the distribution system serving significant reliability needs. In total, these transformers serve nearly 13,000 customers or 21% of the total UGI Electric customer base. With these replacements and related facility upgrades, the customers served by these facilities avoid significant interruptions that occur with failures. Additionally, these replacements reduced the Company's system wide average asset age for transformers from 42 years to 35 years. Looking forward, UGI Electric's LTIIP will continue replacing legacy transformers (one per year).

UGI Electric also accelerated replacement of underground residential development ("URD") primary cable beginning in 2016. Through the LTIIP, UGI Electric has already replaced a significant amount of direct-buried bare concentric neutral (non-jacketed) cable originally installed throughout the 1970s and 1980s. These cables experience the highest frequency of failure and neutral degradation. In the first three years of the LTIIP, UGI Electric replaced 52% of direct-buried cable (i.e., URD cable) on the system. The replacement program has already yielded a declining trend in the number of underground primary faults to residential developments. The accelerated replacement of this cable is expected to continue as outlined in the LTIIP, with the goal of replacing the majority of the remaining direct-buried cable in the next two to three years with a modern, fully insulated and jacketed underground cable, installed in conduit, having an expected life of approximately 30 years.

Q. What other programs does UGI Electric's LTIIP have?

A. In addition to aging infrastructure replacement programs, UGI Electric's LTIIP provides other reliability-based initiatives, including creation of substation tie-lines, distribution automation/sectionalizing, and right-of-way line relocations.

Q. What are substation tie-line projects?

A. Construction of substation tie-lines falls under the Major System Improvement Projects category of the LTIIP. Tie-lines create new inter-substation high-capacity networks that provide a second source of capacity (in the event the primary source and/or its path to customers is disrupted). These projects can take multiple years to complete. Typically, they involve the replacement and upgrade of existing facilities (primarily poles and wire) to accommodate expected load and switching scenarios when utilized as a tie-line during a system emergency.

Q. What are DA Projects?

A. DA projects primarily involve retrofitting existing or installing new reclosers that have the ability to: (1) provide for remote monitoring and control by UGI Electric's System Operations department; and/or (2) create a platform for establishing FLSR type schemes intended to improve system reliability. These reclosers have built-in voltage sensing capabilities on the source and load sides and can engage in high-speed communications (i.e., communicating and coordinating activities with other reclosers). This technology when configured remotely senses and isolates line faults and automatically provides supply to impacted customers from alternate circuits.

The goal of DA is to improve system reliability and safety by enhancing operator visibility, control, and situational awareness, culminating in a more efficient restoration response. While DA projects may involve various types of field equipment, they are primarily focused on pole-mounted distribution circuit reclosers. These devices are the primary means of detecting and isolating system anomalies (i.e., faults) on UGI Electric's distribution system. Additionally, the Company typically incorporates pole-mounted reclosers into primary tie-line designs. Doing so enables restoration of service to part of an impacted circuit faster than traditional manual switching methods.

Q. What are right-of-way relocation projects?

A. Right-of-way reliability relocations move off-road distribution lines to roadside locations. Doing so reduces potential vegetation issues and/or restoration times by improving access for repair crews. UGI Electric has completed eight relocation projects since the beginning of the LTIIP and will continue to identify problematic areas for future projects.

Q. What technology initiative is UGI Electric undertaking to improve system reliability and restoration efficiency?

A. UGI Electric is replacing its original OMS in order to improve performance and functionality in support of enhanced capabilities. The Company began a nearly year-long request for proposal ("RFP") and evaluation process in late 2019 and selected a new OMS in November 2020. Implementation of the new OMS platform is expected to begin in early FY2021 and is estimated to cost approximately $1.7 million. The OMS is anticipated to go live at the end of FY2022. Of that amount, $1.258 million is included for recovery in this case. The remaining amount will be allocated to transmission rates. The new platform will provide improved dispatcher awareness and interface tools, mobile damage assessment functionality, enhanced customer reporting and information capabilities, reliability analytics, and high-availability system architecture. Additionally, it will provide a base platform for future enhancements that enable real-time or near real-time collection, display, and analysis of distribution information, typically described as a Distribution Management System ("DMS"). This enhanced functionality is in-line with industry trends aimed at providing better reliability and operational control as is currently experienced with transmission systems.

B. SAFETY INITIATIVES

Q. What programs does UGI Electric have to promote employee, customer, and system safety?

A. Safety performance continues to be a fundamental imperative at UGI Electric. The Vice President of Environmental Health and Safety and Training oversees UGI's safety initiatives. UGI has several continuing safety initiatives in place to further develop its safety culture and drive sustainable improvements in safety performance. One such program is the UGI Making a Difference Safety Incentive Program, which rewards employees for supporting safety culture through actions such as demonstrating positive safety behaviors, leading safety meetings, reporting safety issues, or participating in safety education. This program is being expanded in 2021 to incorporate rewards for demonstrating achievement of all UGI values, not just safety.

UGI is also in its fifth fiscal year of working on satisfying the elevated standards of the Voluntary Protection Plan ("VPP") program of the United States Occupational Health and Safety Administration ("OSHA"). VPP compliance focuses on both physical facility improvements as well as the implementation of safety and health management protocols.

UGI Electric also maintains a dedicated electric safety and training resource, focused on enhancing electric safety programs to better address personnel training requirements (per Occupational Safety and Health Standards for Electric Power Generation, Transmission and Distribution, section 1910.269).

Q. What other ongoing safety measures does UGI have?

A. Other ongoing safety measures and tools include Smith System driver training; the 24-hour Triage Nurse Hotline; a fleet management tool that generates a driver safety score utilizing GPS technology; and selective driver monitoring technology. The fleet management and driver monitoring technology is under review for replacement in FY2021. Expected improvements from the new software include more accurate data on driving behaviors, improved driver scoring, and in-cab, real time coaching. A dual camera system (front and cab facing) will be placed in all vehicles. The camera system will allow for supervisor coaching of employees that experience a triggering event (hard braking, speeding, harsh cornering). The camera system also will be used for any vehicle incident investigations.

Q. Please describe UGI's driver safety process improvement team.

A. In March 2019, UGI launched a driver safety improvement team to evaluate the Company's use of in-vehicle tools to improve driver safety. The driver safety process improvement team developed recommendations for driver safety improvement in early FY2020. The recommendations implemented include:

- Establishment of a Safe Driver Committee.
- Adoption of a pilot evaluation program for new vehicle camera and telematics system.
- Implementation of a safe driver pilot training program using a third-party vendor.
- Review and discussion of previous month's accountable vehicle accidents.
- Utilization of an external trainer for UGI Electric commercial driver licensed ("CDL") drivers that will supplement the Company's existing in-house driver training program.

Q. Please describe the Safety Culture Transformation Program ("SCTP").

A. In 2018, UGI launched an initiative to transform its safety culture in partnership with DuPont Sustainable Solutions ("DSS"). The first stage of this project was a safety culture assessment, which began in July 2018, to develop a safety culture baseline. This initial assessment included documentation review, focus group interviews at 10 field operating centers, and UGI-wide administration of the DuPont Safety Perception Survey™. DSS reviewed with UGI personnel the current corporate safety programs, and separate workshops were held with UGI leadership and key safety personnel to train on the techniques and strategies for developing effective safety messaging and training.

Based on the initial assessment, UGI and DSS embarked upon the SCTP, which officially launched the week of December 3, 2018, with five UGI-wide presentations to introduce the program and release UGI's new internal safety vision statement "I'll be there." The SCTP is an ongoing endeavor. UGI's focus in 2021 will continue the same strategies from the prior years of: (1) Governance - Operational Rigor and Managing Process; (2) Expanding Safety Leadership Capabilities; and (3) Branding and Communication to Advance the Culture. While activities and focus areas changed over the course of the SCTP, the strategies remain. In 2021, UGI will produce a 5-Year Safety Management Plan with the Safety Department's strategies, roles, and responsibilities aligned to support the Plan. Non-programmatic areas such as (1) Safety Leadership Training; and (2) Safety Communications also will continue to be enhanced in 2021.

IV. CAPITAL PLANNING

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

A. The main areas for which UGI Electric develops capital budgets are: (1) replacement and betterment of infrastructure, which includes transmission, substation, and distribution assets; (2) new business, including expansion of the transmission and distribution system to support growth; (3) facilities; and (4) information technology. The budgeting process is further described in the direct testimony of Company witness Stephen F. Anzaldo (UGI Electric Statement No. 2).

Q. What are replacement and betterment projects?

A. Replacement and betterment ("R&B") projects improve or replace existing infrastructure and make up the majority of projects captured in UGI Electric's LTIIP. Projects are prioritized for inclusion in the budget according to the condition of and risks associated with existing assets. Safety and reliability impacts are also considered. 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. Excluding emergent issues, 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 for 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). Additionally, through its comprehensive inspection and maintenance program, UGI Electric assesses asset conditions, which are used to identify and prioritize maintenance issues or trends. The information collected is used to schedule projects in a manner that mitigates short-term and long-term system impacts. UGI Electric's inspection program goals are documented in its biennial PUC Inspection & Maintenance Plans ("PUC I&M") and its Annual PUC Reliability Reports. These plans and reports detail the Company's inspection and reliability results for the following equipment categories:

- Wood Distribution Pole Inspection and Treatment;
- Overhead Line and Transformer Inspections;
- Capacitor Inspections;
- Distribution Switch Inspections;
- Underground Cable Testing;
- Pad Mounted Transformer & Switch Inspection & Maintenance; and
- Substation Circuit Breaker, Transformer & Relay Testing and Maintenance.

With the results of its inspections, reliability enhancements are developed to incrementally address problem areas identified as “worst performing” circuits or “reliability risk” areas (existing in isolated load pockets). The capital strategy to address these issues includes investment in major system reinforcements to provide for additional substation feeder tie-lines, DA, and implementation of a highly-segmented distribution sectionalizing philosophy. The strategy also now includes a battery project, which will be discussed further in my testimony.

Q. What are new business projects?

A. New business projects provide new or upgraded electric service to customers and may involve primary overhead and underground line extensions, new or upgraded transformer installations, and associated service enhancements. UGI Electric has seen a significant increase in commercial and industrial new business projects in the last several years. This is primarily driven by the development of numerous “greenfield” commercial logistics facilities in Hanover Township. Additional growth has occurred in the same area with respect to manufacturing facilities, with several large expansion projects and new customers, including a kitchen cabinet manufacturing facility.

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

A. The new business portion of the capital budget is developed using historical trends as well as projections that are informed by known large customers, forecasts of new business projects, counts of residential developments and associated customers, and general construction and development trends in the UGI Electric service territory. The final budget layers in the above components considering construction timing and the level of confidence in the customer's ability to meet project timelines.

Q. What are facility projects?

A. Facility projects are related to the buildings and grounds that support the employees, training, equipment, and materials utilized in the day-to-day operation of the Company.

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

A. Facility projects are prioritized and included in the capital budget based on safety, overall condition, space constraints, and emerging needs.

Q. What are Information Technology ("IT") projects?

A. Information technology projects enhance the Company's information systems. These projects: (1) include computerized systems, both in-house and hosted; and (2) improve the Company's ability to manage asset information, operate, and maintain the system, prepare and report financial information, and interface with the Company's customers. A current example of a UGI Electric IT Technology project is the Electric OMS replacement project I discussed earlier in my testimony.

Q. Please describe how information technology projects are selected for inclusion in the capital budget.

A. IT projects are prioritized (for inclusion in the budget) based on the critical need for new systems or for enhancements to existing systems, which support the safe, reliable, and efficient operation of the Company. Budget determinations are prioritized by the Company's IT Prioritization Committee based on overall business impact, availability of system support, and resource availability. IT projects of applicability across UGI are generally spearheaded by the UGI Next Information Technology Enterprise ("UNITE") initiative that is discussed in more detail by UGI Electric witness Christopher R. Brown (UGI Electric Statement No. 1). During FY2021, UGI Electric is planning to implement SAP Fieldglass as part of the UGI's ongoing overall UNITE initiative. Fieldglass is a vendor management system that will assist with improving efficiency, timing, and accuracy of contractor payments.

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

A. Since UGI Electric's last Base Rate Case, the Company's total budgeted capital additions (including all of the above-described categories) were $30,520,590, while the total actual additions were $31,397,452; there was an $876,862 variance. More specifically, during this period, the Company's plant additions were 102.9% of its budget (see UGI Electric Exhibit EWS-3). This close correlation between budgeted and actual plant placed in service since the last UGI Electric Base Rate Case further supports the Company's claimed level of plant in service in this case and is discussed in the direct testimony of UGI Electric witness Vivian K. Ressler (UGI Electric Statement No. 4).

V. <u>COVID-19 – OPERATIONAL RESPONSE</u>

Q. Please discuss how UGI Electric responded to the COVID-19 pandemic?

A. Beginning with Governor Wolf's March 6, 2020 Proclamation of Disaster Emergency ("Emergency Proclamation"), which declared an emergency throughout the Commonwealth as a result of the COVID-19 Pandemic (and all subsequent pandemic-related directives issued by the Commonwealth), UGI Electric utilized and developed plans to maintain safe and reliable electric service for the Company's customers and its employees. Accordingly, the Company developed COVID-19 Safety Protocols for field employees, a COVID-19 Work Plan, a form of job briefing for COVID-19 screening, pandemic-appropriate personal protective equipment ("PPE"), and exposure hazard analysis.

At the onset of the pandemic, the Company's existing Pandemic Plan established the basic framework for continued operations. As the Commonwealth's emergency guidance developed, UGI Electric's plans were continually adjusted as additional safety restrictions issued and PPE became available. In conjunction with the Commonwealth's orders regarding hygiene, social distancing, sanitizing work areas, and use of PPE, early plans utilized work-from-home protocols, where possible, for office employees. The Company also adopted staggered and/or rotating shifts for field employees to ensure minimal employee interaction. The Company further implemented dispatch-from-home practices and used additional vehicles for field employees. With these additional vehicles, the Company implemented a "one occupant per vehicle" practice to maintain employee separation. UGI Electric's contractor workforce also adopted/implemented social distancing protocols by establishing additional dispatch locations to limit crew interactions.

Consistent with the restrictions on businesses throughout the Commonwealth, most maintenance and new business activities were limited to critical needs and emergency actions starting in early March and extending through mid-May. However, the Company was able to meet most of its LTIIP program goals for FY2020. Capital R&B activities (mainly LTIIP work) continued to the extent they could be completed in accordance with current COVID-19 guidance. By the end of May 2020, with adherence to COVID-19 safety protocols, the Company returned to near normal operations.

Finally, UGI Electric implemented strict social distancing and exposure protections for its System Operations Department, a small but essential group responsible for the transmission and distribution systems as well as management of all emergency response activities. Prior to the pandemic, one facility housed this group and the vital infrastructure required to perform these functions. At the onset of the pandemic, the Company established a temporary facility to reduce the number of System Operations Department employees in one location. The temporary facility provided sufficient functionality and redundancy to allow a small number of operators to be segregated between the two facilities. The temporary facility also adopted protocols for cleaning, shift-turnover, and utilization of individual keyboards and headsets. These practices have allowed UGI Electric to provide a greater level of protection for these integral employees.

VI. TARIFF CHANGES – RATE HIGH TENSION POWER

Q. Is UGI Electric making any tariff modifications to address potential commercial/industrial development in its service territory?

A. Yes. UGI Electric is proposing to modify its Rate HTP tariff provisions. The Company does not have any customers receiving service under Rate HTP, nor contemplates any existing customers qualifying for service under Rate HTP. Notably, the proposed modifications update the Rate HTP language to reflect the availability of supply at or above 66,000 volts rather limiting service to 66,000 volts under the current provisions of Rate HTP. The revisions also provide for fully negotiated rate provisions and the elimination of certain Surcharges and Riders inapplicable to service provided at or above 66,000 volts. Related to potential future Rate HTP customers, modifications are also proposed to UGI Electric's DSIC Rider language which clarify that the DSIC may be reduced or eliminated for customers taking Rate HTP, if warranted (e.g., upon demonstration of competitive service alternatives, existence of distribution equipment serving the customer). The revisions to Rate HTP and the DSIC Rider, as included in this case, are also discussed in the testimony of UGI Electric witness Sherry A. Epler (UGI Electric Statement No. 8).

VII. BATTERY STORAGE PROJECT

Q. What other initiative is the Company undertaking to support distribution system reliability and resiliency?

A. UGI Electric is planning a reliability improvement project to install and interconnect a utility-owned, small-scale, energy storage battery into the primary distribution system. The Company plans to use this technology as a targeted means to enhance resiliency and serviceability in a reliability-challenged part of the system. The battery resource will enhance the customer experience during major storm interruptions (similar to the ones that occurred in 2018 and 2019) by establishing a quick responding resource, which can reduce potential hours of service interruptions to just minutes.

Q. Please elaborate further on the benefits that battery storage provides to the distribution system.

A. Traditional distribution system investments include items currently incorporated in the Company's LTIIP (e.g., wires, poles, reclosers, etc.). When these items are damaged in a storm, the restoration time is subject to dispatching crews to investigate, repair, and replace the damaged equipment. Response times can be extended during storm interruptions. A battery can be installed close to customer load and called upon quickly to reduce the impact of any outage event.

When an outage occurs in the battery footprint, it will be disconnected from the damaged portion of the distribution system and operated in an "island" mode, where the stored energy will be discharged to customers in the footprint. Thus, the outage can be quickly isolated, and service can be restored to impacted customers all within a very short period of time. The battery storage will be seamlessly integrated into the distribution system on the circuit similar to any other distribution reliability asset. Therefore, the Company can quickly initiate the battery during outages and effectively control its operation for optimal performance.

Q. What are the components of the battery storage system?

A. The components of the battery system include:

- Battery – 1.25 megawatt-hour ("MWh") capacity lithium-ion based battery.

- Inverter – 500 kilowatt (“kW”) capacity utility grade inverter, which converts the direct current (“DC”) battery output to a nominal alternating current (“AC”) consistent with utility power systems.

- Switchgear & Protection – Electrical devices and interconnection relays used to connect or isolate the battery system from the normal utility primary distribution system.

- Transformation – Step-up transformer that converts the inverter output to utility primary line voltage.

- Primary Distribution Interconnection Equipment – Line reclosers and associated communication and control equipment that provide for the sectionalizing of the battery system from line faults during outages.

- SCADA/PJM Connection – A communication connection and monitoring network that provides for remote monitoring of the battery system and dispatch by PJM in the regulation market.

- Interchange Metering – Used to measure and record output and consumption of the battery system (megawatt (“MW”), megavolt-ampere reactive (“MVAR”), Hertz (“Hz”), kV, etc.). Requirements for metering are defined in PJM Manual 01.

Q. What is the cost of the battery storage project and what design criteria have been applied?

A. The proposed project will cost approximately $1.5 million. The 1.25 MWh battery system is designed to support the expected peak load of 68 customers (in the battery footprint) for up to approximately four hours. This duration can be significantly extended for outage events, which would occur during non-peak periods. The goal of this project is to demonstrate the feasibility of this new technology to support system reliability and to provide the Company, and Company personnel, direct first-hand knowledge and experience with battery storage systems of this type. Moreover, first-hand developments related to detection and isolation protocols, systems controlling the faulted line section, and the subsequent re-energization of customer load from the battery will create processes and procedures that cannot be developed similarly by reviewing case studies of battery applications elsewhere. Once in-service, the battery system is designed to significantly reduce the total number and potential duration of outages for the 68 customers encompassed by this system.

Q. How was the site for the battery storage project chosen?

A. The battery storage project targets a circuit element and associated customers within the Company's service territory near Wapwallopen, PA. The customers on this circuit have experienced multiple interruptions over the last several years. These customers are also located at the end of the feeder in an area of the system that poses a challenge for traditional reliability and resiliency initiatives. A significant portion of the primary three-phase source into this area is bounded by a steep mountain on one side with significant off-right-of-way vegetation as well as a railroad line and river on the other side, which significantly limits feasible line relocation options. The vegetation on the mountain is sloped towards the line. This increases the chances of large trees and vegetation hitting the line and makes vegetation work more difficult relative to reaching and removing trees. UGI Electric has already performed reliability improvements, which include accelerated trimming and danger tree removals of accessible vegetation as well as enhanced line sectionalizing to minimize customer exposure to outages.

Accordingly, the topography and terrain encompassing this circuit poses a challenge to vegetation management and circuit improvement or redesign. While increased vegetation activities and enhanced sectionalizing efforts have helped, the Company believes that the customers on the target line section will continue to experience lengthy outages when significant weather conditions occur. The interruption level for these customers is the highest on the UGI Electric system. Considering the period 2017 through 2019, the proposed battery installation would have saved nearly over 250,000 customer minutes interrupted.

Q. Are there opportunities to reduce the cost impact of the battery installation?

A. As a means to reduce the cost associated with this battery storage system, UGI Electric plans to participate in PJM's frequency market[5] while the battery is in grid-connected mode (during normal operating conditions). The PJM frequency market is discussed in more detail in the direct testimony of Mr. Taylor (UGI Electric Statement No. 6).

Q. What is the useful life of the battery system?

A. The expected life of the battery system is 20 years.

Q. How does UGI Electric plan on procuring the battery system components?

A. The Company plans to use a battery system project engineering firm with extensive experience in battery energy storage systems to competitively procure the battery system components and installation services.

[5] The PJM frequency regulation market is a grid service that balances momentary differences between electricity demand and supply in the transmission system. It involves the injection and withdrawal of power on a second-by-second basis to maintain grid frequency. The balancing authority sends a regulation signal to battery owners who vary output up or down in response to the signal. Pursuant to FERC Order 755, fair compensation is paid to providers of frequency regulation services (i.e., a "pay-for-performance" model).

VIII. ELECTRIC VEHICLE CHARGING STATIONS

Q. Why is UGI Electric proposing to install EV charging stations in its service territory?

A. EV usage is increasing across the country and in the Commonwealth. A significant precursor to EV ownership and accelerated EV utilization is a greater proliferation of EV charging stations. A build-out of the national, state, and local EV-charging facilities helps reduce consumer fears of running out of charge (i.e., range anxiety), which is a significant barrier for consumers converting to plug-in EVs. Additionally, public charging EV stations increase the daily useful range of EVs and reduce the amount of gasoline consumed by traditional automobiles. Despite the passage of time and EV charging station developments, which have occurred throughout the Commonwealth, there are currently no publicly-available EV charging stations, either current DC Fast Charge ("DCFC") charging stations or Level 2 charging station facilities, existing within UGI Electric's service territory (as discussed in the direct testimony of UGI Electric witness John Taylor (UGI Electric Statement No. 6)). Accordingly, UGI Electric plans to install and own three EV charging stations in an effort to support EV development directly within its service territory and gain additional first-hand metrics regarding EV charging utilization demands and usage patterns. Each proposed station location will consist of one DCFC capable of charging a vehicle to approximately 80% of full charge within 30 minutes. Locations will also be evaluated for additional Level 2 charger installations, pending space and cost limitations. Level 2 chargers are generally capable of providing 20 miles of range per hour of charging time.

Q. Has UGI Electric identified locations for the EV charging stations?

A. Yes. UGI Electric has identified three general locations that consider existing electric infrastructure and offer the greatest opportunity for maximum utilization. These locations are along primary transportation corridors within the UGI Electric service territory, are near population centers, and have high levels of traffic. At all locations, UGI Electric will identify and work with a property owner to acquire the necessary easements and to help ensure the charging stations are located in the appropriate location.

Q. What goals will the Company's proposal to own and operate these EV charging stations accomplish?

A. With respect to EV infrastructure, the key goal for UGI Electric is to ensure that EV infrastructure, including all types charging stations, can be reliably and efficiently integrated into the local distribution system. Given the lack of charging infrastructure in the UGI Electric service territory today, this effort and investment will accomplish the following goals:

- Provide an initial backdrop to what eventually will be a market driven service (i.e., to install local, publicly available, electric charging infrastructure);
- Foster a level of experience managing these facilities to accurately consider the impacts on long term distribution planning; and
- Gather charging station metrics, analytics, operational performance, and usage data, which would enable UGI Electric to promote future development of the EV marketplace.

Q. What is the estimated cost of the EV charging station project?

A. The EV project is included in the FY2022 capital budget at a total project cost of $300,000. This includes the cost of all the equipment, site preparation, installation costs, and UGI Electric supply and service make-ready work. Given the identified locations and the available primary capacity at each site, the extent of the supply and service work would be in line with required service parameters (i.e., three-phase transformer, service connection, service panel).

IX. <u>CONCLUSION</u>

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC

EXHIBIT EWS-1

Curriculum Vitae

Eric W Sorber
UGI Utilities Inc. – Electric Division
VP & GM Electric Division
One UGI Center
Wilkes-Barre, PA 18711

October 2, 2020

EXPERIENCE

UGI Utilities
Vice President & General Manager 10/2019 to Present

- Accountable for developing and implementing business unit strategies supporting safety, reliability, regulatory compliance, and customer satisfaction. Establishes key performance indicators to measure implementation effectiveness.
- Develops technical strategies to address emerging technologies including micro-grids, distributed energy resources and electric vehicle charging.
- Ensure effective employee engagement, and efficient use of resources to ensure Division activities are cost effective and meeting the needs of our customers and employees.
- Provide leadership with respect to fostering a positive safety culture while holding managers and employees accountable for following and consistently enforcing all safety related procedures.
- Primary representative on the PJM Transmission Owner Administrative Committee, Members Committee and Section 205 Working Group. Attend and participate on various industry forums. Act as the primary liaison with the PUC Electric Safety Division.
- Oversight of the Division's storm restoration and emergency preparedness activities including mutual assistance planning and utilization.
- Oversight of the Division's budgets and major projects, financial forecasts, variance reporting, as well as strategic capital planning in support of the LTIIP and other capital goals.
- Assist with day to day management of operational execution as warranted.

UGI Utilities
Director Engineering and Operations 11/2014 to 10/2019

- Have overall responsibility for the engineering and operating functions of the Electric Division's transmission and distribution (T&D) operation including electric safety, reliability, labor management and System Operations.
- Responsible for the Electric Division's compliance with applicable FERC Reliability and PAPUC Inspection and Maintenance Standards and PAPUC Electric Safety.
- Responsible for preparing and managing the annual capital budget and expense budgets.
- Currently represents Electric Division on the PJM Members Committee, Markets and Reliability Committee, and the Transmission Owners Agreement Administrative Committee and on the Energy Association of PA Reliability Committee.
- Assisted with the Developed the Electric Division's Long Term Infrastructure and Improvement Plan.

UGI Utilities
Manager – Planning and Operations 03/2008 to 11/2014

- Manage the Electric Division System Operations department to assure the Division's transmission and distribution systems are operated reliably and consistent with PJM Directives.
    - Responsible for storm restoration planning and coordination of storm restoration activities.
    - Responsible for implementing and maintaining the Division's Outage Management System (OMS)
- Manage the Division's NERC Reliability Compliance Program including identification of all applicable Reliability Standard requirements (NERC, FERC, RFC, PJM etc.), responsible parties, schedules, training and documentation necessary to comply with all reliability requirements; periodic audit preparation in

support of the Division's compliance program; implementation and administration of the Division's compliance software.

  - Coordinated preparation of audit materials including RSAWs and supporting evidence and served as the lead audit contact for the 2010 and 2013 RFC Compliance Audits.

- Responsible for short and long term transmission and distribution system planning including the development of capital budget recommendations.
- Responsible for all generation interconnection projects on the UGI system from customer owned solar and wind to large scale commercial projects such as the Hunlock T117 project.
- Supervise the Electric Mapping and Records Department. Responsible for all facility data and for maintaining the Divisions GIS. Evaluate, develop, and integrate new business processes and technology into the Department to advance and support the mission and goals of the Division.
- Supervise and direct the Division's Pennsylvania One Call and underground facility location program.
- Supervise the Electric New Service and Maintenance Call Group
- Represent the Electric Division on the PJM Planning Committee and serve as the Chairman of the EHV Agreement Administrative Committee.
- Coordinate the preparation of the Electric Division's yearly budgets and prepare monthly, quarterly and annual variance reports.

UGI Utilities
Project Engineer, Maps and Records Department 03/2006 to 03/2008
Staff Engineer, Maps and Records Department 12/2005 to 03/2006

- Supervised Electric Division Maps and Records Department. Responsible for maintaining all facility data and for keeping all T&D maps current.
- Managed the conversion of existing AutoCAD drawings to GIS.
- Evaluated, developed and integrated new technology into the Department including research, selection and implementation of the Division's first GIS.
- Coordinate the preparation of the Electric Operation Capital and O&M Budgets along with variance reports and year-end analysis.
- Supervise all joint pole use and attachment activities with the telephone companies, cable TV companies, and others.
- Responsible for overall system planning on the transmission and distribution system.
- Prepared the annual T&D System Planning Recommendations for the Capital Budget.
- Provide operational support to the System Operations Department.
- Responsible for investigating and resolving all damage and injury claims against the Division.
- Participated in various PJM Committees and working groups including the Planning Committee and the Small Generator Interconnection Working Group.
- Assisted with the development of the UGI Critical Asset Identification (CIP-002) and UGI Facility Ratings (FAC-008) Methodologies in compliance with NERC Reliability Standards.
- Developed the Electric Divisions Distributed Generation Interconnection Requirements which are posted on the UGI website.
- Lead Supervisor for recruiting college engineering graduates to UGI EUD.
- Participated in storm restoration activities.

Staff Engineer, Distribution Engineering Department 11/2002 to 12/2005

- Design and engineer large distribution projects including production of design packages and cost estimates. Optimize plans for the expansion of the T&D system. Evaluate/Develop programs to improve EUD planning, engineering and operations functions.
- Coordinated the design and planning studies leading to the approval of the $4.0M Mountain Substation expansion project.
- Responsible for performing transmission load flow analysis using PSLF software and for making planning recommendations based on the results.

- Development of the Cyme distribution engineering model. Performed engineering studies utilizing the Cyme program and made planning recommendations on various transmission and distribution projects.
- Developed a variety of in-house applications in support of various departments including the ED Callout Program, In-house Outage Management System, Injury/Sick Time Database and OMDB Management Tools.
- Participated in storm restoration activities.

Staff Engineer, Rates and Regulatory Department 02/1999 to 11/2002

- EDI Administrator Responsible for all areas of the Electric & Gas Division's Electronic Data Interchange (EDI) Program including, mapping, testing, trading partner set-up and interaction as well as the GISB Internet Transfer Mechanism and the Value-Added Network connection.
- Responsible for developing and implementing business practices and requirements regarding EDI and the Pennsylvania Electric Deregulation Customer Choice Program.
- Member of the Pennsylvania Electronic Data Exchange Working Group.
- Responsible for Rate Design, Cost of Service Model, Regulatory Compliance, PJM Energy Reconciliation, Demand Side Response Program, Distributed Generation, Supplier Management System.
- Participated in storm restoration activities.

Engineer I & II, Resource Planning Department 02/1992 to 02/1999

- Coordinated the purchase, installation, and implementation of the Division's EDI System, including integration with mainframe application programs.
- Assisted with the implementation and management of the Division's Electric Deregulation Customer Choice Program.
- Assisted with the preparation of the 1997 Restructuring Filing and 1995 and 1993 Rate Case Filings.
- Responsible for relay protection and coordination on the 66KV and 230KV transmission systems.
- Responsible for the compliance of the Hunlock Power Station's Continuous Emission Monitoring System.

OTHER LEADERSHIP ACTIVITIES

- Chair of the Administrative Board - Hunlock Creek United Methodist Church 2012 - present
- Trustee – Hunlock Creek United Methodist Church 2005 - present

EDUCATION

B.S. Electrical Engineering – Pennsylvania State University 1988

UGI ELECTRIC

EXHIBIT EWS-2

UGI Utilities, Inc. - Electric Division Reliability Scores - 2004 through 2020

	Rolling 12-Month Score																		
Metrics	Benchmark	Standard	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CAIDI	169	228	143	119	112	167	135	105	99	128	122	110	144	103	125	131	178	188	163
SAIFI	0.83	1.12	0.65	0.64	0.79	0.68	0.67	0.76	0.48	0.95	0.44	0.77	0.44	0.4	0.63	0.49	1.19	0.96	0.4
SAIDI	140	256	93	76	88	114	90	80	48	121	54	85	63	41	78	64	213	182	66
Reportable Storms			0	0	0	1	0	0	0	1	1	0	0	0	0	0	0	2	0

UGI ELECTRIC

EXHIBIT EWS-3

UGI UTILITIES, INC. - ELECTRIC DISTRIBUTION DIVISION
Plant Placed in Service Budget Compared to Actuals
$ amounts in '000s

	2019		2020		2 Year Total	
	Budget	Actual	Budget	Actual	Budget	Actual
Distribution	$ 16,601	$ 18,304	$ 12,104	$ 12,035	$ 28,705	$ 30,339
General Electric	$ 1,075	$ 70	$ 1,379	$ 1,361	$ 2,454	$ 1,431
% allocated to Rate Case	74%	74%	74%	74%	74%	74%
General Electric for Rate Case	$ 796	$ 52	$ 1,020	$ 1,007	$ 1,816	$ 1,059
Total Additions for Rate Case	$ 17,397	$ 18,355	$ 13,124	$ 13,042	$ 30,521	$ 31,397
					(1)	**(2)**

Capital Spend as % of Budget **(2) / (1)** **102.9%**

UGI ELECTRIC STATEMENT NO. 4

VIVIAN K. RESSLER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3023618

UGI Electric, Inc. – Electric Division

Statement No. 4

Direct Testimony of
Vivian K. Ressler

Topics Addressed:	**Accounting** **Historic Costs** **Rate Base** **Capital Treatment of Certain Information Technology Costs** **Accounting for COVID-19 Related Costs**

Dated: February 8, 2021

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vivian K. Ressler. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

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

A. I am employed by UGI Utilities, Inc. ("UGI") as Senior Manager SOX, Plant Accounting and Accounts Payable. 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 SOX, Plant Accounting and Accounts Payable?

A. I have responsibility for the Sarbanes-Oxley ("SOX") controls (design and implementation), plant accounting, and the accounts payable function. My duties also include the coordination of these functions with UGI's Controller and Chief Financial Officer as well as financial accounting and reporting personnel at UGI Corp.

Q. Please describe your educational background and work experience.

A. My full educational background and work experience are set forth in my resume attached as UGI Electric Exhibit VKR-1.

Q. Have you testified previously before this Commission?

A. Yes. I provided testimony in the 2020 Base Rate Case proceeding for UGI Gas at Docket No. R-2019-3015162.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Electric in support of the Company's rate case accounting methodology. First, I will explain UGI Electric's accounting processes, which were used to develop the actual book accounting results inputted into the Company's historic test year ended September 30, 2020 ("HTY") (Part II).[1] Second, I will present the Company's claim for rate base in this proceeding using a fully projected future test year ("FPFTY") methodology (Part III). Third, I will address the Company's accounting for certain Information Technology ("IT") costs (Part IV). Finally, I will address the accounting methodology used to treat the costs the Company has incurred due to the COVID-19 pandemic as a regulatory asset (Part V).

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

A. Yes. I am sponsoring UGI Electric Exhibits VKR-1 through VKR-3. In addition, I am sponsoring those portions of UGI Electric Exhibit A (Fully Projected), Exhibit A (Future) and Exhibit A (Historic), which address rate base and certain adjustments to rate base and operating expenses discussed later in my testimony. I am also sponsoring those responses to the Commission's standard filing requirements as stated on the master list accompanying this filing.

[1] The budgets for the future test year ending September 30, 2021 ("FTY") and the FPFTY ending September 30, 2022 are discussed in the direct testimony of Stephen F. Anzaldo (UGI Gas Statement No. 2).

II. ACCOUNTING PROCESS AND HISTORIC COSTS

Q. How are the accounting records of UGI Electric maintained?

A. The accounting records of UGI Electric are kept in accordance with generally accepted accounting principles ("GAAP") and the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts as required under the provisions of 52 Pa. Code § 57.42. The Company also maintains a continuing property records system in accordance with the requirements of 52 Pa. Code § 57.46.

Q. Are the books and records of UGI Electric subject to audit?

A. Yes. The books and records of UGI Electric are audited by its internal auditors. In addition, UGI Electric's books and records are included in Company-wide audits of UGI Utilities, Inc., performed by its external auditor, Ernst & Young, LLP. The Company's books and records are further subject to audit by the PUC and the FERC.

Q. Do the continuing property records of UGI Electric reflect the original cost value of property?

A. Yes, they do. UGI Electric's plant in service, plant additions, retirements, and book adjustments have been recorded on an original cost basis in accordance with GAAP and the Uniform System of Accounts requirements.

Q. What process does UGI Electric follow to assure that property reflected in its plant accounts is in service?

A. UGI Electric's capital project managers create records that document the costs of projects and/or asset purchases. When a capital project or asset is placed into service, the project manager records the in-service date and the retirement detail for any related assets that are taken out of service. Then, the record is provided to accounting personnel. This information is transferred through accounting entries into the appropriate UGI Electric plant property accounts, subject to review by authorized individuals who approve the entries and further review by internal and external auditors.

Q How was the Company's accounting process used in preparing the Company's filing?

A. The above-described accounting process was used to prepare the principal accounting exhibits that support UGI Electric's claim in this proceeding. As discussed in the direct testimony of Company witnesses Christopher R. Brown (UGI Electric Statement No. 1) and Mr. Anzaldo (UGI Electric Statement No. 2), the Company's claim is based on the FPFTY. The accounting data for the FPFTY was derived from UGI Electric's operating and capital budgets for the 12 months ending September 30, 2022, as shown in UGI Electric Exhibit A (Fully Projected). The accounting data for the FTY was derived from UGI Electric's operating and capital budgets for the 12 months ending September 30, 2021, as shown in UGI Electric Exhibit A (Future). The accounting data for the HTY was derived from UGI Electric's books and records for the 12 months ending September 30, 2020, as shown in UGI Electric Exhibit A (Historic).

III. FULLY PROJECTED FUTURE TEST YEAR RATE BASE

Q. With reference to UGI Electric Exhibit A (Fully Projected), please discuss how the Company's specific rate base items are determined.

A. UGI Electric's rate base presentation is shown in UGI Electric Exhibit A (Fully Projected), Schedule C-1. It summarizes the UGI Electric rate base values for the FPFTY. Column 1 provides the schedule upon which the calculation of each of the rate base elements is found. Columns 3 and 5 show the amounts at present and proposed rates, respectively. UGI Electric's total FPFTY rate base claim—net of deductions for accumulated depreciation, accumulated deferred income taxes and customer deposits—is $131.8 million. Except where otherwise noted, I will describe each of these rate base elements in greater detail below.

1. Utility Plant in Service

Q. Please explain how UGI Electric determined its FPFTY rate base value for plant in service.

A. UGI Electric's claim for utility plant in service represents the sum of the closing plant balances as of September 30, 2020, and budgeted plant additions for the years ending September 30, 2021 and September 30, 2022, less budgeted FTY and FPFTY plant retirements. The direct testimony of Company witness Eric W. Sorber (UGI Electric Statement No. 3) discusses the capital addition planning process.

Q. Please describe Schedule C-2 to UGI Electric Exhibit A (Fully Projected).

A. This schedule includes 5 pages and presents UGI Electric's FPFTY claim of $226.9 million for used and useful electric utility plant in service on page 1, column 2, line 48. Electric utility plant enables UGI Electric to provide safe and reliable electric service to its customers.

Q. How was the electric utility plant in service amount of $226.9 million shown on Schedule C-2, page 1, column 2, line 48 determined?

A. As noted above, this amount is based on the *pro forma* balance as of September 30, 2022. The amount includes: (1) utility plant in service as of September 30, 2020 and (2) budgeted capital expenditures expected to be placed in service for the 12-month periods ending September 30, 2021 and 2022, less plant retirements during the same period. UGI Electric witness Eric W. Sorber (UGI Electric Statement No. 3) also discusses the basis for the plant additions in the FTY and FPFTY.

Q. Please describe the information included on Schedule C-2, page 2.

A. This information provides a summary of UGI Electric's *pro forma* claim for utility plant in service by service category. Column 2 shows the FPFTY ending balances based on the placed in-service budget; column 3 shows the net effect of the various plant adjustments, if any; and column 4 provides the adjusted FPFTY plant in service.

Q. What information is included on Schedule C-2, page 3?

A. Columns 2 and 3 on this page show the electric plant in service balances for 2021 and 2022 based on the placed in-service budget. Column 5 provides the ending FPFTY plant balance.

Q. Where are the FPFTY and FTY additions shown?

A. Page 4 of Schedule C-2 provides actual and projected plant additions. The Company categorizes plant additions by FERC account.

Q. Where are the FPFTY and FTY retirements shown?

A. Page 5 of Schedule C-2 provides actual and projected plant retirements. Retirements for most plant accounts were projected by plant account. The Company applied the average retirement rate, as a percent of additions, for the five fiscal years 2016 through 2020, to the FPFTY and FTY plant additions. For certain General Plant accounts subject to amortization accounting, retirements are recorded when a vintage is fully amortized. For these accounts, all units are retired per books when the vintage is fully amortized.

2. Accumulated Depreciation

Q. Please explain how UGI Electric determined its rate base deduction for accumulated depreciation.

A. UGI Electric started with accumulated depreciation as of September 30, 2020, added the budgeted level of depreciation expense for the FTY and FPFTY, and calculated the impact of the FTY and FPFTY plant retirements and a provision for net salvage as shown on Schedule C-3. The depreciation rates and test year expense levels are discussed in the direct testimony of John F. Wiedmayer (UGI Electric Statement No. 7), with the underlying FPFTY depreciation analysis provided in UGI Electric Exhibit A (Fully Projected).

Q. Please describe UGI Electric's accumulated depreciation claim.

A. UGI Electric's accumulated depreciation claim is shown on Schedule C-3 of UGI Electric Exhibit A (Fully Projected). This schedule, containing 6 pages, presents the accumulated provision for depreciation as of September 30, 2022, distributed among the various FERC accounts. The total amount for accumulated depreciation, $74.8 million, is summarized on page 1 of this schedule. That amount is reflected on line 2 of the measure of value summary on Schedule C-1.

Page 2 shows the *pro forma* FPFTY level of accumulated depreciation distributed to the various plant categories. Page 3 shows the details of the accumulated depreciation by FERC account for fiscal year 2021 and 2022 based on budget plus adjustments to arrive at the FPFTY balance. Pages 4 and 5 show the cost of removal and negative net salvage amortization by FERC account, respectively. Page 6 includes the salvage amounts by FERC account. All of these amounts are included in the FPFTY accumulated depreciation calculations. The amortization of negative net salvage was calculated using a 5-year amortization schedule in accordance with Commission precedent.

3. Cash Working Capital

Q. Please explain how UGI Electric determined its rate base value for cash working capital ("CWC").

A. CWC is the capital requirement arising from the difference between (1) the lag in the receipt of revenue for rendering service and (2) the lag in the payment of cash expenses incurred to provide that service, as shown in Schedule C-1. A detailed analysis of UGI Electric's CWC requirements is provided in Schedule C-4.

Q. What data is shown on page 2 of Schedule C-4?

A. Page 2 summarizes the derivation of UGI Electric's revenue collection lag and overall expense payment lag. The revenue lag days (*i.e.*, 60.14) are shown on line 1. The expense lag days are shown for each component on lines 3-5, which amount to 29.03 (on line 7). Expense lag days include three categories of expenses: (1) payroll; (2) purchased power costs; and (3) other expenses. The net lag in the collection of revenue is 31.11 days as shown on line 8. This number is then multiplied by the average daily operating expense balance on line 9 to arrive at a base CWC amount for Operations and Maintenance ("O&M") expense of $5.8 million. The average daily expense balance of $185,000 shown on line 9 is determined by dividing the total *pro forma* annual operating expenses, excluding uncollectible accounts expense of $67.8 million, as shown on line 6 of column 2, by the number of days in the year, or 366. I will describe the other components of the CWC claim when I discuss the related schedules.

Q. Please describe the revenue lag calculation shown on Schedule C-4, page 3.

A. The Company's calculation for the total revenue lag days of 60.14 (line 23) is comprised of several steps. First, the annual revenue (line 18, column 3) was divided by the average month-end accounts receivable balances for the thirteen months ended September 30, 2020 (line 17, column 2). This results in an accounts receivable turnover rate of 8.37 (line 19, column 4), which is equivalent to 43.73 lag days (line 20, column 5) (*i.e.*, 365 divided by 8.37 accounts receivable turnover rate). As shown on lines 20-23, the payment portion of the revenue lag is added to (1) the 1.16 day lag between the meter reading day and the day bills are sent out and recorded as revenue and accounts receivable by the Company; and

(2) the 15.25 day service lag (*i.e.*, midpoint lag factor), which is the time from the mid-point of the service period until the meter reading date. This calculation results in a total revenue lag of 60.14 days.

Q. How was the mid-point of the service period calculated?

A. The mid-point of the service period is equal to the number of days in an average service month (366 days divided by 12, or 30.5 days) divided by two.

Q. How are the payroll expense lag days for the CWC claim calculated?

A. This calculation is shown on page 4 of Schedule C-4, lines 1-6. The payroll amounts shown there reflect the payroll for the FPFTY, which is shown on Schedule D-7. The lag periods for union and non-union payroll are shown separately on page 4 of Schedule C-4, lines 1-2, with the same bi-weekly pay period. The lag days are calculated based on 14 days in the pay period divided by 2 (for an average) with a 5-day payroll processing time period added, resulting in a 12-day lag period.

Q. How were the lag days associated with the purchased power costs shown on Schedule C-4, page 4, line 8 calculated?

A. This calculation is shown on page 6 of Schedule C-4, and is based on a review of electric purchases during the 12-month period of October 2019 through September 2020. The total dollar amount of electricity purchased during this period was $34.735 million (on line 13, column 2). The average payment lag was calculated by dividing the total dollar days for purchased power costs (or $1,064,073) by the total dollar amount of electric supply purchased (or $34.735 million), which equals 30.63 days (on line 14). The payment lag was determined using the midpoint of the service period for each of the payments and the payment date for each, averaged over the 12-month study period.

Q. How were the Other O&M Expense lag days, shown on Schedule C-4, page 4, line 22, calculated?

A. The calculation is shown on page 5 of Schedule C-4. The average payment lag for all remaining expenses was derived from data over twelve months, (October 2019 – September 2020) as shown in more detail on page 5 of Schedule C-4. A summary list of all cash disbursements, including the invoice date, the amount of the disbursement, the date the payment was made, and the type of disbursement (for capital, commodity or expense), during each of these months was used. As shown on page 5, lines 1-24, columns 1 and 2, each month's listing contained numerous cash disbursements. Once the raw payment data was assembled, the dollar days for expense purchases were determined by multiplying the amount of the disbursement by either (i) the number of days from invoice date until bank clearance for wire and Automated Clearing House (“ACH”) payments, or (ii) the number of days from the invoice date until check date, plus seven days for payments made by check. Disbursements were eliminated if they were included in another calculation (*e.g.*, electric commodity purchases), or were paid for capital items. After these adjustments, the average of the expense lag days for each month shown on Schedule C-4, page 5, column 4, line 25, resulted in a payment lag for general disbursements of 30.70 days. The 30.70 day lag for Other Disbursements is then brought forward to Schedule C-4, page 4, line 22 and Schedule C-4, page 2, column 3, line 5.

Q. Please explain how the interest payment amount included on line 2 of Schedule C-4, page 1 was determined.

A. The calculation of this amount is shown on Schedule C-4, page 7. This calculation measures the lag associated with the payment of interest on outstanding debt. The *pro forma* annual interest expense shown on line 4 is divided by 366 to obtain the daily interest expense of $7,000 shown on line 5. That amount is then multiplied by the net payment lag, resulting in a reduction to the working capital allowance of $234,000 as shown on page 7, line 9 of Schedule C-4. This amount is then included on page 1, line 2 of Schedule C-4.

Q. How was the tax payment lag for the working capital requirement, shown on line 3 of Schedule C-4, page 1, determined?

A. This calculation is shown on page 8 of Schedule C-4. Separate tax payment lag calculations (for working capital) are made for federal income tax, state income tax, PA Property Tax and Public Utility Realty Tax Act ("PURTA") taxes. Each of these calculations is based on anticipated FPFTY tax payments and an April 1 mid-point of annual service. The result for each of these components is shown and summed in column 10 to derive the net working capital allowance for tax payments of $175,000.

Q. How was the working capital allowance for pre-payments, shown on line 4 of Schedule C-4, page 1, derived?

A. That amount is calculated on page 9 of Schedule C-4 and represents the thirteen-month average of actual pre-paid amounts for each month ended from September 2019 through

September 2020. The 13-month average of total actual pre-paid amounts during that period is $1.962 million.

Q. What is the total amount of the Company's CWC claim?

A. UGI Electric's claim for CWC is $7.657 million. This amount is shown on Schedule C-4, page 1, line 5; Schedule C-1, line 4; and on Schedule A-1, line 4.

4. Accumulated Deferred Income Taxes

Q. Please explain how the rate base value for ADIT and EDFIT was calculated.

A. The Company's determination of its rate base value for Accumulated Deferred Income Taxes ("ADIT"), including Excess Deferred Federal Income Taxes ("EDFIT"), is shown on Schedule C-6 and is discussed in the direct testimony of Company witness Nicole M. McKinney (UGI Electric Statement No. 9).

5. Customer Deposits

Q. Please explain how the Company calculated the rate base value for customer deposits.

A. Customer deposits offset the need for UGI Electric to provide capital. UGI Electric's claim for customer deposits is based on the average customer deposit balance for the 13-month period ending September 30, 2020, as shown on Schedule C-7.

Q. What is the rate base offset for customer deposits?

A. The customer deposit offset is $1.197 million as shown on Schedule C-1, line 6 and on Schedule A-1, line 6.

6. Materials and Supplies Inventory

Q. What is the rate base claim for materials and supplies inventory?

A. UGI Electric maintains various materials and supplies in inventory for use in its operations. Its claim for those items is $1.309 million, as shown on Schedule C-1, line 7. This amount is based on the average inventory for the 13-month period ending September 30, 2020, as shown on Schedule C-8. This value is also shown on Schedule A-1, line 7. The Company will update this average during the course of this proceeding.

IV. <u>CAPITAL TREATMENT OF CERTAIN INFORMATION TECHNOLOGY COSTS</u>

Q. What is the Company's policy for capital treatment of certain information technology costs?

A. Since 2016, the Company has capitalized certain information technology ("IT") costs associated with software implementation projects, including preliminary-stage project and business and technology reengineering expenses. These IT costs are comprised of internal labor, external consulting expense, and other expenses related to the preparation of the vendor and system integrator requests for proposals. IT costs also consist of current-state assessments, reengineering business processes to adapt to the new system, data conversion, cleansing and migration (including field verification and digitization of asset attributes required for accurate data and facility capture), and pre-implementation training costs. Additionally, the Company capitalizes the above-mentioned cost items for cloud computing software implementation projects. Further, beginning in 2019, the Company began capitalizing Hypercare costs associated with large software implementation projects.

Hypercare is a term for post-implementation support following the deployment of an IT project to ensure that the newly implemented system operates as planned.

Q. What is the accounting treatment for these IT costs under the U.S. GAAP and FERC Uniform System of Accounts methodologies?

A. These costs are typically required to be fully or partially expensed in accordance with U.S. GAAP accounting standards; specifically, the Accounting Standards Codification ("ASC")-350-40 "Internal Use Software." Conversely, under the FERC Uniform System of Accounts, these expenses fit the definition of costs that should be capitalized once placed in service.

Q. Has the Commission previously permitted the Company to capitalize these IT costs?

A. Yes, the Commission has approved capital treatment for these IT costs in each of the Company's following base rate proceedings:

- In 2017, the Company received Commission approval in the UGI Penn Natural Gas, Inc. ("PNG") base rate proceeding at Docket No. R-2016-2580030 to capitalize the costs incurred to prepare databases for cloud-based services;
- In 2018, the Company similarly received Commission approval in the UGI Electric base rate proceeding at Docket No. R-2017-2640058 to capitalize implementation costs related to cloud-based information assets.[2] In the 2018 UGI Electric Rate Case, the Company was also permitted to capitalize preliminary-stage project costs and business

[2] While ASU 2018-15 (which was issued in August 2018) provides accounting guidance to expense certain preliminary-implementation and post-implementation project stage costs, the Commission allowed the Company to capitalize such costs in the 2018 Electric Rate Case and the 2019 Gas Rate Case.

and technology reengineering costs associated with Phase II of the UGI's Next Information Technology Enterprise ("UNITE") system replacement project;

- In the 2019 Gas Rate Case at Docket No. R-2018-3006814, the Company received Commission approval to capitalize Hypercare costs associated with the UNITE Phase II project; and
- In UGI Utilities, Inc. - Gas Division's 2020 base rate proceeding at Docket No. R-2019-3015162, the Company continued to capitalize costs associated with information technology projects consistent with the prior cases.

Q. Is the Company planning to capitalize these IT costs in this proceeding?

A. Yes. The Company continues to capitalize costs associated with IT projects as permitted by the Commission in the cases discussed above. For this case, the Company's budgeted IT costs (inclusive of the type of costs discussed above) appear within Exhibit A (Future) and Exhibit A (Fully Projected).

V. ACCOUNTING FOR COVID-19 RELATED COSTS

Q. Are you familiar with the Commission's May 13, 2020 Secretarial Letter regarding *COVID-19 Cost Tracking and Creation of Regulatory Asset* at Docket No. M-2020-3019775?

A. Yes. The May 13, 2020 Secretarial Letter ("Secretarial Letter") responded to Governor Wolf's March 6, 2020 Proclamation of Disaster Emergency ("Emergency Proclamation"), which declared an emergency throughout the Commonwealth as a result of the COVID-19 pandemic. The Emergency Proclamation authorized the suspension of regulatory statutes, rules or regulations to the extent compliance therewith would undermine emergency mitigation efforts. To that end, the Commission issued an "Emergency Order" at Docket No. M-2020-3019244 that it ratified on March 26, 2020. The Emergency Order declared a termination moratorium for public utility services. Recognizing the pandemic in general and the termination moratorium would likely increase costs to utilities (e.g., uncollectible expense), the Commission then issued a Secretarial Letter dated May 13, 2020, that directed public utilities to "account for prudently incurred incremental extraordinary, nonrecurring expenses related to COVID-19, which result from compliance with the Commission's moratorium suspension."

More specifically, the Secretarial Letter directed utilities to track extraordinary, nonrecurring incremental COVID-19 expenses. Utilities also were authorized to create regulatory assets for incremental uncollectible expenses (related to COVID-19) above those embedded in base rates (since the Commission's March 26, 2020 Emergency Order). Therefore, the Secretarial Letter laid the foundation for utilities to seek recovery of extraordinary, nonrecurring incremental costs related to COVID-19. Finally, the Secretarial Letter directed utilities to claim deferred COVID-19 costs, at the first available opportunity.

Q. Is the Company seeking recovery of certain extraordinary, nonrecurring incremental COVID-19 costs as a part of this proceeding?

A. Yes. As this is the Company's first base rate proceeding since the Commission's May 13, 2020 Secretarial Letter and the March 26, 2020 Emergency Order, this proceeding is the first available opportunity for the Company to seek recovery of deferred COVID-19 costs. As explained below, the Company has experienced both increased uncollectible accounts expenses and increased costs in other areas due to COVID-19. Below, I detail the Company's experience with respect to increased uncollectible accounts expense, its creation of a regulatory asset for this expense, and how the Company proposes to recover these costs as a part of this proceeding. I then provide a similar explanation with respect to increased costs other than uncollectible accounts expense experienced by the Company due to COVID-19.

Q. Has the Company experienced incremental COVID-19 expenses related to uncollectible accounts expense?

A. Yes. As a result of the Commission's termination moratorium, the Company experienced increased levels of overdue receivables, which increased uncollectible accounts expense above the amount currently embedded in base rates. The uncollectible accounts costs included within the Company's rates for the HTY are $1,015,000 (based on its most recent rate case at Docket No. R-2017-2640058).

Q. How was the $1,015,000 uncollectible accounts expense included within the Company's current rates calculated?

A. The amount was calculated in accordance with the Commission's Opinion and Order in the 2018 Electric Rate Case at Docket No. R-2017-2640058. In the Opinion and Order, the Commission approved an annual revenue increase of $3.201 million (i.e., 37.7% of the Company's $8.491 million requested revenue increase (as adjusted to reflect the Tax Cuts and Job Act of 2017)). As detailed in UGI Electric Exhibit VKR-3, the Company applied this percentage to its proposed uncollectible accounts expense in the 2018 Rate Case. In that case, the Company claimed $978,000 of uncollectibles expense at Pro Forma Present Rate Revenues and proposed a $94,000 increase. The proposed increase to uncollectibles expense was reduced down to $35,000 after applying the approved 37.7%. As a result, the Company's total uncollectible accounts expense for the FPFTY in the 2018 Rate Case was $1,015,000, inclusive of rounding.

Q. Did the Company create a regulatory asset for its incremental COVID-19 expenses (related to uncollectible accounts expense) for the HTY?

A. Yes. The Company has recorded a regulatory asset for the increased uncollectible accounts expense above the $1,015,000 amount embedded within its current rates. The amount of the regulatory asset, which represents the uncollectible expense in excess of the amount included in rates for the twelve months ended September 30, 2020, is $1,013,000. Within this rate proceeding, and as directed in the May 13, 2020 Secretarial Letter, the Company is requesting recovery of the excess uncollectible accounts expense related to its Fiscal Year 2020 (through September 30, 2020) over a two-year period. This adjustment is set forth in UGI Electric Exhibit A (Fully Projected), Schedule D-11.

Q. How would the Company recover any future incremental COVID-19 expenses related to uncollectible accounts expense for years subsequent to the HTY?

A. At the time of this filing, the Commonwealth of Pennsylvania continues to be impacted by the COVID-19 pandemic, and the Company is continuing to incur elevated levels of uncollectibles beyond the end of the HTY. As described above, the Company recorded a regulatory asset for the increased uncollectible accounts expense in excess of the amount already included in rates for the twelve months ended September 30, 2020. For any period prior to the effective date of revised rates, the Company will record a regulatory asset for annualized costs in excess of the amount of uncollectible accounts expense in its current rates (*i.e.*, $1,015,000).

For periods subsequent to the effective date of the rates revised in this case, the Company proposes to collect an uncollectible accounts expense of $1,347,000 through base rates (as calculated for the FPFTY). This amount represents the uncollectible accounts expense claimed within this case (see Schedule D-11, line 7, column 4) and is based on a three-year average (adjusted for the Company's revenue claim). The three years included within the average calculation are 2018 and 2019 (both of which were not impacted by the COVID-19 pandemic) and 2020 (which was impacted by the COVID-19 pandemic). While COVID-19 impacted uncollectibles expense in 2020, the impact is in the form of the aforementioned regulatory asset. Therefore, the uncollectibles expense amount for 2020 is based on the uncollectible expense currently included within UGI Electric rates, exclusive of the incremental impact of the COVID-19 pandemic. Because the impact of the COVID-19 pandemic is not included within the three-year average for the base uncollectibles expense, the Company proposes to continue to recognize and record as a regulatory asset any incremental uncollectible accounts expense in excess of $1,347,000 after the implementation of its revised rates. UGI Electric further proposes to seek recovery of these excess costs, which will be tracked as a regulatory asset, in a future rate proceeding.

Q. Has the Company experienced incremental costs associated with COVID-19 other than incremental uncollectibles expense?

A. Yes. The Company has also tracked and maintained records of other extraordinary, nonrecurring incremental COVID-19 related expenses associated with the pandemic.

Q. Please describe these other COVID-19 costs.

A. These expenses include primarily the following: (1) lost revenues related to late fees, which were not charged during the pandemic; (2) the portion of salaries and benefits associated with leave time for employees who were unable to work due to the Governor's restrictions on construction activities, quarantine, or social distancing which would have been capitalized if the employee had been performing normal duties; (3) costs of incremental personal protective equipment to ensure employee safety during the pandemic; and (4) vehicle rentals necessary to ensure social distancing. UGI Electric Exhibit VKR-2 provides a summary of these costs.

Q. Did the Company experience any savings as a result of the COVID-19 pandemic?

A. Yes. As shown at Exhibit VKR-2, the Company estimates its expense savings as a result of the COVID-19 pandemic at $74,000.

Q. Is the Company proposing to recover any COVID-19 costs unrelated to uncollectibles?

A. Yes. As shown at Schedule D-12, the Company is requesting to recover $440,000 of COVID-19 costs unrelated to uncollectibles, which were incurred through November 2020, net of related savings. The Company is proposing to recover these expenses over a two-year period.

Q. How is the Company proposing to treat specific COVID-19 costs unrelated to uncollectibles incurred subsequent to November 2020?

A. For these expenses, the Company is proposing to create a regulatory asset for all future costs that are extraordinary, nonrecurring and incremental related to COVID-19 to be recovered over a two-year period.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC

EXHIBIT VKR-1

Vivian K. Ressler

Sr. Manager – SOX, Plant Accounting & Accounts Payable

Work Experience

Feb. 2020 – Current	Sr. Manager – SOX, Plant Accounting & Accounts Payable UGI Utilities, Inc. – Denver, PA
June 2018 – Feb. 2020	Manager – Technical Accounting & Controls UGI Utilities, Inc. – Denver, PA
May 2014 – May 2018	Departmental Vice President – Corporate Accounting The Bon-Ton Stores, Inc. – York, PA
May 2012 – May 2014	Supervisor – Attest Services Trout, Ebersole & Groff, LLP – Lancaster, PA
Nov. 2007 – May 2012	Sr. Manager – Corporate Accounting & Tax BI-LO, LLC – Greenville, SC
Sept. 1998 – Oct. 2007	Staff Accountant through Sr. Manager – Audit Services Deloitte & Touche, LLP – Greenville, SC

Previous Testimony Before the Pennsylvania Public Utility Commission

UGI Gas Base Rate Case	Docket No. R-2019-3015162

Education & Professional Certification

B. S. in Accounting – Bob Jones University, Greenville, SC

Certified Public Accountant – Commonwealth of Pennsylvania

UGI ELECTRIC

EXHIBIT VKR-2

UGI Utilities, Inc. Summary of COVID-19 Related Costs
Electric Division
$ in Thousands

	FY2020	Oct & Nov FY2021	Total
COVID-19 Related Margin Impact:			
Late Fees and Other Misc Fees	285	75	360
Total COVID-19 Related Margin Impact - all Distribution	**$ 285**	**$ 75**	**$ 360**
COVID-19 Related OPEX:			
Salaries & Benefits	82	2	84
Other Costs (Increased PPE, Vehicle Rentals, Etc)	117	7	124
Total Incremental or Nonproductive COVID-19 Related OPEX	$ 199	$ 9	$ 208
Less: Portion attributable to Transmission	(52)	(2)	(54)
Total Incremental or Nonproductive COVID-19 Related OPEX - Distribution	**$ 147**	**$ 7**	**$ 154**
COVID-19 Related Savings:			
Estimated savings related to COVID-19	(100)	-	(100)
Less: Portion attributable to Transmission	26	-	26
Total COVID-19 Related Savings - Distribution	**$ (74)**	**$ -**	**$ (74)**
Total COVID-19 Related Costs - Distribution	**$ 358**	**$ 82**	**$ 440**

UGI ELECTRIC

EXHIBIT VKR-3

Electric Uncollectibles in Rates
Based on 2018 Electric Rate Case (revised for TCJA impact)
Dollar Amounts in '000s

Rate increase pro rata calculation:

Rate increase request	$ 8,491	Schedule A-1, line 24 (as revised)
Rate increase actual	$ 3,201	Final Order
% of ask realized	37.7%	

Calculation of Uncollectibles in Rates

Schedule D-11 (FPFTY), line 7		
Pro Forma at Present Rates	$ 978	A
Schedule D-2 (FPFTY), Line 16, column [5]		
Increase request based on rate increase	94	
Pro rata increase based on rate increase	35	B
$94 increase * 37.7% of ask realized		
Rounding	2	C
Uncollectibles expense in rates	$ 1,015	A + B + C

UGI ELECTRIC STATEMENT NO. 5

PAUL R. MOUL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3023618

UGI Utilities, Inc. – Electric Division

Statement No. 5

Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

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

Dated: February 8, 2021

UGI Utilities, Inc. – Electric Division
Direct Testimony of Paul R. Moul
Table of Contents

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CWIP	Construction Work in Progress
DCF	Discounted Cash Flow
FERC	Federal Energy Regulatory Commission
FOMC	Federal Open Market Committee
g	Growth rate
IGF	Internally Generated Funds
Lev	Leverage modification
LT	Long Term
M&A	Merger and Acquisition
P-E	Price-earnings
PUC	Pennsylvania Public Utility Commission
r	represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Market risk premium
RP	Risk Premium
s	Represents the new common shares expected to be issued by a
s x v	Represents external growth
S&P	Standard & Poor's
UGIU	UGI Utilities, Inc.
UGI	UGI Corporation
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value

DIRECT TESTIMONY OF PAUL R. MOUL

<u>INTRODUCTION AND SUMMARY OF RECOMMENDATIONS</u>

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

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in UGI Electric Exhibit PRM-1, which follows my direct testimony.

Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate cost of common equity and overall rate of return that the Pennsylvania Public Utility Commission ("PUC" or the "Commission") should recognize in the determination of the revenues that UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company") should be authorized as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in UGI Exhibit B, which is a multi-page document divided into fourteen (14) schedules. All references to schedules in my testimony refer to portions of UGI Electric Exhibit B.

Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return for the Company?

A. My conclusion is that the Company should be afforded an opportunity to earn a cost of equity of 10.75%. The 10.75% rate of return on common equity does not include any recognition of the strong performance of the Company’s management. My 10.75% cost of equity recommendation is established using capital market and financial data relied upon by investors when assessing the relative risk, and hence cost of capital for the Company. While recommended cost of equity does not factor in any recognition of the Company’s effective management performance, the direct testimony of Company witness Christopher R. Brown, VP and General Manager of Rates and Supply (UGI Electric

Statement No. 1), explains that the Company has elected to forgo the management effectiveness component of the rate of return on common equity due to the effects associated with the COVID-19 Pandemic and to promote affordability of the electric service for its customers. However, if management effectiveness was included in my calculation of return on equity, I would recommend that the Company be entitled to an additional 0.20% in recognition of the strong performance by the Company in the area of management effectiveness.

Q. Are there unusual factors that you included in your analysis of the cost of equity for UGI Electric that make this case unique?

A. Yes. My cost of equity analysis reflects the impact of the coronavirus pandemic and the collapse of crude oil prices that occurred in the first quarter of 2020. These events have had a significant impact on the capital markets -- both debt and equity. Extraordinary events around the COVID-19 pandemic have produced significant turmoil that has rocked the stock and bond markets beginning in the February-March 2020 time frame. During this period, we saw abrupt reaction to the coronavirus pandemic and declines in the price of crude oil. These events led to the end of the record-setting 128-month economic expansion. As we entered a recession in February 2020, extraordinary actions were taken by the Federal Open Market Committee ("FOMC") to address these disruptions. How these events are fully resolved is yet to be determined.

I have considered these events as they impact the inputs that I used in the various models of the cost of equity. I have analyzed the cost of equity models using input data that generally follows the beginning of the economic recession. As shown on page 1 of Schedule 1, I have presented the 7.57% weighted average cost of capital for the Company, which is calculated with the September 30, 2022 fully projected future test year ("FPFTY) end capital structure ratios. This rate of return includes the 10.75% cost of equity that excludes any recognition of management effectiveness. The resulting overall cost of capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital and, if achieved, will provide the Company with the ability to attract capital on reasonable terms.

Q. What background information have you considered in reaching a conclusion concerning the Company's cost of capital?

A. UGI Utilities, Inc. ("UGIU") is a combination gas distribution and electric utility. UGIU is a wholly-owned subsidiary of UGI Corporation ("UGI"). UGIU provides electric distribution service to approximately 62,000 customers in portions of Luzerne and Wyoming Counties. UGIU also provides natural gas distribution services to approximately 642,000 customers in 45 eastern and central Pennsylvania counties.

The deliveries (i.e., direct sales and POLR) on UGIU's electric system in 2019 were approximately 56% to residential, 32% to commercial, and 12% to industrial customers. Of these percentages, 26% were direct sales and 74% were POLR. The Company obtains energy for its POLR and direct sales services primarily from the wholesale market and also delivers electricity that customers purchase directly from other suppliers.

Q. How have you determined the cost of equity in the case?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence, the cost of equity for an electric utility, such as the Company. In this regard, I have relied on four well recognized measures: the Discounted Cash Flow ("DCF") model, the Risk Premium analysis, the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings approach. By considering the results of a variety of approaches, I determined that 10.75% represents a reasonable cost of equity. To that equity cost rate, the Company is also entitled to a further 0.20% to recognize the strong performance of UGIU in the area of management effectiveness. But for reasons previously explained, the Company's rate filing has been limited to the 10.75% cost of equity.

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

A. The rate of return utilized by the Commission to set rates must be sufficient to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to raise capital on reasonable terms. The return that I propose fulfills these established standards of a fair rate of return set forth by the landmark Bluefield and Hope cases.[1] That is to say, my proposed rate of return is commensurate with returns available on investments having corresponding risks.

Q. What approach have you used in measuring the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed for my proxy group of nine (9) electric companies. The proxy group consists of electric companies that: (i) have publicly-traded common stock, (ii) are contained in The Value Line Investment Survey and are classified in the Electric Utility East group, (iii) are not currently the target of an announced merger or acquisition, (iv) are not engaged in the construction of a nuclear generating plant and (v) have not recently reduced its common dividend. The companies in the proxy group are identified on page 2 of Schedule 3. I will refer to these companies as the "Electric Group" throughout my testimony. The Electric Group relied on for my testimony in this case differs only slightly from the group I utilized in the 2018 UGI Electric rate case.[2] In this case I have deleted Dominion Energy because it recently cut its dividend.

[1] Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

[2] Pa PUC v. UGI Utilities, Inc – Electric Division, Docket No. R-2017-2640058.

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

A. I have applied the models/methods for estimating the cost of equity using the average data for the Electric Group. I have not measured separately the cost of equity for the individual companies within the Electric Group, because the determination of the cost of equity for an individual company has become increasingly problematic. If the models of the cost of equity were applied with individual company data, there is the possibility of anomalous results shown for selected companies. My approach of using average data for a portfolio of companies reduces the possibility that anomalous results might be shown by the models of the cost of equity. By employing group average data, rather than individual companies' analysis, I have helped to minimize the effect of extraneous influences on the market data for an individual company.

Q. Why have you imposed a criteria that a member of the proxy group should not have cut its dividend?

A. If a member of the proxy group has cut its dividend, then the resulting DCF calculation of the cost of equity becomes problematic. I say this because the dividend yield component of the DCF is usually calculated over a recent period of time, such as three-months, six-months, or twelve months. In making that calculation, a company's stock price is used along with the most recent quarterly dividend payment amount, which is annualized. If investors expect that a dividend cut is imminent, they will bid-down the stock price to reflect the lower dividend payment, but the dividend amount used in the yield calculation will be at the higher historical rate. As such, the dividend yield will be overstated in the DCF calculation, because there is a disconnect between the price and the dividend amount. This makes the exclusion of dividend cutters required in the formation of a proxy group. Regulators routinely make these exclusions, most notably the Federal Energy Regulatory Commission ("FERC").

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, a single method can provide an incomplete measure of the cost of equity depending upon extraneous factors that may influence market sentiment. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches, as shown on page 2 of Schedule 1.

DCF	10.84%
Risk Premium	10.25%
CAPM	14.86%
Comparable Earnings	13.20%

From these measures, I recommend a cost of equity of 10.75%, with no recognition for the Company's strong management performance, as previously explained.

To obtain new capital to support an expanded construction program and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements. In recognition of its performance, the Company should be granted an opportunity to earn a 10.75% cost of equity.

ELECTRIC UTILITY RISK FACTORS

Q. Please identify some of the factors that make the electric utility industry generally different today than it was in the past.

A. Electric utilities generally are faced with a variety of challenges that affect their operations, while retaining the obligation to serve under cost of service pricing that continues to dominate their business risk profile. On January 1, 1999, customer choice was fully available on UGI Electric's system. From that point forward, UGI Electric's responsibility became primarily the provision of delivery service at regulated prices, while it also retained the responsibility for Provider of Last Resort ("POLR") service.

UGIU Electric is part of the PJM Interconnection, LLC. Aside from its traditional responsibility to maintain reliability and comply with the mandates of PJM, a different set of risks apply to the electric delivery business in Pennsylvania.

The risk of distributed generation is a concern, and could have an increasing influence on the business of electric delivery utilities. With technological advances in micro-turbines, potential commercialization of fuel cells, development of wind and solar power, and the creation of micro-grids, utilities face the potential for bypass and the resulting declines in transmission and distribution revenues. That is to say, the development of distributed generation and local alternative energy has the potential to displace delivery revenue that can impact the incumbent utility's financial profile. This risk is exacerbated by net metering rules that require offsets against distribution rates even though distribution costs may not be reduced as a result of the installation of distributed generation.

The cost to replace aging infrastructure also adds to the risk of electric delivery utilities, such as UGI Electric, because these expenditures increase costs without any concomitant increase in revenues, except through regulatory approved rate increases, such as the Distribution System Improvement Charge ("DSIC"). The Company continues to make substantial investments to increase the resiliency and reliability of its system to reduce the number and duration of storm-related outages experienced by customers. The DSIC contains a variety of limitations that will not eliminate the need for periodic rate cases to cover the significant new investment that is being made by UGI Electric.

Since 2011, UGI Electric has also been engaged in an energy efficiency and conservation ("EE&C") program, modeled on the programs mandated for large electric utilities by Act 129 of 2008, P.L. 1592 ("Act 129"). Costs to the Company from demand response programs such as the Company's EE&C program are recoverable only on a prospective basis in future rate cases and can result in the loss of sales between rate cases. Hence, until rates are reset, the Company is subject to lost revenues due to the promotion of energy conservation.

Q. What are the primary risk factors facing the electric delivery utilities industry?

A. A pricing structure restricted by regulation diminishes management's ability to adjust its business strategy quickly to changing market conditions to respond to broadening competition and the potential for bypass arising from self-generation or distributed-generation. The financial structure of the electric business is uncertain due to the adequacy of capital recovery, counter-party risk, potential for financial penalties associated with operational problems, and growth in the utilization of the transmission and distribution network by non-affiliated generators and marketers. Regulatory risks include the overall framework of ratesetting, cost allocation, and rate design issues, and the level of return that will be allowed.

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

A. The Company is faced with the requirement to undertake investment to maintain and upgrade existing facilities in its service territory and to meet growth. Over four years, the Company's total capital expenditures (transmission and distribution), as shown in the table below, are expected to be $94.350 million:

Year	Construction
2021	$20,878,910
2022	$21,505,277
2023	$29,150,436
2024	$22,814,949
Total	$94,349,572

These expenditures represent approximately 62% ($94.350 million ÷ $152.574 million) of the Company's total net utility plant at December 31, 2019. On a total Company basis including both natural gas and electric divisions, the four year total of capital expenditures will represent 64% ($1,968.715 million ÷ $3,063.330 million) of net utility plant. Total Company capital needs are important because UGIU raises capital for both its divisions on a combined basis. A reasonable opportunity to experience a fair rate of return represents the key to a financial profile that will provide the Company with the ability to raise capital in all market conditions to meet its needs, and to satisfy investor requirements in an evolving industry.

Q. How should the Commission respond to the evolving business environment facing the Company?

A. In the situation where additional capital is required, as shown by the projected construction expenditures indicated above, the regulatory process must establish a return on equity that provides a reasonable opportunity for the Company to actually achieve its cost of capital. Where ongoing capital investment is required to meet the high quality of service that customers demand, supportive regulation is essential.

FUNDAMENTAL RISK ANALYSIS

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for the determination of the cost of equity?

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors which bear upon investors' assessment of overall risk. The qualitative factors that bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. For this purpose, I have compared UGIU to the S&P Public Utilities, an industry-wide proxy consisting of all types of public utility endeavors, and the Electric Group. In this analysis, I have used UGIU on a consolidated basis as it is the consolidated capital structure that is used to compute the weighted average cost of capital for this case.

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

A. The S&P Public Utilities is a widely recognized index comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4. I have used this group as a broad-based measure of all types of regulated public utility endeavors.

Q. What companies comprise your Electric Group?

A. My Electric Group obtained from the Value Line publication consists of the following companies: AVANGRID, Inc., Consolidated Edison, Duke Energy, Eversource Energy, Exelon Corp., FirstEnergy Corp., NextEra Energy, PPL Corp., and Public Service Enterprise Group.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is an important determinant in analyzing a company's cost of equity because the cost of each type of capital is directly related to the associated risk of the firm. So, while a company's credit quality risk is directly shown by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus a premium to recognize the higher risk of an equity investment compared to debt.

Q. How do the bond ratings compare for the Company, the Electric Group, and the S&P Public Utilities?

A. Presently, the Company's Long Term ("LT") issuer rating is A2 from Moody's and A- from Fitch. The LT issuer rating by Moody's focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. The Company's credit quality is fairly similar to that of the Electric Group, which has an average A3 and A- credit rating from Moody's and S&P, respectively. For the S&P Public Utilities, the average composite credit rating is A3 by Moody's and A- by S&P. Many of the financial indicators which I will subsequently discuss are considered during the rating process.

Q. How do the financial data compare for the Company, UGIU, the Electric Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedule 2, 3 and 4. The data cover the five-year period 2015-2019. I will highlight the important categories of relative risk may be summarized as follows:

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

Market Ratios. Historical market-based financial ratios, such as price-earnings multiples and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return for companies which exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[3]

Since UGIU's stock is not traded, there are no market ratios for the Company. The five-year average price-earnings multiple was fairly similar for the Electric Group and

[3] For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

the S&P Public Utilities. The five-year average dividend yield for the Electric Group was somewhat higher than the S&P Public Utilities. The average market-to-book ratios were somewhat lower for the Electric Group than the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has low financial risk, while a firm with a low common equity ratio has high financial risk. The five-year average common equity ratios, based on permanent capital based on book value, were 57.6% for UGIU, 47.7% for the Electric Group, and 42.2% for the S&P Public Utilities. During the past five years, the Company's common equity ratio has been trending downward. Nevertheless, the financial risk of UGIU historically was somewhat lower than the Electric Group. For this case, the Company's common equity ratio is below its historical average, thereby indicating higher financial risk prospectively.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relative levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficient of variation, the greater degree of variability. During the five-year period, the coefficients of variation were 0.122 (1.5% ÷ 12.3%) for UGIU, 0.098 (0.9% ÷ 9.2%) for the Electric Group, and 0.049 (0.5% ÷ 10.2%) for the S&P Public Utilities. These comparisons show much higher earnings variability for the Company compared to the Electric Group and the S&P Public Utilities. This signifies much higher risk for UGIU compared to the Electric Group.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation and taxes other than income).[4] The five-year average operating ratios were 76.7% for UGIU, 76.8% for the Electric Group, and 78.8% for the S&P Public Utilities. The operating ratio for UGIU was similar to the Electric Group thus indicating similar risk.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average pre-tax interest coverage (excluding AFUDC) was 5.40 times for UGIU, 3.48 times for the Electric Group, and 3.22 times for the S&P Public Utilities. The higher interest coverage for UGIU suggests lower credit risk.

Quality of Earnings. Measures of earnings quality are usually revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds. Quality of earnings has not been a significant concern for UGIU and the Electric Group.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to construction expenditures was 74.8% for UGIU, 77.6% for the Electric Group, and 74.1% for the S&P Public Utilities. This indicates a fairly comparable risk for the Company and the reference groups.

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

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities. Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market.[5] A comparison of market risk is shown by the Value Line betas of .88 as the average for the Electric Group provided on page 2 of Schedule 3 and .60 as the average for the S&P Public Utilities provided on page 3 of Schedule 4. The systematic risk was higher for the Electric Group as compared to the S&P Public Utilities.

Q. Please summarize your risk evaluation of UGIU and the Electric Group.

A. The investment risk of UGIU parallels that of the Electric Group in certain respects. In certain regards, principally related to its small size and much more variable earned returns, UGIU has higher risk traits. UGIU has lower risk as shown by its higher common equity operating ratio and higher interest coverages. Operating ratios, quality earnings and IGF to construction indicate comparable risk to the Electric Group. On balance, the cost of equity for the Electric Group would fairly represent the Company's cost of equity for this case.

RECOMMENDED CAPITAL STRUCTURE RATIOS

Q. Please explain the selection of capital structure ratios for UGIU in this case.

A. In the situation where the operating public utility raises its own long-term debt directly in the capital markets, as is the case for UGIU, it is proper to employ the capital structure ratios and senior capital cost rates of the regulated public utility for rate of return purposes. In that case, the property and earnings of the operating public utility forms the basis of

[5] The procedure used to calculate the beta coefficient published by Value Line is described on page 3 of Schedule 14. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

the capital employed and the capital cost rates are directly identifiable. The circumstances of UGIU indicate that its capital structure ratios should be used for rate of return purposes for each of its utility divisions.

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

A. Yes. Schedule 5 presents UGIU capitalization and related capital structure at September 30, 2020, the end of the historic test year. Also, shown on Schedule 5 is the UGIU capital structure estimated at September 30, 2021, the end of the future test year, and at September 30, 2022, the end of FPFTY. The changes in the Company's capital structure consist of: (i) sinking fund payments on a series of Senior Notes (ii) the issuance of $175 million of long-term debt in the future test year, (iii) the issuance of $190 million of long-term debt in FPFTY, and (v) the Company's projection of retained earnings at the end of the future test year and FPFTY. The Company's planned issue of long-term debt is part of the financial plan reflected in its budgeting process.

Q. Have you made adjustments to the Company's capitalization for ratesetting purposes?

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

Q. Why have you removed capitalized lease obligations from the Company's capital structure?

A. I have made this elimination because for ratesetting purposes, the Company includes its total lease obligations as operating leases. That is to say, the total amount of lease payments, including the capital component, is reflected in the Company's operating expenses. To avoid double-counting, capitalized leases must be removed from the capital structure for ratesetting purposes.

Q. Please explain the justification for removing the accumulated OCI?

A. The accumulated OCI must be eliminated from the capital structure for ratesetting purposes. OCI arises from a variety of sources, including: minimum pension liability ("MPL"), foreign currency hedges, unrealized gains and losses on securities available for sale, interest rate swaps, and other cash flow hedges. The accumulated OCI for the Company has its roots in the MPL and interest rate hedges associated with the variable-rate term-loan. An MPL entry must be recorded on the balance sheet when the present value of the pension benefit earned by employees exceeds the market value of trust fund assets. It should be noted that the Company records the change related to prior service cost and actuarial valuations as a regulatory asset for the portion of pension attributable to its retirees and employees that are part of its regulated utility operations. The amount in the accumulated OCI is just related to the portion attributable to employees of UGI Corporation and non-utility subsidiaries. That is to say, the accumulated OCI associated with MPL is not related to utility operations. The interest rate hedges, as they affect OCI, must also be removed because they have been reflected in the embedded cost of debt.

Q. Have you included short-term debt in the capital structure for UGIU?

A. No. In reaching this conclusion, I have analyzed the 12-month average balances of short-term debt for the historic test year, future test year, and FPFTY and compared those amounts to the Company's construction work in progress ("CWIP"). I have done this because the Company follows the FERC formula to calculate its AFUDC rate. That formula assigns short-term debt first to CWIP, with any excess balance of CWIP receiving the Company's overall rate of return. In order to avoid double-counting the amount of short-term debt that finances CWIP, those amounts must be removed from the average short-term debt amounts for rate case purposes. For the FPFTY, the CWIP balances approximately offsets the average amount of short-term debt. Therefore, the de minimis amount of short-term debt is removed from the capital structure for the FPFTY.

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

A. Since ratemaking is prospective, the rate of return should reflect known conditions that will exist during the period of time the proposed rates are to be effective. I will adopt the Company's capital structure ratios at the end of the FPFTY of 48.80% long-term debt and 51.20% common equity. These ratios are within the ranges indicated for the Electric Group. I should note that due to the small size of UGIU and UGI Electric, less debt and more equity would be appropriate and an equity ratio in the upper end of the range would be warranted. These capital structure ratios are the best approximation of the mix of capital the Company will employ to finance its rate base during the period new rates are in effect.

EMBEDDED COST OF DEBT

Q. What cost rate have you assigned to the long-term debt portion of the capital structure?

A. Consistency requires that the embedded senior capital cost rates of UGIU must be used for developing a fair rate of return. It is essential that the cost rate of long-term debt is related to the same proportion of senior capital employed to arrive at the capital structure ratios. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is due to the fact that the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Schedule 6, I have computed the actual embedded cost rate of long-term debt at September 30, 2020. On page 2 of Schedule 6, I have shown the estimated embedded cost rate of long-term debt at September 30, 2021. And on page 3 of Schedule 6, the embedded cost of long-term debt is shown for the FPFTY. The development of the individual effective cost rates for each series of long-term debt, using the cost rate to maturity technique, is shown on page 4 of Schedule 6. The cost rate, or yield to maturity, is the rate of discount that equates the present value of all future interest and principal payments with the net proceeds of the bond.

I will adopt the 4.25% forecast embedded long-term debt cost rate at September 30, 2022, as shown on page 3 of Schedule 6. This rate is related to the amount of long-term debt shown on Schedule 5 which provides the basis for the 48.80% long-term debt ratio.

COST OF EQUITY – GENERAL APPROACH

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

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among UGIU, the Electric Group, and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I identified above. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As I describe below, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Electric Group and arrived at a cost of equity of 10.75% for UGI Electric, which excludes 0.20% in recognition of strong management effectiveness.

DISCOUNTED CASH FLOW

Q. Please describe the Discounted Cash Flow model.

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF-determined return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model, which assumes that future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: P = D/(k-g), where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: k= D/P + g. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model.[6] My DCF results are provided on Schedule 1, page 2, for the Electric Group. The DCF return is 10.84% for the Electric Group.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

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

A. The dividend yield reveals the portion of investors' cash flow that is generated by the return provided by the dividends an investor receives. It is measured by the dividends per share relative to the price per share. The DCF methodology requires the use of an

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

expected dividend yield to establish the investor-required cost of equity. For the twelve months ended September 2020, the monthly dividend yields are shown on Schedule 7. The month-end prices were adjusted to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the twelve months ended September 2020 the average dividend yield was 3.77% for the Electric Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six-month and three-month periods were 4.03% and 4.04%, respectively. For applying the DCF model, I have used the six-month average dividend yield of 4.03% for the Electric Group. The use of this dividend yield will reflect current capital costs, while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investors' anticipated cash flows. I have adjusted the six-month average dividend yield in three different, but generally accepted, manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Schedule 7. This adjustment adds twelve basis points to the six-month average historical yield, thus producing the 4.15% adjusted dividend yield for the Electric Group.

Q. What factors influence investors' growth expectations?

A. As noted previously, investors are interested principally in the dividend yield and future growth of their investment (i.e., the price per share of the stock). Future growth in earnings per share is the DCF model's primary focus because, under the model's assumption that the price-earnings multiple remains constant, the price per share of stock will grow at the same rate as earnings per share. A growth rate analysis considers a variety of variables to reach a consensus of prospective growth, including historical data and widely available analysts' forecasts of earnings, dividends, book value, and cash flow (all stated on a per-share basis). A fundamental growth rate analysis is frequently based upon internal growth ("b x r"), where "r" is the expected rate of return on common equity and "b" is the retention rate (a fraction representing the proportion of earnings not paid out as dividends). To be complete, the internal growth rate should be modified to account for sales of new common stock (external growth), which is represented by the formula s x v, where "s" is the number of new common shares the firm expects to issue and "v" is the value that accrues to existing shareholders from selling stock at a price above book value. Fundamental growth, which combines internal and external growth, encompasses the factors that cause book value per share to grow over time.

Growth also can be expressed in multiple stages. This expression of growth consists of an "initial" stage where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilize at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time. For these reasons, there is no need to analyze growth rates individually for each cycle, but rather to rely upon analysts' growth forecasts, which are those used by investors when pricing common stocks.

Q. How did you determine an appropriate growth rate?

A. The growth rate used in a DCF calculation should measure investor expectations. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. Investors are not influenced solely by a single set of company-specific variables weighted in a formulaic manner. Therefore, all relevant growth rate indicators should be evaluated using a variety of techniques when formulating a judgment of investor-expected growth.

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

A. I considered the growth in the financial variables shown on Schedules 8 and 9, which reflect historical (Schedule 8) and projected (Schedule 9) rates of growth in earnings per share, dividends per share, book value per share, and cash flow per share for the Electric Group. While analysts will review all measures of growth, as I have done, earnings per share growth directly influences the expectations of investors for the future performance of utility stocks. Forecasts of earnings growth are required because the DCF model is forward-looking, and, with the constant price-earnings multiple and constant payout ratio that the DCF model assumes, all other measures of growth will mirror earnings growth. The historical growth rates were obtained from the Value Line publication that provides those data. While historical data cannot be ignored, it is much less significant in applying the DCF model than projections of future growth. Investors cannot purchase the past earnings of a utility. To the contrary, they are only entitled to future earnings, which are the focus of growth projections. Furthermore, if significant weight is assigned to historical performance, the historical data are double counted because they are already factored into analysts' forecasts of earnings growth.

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

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

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

A. Schedule 9 provides projected earnings per share growth rates taken from analysts' five-year forecasts compiled by IBES/First Call, Zacks, and Value Line. These are all reliable authorities of projected growth that investors use to make buy, sell and hold decisions.

The IBES/First Call, and Zacks estimates are obtained from the Internet and are widely available to investors. The growth rates reported by IBES/First Call and Zacks are consensus forecasts taken from a survey of analysts that make growth projections for these companies. Notably, First Call's earnings forecasts are frequently quoted in the financial press. The Value Line forecasts also are widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries. The IBES/First Call, and Zacks forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share for the Electric Group are also included on Schedule 9.

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

A. Schedule 9 shows the prospective five-year earnings per share growth rates projected for the Electric Group by IBES/First Call (4.33%), Zacks (4.80%), and Value Line (5.39%).

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

A. Yes. While a variety of factors should be examined to reach a reasonable conclusion on the DCF growth rate, growth in earnings per share should receive the greatest emphasis. Growth in earnings per share is the primary determinant of investors' expectations of the total returns they will obtain from stocks because the capital gains yield (i.e., price appreciation) will track earnings growth if the P-E multiple remains constant, as the DCF model assumes. Moreover, earnings per share (derived from net income) are the source of dividend payments and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In fact, Professor Myron Gordon, the foremost proponent of the use of the DCF model in setting utility rates, concluded that the best measure of growth for use in the DCF model is a forecast of earnings per-share growth.[7] Consistent with Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, and Value Line, provide the best indication of investor expectations.

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

A. The forecasts shown on Schedule 9 for the Electric Group exhibit a range of average earnings per share growth rates from 4.33% to 5.39%. DCF growth rates should not be established by mathematical formulation, and I have not done so. In my opinion, a growth rate of 5.25% is a reasonable estimate of investor-expected growth for the Electric Group. This value is within the array of analysts' forecasts of five-year earnings per share growth rates and is below the midpoint of that data set. The reasonableness of this growth rate is also supported by the expected continuation of electric utility infrastructure spending.

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

A. The components of the DCF model are adequate for that purpose only if the capital structure ratios are measured by the market value of debt and equity. In the case of the Electric Group, average capital structure ratios are 40.98% long-term debt, 0.04% preferred stock, and 58.97% common equity using the market values of debt, preferred stock and common equity, as shown on Schedule 10. If book values are used to compute the capital structure ratios, then a leverage adjustment is required.

Q. What is a leverage adjustment?

A. If a firm's capitalization, as measured by its stock price, diverges from its capitalization, measured at book value, the potential exists for a financial risk difference. Such a risk difference arises because a market-valued capitalization contains more equity and less

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

debt than a book-value capitalization and, therefore, has less risk than the book-value capitalization. A leverage adjustment properly accounts for the risk differential between market-value and book-value capital structures.

Q. Why is a leverage adjustment necessary?

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

Schedule 10, under the heading "M&M," provides a return of 7.40% when applicable to a capital structure with 100% common equity.

Q. Are there specific factors that influence market-to-book ratios that determine whether the leverage adjustment should be made?

A. No. The leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations concerning market prices relative to book are not on point. The leverage adjustment deals with the issue of financial risk and does not transform the DCF result to a book value return through a market-to-book adjustment. Again, the leverage adjustment that I propose is based on the fundamental financial precept that the cost of equity is equal to the rate of return for an unleveraged firm (i.e., where the overall rate of return equates to the cost of equity with a capital structure that contains 100% equity) plus the additional return required for introducing debt and/or preferred stock leverage into the capital structure.

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

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

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

A. No, it is not. What I label a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g) when the DCF return applies to a capital structure used for ratemaking that is computed with book-value weighting rather than market-value weighting. Although I specify a separate factor, which I call the leverage adjustment, there is no need to do so other than to identify this factor. If I expressed my return solely in the context of the book value weighting that we use to calculate the weighted average cost of capital and ignore the familiar D/P + g expression entirely, then a separate element in the DCF cost of equity determination would not be needed to reflect the differential in financial leverage between a market-value and book-value capitalization. As shown in the bottom panel of data on Schedule 10, the equity return applicable to the book value common equity ratio is equal to 7.40%, which is the return for the Electric Group appropriate for a capital structure with no debt (i.e., a 100% equity ratio) plus 3.43% to compensate investors for the risk of a 54.09% debt ratio and 0.01% for preferred stock ratio of 0.27%. Under this approach, the parts sum to 10.84% (7.40% + 3.43% + 0.01%), and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I summed the 4.15% dividend yield, the 5.25% growth rate, and 1.44% for the leverage adjustment in order to arrive at the same 10.84% (4.15% + 5.25% + 1.44%) return. I know of no means to mathematically solve for the 1.44% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 1.44% adjustment is merely a convenient way to compare the 10.84% return computed using the Modigliani & Miller formulas to the 9.40% return generated by the DCF model (i.e., $D_1/P_0 + g$, or the traditional form of the DCF shown on Schedule 7, page 1) based on a market-value capital structure. A 9.40% return assigned to anything other than the market value of equity cannot equate to a reasonable return on book value that has higher financial risk. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

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

A. As explained previously, I have utilized a six-month average dividend yield ("D_1/P_0") adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate ("g") previously developed. The DCF also includes the leverage modification ("lev.") required when the book value equity ratio is used in determining the weighted average cost of capital in the ratesetting process rather than the market value equity ratio related to the price of stock. The resulting DCF cost rate is 10.84%, computed as follows:

	D_1/P_0	+	*g*	+	*lev.*	=	*K*
Electric Group	4.15%	+	5.25%	+	1.44%	=	10.84%

The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant-growth assumption. I should reiterate, however, that the DCF-indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market because price-earnings multiples do not remain constant. This is one of the constraints of this model that makes it important to consider the results of other models when determining a company's cost of equity.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the risk premium approach to determine the cost of equity.

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on Schedule 1, page 2. That result is 10.25%.

Q. What long-term public utility debt cost rate did you use in your risk premium analysis?

A. In my opinion, and as I will explain in more detail further in my testimony, a 3.50% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

Q. What historical data are shown by the Moody's data?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on Schedule 11, page 1. For the twelve months ended September 2020, the average monthly yield on Moody's index of A-rated public utility bonds was 3.15%. For the six and three-month periods ended September 2020, the yields were 2.95% and 2.77%, respectively. During the twelve-months ended September 2020, the range of the yields on A-rated public utility bonds was 2.73% to 3.50%. Page 2 of Schedule 11 shows the long-run spread in yields between A-rated public utility bonds and long-term Treasury bonds. As shown on page 3 of Schedule 11, the yields on A-rated public utility bonds have exceeded those on Treasury bonds by 1.43% on a twelve-month average basis, 1.58% on a six-month average basis, and 1.41% on a three-month average basis. Giving greater emphasis to the six-month average spread, 1.50% represents a reasonable spread for the yield on A-rated public utility bonds over Treasury bonds.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe below. Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on October 1, 2020, and a yield spread of 1.50%, derived from historical data.

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

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

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2020	Fourth	2.3%	3.5%	1.5%	1.50%	3.00%
2020	First	2.4%	3.6%	1.6%	1.50%	3.10%
2020	Second	2.5%	3.6%	1.6%	1.50%	3.10%
2020	Third	2.6%	3.7%	1.7%	1.50%	3.20%
2021	Fourth	2.7%	3.7%	1.8%	1.50%	3.30%
2021	First	2.7%	3.8%	1.9%	1.50%	3.40%

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

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its June 1, 2020 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2022-2026	3.90%	5.00%	3.00%
2027-2031	4.60%	5.70%	3.80%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. A 3.50% yield on A-rated public utility bonds represents a reasonable benchmark for measuring the cost of equity in this case. All the data I used to formulate my conclusion as to a prospective yield on A-rated public utility debt are available to investors, who regularly rely upon those data to make investment decisions.

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

A. To develop an appropriate equity risk premium, I analyzed the results from 2020 SBBI Yearbook, Stocks, Bonds, Bills and Inflation. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline, and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on Schedule 12, page 1.

Common Equity Risk Premiums	
Low Interest Rates	6.70%
Average Across All Interest Rates	5.69%
High Interest Rates	4.69%

Based on my analysis of the historical data, the equity risk premium was 6.70% when the marginal cost of long-term government bonds was low (i.e., 2.88%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.09% on average during periods of high interest rates), the spread narrowed to 4.69%. Over the entire spectrum of interest rates, the equity risk premium was 5.69% when the average government bond yield was 4.99%. I have utilized a 6.75% equity risk premium. The equity risk premium of 6.75% that I employed is associated with low interest rates.

Q. What common equity cost rate did you determine based on your risk premium analysis?

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i"), and the equity risk premium (i.e., "RP"). The Risk Premium approach provides a cost of equity of 10.25%, computed as follows:

	i	+	*RP*	=	*k*
Electric Group	3.50%	+	6.75%	=	10.25%

<u>CAPITAL ASSET PRICING MODEL</u>

Q. How is the CAPM used to measure the cost of equity?

A. The CAPM uses the yield on a risk-free interest-bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Schedule 1, the result of the CAPM is 14.86% for the Electric Group. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 2 of Schedule 3, the average beta is 0.88 for the Electric Group.

Q. Did you use the Value Line betas in the CAPM determined cost of equity?

A. I used the Value Line betas as a foundation for the leverage adjusted betas that I used in the CAPM. The betas must be reflective of the financial risk associated with the ratesetting capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line (market value) betas have been unleveraged and re-leveraged for the book value common equity ratios using the Hamada formula,[8] as follows:

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

where ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.61 for the Electric Group if it employed no leverage and was 100% equity financed. Those calculations are shown on Schedule 10 under the section labeled "Hamada," who is credited with developing those formulas. With the unleveraged beta as a base, I calculated the leveraged beta of 1.08 for the book value capital structure of the Electric Group.

[8] Robert S. Hamada, "The Effects of the Firm's Capital Structure on the Systematic Risk of Common Stocks" *The Journal of Finance* Vol. 27, No. 2, Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, December 27-29, 1971. (May 1972), pp. 435-452.

Q. What risk-free rate have you used in the CAPM?

A. As shown on page 1 of Schedule 13, I provided the historical yields on Treasury notes and bonds. For the twelve months ended September 2020, the average yield on 30-year Treasury bonds was 1.72%. For the six- and three-months ended June 2020, the yields on 30-year Treasury bonds were 1.37% and 1.36%, respectively. During the twelve-months ended September 2020, the range of the yields on 30-year Treasury bonds was 1.27% to 2.30%. The low yields that existed during recent periods can be traced to the financial crisis and its aftermath commonly referred to as the Great Recession, which covered the period December 2007 through June 2009 and was associated with the Financial Crisis of 2007-08. The resulting decline in the yields on Treasury obligations was attributed to a number of factors, including the sovereign debt crisis in the euro zone, concern over a possible double dip recession, the potential for deflation, the Federal Reserve's large expansion of its balance sheet through the purchase of Treasury obligations and mortgage-backed securities (also known as QEI, QEII, and QEIII), the reinvestment of the proceeds from maturing obligations, and lengthening of the maturity of the Fed's bond portfolio by selling short-term Treasuries and purchasing long-term Treasury obligations (also known as "operation twist").

As noted previously, low interest rates were the product of the policy of the FOMC in its attempt to deal with stagnant job growth, which is part of its dual mandate. The FOMC ended its bond purchasing program at its policy meeting on October 29, 2014. At its December 16, 2015 meeting, the FOMC increased the federal funds rate range by 0.25 percentage points. On December 14, 2016, the FOMC acted again by raising the federal funds rate by one-quarter percentage point. The FOMC also used this occasion to signal a more aggressive approach to future increases in interest rates. In addition, the Fed has indicated that it will reduce the size of its balance sheet. FOMC increased the federal funds rate on three occasions in 2017 (i.e., March 15, 2017, June 14, 2017 and December 13, 2017) by one-quarter percentage point each. At its policy meetings on March 21, 2018, June 13, 2018, September 26, 2018, and December 19, 2018, the FOMC acted again to increase the federal funds rate by one-quarter percentage point in each instance. There have been nine (9) one-quarter percentage point increases in the Fed Funds rate since the FOMC began to normalize interest rates following the financial crisis and the Great Recession.

Recently, the FOMC has reversed course based on its perception of lower measures of inflation and began to reduce the Fed Funds rate (i.e., one-quarter percentage point reductions occurred on July 31, 2019, September 18, 2019, and October 30, 2019). These reductions were attributed to a perceived weakening of the global economy due in part to the trade war with China. The FOMC has specifically noted weakness in business fixed investment and exports. These increases have been offset by the decline in the risk-free rate of return. The FOMC specifically noted weakness in business fixed investment and exports. Further action was taken by the FOMC to support the money and capital markets during the coronavirus pandemic. This brought the Fed Funds rate to near zero.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on October 1, 2020 indicate that the yields on long-term Treasury bonds are expected to be in the range of 1.5% to 1.9% during the next six quarters. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 3.0% from 2022 through 2026 and 3.8% from 2027 to 2031. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a 2.00% risk-free rate of return for CAPM purposes, which considers the Blue Chip forecasts.

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

A. As shown in the lower panel of data presented on Schedule 13, page 2 the market premium is derived from historical data and the forecast returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on Schedule 12, page 1. On that schedule, the market return was 11.92% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 2.88% when interest rates were low. As such, I carried over to Schedule 13, page 2, the average large common stock returns of 11.92% and the average yield on long-term government bonds of 2.88%. The resulting market premium is 9.04% (11.92% - 2.88%) based on historical data, as shown on Schedule 13, page 2. As also shown on Schedule 13, page 2, I calculated the forecast returns, which show a 14.87% total market return from the Value Line data. With this forecast, I calculated a market premium of 12.87% (14.87% - 2.00%) using forecast data. The resulting market premium applicable to the CAPM derived from these sources equals 10.96% (12.87% + 9.04% = 21.91% ÷ 2).

Q. Are there adjustments to the CAPM that are necessary to fully reflect the rate of return on common equity?

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. As the size of a firm decreases, its risk and required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms. Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled “Equity and the Small-Stock Effect,” it was demonstrated that the CAPM could understate the cost of equity significantly according to a company’s size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. As noted previously, UGIU is relatively smaller than the Electric Group. To recognize this fact, I used the mid-cap adjustment of 1.02%, as revealed on page 3 of Schedule 13, for the CAPM calculation.

Q. What does your CAPM analysis show?

A. Using the 2.00% risk-free rate of return, the leverage adjusted beta of 1.08 for the Electric Group, the 10.96% market premium, and the 1.02% size adjustment, the following result is indicated.

	Rf	+	*ß*	*x*	*(*	*Rm-Rf*	*)*	*+*	*size*	*=*	*k*
Electric Group	2.00%	+	1.08	x	(	10.96%	)	+	1.02%	=	14.86%

COMPARABLE EARNINGS APPROACH

Q. What is the Comparable Earnings approach?

A. The Comparable Earnings approach estimates a fair return on equity by comparing returns realized by non-regulated companies to returns that a public utility with similar risks characteristics would need to realize in order to compete for capital. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into investor expectations for public utility returns. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided.

There are two avenues available to implement the Comparable Earnings approach. One method involves the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms in order to avoid the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works vs. Public Service Commission, 262 U.S. 668 (1923).

It is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

Q. Did you compare the results of your DCF and CAPM analyses to the results indicated by a Comparable Earnings approach?

A. Yes. I selected companies from The Value Line Investment Survey for Windows that have six categories of comparability designed to reflect the risk of the Electric Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Electric Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The definition for these parameters is provided on Schedule 14, page 3. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on Schedule 14, page 1.

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

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

A. I used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 13.2% using only the returns that were less than 20%, as shown on Schedule 14, page 2. The average forecasted rate of return as published by Value Line is 13.2% also using values less than 20%, as provided on Schedule 14, page 2. Using the average of these data my Comparable Earnings result is 13.20%, as shown on Schedule 1, page 2.

CONCLUSION ON COST OF EQUITY

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

A. Based upon the application of a variety of methods and models described previously, it is my opinion that a reasonable rate of return on common equity is 10.75% for UGI Electric. If a strong management performance increment were included, the rate of return on common equity would be 10.95%. My cost of equity recommendation is within the range of results and should be considered in the context of the Company's risk characteristics relative to the barometer group companies. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method. In summary, the Company should be provided an opportunity to realize a 10.75% rate of return on common equity so that it can compete in the capital markets, attain reasonable credit quality, sustain its cash flow in the context of the its high levels of capital expenditures, and receive recognition of the significant accomplishments that management has achieved.

Q. Does this complete your direct testimony?

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

UGI ELECTRIC

EXHIBIT PRM-1

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past forty-two years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty-seven (37) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on Environmental Quality. My testimony has been offered in over 300 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509).

I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).