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 – PAUL J. SZYKMAN
UGI ELECTRIC STATEMENT NO. 2 – STEPHEN F. ANZALDO
UGI ELECTRIC STATEMENT NO. 3 – ERIC W. SORBER
UGI ELECTRIC STATEMENT NO. 4 – MEGAN MATTERN
UGI ELECTRIC STATEMENT NO. 5 – PAUL R. MOUL

ORIGINAL TARIFFS
UGI UTILITIES, INC. – ELECTRIC DIVISION
PA P.U.C. NOS. 6 & 2S

DOCKET NO. R-2017-2640058

Issued: January 26, 2018 **Effective: March 27, 2018**

UGI ELECTRIC STATEMENT NO. 1 – PAUL J. SZYKMAN

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2017-2640058

UGI Utilities, Inc. – Electric Division

Statement No. 1

Direct Testimony of
Paul J. Szykman

Topics Addressed:

Need for Rate Relief and Tariff Updates
Overview of Witnesses and Testimony
Management Performance
UGI-1 Initiative and UNITE Systems Modernization

Dated: January 26, 2018

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

Q. Please state your name and business address.

A. My name is Paul J. Szykman. My business address is 2525 North 12th Street, Suite 360, Reading, PA 19612-2677.

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

A. I am employed by UGI Utilities, Inc. ("UGI") as Chief Regulatory Officer.

Q. Please briefly describe your responsibilities in that capacity.

A. As Chief Regulatory Officer, I am responsible for all rate, governmental affairs and regulatory compliance activities for UGI Utilities, Inc. – Gas Division ("UGI Gas"), UGI Penn Natural Gas, Inc. ("UGI PNG"), UGI Central Penn Gas, Inc. ("UGI CPG") and UGI Utilities, Inc. – Electric Division ("UGI Electric" or "Company"). Regarding rates, 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 filings, electric provider of last resort ("POLR") filings, Section 1307(e) filings, base rate cases, and UGI's gas management information technology systems. My government relations responsibilities include managing the development and implementation of the Company's strategies in federal and state legislative and regulatory arenas. My regulatory compliance responsibilities cover a broad range of oversight and compliance for the state and federal jurisdictional activities of UGI's four operating utilities. Prior to my role as Chief Regulatory Officer, I was Vice President – Rates & Government Relations and Vice President & General Manager – Electric Utilities. In my current role I report directly to the President and Chief Executive Officer of UGI.

Q. What is your educational and professional background?

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

Q. Have you testified previously before this Commission?

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

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. In addition to UGI Electric Exhibit PJS-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. <u>PURPOSE OF TESTIMONY</u>

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

A. My testimony addresses several issues. First, I present an overview of the need for UGI Electric to make this rate filing, including a brief explanation of the rate relief requested, proposed tariff changes and the key reasons for requesting rate relief. Second, I present the Company's list of witnesses and an outline of the testimony elements covered by each witness. Third, I discuss the Company's overall management performance and the fact that this performance supports an equity incentive recognition in this case. Fourth, I will discuss more details surrounding the UGI-1 initiative, including the important investments being made as part of this initiative. Lastly, I summarize the reasons this rate relief request should be granted.

III. THE COMPANY'S NEED FOR RATE RELIEF AND TARIFF UPDATES

Q. Please briefly describe the UGI Electric distribution system operations.

A. UGI Electric provides electric distribution service to approximately 62,000 customers throughout portions of Luzerne and Wyoming Counties. The Company maintains over 1,200 miles of overhead and underground primary distribution lines, twelve distribution substations, and forty-nine distribution circuits.

Q. Please discuss the rate relief and tariff changes that UGI Electric is requesting in this filing.

A. UGI Electric is requesting an increase in its annual base rate operating revenues of $9.254 million, or 10.4 percent on a total revenue basis, with a proposed effective date of March 27, 2018. If the Company's entire request is approved, the total bill for a residential customer using 1,000 kilowatt-hours (kWh) per month and receiving default power service from the Company would increase from $112.28 to $125.56 per month or by 11.8%. The total bill for a small commercial customer using 1,000 kWh per month and receiving default power service from the Company would not change from the current bill of $120.74 per month. Rates for an industrial customer using 50,000 kWh per month and receiving default power service from the Company would increase from $4,792.16 to $4,860.44 per month or by 1.4%.

This is the Company's first general base rate case filing since its last rate case filing approved in 1996 at Docket No. R-00953534. The base rate increase requested in this filing is based on the use of a Fully Projected Future Test Year ("FPFTY") ending September 30, 2019. The Company also proposes certain changes to its existing tariff which update certain terms and conditions, eliminate outdated provisions and rate schedules, propose rate consolidation and rate design simplification, replace the Company's current Customer Assistance Plan ("CAP") Rider with a new Universal Service Plan ("USP") Rider, add a new Storm Expense Rider, and add a new electric vehicle charging station service rate schedule.

I would note that this initial filing does not address the impact of the recently enacted federal tax law changes given the timing of these changes in relation to the preparation of this filing. The impact of these changes on the Company is still under review and the Company anticipates filing Supplemental Direct Testimony to present the impact of these changes on the rate relief requested in this case.

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. Since its last rate case in 1996, UGI Electric has made significant system investments which have increased rate base by nearly 60% to over $100 million. Several key initiatives are contributing to this rate base growth through the end of the FPFTY. Specifically, UGI Electric has recently accelerated investment in the repair, replacement or improvement of aged and aging distribution infrastructure. This accelerated pace of investment has been incorporated into a Long Term Infrastructure Improvement Plan ("LTIIP") which was recently approved by the Pennsylvania Public Utility Commission ("PA PUC" or "Commission") on December 21, 2017, at Docket No. P-2017-2619834. Under the LTIIP, the

Company's investment in the repair, replacement or improvement of aged and aging distribution infrastructure has been increased by over 100% compared to historic baseline levels, contributing to rate base growth.

Additionally, as part of the larger UGI Next Information Technology Enterprise ("UNITE") system modernization initiative at UGI, UGI Electric is and will be benefitting from replacement of UGI's core technology systems. These replacements should improve customer experience, help UGI Electric make better informed decisions, and streamline business processes across UGI. UNITE Phase 1 activities included investing in a replacement of two multi-decade old Customer Information Systems ("CISs") with one new state-of-the-art CIS. UNITE Phase 2 plans include investing in modern financial information technology systems over the next 18 months.

UGI Electric is also investing in a facilities modernization and consolidation effort that will relocate almost all UGI Electric operations personnel into one location with new offices, warehouse space, field yard, training space, and linemen and contractor crew assembly facilities. UGI is also investing in new corporate headquarters facilities that will modernize facilities, improve facility and system security and control, and consolidate certain personnel currently spread across multiple locations. A portion of the investment in the new corporate headquarters facilities is allocated to UGI Electric.

Together, UGI Electric's focus on upgrading and modernizing the distribution system, technologies and facilities will support the Company's efforts to continue to provide safe and reliable distribution service and high-quality customer service.

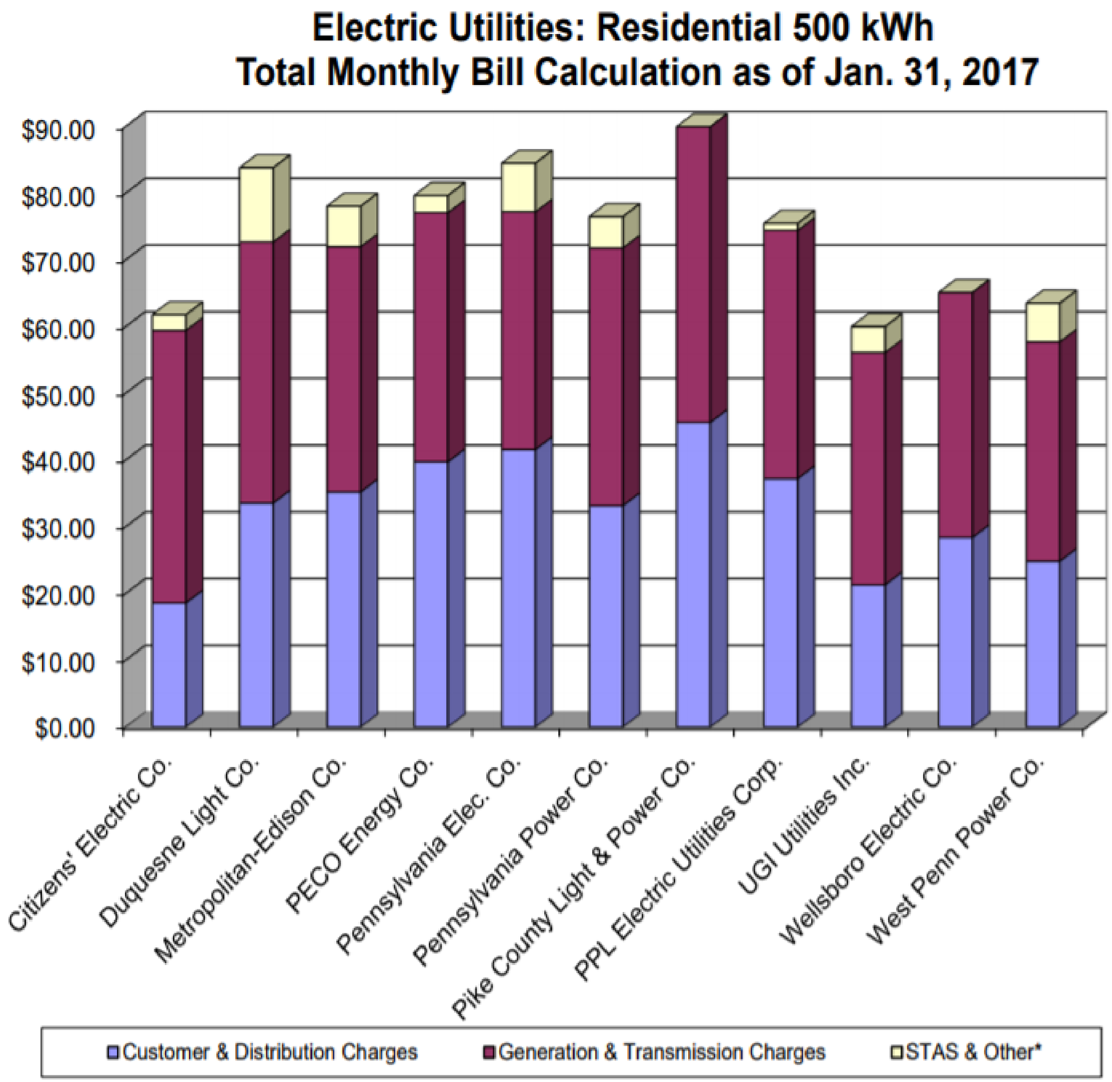
Also, since its last base rate case, UGI Electric has adopted modest annual wage and salary adjustments and will continue to do so, where reasonable. UGI Electric has also experienced other general price increases for necessary products and services. The growth in operating and capital costs, along with relatively stagnant customer usage and growth trends, are the primary reasons why UGI Electric will be unable to earn a fair rate of return on its investments, at present rate levels.

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 3.20%, which equates to a return on common equity of only 1.92% for the twelve months ending September 30, 2019. 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.

I would note that the Company has sought to offset its increased costs by operating efficiently. The Company's last base rate case was filed 22 years ago in 1996, and since that time it has been able to offer excellent service to customers at very reasonable rates. A comparison of residential service rates among Pennsylvania's Electric Distribution Companies ("EDCs"), shown in Table 1 below, illustrates that UGI Electric's total bill for a residential customer using

500 kWh per month is the lowest among all other Pennsylvania EDCs. Moreover, this comparison also shows that UGI Electric maintains the second lowest residential distribution rates among all other Pennsylvania EDCs.

<u>Table 1</u>[1]



*Other charges may include any of the following: Universal Service Charges, Education Charges, Customer Assistance Program Charges, Systems Benefits Charges, Demand Charges, Default Service Support Rider, Gross Receipts Tax, Smart Meter Charges, EE&C Charges, CTC, or DSIC. Please see a utility's individual chart for a breakdown of what charges can be found on its bill.

[1] Source: Pennsylvania Public Utility Commission Rate Comparison Report, April 15, 2017.

However, for the reasons stated above, the Company cannot reasonably expect to meet its reasonable revenue requirements going forward without rate relief.

IV. <u>OVERVIEW OF WITNESSES AND TESTIMONY</u>

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, Rates and Regulatory Planning at UGI. Mr. Anzaldo explains UGI Electric's budgeting processes and revenue requirement exhibits for the Historic Test Year ended September 30, 2017 ("HTY"), Future Test Year ending September 30, 2018 ("FTY"), and the FPFTY. Mr. Anzaldo also presents testimony on how the Company's capital spending satisfies the requirements of recently enacted Section 1301.1 of the Public Utility Code regarding consolidated tax adjustments.

Eric W. Sorber (UGI Electric Statement No. 3) serves as Director, Engineering and Operations at UGI. Mr. Sorber provides an overview of UGI Electric's operations and discusses the Company's electric distribution system and its recently approved LTIIP, including the development of capital planning and supportive operations expense budget. Mr. Sorber also discusses the anticipated impact the LTIIP will have on operations resources, including several resource additions, and other initiatives related to system performance, safety, and reliability. Additionally, Mr. Sorber discusses the Company's workplace safety program and the favorable impact those changes have had on various employee safety performance metrics. Mr. Sorber also addresses the initiative underway to modernize and consolidate the Company's operating facilities.

Megan Mattern (UGI Electric Statement No. 4) serves as Controller at UGI. Ms. Mattern addresses the Company's accounting processes. She also presents the Company's rate base development for the HTY, FTY, and FPFTY. Ms. Mattern also addresses *pro forma* adjustments to the Company's HTY, FTY and FPFTY schedules associated with common plant allocations, including information technology systems and cloud-based technology services.

Paul R. Moul (UGI Electric Statement No. 5) is Managing Consultant of P. Moul & Associates, Inc. Mr. Moul presents expert testimony concerning the overall rate of return that UGI Electric should be afforded in order to have a fair opportunity to earn a fair return on its rate base investment. Mr. Moul also supports the Company's claimed capital structure, its embedded cost of debt, as well as its requested return on common equity. Schedules and work papers supporting Mr. Moul's findings are set forth in UGI Electric Exhibit B.

John D. Taylor (UGI Electric Statement No. 6) is an expert witness from Black & Veatch. Mr. Taylor prepared and sponsors the Company's fully allocated cost of service studies used in this case, which are found in UGI Electric Exhibit D.

John F. Wiedmayer (UGI Electric Statement No. 7) is Project Manager at Gannett Fleming Valuation & Rate Consultants, LLC. Mr. Wiedmayer developed and supports the Company'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).

David E. Lahoff (UGI Electric Statement No. 8) serves as Manager – Tariff & Supplier Administration at UGI. Mr. Lahoff is responsible for all areas of the Company's rate design and revenue allocation. Mr. Lahoff also addresses and sponsors related exhibits that show the proof of revenues and proposed rate design, as presented in UGI Electric Exhibit E - Proof of Revenue. Mr. Lahoff's testimony also presents the supporting sales and revenue adjustments for certain tariff customer classes, including related assumptions. Mr. Lahoff is also sponsoring UGI Electric Exhibit F, which is Original Tariff – Electric Pa. P.U.C. No. 6 ("Tariff No. 6"), which replaces current Tariff – Electric Pa. P.U.C. No. 5. Mr. Lahoff 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 Tariff No. 6 as Tariff No. 2-S. Mr. Lahoff also provides an explanation of the USP Rider, which is replacing the existing CAP Rider, the new proposed Storm Expense Rider, and proposed new Rate EV – Electric Vehicle Charging.

Nicole McKinney (UGI Electric Statement No. 9) is Manager, Tax and Regulatory Accounting at UGI. Ms. McKinney addresses 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 ratemaking treatment of the impact of the Company's repairs tax method election on federal and state income taxes, and issues pertaining to UGI Electric's participation in a consolidated group for federal income tax purposes. Ms. McKinney, however, does not initially address the impact of the recently enacted federal tax law changes as the impact of these changes on UGI Electric is still under review and analysis. The Company anticipates filing Supplemental Direct Testimony at a later date to address the impact of these tax law changes on UGI Electric.

V. <u>MANAGEMENT PERFORMANCE AND RECOGNITION</u>

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>A PA PUC-approved LTIIP</u>. This plan was filed voluntarily by the Company and included a detailed accelerated infrastructure replacement plan focused on improving, replacing or repairing aged infrastructure, such as poles, underground conductor, transformers and circuit breakers. The elements of the LTIIP are further explained in the testimony Mr. Sorber (UGI Electric Statement No. 3).
- <u>High standards for electric reliability</u>. UGI Electric is performing above the PA PUC established Benchmark levels for maintaining service reliability. As reported in the PA PUC's *Electric Service Reliability in Pennsylvania* report for 2016, 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 26.0%, 24.1% and 44.3% better than Benchmark levels, respectively. These performance levels ranked UGI Electric 1st, 3rd and 2nd respectively in

exceeding CAIDI, SAIFI and SAIDI Benchmark levels among all Pennsylvania EDCs.

- An Energy Efficiency and Conservation Plan. While not required under Act 129, the Company filed Phase I of this voluntary plan in 2010 in response to a PA PUC Secretarial Letter encouraging voluntary plans. This plan was approved and became effective in 2012. On April 9, 2015, the Company filed Phase II of this voluntary plan which was approved on June 9, 2016 at Docket No. M-2015-2477174, and this Phase II plan was subsequently extended until May 31, 2019. The Company's Energy Efficiency and Conservation Plan provides education and incentives to UGI Electric customers to encourage the efficient use of electricity and incents smart appliance purchase decisions.
- A new state-of-the-art Customer Information System. As part of Phase 1 of UGI's UNITE initiative, discussed in detail later in my testimony, UGI Electric now has in place a new CIS that allows for the Company to provide customers with greater levels of service quality, information availability and around the clock accessibility. This new system went "live" for all of the UGI operating companies on September 4, 2017. Importantly, this CIS upgrade project was completed on-time and on-budget, marking a significant achievement for both UGI and all of UGI's customers.

- Continued information technology system replacements. UGI has begun Phase 2 of its UNITE initiative, with a plan to replace its aged and outdated financial systems. UNITE Phase 2 is scheduled for completion and go-live in April 2019 and will provide improved system capability related to capital activity tracking and recording, as well as financial system support.
- Electric vehicle support. UGI Electric is proposing a new Rate EV (Electric Vehicle Services) in this rate case filing. It is designed to support and promote the expanded growth of electric vehicles within the Company's service territory by offering charging equipment rates that will support electric vehicle charging infrastructure build-out. Rate EV is further explained in the testimony of Mr. Lahoff (UGI Electric Statement No. 8).
- Top-tier customer satisfaction. UGI has finished in first or second place in the J.D. Power award for customer satisfaction among utilities in each of the last 5 years, and has won the award a total of 7 times (2003-2007, 2013, 2014) since UGI was first included in the survey in 2003 by J.D. Power. UGI Electric's customers receive the same call center customer service experience as the other regulated UGI affiliates.
- A safety focus. UGI has developed and implemented numerous safety improvement initiatives designed to reduce or prevent injuries and motor vehicle accidents. These initiatives include pursuing

Occupational Safety and Health Administration verification of a Voluntary Protection Program, a First Move Forward policy, a 360-degree "cone" policy, a "Making a Difference" safety program, use of dash-cams to record and review incidents or close-calls, Smith Driving School training, an annual Safety Summit involving all employees, establishing safety committees for accident analysis and review, and Company-wide education and appropriate employee coaching and engagement tracks.

- A company-wide focus on efficiency and effectiveness. UGI has launched a Company-wide initiative, UGI-1, which is aligning UGI people, processes and tools to drive additional efficiencies and effectiveness across the organization, including the implementation of new state-of-the-art customer information, work management and other supportive systems. A more detailed review of UGI-1 is provided later in my testimony.
- Universal Service offerings. In its most recent triennial review at Docket No. M-2013-2371824, UGI Electric received approval from the Commission to implement several new components to its Universal Service Programs that have assisted low-income customers by eliminating the maximum level of low-income customers that can be served under the Company's Customer Assistance Program ("CAP"). Also, UGI Gas agreed as part of a Commission-approved settlement in the UGI Gas 2016 base rate case at Docket No. R-2015-2518438, and in UGI PNG's 2017 base rate case at Docket No. R-2016-2580030 to

implement certain customer service-focused practices and procedures. As UGI manages Customer Operations collectively, these changes have also been implemented for UGI Electric customers. Moreover, UGI Electric formally incorporated these revisions in its Universal Service and Energy Conservation Plan filing for the period of January 1, 2018 through December 31, 2020 submitted on June 30, 2017 at Docket No. M-2017-2598190. The filing is currently pending before the PA PUC.

- Lowest rates. As noted earlier in my testimony, UGI Electric's rates are among the lowest in the state. These low rates have provided significant value for UGI Electric's customers for years. Even with the proposed rate increase, UGI Electric's distribution rates will still be among the lowest in the Commonwealth.

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. The Company believes that the management efforts described above and the other improvements described by the UGI Electric witnesses in this proceeding support an additional upward adjustment to the Company's rate of return in recognition of its management effectiveness. This recognition of UGI Electric's management effectiveness is included in the 10.95% equity return requested by the Company and discussed in the testimony of Mr. Moul (UGI Electric Statement No. 5).

Q. Does UGI Electric play a constructive role in the communities it serves?

A. Yes, as part of the family of UGI distribution companies, UGI Electric shares in providing community support. For example, UGI: invests more than $1.5 million annually to support education improvement programs across the Company service territory, including $250,000 in the overlapping UGI Electric and UGI PNG service territories; supports pre-K, childhood literacy, enhanced "STEM" (science, technology, engineering and math) curriculum in elementary schools; provides funding for technical training programs for high school students; and participates in programs that provide support and mentoring for women and minority engineering school students.

UGI employees also commit significant personal time and resources to support community initiatives. For example, UGI Electric employees donated more than 1,900 hours to assist their communities in 2016. UGI Electric employees also donated personal funds to better their communities, including $5,800 contributed to the Company's 2017 United Way campaign. Combined with Corporate contributions, total support provided to United Way agencies serving communities in the UGI Electric Division service territory in 2017 totaled more than $43,800.

VI. UGI-1 INITIATIVE INCLUDING UNITE SYSTEMS MODERNIZATION

Q. Please describe the UGI-1 and UNITE initiatives in more detail.

A. UGI-1 is a company-wide improvement initiative focusing on people, tools and processes. UGI Electric and its utility affiliates have a history of pursuing excellent performance for its customers, employees and shareholders. Moving forward, the Company plans to build on this past performance and provide even better service in the future. Over the past few years, UGI Electric has developed a focus on distribution system modernization. In support of these modernization activities, UGI Electric is taking advantage of synergies where possible, equipping employees for future success, improving communications throughout the organization and driving greater management effectiveness, all under the umbrella of the UGI-1 initiative focused on people, processes and tools.

With regard to people, UGI Electric has reviewed resource needs and either provided fill-in where gaps have been identified, as was the case when the Company recently hired a dedicated safety manager, or is proposing fill-in to occur by the end of the FPFTY. Mr. Sorber discusses these incremental personnel additions in UGI Electric Statement No. 3.

With regard to process, UGI-1 includes a number of fundamental improvement efforts, including such programs as: UGI Electric's "Making a Difference" safety improvement program; the migration of all employee computer workstations to a set of common workplace applications; UGI Electric facilities modernization and consolidation improvements; an enhanced focus on physical and cyber security; a range of enhanced and expanded employee development and training programs; and the system improvements which are or will be part of the UNITE technology improvement project.

When it comes to tools, the centerpiece of UGI-1 is the UNITE technology improvement project. UNITE is a multi-phased program that was launched to address current business and technology opportunities for improvement. UGI's current fragmented technology and business processes have resulted in improvement opportunities for operational capabilities and efficiencies. The

UNITE program focuses on replacing UGI's core technology systems, improving business information to make better informed decisions, and reducing the number of duplicate business processes across UGI. UNITE includes strategic objectives to build systems that are scalable for growth and increase flexibility to adapt to new business practices. UNITE also focuses on operational efficiency by: standardizing and adopting common industry-leading electric and gas modern processes; automating manual, time consuming processes; and retiring legacy mainframe equipment. UNITE further includes appropriate risk management tools that focus on (a) reducing risks associated with aging infrastructure and reliance on institutional knowledge and (b) regulatory and compliance risks.

Phase 1 of UNITE focused on replacing UGI's current legacy customer service and meter management systems that have been in place for nearly forty years. These systems contained numerous manual-based customer service and billing processes that were not standardized across each of the UGI's companies and limited the ability to integrate new technologies for evolving customer needs. UNITE Phase 1 was completed early September 2017 with a cut-over to a new CIS. The specific benefits of the UNITE CIS replacement included improving the customer experience by offering a consistent and complete customer experience via multiple interaction channels (web, mobile, IVR, phone) and supporting and promoting strong customer adoption (self service). UNITE CIS also strengthens internal capabilities by: enabling powerful system performance with manageable exceptions; facilitating impactful user adoption and readiness; enabling business intelligence and intuitive reporting; implementing standardized; efficient electric and gas practices with minimal tailoring; and retiring the legacy mainframe applications.

UNITE Phase 2 will be focused on the replacement of UGI's existing 10-year old Oracle Financials systems. UNITE Phase 2 will address key business processes within financial and capital records management such as Procure-to-Invoice, Invoice-to-Pay, Record-to-Report and Acquire-to-Retire (Fixed Assets).

Q. How do all of the changes envisioned by UGI-1 benefit customers?

A. The overall goal of UGI-1 is to place all of UGI's operations on a common set of information systems, tools, equipment, and uniform work management and performance platforms. This will allow UGI to become more efficient and effective in performing all aspects of its business, including: handling calls from customers; performing billing and related activities; constructing new distribution facilities and repairing; replacing and improving aging distribution facilities; and managing emergencies and outage events.

Q. Please provide some examples of the operational benefits that are being derived from the UGI-1 initiative.

A. Mr. Sorber (UGI Electric Statement No. 3) provides an overview of UGI Electric's initiatives that focus on safety, reliability and operational efficiency and effectiveness. The initiatives are focused on improving consumer value in areas related to safety, reliability, service satisfaction and efficient electric usage.

For example, UGI Electric's focus on distribution system sectionalizing as part of its distribution system automation focus will allow for more timely identification of outage locations and allow for remote sectionalizing, which will decrease restoration times compared to historical outage management performance. Also, as part of UGI's UNITE Phase 1 CIS initiative, recently approved tariff provisions for UGI Electric and UGI PNG have allowed for the roll-out of joint billing of electric and natural gas services on one bill for UGI customers who receive both electric and gas service from UGI. This joint billing of electric and natural gas service provides greater customer convenience and customer satisfaction for customers of UGI Electric and UGI PNG. Moreover, this new system supports key customer Choice business processes, including seamless moves, instant connects and 3-day switching, which have been designed to foster greater participation in shopping for power suppliers.

UNITE has addressed a number of other objectives including: reducing operational risks related to the age of certain applications where there is no vendor support and the people who know the systems best are retiring; improving operational capabilities with new "scalable" technology platforms; standardizing and reducing the number of systems and duplicate processes across UGI; improving business information to make more informed business decisions; and gaining efficiency related to process and system integration.

Additionally, UGI's new SAP customer information system is allowing UGI Electric to better manage and support customer relationships. For example, the new customer information system offers greater self-service web functions that are available 24/7 and supports mobile platforms.

VII. SUMMARY OF FILING

Q. Please summarize the Company's filing.

A. UGI Electric is requesting a rate increase of $9.254 million. This increase represents an increase in total revenues of 10.4%. Notably, a key driver of this rate increase relates to the repair, replacement and improvement of aged and aging distribution system assets. In addition, UGI and UGI Electric have invested and will continue to invest in facilities and information system modernization initiatives, as well as personnel resources, which will support the continued provision of safe and reliable electric distribution service to the Company's approximately 62,000 customers. The Company's requested return on equity is 10.95%, which is inclusive of recognition for management performance, will allow the Company a fair opportunity to earn a reasonable return on rate base, which is projected at over $100 million. Lastly, even with the requested rate increase, UGI Electric will still maintain the one of the lowest residential electric distribution rates in the Commonwealth.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC EXHIBIT PJS-1

PAUL J. SZYKMAN

CHIEF REGULATORY OFFICER

May 2017 – Present	Chief Regulatory Officer UGI Utilities, Inc., Reading, PA
2015 – April 2017	Vice President – Rates & Government Relations Vice President & General Manager – Electric Utilities UGI Utilities, Inc., Reading, PA
2014 – 2015	Vice President – Rates & Government Relations UGI Utilities, Inc., Reading, PA
2008 – 2014	Vice President – Rates UGI Utilities, Inc., Reading, PA
2003 – 2008	Director, Rates & Gas Supply UGI Utilities, Inc., Reading, PA
2001 – 2003	Manager, Rates & Strategic Planning UGI Utilities, Inc., Reading, PA
1999 – 2001	Manager, Federal Regulatory Affairs & Contract Admin. UGI Utilities, Inc., Reading, PA
1999 – 1999	Principal AMS, Fairfax, VA
1996 – 1999	Manager, Rates & Strategic Planning UGI Utilities, Inc., Reading, PA
1994 – 1996	Supervisor, Transportation UGI Utilities, Inc., Reading, PA
1991 – 1994	Rate Designer UGI Utilities, Inc., Reading, PA
1989 – 1991	Market Research Analyst UGI Utilities, Inc., Reading, PA
1986 – 1989	Industrial / Commercial Representative UGI Utilities, Inc., Reading, PA
1981 – 1985	Penn State University B.S. Mechanical Engineering

Previous testimony before the Pennsylvania Public Utility Commission at Dockets:

R-00932927	UGI Utilities, Inc. – Gas Division; Restructuring (Supplement 91)
R-00016376	UGI Utilities, Inc. – Gas Division; Stroehmann Bakeries
P-00032043	UGI Utilities, Inc. – Gas Division; Granger Energy
P-00032054	UGI Utilities, Inc. – Gas Division; Modification of Security Requirements
R-00049422	UGI Utilities, Inc. – Gas Division; Purchased Gas Cost 1307(f)
R-00050539	UGI Utilities, Inc. – Gas Division; Purchased Gas Cost 1307(f)
R-00061502	UGI Utilities, Inc. – Gas Division; Purchased Gas Cost 1307(f)
R-00072334	UGI Penn Natural Gas; Purchased Gas Cost 1307(f)
R-00072335	UGI Utilities, Inc. – Gas Division; Purchased Gas Cost 1307(f)
R-2008-2039284	UGI Penn Natural Gas; Purchased Gas Cost 1307(f)
R-2008-2039417	UGI Utilities, Inc. – Gas Division; Purchased Gas Cost 1307(f)
R-2008-2079675	UGI Central Penn Gas; Base Rate Case
R-2008-2079660	UGI Penn Natural Gas; Base Rate Case
R-2009-2105911	UGI Utilities, Inc. – Gas Division; Purchased Gas Cost 1307(f)
R-2009-2105904	UGI Penn Natural Gas; Purchased Gas Cost 1307(f)
R-2009-2105909	UGI Central Penn Gas; Purchased Gas Cost 1307(f)
R-2010-2214415	UGI Central Penn Gas; Base Rate Case
R-2015-2518438	UGI Utilities, Inc. – Gas Division; Base Rate Case
R-2016-2580030	UGI Penn Natural Gas; Base Rate Case

UGI ELECTRIC STATEMENT NO. 2 –
STEPHEN F. ANZALDO

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2017-2640058

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 Act 40 of 2016**

Dated: January 26, 2018

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. Stephen F. Anzaldo, 2525 North 12th Street, Reading, Pennsylvania 19612-2677.

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") as well as two wholly-owned subsidiaries, UGI Central Penn Gas, Inc. ("UGI CPG") and UGI Penn Natural Gas, Inc. ("UGI PNG"), each of which are regulated as public utilities 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 the utility business unit rate and regulatory filings before federal and state regulatory commissions, as well as the central coordination of regulatory planning for all UGI utility operating companies. In this capacity I report directly to the Chief Regulatory Officer of UGI. On behalf of the Rates Department, I am responsible for budgeting/financial planning for UGI Electric, which is a joint effort with the Rates Department preparing the revenue and margin portion and the Financial Planning and Analysis Department preparing the operating and capital budget sections.

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, 2017 ("HTY"), future test year ending September 30, 2018 ("FTY") and the fully projected future test year ending September 30, 2019 ("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 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 (Megan Mattern, UGI Electric Statement No. 4), operating revenue (David Lahoff, UGI Electric Statement No. 8), fair rate of return (Paul Moul, UGI Electric Statement No. 5), depreciation expense

(John Wiedmayer, UGI Electric Statement No. 7), and tax adjustments (Nicole McKinney, UGI Electric Statement No. 9). I am also sponsoring those responses to the Commission's filing requirements and standard data requests where my name is indicated as the sponsoring witness.

II. 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 for the FPFTY ending September 30, 2019, including principal accounting exhibits, 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, 2019. UGI Electric Exhibit A (Future) is the principal accounting exhibit for the FTY ending September 30, 2018, 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, 2018. UGI Electric Exhibit A (Historic) is the principal accounting exhibit for the HTY ended September 30, 2017, with appropriate ratemaking adjustments. The HTY information is derived from the book accounting data for the 12-months ended September 30, 2017. The FTY and HTY schedules are provided as a benchmark for comparison with the FPFTY claim, which as explained above is the basis for UGI Electric's proposed revenue increase.

The Company's 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 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). This presentation is comprised of four sections:

Section A summarizes UGI Electric's requested rate base, revenues, and expenses at present rates and the calculation of its requested revenue increase.

Section B 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, and 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, 2017, and the fiscal year ending September 30, 2018, 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 the UGI Electric's books and records, and capital and operating budgets. UGI Electric Exhibit A (Future) is based on adjusted budgeted data for the year ending September 30, 2018. UGI Electric Exhibit A (Historic) is based on adjusted experienced data for the year ended September 30, 2017.

III. BUDGETING PROCESS

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, 2017 through September 30, 2018 fiscal year was prepared in the spring of 2017.

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. 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, new or changed programs, and inflation. 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 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 and Chief Executive Officer of the Company 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 responsible for that 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.

The UGI Electric Capital Budget is prepared in conjunction with the Operating Budget. 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 priorities, 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).

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 assumptions concerning growth in numbers of customers. Similarly, FTY budget expense amounts are adjusted for salary and personnel increases, known program changes and expense needs, and inflation. 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 also 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 Corporation, 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 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. Activity is measured by total revenues and total operating expenses and size is measured by tangible net assets employed (excluding acquisition goodwill).

Q. Do you believe that the charges incurred by UGI Electric under these agreements are reasonably determined?

A. Yes. These arrangements and the methods used to allocate the costs to the companies receiving service have been reviewed by the Commission in various management audits of UGI Electric, the most recent of which was the Focused Management and Operations Audit of UGI Utilities, Inc., prepared by the PUC's Bureau of Audits, issued in April of 2012, at Docket No. D-2011-2221061 ("Audit Report"). The Audit Report found UGI Corporation's and UGI Utilities' cost allocation methods to be reasonable and appropriate. Audit Report at p. 26. Additionally, in response to a more recent Management Efficiency Investigation of UGI Utilities, at Docket No. D-2015-2473202, UGI Utilities accepted and implemented certain recommendations regarding allocation of costs.

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 have been assigned and/or allocated between the FERC and PUC jurisdictions, and the proposed revenue increase has been determined on a PUC jurisdictional basis. Revenue in the amount of $5 million related to transmission revenue was adjusted and removed from this filing. In addition, expenses related to the transmission operations were also adjusted and removed from this filing. Please see Exhibit SFA-2 pages 1 through 3 for the summary statements of Operating Income before Federal and State Income Taxes, which will tie to Schedule B-2 for the test periods presented.

IV. 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 4 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 8.07%. 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 8.07%.

Q. What is the overall requested increase in revenue?

A. The overall requested increase in revenue is $9.254 million. This represents the difference between the *pro forma* FPFTY revenue requirement of $98.188 million and the annual level of operating revenues of $88.934 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 David E. Lahoff (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, 2019. 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, 2017 and 2018, 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 David E. Lahoff (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 $9.254 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 $8.338 million. This represents a $5.035 million increase from the level under current rates ($3.303 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, 2019. 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 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 schedules D-5a and D-5b) and D-6 and discussed in the direct testimony of witness David E. Lahoff (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 17-55. The details for these adjustments are found in Schedules D-4 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 any other revenue adjustments being shown on D-5B.

A. Schedule D-5(B) shows a $78,000 increase to Rent from Electric Properties to normalize the revenue billed and collected to outside parties for attachments to its utility pole infrastructure as presented in the FPFTY.

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

A. Schedule D-7 shows a $34,000 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 increase 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 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. What adjustments are shown on Schedule D-8?

A. The adjustment is designed to enable the Company to fully recover its Environmental remediation expense incurred for excavation, loading, transportation and disposal services at the UGI Electric site in Forty Fort, Pennsylvania. UGI Electric proposes to amortize the costs over a three-year period, at an annual cost of $139,000. Company witness Eric W. Sorber (UGI Electric Statement No. 3) elaborates on this expense in his direct testimony.

Q. Please discuss Schedule D-9, which shows an adjustment for payroll and benefits expense attributed to an assortment of employee related costs.

A. The adjustment for employee additions shown in Schedule D-9 is made up of payroll changes that were not factored into the Company's FPFTY budget and total $494,000 for three additional support personnel. These three positions will support both the Company's distribution and transmission functions. The portion of the additional payroll expense for these three new positions allocated to Distribution Operations is 77.4428%, which equals $382,000. The direct testimony of Company witness Eric W. Sorber (UGI Electric Statement No. 3) supports the need for these three additional positions.

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 $676,000. That amount is then normalized over a three-year period reflecting the expected period between future base rate case filing. The rate case expense is incurred in the FTY, but is not budgeted in the FPFTY. The FPFTY budget therefore was increased by $225,000 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 Program.

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

A. Schedule D-11 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 2015 to 2017. 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 1.107 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 $978,000 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 $785,000 as shown on line 5. The 1.107 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.

Q. Please discuss Schedule D-13, which shows an adjustment to Storm Damage Expense.

A. The Company is proposing to add a Storm Expense Rider (SER) to its Proposed Tariff Pa. P.U.C. No. 6. As explained in the direct testimony of David E. Lahoff (UGI Electric Statement No. 8), the SER Rider is a reconcilable rider that will recover or refund qualified storm damage expenses incurred by the Company that are not otherwise currently recovered through its base rates. Qualifying expenses from major storm events occurring during the period 2013 through 2017, total $1.773 million. To determine the amount of qualified storm expenses that will be recovered through base rates, the Company normalized these qualifying expenses over a five-year period with a portion allocated to transmission operations, which resulted in a total of $275,000 for storm expenses that will be recovered through base rates as shown in Schedule D-13.

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

A. The adjustment shown on Schedule D-14 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 Corporate and UGI Utilities' pension expense that is included in the expenses allocated to UGI Electric.

Q. Please discuss the *pro forma* adjustment on Schedule D-15 for Membership Fees.

A. The Company budgeted the full amount of the anticipated expenses for the Edison Electric Institute, the Energy Association of Pennsylvania and other related membership expenses. A portion of these industry association fees relate to lobbying activities and are excluded from UGI Electric's membership expense claim. The amount on line 1, equal to $71,000, represents the portion of membership expenses for lobbying activities budgeted in the FPFTY that is not being claimed in this case. Otherwise, these memberships provide the Company and its customers with operational, customer service, and other service related benefits.

Q. Please explain the adjustment for Distribution Expense on Schedule D-15 identified as Inspection, Replacement, and Transfer of currently Company--owned Services?

A. The amount shown in D-15 in the amount of $314,000 reflects an increase in operating expenses in excess of the budgeted amount attributable to an accelerated inspection, replacement, and transfer of Company-owned service panels and related equipment. Company witness Eric W. Sorber (UGI Electric Statement No. 3) discusses this accelerated inspection and replacement program in his direct testimony.

Q. The next adjustment on Schedule D-15 shows a $57,000 cost item for Interest on Customer Deposits at line 18. 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 average level of customer deposits anticipated for the FPFTY ($1.419 million) times the required interest rate (4 percent) anticipated for the FPFTY, as published by the Pennsylvania Department of Revenue and required under the Company's tariff.

Q. Please explain the adjustment for Licensing Fees related to UNITE Phase 2shown on Schedule D-15 in the amount of $91,000.

A. This amount represents UGI Electric's allocable portion of annual recurring fees related to Phase 2 of UGI's Next Information Technology Enterprise ("UNITE") system replacement project. Since the budget was developed for 2019, the Company has identified additional annual licensing fees. UNITE Phase 2 is expected to be implemented during the FPFTY and costs are based on vendor supplied quotes.

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

A. This adjustment in the amount of $331,000 is needed to reflect the expense related to UGI Electric's Universal Service programs previously subject to recovery through UGI Electric's base rates but will be recovered through UGI Electric's Universal Service Surcharge on a prospective basis, consistent with the recovery method for such expenses approved for UGI Gas, UGI PNG and UGI CPG. Please see the direct testimony of David E. Lahoff (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 ($1.025) million 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 $1.933 million is to adjust the Power Supply Expense for the normalized and annualized use per customer. This adjustment is designed to increase power supply expense (net of Gross Receipts Tax) in order to match power supply revenue at current December 1, 2017 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 David E. Lahoff (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 is needed to reflect the incremental expense related to the Company's EE&C program. The Company's Phase II EE&C program received PUC approval at Docket No. M-2015-2477174.

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, 2019 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 presents the depreciation analysis that serves as the foundation of the depreciation adjustment. The adjustment for depreciation expense of $546,000 set forth on Schedule D-21, column 3, is designed to annualize budgeted FPFTY depreciation expense in order to calculate an entire year's worth of depreciation on plant in service as of the end of the FPFTY, ending September 30, 2019. This schedule also shows an increase to the net negative salvage amortization of $85,000. The total annualized depreciation expense for the FPFTY, net of costs charged to clearing accounts and net salvage amortization, is $635,000 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 $352,000 on line 1 provides for a pro forma tax expense of $449,000. The valuation is based on the 2016 Notice of Determination dated August 1, 2017 for UGI Utilities, Inc. The total PURTA liability per this notice is $2.496 million with 18% allocated to the Electric operations resulting in the $449,000. Line 2 provides an adjustment to the Gross Receipts tax in the amount of ($1.025) million 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 $68,000. 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 Paul R. 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.

V. ACT 40 REQUIREMENTS

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

A. Yes, I understand that the legislation, among other things, eliminated the use of consolidated tax savings adjustments for setting rates for public utilities in Pennsylvania, but requires a utility to demonstrate that at least 50 percent of what otherwise would have been the revenue requirement associated with a consolidated tax savings adjustment is used to support reliability or infrastructure related to the rate-base eligible capital investment and the other 50 percent must 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 level of a consolidated tax savings adjustment for UGI Electric under ratemaking prior to the enactment of Section 1301.1 of the Public Utility Code?

A. Yes, Company witness Nicole McKinney presents such a calculation in her testimony, UGI Electric Statement No. 9 wherein she determines that the amount of consolidated tax savings adjustment applicable to UGI Electric would have been $41,000. Applying the gross revenue conversion factor to that amount of tax expense results in a revenue requirement of $75,400.

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 reliability or infrastructure related capital investment?

A. Yes, as shown in Schedule C-2 and as discussed in the direct testimony of Eric Sorber (UGI Electric Statement No. 3), UGI Electric's *pro forma* capital additions for reliability or infrastructure projects in the FTY is $10.950 million and for the FPFTY is $11.770 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 consolidate tax adjustment. Indeed, the Company anticipated an operating expense budget of more than $81 million in operating expenditure to be used to render electric distribution service; 50 percent of the consolidated tax adjustment revenue requirement would equate to only $37,700.

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., Reading, PA
2011 – 2013	Director – FP&A, Mid-Atlantic Region America Water 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

Default Service Plan:	Docket Nos. P-2016-2543523, G-2016-2543527

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, 2017		
	TOTAL T&D OPERATIONS	LESS: FERC JURISDICTIONAL	PA PUC JURISDICTIONAL
Operating Revenues:			
Electric Revenues	$ 81,689	$ -	$ 81,689
Other Electric Revenues	6,845	5,779	1,066
Total Operating Revenues	88,534	5,779	82,755
Operating Expenses:			
Operation and Maintenance Expenses			
Power Production Expenses	46,019		46,019
Transmission Expenses	2,084	2,084	-
Distribution Expenses	6,957	-	6,957
Customer Accounts Expenses	4,553	-	4,553
Customer Service & Informational Expenses	1,733	-	1,733
Sales Expenses	32	-	32
Administrative and General Expenses	7,996	1,804	6,192
Total Operation and Maintenance Expenses	69,374	3,888	65,486
Depreciation and Amortization Expenses	4,975	1,186	3,789
Taxes Other Than Income Taxes	5,576	136	5,440
Total Operating expenses Prior To Federal & State Income Taxes	79,925	5,210	74,715
Operating Income Prior To Federal & State Income Taxes	$ 8,609	$ 569	$ 8,040

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

	AS OF SEPTEMBER 30, 2018		
	TOTAL T&D OPERATIONS	LESS: FERC JURISDICTIONAL	PA PUC JURISDICTIONAL
Operating Revenues:			
Electric Revenues	$ 86,125	$ -	$ 86,125
Other Electric Revenues	6,082	5,146	936
Total Operating Revenues	92,207	5,146	87,061
Operating Expenses:			
Operation and Maintenance Expenses			
Power Production Expenses	47,005		47,005
Transmission Expenses	2,223	2,223	-
Distribution Expenses	7,274	-	7,274
Customer Accounts Expenses	4,988	-	4,988
Customer Service & Informational Expenses	2,075	-	2,075
Sales Expenses	57	-	57
Administrative and General Expenses	8,792	1,983	6,809
Total Operation and Maintenance Expenses	72,414	4,206	68,208
Depreciation and Amortization Expenses	5,964	1,908	4,056
Taxes Other Than Income Taxes	7,680	274	7,406
Total Operating expenses Prior To Federal & State Income taxes	86,058	6,388	79,670
Operating Income Prior To Federal & State Income Taxes	$ 6,149	$ (1,242)	$ 7,391

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

	AS OF SEPTEMBER 30, 2019		
	TOTAL T&D OPERATIONS	LESS: FERC JURISDICTIONAL	PA PUC JURISDICTIONAL
Operating Revenues:			
Electric Revenues	$ 86,243	$ -	$ 86,243
Other Electric Revenues	6,082	5,146	936
Total Operating Revenues	92,325	5,146	87,179
Operating Expenses:			
Operation and Maintenance Expenses			
Power Production Expenses	47,160		47,160
Transmission Expenses	2,272	2,272	-
Distribution Expenses	7,505	-	7,505
Customer Accounts Expenses	4,870	-	4,870
Customer Service & Informational Expenses	2,005	-	2,005
Sales Expenses	59	-	59
Administrative and General Expenses	8,881	2,004	6,877
Total Operation and Maintenance Expenses	72,752	4,276	68,476
Depreciation and Amortization Expenses	6,484	1,456	5,028
Taxes Other Than Income Taxes	7,706	280	7,426
Total Operating expenses Prior To Federal & State Income taxes	86,942	6,012	80,930
Operating Income Prior To Federal & State Income Taxes	$ 5,383	$ (866)	$ 6,249

UGI ELECTRIC STATEMENT NO. 3 – ERIC W. SORBER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2017-2640058

UGI Utilities, Inc. – Electric Division

Statement No. 3

Direct Testimony of
Eric W. Sorber

Topics Addressed:	**System Operations**
	System Reliability and Safety
	Capital Planning
	Certain Budget Adjustments

Dated January 26, 2018

I. INTRODUCTION

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 as Director Engineering and Operations, by UGI Utilities, Inc. ("UGI").

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 Director Engineering and Operations?

A. As Director Engineering and Operations, I provide leadership for engineering, operations, and technical services functions for the UGI Utilities, Inc. - Electric Division ("UGI Electric" or the "Company"), a certificated electric distribution company ("EDC"). I report directly to the Chief Operations Officer ("COO") and assist the COO in budgeting and capital planning for UGI Electric and development of 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 & standards; (3) substation; (4) planning and compliance; and (5) safety.

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: (1) UGI Electric's system operations; (2) UGI Electric's system reliability and safety record; (3) capital planning; and (4) support for certain UGI Electric budget adjustments.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following 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.

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. The UGI Electric service territory is mainly rural, with urban areas located on the outskirts of Wilkes Barre. UGI Electric owns, operates and maintains over 1,200 circuit miles of overhead and underground primary distribution lines; twelve distribution substations; and forty-nine distribution circuits. In addition to distribution facilities, UGI Electric owns and operates one Bulk Electric System substation and over 126 miles of transmission lines. UGI Electric is a member of the PJM Interconnection LLC ("PJM"), which is a regional transmission organization, and sits on the PJM Transmission Owners Agreement-Administrative Committee.

Included in UGI Electric's facilities are approximately 16.5 miles of double circuit 230 kV high voltage electric transmission lines. The costs associated with owning and operating these 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. The costs associated with these transmission 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 maintains one main office location at One UGI Center in Wilkes Barre, which houses the bulk of the Company's employees, including: operations management, engineering, clerical and a number of field personnel. UGI Electric also maintains a combined warehouse and linemen service center location in Forty Fort, a substation service center in Hanover Township, and a System Operations control center in Edwardsville, Pennsylvania.

Q. How does UGI Electric staff its operations?

A. As of September 30, 2017, UGI Electric had a total of sixty-eight full-time positions with the following job descriptions:

- 1 – Director
- 4 – Managers
- 17 – Engineers/Technicians
- 7 – Supervisors
- 7 – Clerical/Admin/Support
- 6 – System Operators
- 1 – Safety/Training
- 25 – Union (10 linemen, 5 substation, 4 meter shop, 5 meter service, 1 warehouse)

UGI Electric also receives executive, regulatory, safety and accounting and budget support from UGI Utilities personnel outside of the Electric Division. UGI Electric also benefits from management and support services provided by the parent company of UGI Corporation (*e.g.*, insurance, legal, treasury operations, and corporate governance).

Finally, as described below, UGI Electric plans on adding certain additional personnel by December 1, 2018.

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

A. Due to its long-term operation, the UGI Electric distribution system has evolved to keep up with increasing customer demand and efforts to improve system reliability. The distribution system is comprised of twelve 66-13.8 kV substations that source forty-nine 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 in the event of an equipment failure or a main line distribution failure. Typical wood pole construction serves as the primary method for extending the distribution system throughout the UGI Electric service territory. The distribution system is predominantly overhead making up approximately 88% of the total primary system. UGI Electric distribution assets range in age from 20 to 70 years. To address aging distribution assets and the associated potential reliability and safety issues, UGI Electric has implemented targeted repair and replacement programs for key assets, such as wood poles, distribution substation transformers and underground residential primary cable.

Q. Please discuss UGI Electric's key replacement programs.

A. UGI Electric, like other utilities, faces an aging infrastructure challenge affecting key system components. UGI Electric's key replacement programs are reflected in its Long-Term Infrastructure Improvement Plan ("LTIIP") recently approved by an Opinion and

Order of the Commission entered on December 21, 2017 at Docket No. P-2017-2619834. These LTIIP programs include: (1) wood pole replacement; (2) distribution substation transformer replacement; and (3) underground cable replacement.

UGI Electric has over 45,000 wood distribution poles with an average age of forty years and a population of 14,000 poles older than fifty years. UGI Electric relies on a pole 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, resulting in less than thirty pole replacements/reinforcements per year. Subsequent inspections years have seen 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 in 2016 targeting 150 to 200 poles per year, specific to the inspection program. This pole replacement program was included in the approved UGI Electric LTIIP.

A second major replacement program involves substation transformers. UGI Electric has nineteen 66-13.8 kV transformers with an average age of forty-two years, including thirteen transformers exceeding forty years. These substation transformers are a major component of the distribution system with significant reliability impacts and long lead time replacement. Due to their criticality and the balance of units beyond forty years, UGI Electric included substation transformers in the approved LTIIP with a replacement schedule of one transformer per year.

UGI Electric also accelerated replacement of underground residential development (URD) primary cable beginning in 2016. UGI Electric still has a significant amount of direct buried bare concentric neutral (non-jacketed) cable originally installed throughout the late 1970's and 1980's, which experience the highest frequency of cable failures and neutral degradation. The accelerated replacement of this cable is expected to continue as outlined in the LTIIP with the goal of replacing the majority of the direct buried cable in the next five to six years with a modern, fully insulated and jacketed underground cable, installed in conduit, with an expected life of approximately thirty years.

Q. Are there any new system-wide initiatives that UGI Electric is undertaking to improve system reliability?

A. Yes. UGI Electric has several system-wide initiatives aimed at improving system reliability. These capital projects are included in the UGI Electric LTIIP. The first, Distribution Automation, primarily involves the installation of communication assisted reclosers that provide for remote monitoring and control to aid with more efficient and accurate identification of system anomalies and restoration of service. A second key initiative involves Major System Improvement Projects. These sometimes-multi-year projects are focused on the creation of new inter-substation tie-lines, reconductoring to add capacity and to replace multi-splice conductors, and the development of new feeders to service existing and future load providing contingency switching options. A third program is for the installation of additional distribution sectionalizing through the use of more traditional isolation devices such as disconnects, air-breaks and fuses. These devices are used to either limit the initial number of customers exposed to an outage, or to sectionalize and quickly restore, post fault, a greater number of customers without having to wait on repairs. UGI Electric began this program in 2013 with over 142 new devices installed to date. Finally, right-of-way reliability relocations involve the relocation of off-road distribution lines to roadside locations to reduce potential vegetation issues and/or to reduce restoration time.

III. SYSTEM RELIABILITY AND SAFETY

Q. How is UGI Electric's performance in the area of system reliability?

A. UGI Electric continues to demonstrate very good system reliability as indicated by the positive results in all reportable reliability indices. As shown on UGI Electric Exhibit EWS-2, UGI Electric has a recent history of performing better than PUC-established benchmark standards. Primary drivers for this favorable trend are UGI Electric's robust vegetation management program, relatively low equipment failure rates, and effective operational response by field crews and supervisors.

Q. What actions has UGI Electric undertaken to improve employee safety?

A. The safety program is collectively managed for UGI Utilities and its subsidiaries UGI Central Penn Gas, Inc. ("CPG") and UGI Penn Natural Gas, Inc. ("PNG") (collectively the "UGI Distribution Companies"). The UGI Distribution Companies have undertaken significant efforts to build a safety-centric culture to better support and enhance employee safety. Encouraging a safety culture is fundamental to driving safety performance.

Some of the strategies implemented to build a safety culture include, but are not limited to: performing detailed accident reviews, holding an annual Employee Safety Summit, and implementing enhancements to the employee safety incentive program. Additionally, the UGI Distribution Companies have recently taken steps to join the Voluntary Protection Plan ("VPP") program of the United States Occupational Health and Safety Administration ("OSHA").

Specific to UGI Electric, the Company maintains a dedicated electric safety and training resource, focused on enhancing electric specific safety programs to better address personnel training requirements like those contained in the Occupational Safety and Health Standards for Electric Power Generation, Transmission and Distribution, section 1910.269. Current work involves significant revisions to UGI Electric's switching and tagging, and job briefing training programs.

Q. Please describe the UGI Distribution Companies' accident review process.

A. Supervisory engagement in post-accident reviews ensures consistency in assessing causal factor trends and in implementing enterprise wide process improvements. Following each accident or injury, supervisors review and document the circumstances of the accident with the employee noting any contributing factors. On a monthly basis, supervisors of employees involved in an accident or personal injury participate in a conference call to review the circumstances surrounding each instance. The calls help drive supervisor accountability for safety performance and provide visibility to any underlying trends. UGI Electric personnel from both safety and operations also conduct, as necessary, investigations, lessons learned reviews and root-cause analyses following operational emergencies, electrical incidents, switching errors and operating instruction violations.

Q. Please discuss the UGI Employee Safety Summit.

A. In April 2017, just prior to the seasonal ramp up in construction activity, a broad cross-functional group of over 580 employees from across the UGI Distribution Companies participated in our second annual full day safety summit. The event included a wide variety of safety education sessions covering topics such as safety culture, excavation safety, dog bite prevention, and distracted driving. Employee feedback was overwhelmingly positive. In fiscal years 2018 and 2019, new groups of employees will be invited, such that the full employee population will have attended the summit over a three-year period. Going forward, additional employee-developed content will be emphasized to further cultivate employee ownership of and responsibility for safety.

Q. Please describe the UGI Safety Incentive Program.

A. In 2015, the collective UGI Safety Incentive Program was re-designed to emphasize individual employee engagement in safety. Known as "Making a Difference," the enhanced program 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. The advantages of the incentive program include simplicity of administration, customization of reward redemptions, visibility of acknowledgement, and creation of constructive competition around advancing safety. In fiscal year 2017, the third year of the program, 8,012 individual recognition cards (seventy-five specific to UGI Electric personnel) were redeemed for merchandise via an on-line store, which is a 24% increase from the 6,438 cards redeemed the year prior. In addition, in fiscal year 2017, 605 peer-nominated safety award nominations were made. The Safety Incentive Program and other specific UGI Electric safety programs, such as the Quarterly Electric Safety Breakfast that brings all UGI Electric employees together to discuss current safety initiatives and promotes an active safety discussion, are intended to move UGI Electric to an optimal end-state safety culture.

Q. Please discuss the OSHA Voluntary Protection Plan program.

A. The UGI Distribution Companies are collectively implementing the OSHA VPP. The VPP will help UGI Electric and its affiliates focus on continuous improvement of work-site-based safety and health. The structure of the program focuses on developing: (1) an effective safety and health program; (2) injury and illness rates below industry average; and (3) management and labor working together to prevent and eliminate hazards. During 2017, two of the three UGI Electric remote sites at the Forty Fort Warehouse (Warehouse) and Vine St. Electric Control Center (CC) were assessed from a VPP and condition perspective. As the CC is a new facility, only minor VPP issues were noted and fixes have been or will soon be completed. Assessment results for the Warehouse indicated the facility would require a capital investment of approximately $1.0 million to rectify identified deficiencies. The need for an investment of this magnitude, in a nearly 100-year-old facility, is one of the drivers that led UGI Electric to conclude, as discussed in more detail below, that it needed to develop a consolidated UGI Electric operations center.

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; (4) information technology; and (5) supply. The budgeting process is further described in the direct testimony of Stephen F. Anzaldo (UGI Electric Statement No. 2).

Q. How are projects chosen for inclusion in UGI Electric's capital budget?

A. Projects for the replacement and betterment of infrastructure are selected and prioritized for inclusion in the capital budget considering two key criteria: condition based replacements and reliability enhancements. In some instances, the condition of an asset has resulted in reliability issues and the subsequent replacement of the asset satisfies both criteria. Condition based enhancements are focused on the replacement of "aging infrastructure" such as poles, transformers, underground primary cable, open wire secondary and deteriorated or failed pole mounted equipment such as switches, reclosers and capacitors. Reliability enhancements are intended to incrementally address problem areas identified as worst performing circuits or reliability risk areas such as isolated load pockets. The capital strategy to address these issues includes investment in major system reinforcements to provide for additional substation feeder tie-lines, distribution automation and implementation of a highly-segmented distribution sectionalizing philosophy.

New business projects are chosen based on projections that in turn are informed by known large customers, forecasts of new business, customer counts, and construction and development in the UGI Electric service territory. Facilities projects are a prioritized set of building-related projects driven by condition, space constraints and emerging needs. Information Technology ("IT") projects are selected based on need for investment in new systems and hardware, and replacement of old systems and hardware. Capital projects of general application are budgeted by UGI and costs are generally allocated to UGI Electric in accordance with the Modified Wisconsin formula ("MWF").

Q. Please describe the risk-based prioritization process used to evaluate replacement and betterment infrastructure projects.

A. UGI Electric's risk-based prioritization process is based on a comprehensive inspection and maintenance program to identify and prioritize maintenance issues or trends which may have immediate or long-term system impact. UGI Electric's inspection programs and goals are documented in the biennial PUC Inspection & Maintenance Plan ("PUC I&M") and the Annual PUC Reliability Report. These programs include:

- 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
- Substation Circuit Breaker, Transformer & Relay Testing and Maintenance

UGI Electric's prioritization of projects for its capital budgets is consistent with its recently filed and approved LTIIP for 2018-2022.

Q. How does UGI Electric's actual capital spend compare to budgeted capital spend?

A. With respect to total distribution replacement and betterment spending, UGI Electric's spending was less than budget over the last three years. This was due to a ramp-up in the replacement and betterment budget which outpaced the ramp-up in engineering and construction resources. Total distribution replacement and betterment spending in 2016 increased by 54% versus 2015 and an additional 6% in 2017. With respect to replacement and betterment goals for fiscal year 2016 and fiscal year 2017, total capital expenditures associated with accelerated spending for wood pole and underground cable replacements were within 5% of budget for the two-year period. UGI Electric's total distribution replacement and betterment spending for the period 2014 through 2017 is provided in UGI Electric Exhibit EWS-3.

Going forward, UGI Electric anticipates that engineering and construction resources will now be in place to fully execute planned capital spending in all areas. I also note that UGI Electric's LTIIP became effective on January 1, 2018. Absent Commission approval of a modification to the LTIIP, UGI Electric will be generally required to spend up to the budgeted amount for each LTIIP repair and replacement program.

IV. SUPPORT FOR VARIATIONS FROM BASE BUDGET AMOUNTS

Q. Has UGI Electric included in its expense claim in this case the costs of additional staffing not originally included in UGI Electric's budget?

A. Yes, UGI Electric has included the costs of three additional positions. The first is for a General Manager (GM) position. This executive position will report to the UGI Utilities Inc. Chief Operating Officer, and have executive management responsibilities for UGI Electric including safety, reliability, budget, operations, engineering, construction, PJM, PUC and overall UGI Electric metrics and goals. The addition of a GM position for UGI Electric is necessary, in part, to help manage and direct the increased replacement and betterment activities associated with UGI Electric's LTIIP. The General Manager will also help manage and direct activities to comply with Commission electric safety initiatives, FERC reliability standards, PJM requirements, and activities needed to meet commercial and industrial customer requirements.

The second position is for a New Business Engineer. This position will focus on both supporting commercial and industrial accounts and will provide emerging technology support. More specifically, this position will: (a) provide a dedicated single point of contact for commercial/industrial new business customers, from initial contact through contract, design, construction and service initiation; (b) enable customer-specific support and outreach related to service enhancements and modifications, power quality, rate analysis and energy efficiency; (c) support development and installation of customer-owned distributed generation and electric vehicle ("EV") technologies; and (d) manage UGI Electric's lighting program, including the expansion of LED technology and the replacement/phase-out of existing Mercury Vapor and Metal Halide lights.

The third position is a senior position designated as a Business Support Engineer. This position will support UGI Electric in several key areas, including: (a) establishing a dedicated PUC Electric Safety Division interface; (b) consolidating and enhancing contractor administration (bidding, qualification, performance tracking, inspection and cost analysis); (c) enhancement of underground field construction inspection; (d) management and administration of Company's Service Transition Program described below; (e) management and administration of pole attachment permitting/make-ready and compliance, as well as attachment inspections and audits; and (f) compliance and reporting associated with all aspects of UGI Electric's Commission-approved LTIIP.

These three positions are expected to be filled by December 1, 2018. The additional expense associated with these positions is included in UGI Electric Exhibit A, Schedule D-9.

Q. Has UGI Electric included in its expense claim any other previously unbudgeted amounts?

A. Yes, UGI Electric has included in its expense claim an annual amount of $314,000 of previously unbudgeted expense for a Company-Owned Service (COS) Transition Program. As a result of a marketing program that ended in the early 1970s, UGI Electric currently owns and maintains nearly 5,000 of these COS services, mainly residential services. These UGI Electric-owned facilities include the service entrance cable, meter socket, panel box, main breaker and 240 volt breakers, of which some equipment is located inside the customers' homes. Maintenance of the equipment within the home has proven difficult due to the Company's service technicians' limited ability to gain access to the equipment.

With this filing, UGI Electric is proposing to implement a new program to transition ownership of these COS facilities to homeowners. Specifically, UGI Electric will send notices to affected customers and will schedule an appointment(s) to inspect and, if necessary, repair or replace its COS equipment so that it passes an inspection by an approved electrical inspector certified by the Pennsylvania Department of Labor and Industry. If customers do not cooperate in providing access, UGI Electric will utilize all regulatory options available, including its tariff rights to potentially interrupt service until access is granted, to complete inspection of and repair or replacement of, as necessary, its COS equipment. Once the approved electrical inspector inspection is completed, the Company's former COS equipment will be deemed customer-owned equipment consistent with the terms of UGI Electric's tariff, and UGI Electric may further reinforce this status by having the customer execute a bill of sale for a nominal stated consideration.

UGI Electric expects this program will result in the inspection and transfer of responsibility for approximately 500 services a year for the next ten years. The total program cost over the ten-year period is estimated at $4.544 million. The annual program budget estimate is included in UGI Electric Exhibit A, Schedule D-15.

Q. Does UGI Electric's claim in this proceeding include certain previously unbudgeted capital investments?

A. Yes, this filing includes claims associated with three capital projects that were not included in UGI Electric's original 2018 and 2019 capital budgets. First, the Company has included an additional $2.116 million increase in its planned capital investment for the Loomis Substation project. The preliminary UGI Electric 2018 and 2019 Capital Budgets included funding for the development of a two transformer (Type II) distribution substations that will provide capacity for existing and new customers as well as reliability based tie-lines to other distribution substations. The $2.116 million increase reflects UGI Electric's current revised cost estimate for this project. The project is scheduled to be completed by July 31, 2019.

Second, the Company has included a $600,000 incremental capital investment to construct a 13.8 kV distribution circuit from the new Loomis Substation to a new commercial load site currently being planned in Nanticoke, Pennsylvania. Plans for the new commercial site and associated circuit were not developed until after the budget for fiscal year 2019 was completed.

Third, the Company has included $10.0 million for the construction and relocation of UGI Electric personnel to a new consolidated Electric Division Operations and Engineering Center. Currently the bulk of UGI Electric employees are located outside the service territory at a UGI PNG complex located in Wilkes-Barre. The remaining employees are located at the UGI Electric Warehouse in Forty Fort, the UGI Electric Energy Control Center (CC) in Edwardsville, and the Dundee Service Center in

Hanover Twp. The new consolidated Electric Division Operations and Engineering Center will permit:

- Consolidation of UGI Electric employees, other than those at the CC, at a single location within the service territory. Consolidation of all UGI Electric employees at a single location should improve operational efficiency.
- Development of a modern warehouse to replace the Forty Fort location. As previously noted, retaining certain employees at this location, built in 1920s; would requires an estimated $1.0 million in upgrades to improve the general condition of the facility and to meet electrical, Americans with Disability Act ("ADA") and OSHA VPP compliance requirements. Moreover, the existing building is and will become more space-constrained as the Company accelerates its capital investments consistent with its Commission-approved LTIIP. The new warehouse should also accommodate the consolidation of substation inventory, some of which is currently stored in an area that can be isolated or damaged by river flooding.
- The location of a back-up energy control center that is within the bounds of the UGI Electric sonnet fiber network.
- The development of a comprehensive electric training facility that does not exist today.
- Given most UGI Electric personnel are currently located at the UGI PNG complex, the relocation of these employees will eliminate the need to incorporate UGI Electric personnel, and the associated costs, in the facility modernization plans for this UGI PNG facility.

The above capital additions are reflected in UGI Electric Exhibit A, Schedule C-2.

Q. Is there any environmental remediation associated with the relocation of the UGI Electric warehouse?

A. Yes. As part of the development of a consolidated UGI Electric Operations and Engineering Center and relocation and sale of the existing UGI Electric warehouse property, a minor amount of ground remediation will be required within one of the existing large warehouse buildings. The structure, designated as the "lower shed", is basically used to provide covered parking for line construction vehicles and to store miscellaneous items, such as pole trailers and wire pulling equipment. The building, which was constructed in the 1920s, has a packed earth floor that has experienced surface contamination. Based on an environmental analysis, soil remediation is required to an estimated depth of two-feet. Included in UGI Electric Exhibit A, Schedule D-8, is the estimated cost of $417,000 for the site remediation work that was not, because of timing, previously included in the Company's budget. In its filing, UGI Electric has proposed to amortize and recover this cost over a three-year period.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC EXHIBIT EWS-1

Eric W Sorber
UGI Utilities Inc. – Electric Division
Director Engineering and Operations
One UGI Center
Wilkes-Barre, PA 18711

EXPERIENCE

UGI Utilities

Director Engineering and Operations 11/2014 to Present

- Have overall responsibility for Electric Division engineering and operating functions related to transmission, distribution and substation activities 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 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.
- Primary author for the Electric Division's Long Term Infrastructure and Improvement Plan.

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.
  - Served as the lead audit contact and witness 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.

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.

- 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.
- Responsible for overall system planning on the transmission and distribution system.
- Prepared the annual T&D System Planning Recommendations for the Capital Budget.
- 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.
- Developed the Electric Divisions Distributed Generation Interconnection Requirements

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.

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.

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.

EDUCATION

B.S. Electrical Engineering – Pennsylvania State University 1988

UGI ELECTRIC EXHIBIT EWS-2

UGI Electric Exhibit EWS-2

UGI Utilities Inc. – Electric Division
Electric Service Reliability

	SAIDI	SAIFI	CAIDI
12-Month Standard	**256**	**1.12**	**228**
12-Month Benchmark	**140**	**0.83**	**169**
2016 UGI Results	78	0.63	125
2015 UGI Results	41	0.40	103
2014 UGI Results	63	0.44	144

SAIFI, SAIDI and CAIDI results are on a 12-month rolling average ending December.

UGI ELECTRIC EXHIBIT EWS-3

UGI Electric Exhibit EWS-3

UGI Utilities Inc. – Electric Division
Capital Spend Versus Budget
Total Distribution Replacement and Betterment

BUDGET YEAR	ACTUAL	BUDGET	VARIANCE
2014	$ 4,255,154	$ 3,471,530	$ (783,624)
2015	$ 3,852,652	$ 4,307,000	$ 454,348
2016	$ 5,916,079	$ 6,812,500	$ 896,421
2017	$ 6,246,158	$ 7,230,000	$ 983,842

UGI ELECTRIC STATEMENT NO. 4 – MEGAN MATTERN

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2017-2640058

UGI Electric, Inc. – Electric Division

Statement No. 4

Direct Testimony of
Megan Mattern

Topics Addressed:	**Accounting** **Historic Costs** **Rate Base** **Accounting for Data Preparation Costs for Cloud Based Services** **Accounting for UNITE Phase 2 Costs**

Dated: January 26, 2018

I. INTRODUCTION

Q. Please state your name and business address.

A. Megan Mattern, 2525 North 12th Street, Reading, Pennsylvania 19612-2677.

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

A. I am employed by UGI Utilities, Inc. ("UGI") and its subsidiaries as Controller and Principal Accounting Officer. UGI is a subsidiary of UGI Corporation ("UGI Corp."). UGI has both a Gas Division ("UGI Gas"), which is a certificated NGDC, and an Electric Division ("UGI Electric"), a certificated electric distribution company ("EDC"), that are both regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your responsibilities as Controller?

A. I have overall responsibility for the accounting functions for UGI. My duties currently include accounting, accounts payable, cash remittance and Sarbanes-Oxley ("SOX") functions for all of the utilities in the UGI system and the coordination of these functions with UGI's Chief Financial Officer, as well as financial accounting and reporting personnel at UGI Corp. I am also currently responsible for directing the preparation and submission of financial, accounting, and related regulatory filings with the PUC, Federal Energy Regulatory Commission ("FERC"), the United States Securities and Exchange Commission ("SEC") and the United States Internal Revenue Service ("IRS").

Q. Please describe your educational background and work experience.

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

Q. Have you testified previously before this Commission?

A. Yes. I filed testimony in the base rate case proceeding for UGI Penn Natural Gas, Inc. ("UGI PNG") at Docket No. R-2016-2580030.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Electric. First, I will explain UGI Electric's accounting processes and present the actual book accounting results used in the Company's historic test year ended September 30, 2017 ("HTY") (Part II), while the future test year ending September 30, 2018 ("FTY") and fully projected future test year ending September 30, 2019 ("FPFTY") budgets are discussed in the direct testimony of Stephen F. Anzaldo (UGI Electric Statement No. 2). Second, I will present the Company's claim for rate base for the HTY, FTY, and FPFTY (Part III). Third, I will highlight the Company's accounting position on cloud based data preparation costs (Part IV). Fourth, I will address the Company's accounting of costs for Phase 2 of UGI's Next Information Technology Enterprise ("UNITE") project (Part V).

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

A. Yes. I am sponsoring those portions of UGI Electric Exhibit A (Fully Projected), Exhibit A (Future) and Exhibit A (Historic) addressing rate base and certain adjustments to rate base and operating expenses that I discuss later in my testimony. I am also sponsoring those responses to the Commission's filing requirements and standard data requests where my name is indicated as the sponsoring witness.

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 FERC's Uniform System of Accounts as required under the provisions of 52 Pa. Code § 59.42. The Company also maintains a continuing property records system in accordance with the requirements of 52 Pa. Code § 59.47.

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 and its external auditor, Ernst & Young, LLP. They are also subject to audit by the PUC.

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 used and useful?

A. UGI Electric requires field personnel to create a record when property is placed into service or retired. The information from these records is then transferred through accounting entries into the appropriate UGI Electric plant property accounts, subject to review by authorized individuals, who must approve the entries. The process employed by UGI Electric is the same as that employed by UGI Gas, and affiliates UGI Central Penn Gas, Inc. ("UGI CPG") and UGI Penn Natural Gas, Inc. The integrity of this process has been reviewed and approved 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 used to support UGI Electric's claim in this proceeding. As discussed in the direct testimony of Company witnesses Paul Szykman (UGI Electric Statement No. 1) and Stephen F. Anzaldo (UGI Electric Statement No. 2), the Company's claim is based on a FPFTY period ending September 30, 2019. The accounting data for the FPFTY was derived from UGI Electric's operating and capital budgets for the 12 months ending September 30, 2019, as shown in UGI Electric Exhibit A (Fully Projected). The accounting data for the HTY and FTY was 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 year ending September 30, 2018. UGI Electric Exhibit A (Historic) is based on adjusted experienced data for the year ended September 30, 2017.

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. Schedule C-1 summarizes the UGI Electric rate base values for the FPFTY. Column 2 indicates the schedule upon which the calculation of each of the rate base elements is found. Columns 3-5 show the amounts at present and proposed rates, respectively. UGI Electric's total FPFTY rate base claim -- net of deductions for accumulated deferred income taxes, customer deposits, and customer advances -- is $102.4 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, 2017, and budgeted plant additions for the years ending

September 30, 2018 and September 30, 2019, less budgeted FTY and FPFTY plant retirements.

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 $183.3 million for used and useful electric utility plant in service on page 1, column 2, line 47. 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 $183.3 million shown on Schedule C-2, page 1, column 2, line 47 determined?

A. As noted above, this amount is based on the *pro forma* balance as of September 30, 2019. The amount includes: (1) utility plant in service as of September 30, 2017 and (2) budgeted capital expenditures expected to close to plant for the 12-month periods ending September 30, 2018 and 2019, less plant retirements during the same period. UGI Electric witness Eric W. Sorber (UGI Electric Statement No. 3) discusses the capital addition planning process and 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 budget; column 3 shows the net effect of the various plant adjustments; and column 4 provides the adjusted FPFTY plant in service.

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

A. Columns 2 and 3 on this page show the electric plant in service balances for 2018 and 2019 based on the budget, plus the amount of plant additions budgeted as of the end of the FPFTY. Column 4 represents various plant adjustments and column 5 provides the adjusted FPFTY plant balance.

Q. Where is the information for FPFTY and FTY additions shown?

A. Page 4 of Schedule C-2 provides actual and projected plant additions. The Company categorizes plant addition by FERC account. Plant additions are discussed in more detail in the direct testimony of Eric W. Sorber (UGI Electric Statement No. 3).

Q. Where is the information for 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 by applying the average retirement rate, as a percent of additions, for the five fiscal years 2013 through 2017, 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 value for accumulated depreciation.

A. UGI Electric started with accumulated depreciation as of September 30, 2017, 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, 2019, distributed among the various FERC accounts. The total amount for accumulated depreciation, $59.7 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 2018 and 2019 based on budget plus adjustments to arrive at the FPFTY balance. Pages 4-5 show the cost of removal and negative net salvage amortization by FERC account. Page 6 includes the salvage amounts for the FPFTY. 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.

Q. Are there adjustments to the budgeted amounts for accumulated depreciation?

A. Yes. Similar to the plant assets shown on Schedule C-2, the accumulated depreciation must also be reduced by the accumulated depreciation on common assets allocated to affiliated companies. These adjustments are shown in column 3 on Schedule C-3, page 2 and column 4 on Schedule C-3, page 3.

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 are shown on line 1. The expense lag days are shown for each component on lines 3-5. 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 29.13 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 cash working capital amount for O&M expense of $5.7 million. The average daily expense balance of $196,000 shown on line 9 is determined by dividing the total *pro forma* annual operating expenses, excluding uncollectible accounts expense of $71.4 million, as shown on line 6 of column 2, by the number of days in a year, or 365. 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 total revenue lag days (line 23) were determined by dividing the annual revenue billed during the year (line 18, column 3) by the average month-end accounts receivable balances for the thirteen months ended September 30, 2017 (line 17, column 2). This results in an accounts receivable turnover rate of 9.6 (line 19, column 4), which is equivalent to 38.02 lag days (line 20, column 5) (365 divided by 9.6 accounts receivable turnover rate). As shown on lines 20-23, the payment portion of the revenue lag is added to (1) the 2.7 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 15.21 day service lag, 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 55.93 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 (365 days divided by 12, or 30.42 days) divided by two days.

Q. How are the payroll expense lags 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.

Q. How were the lag days associated with the electric 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 2016 through September 2017. The total dollar amount of electricity purchased during this period was $41 million, and the average payment lag equaled 33.33 days. The payment lag was determined using the midpoint of the service payment for each of the payments and the payment date for each, averaged over the 12-month study period.

Q. How was the Other O&M Expense lag days, shown on Schedule C-4, page 4, line 14, 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 four months, as shown in more detail on page 5 of Schedule C-4. A list of all cash disbursements during each of these months was used in a format that shows the payee, the invoice date, the amount of the disbursement, the date the payment was made, the account to which the disbursement was charged and other data associated with the disbursements. As shown on page 5, lines 1-8, each month's listing contained numerous cash disbursements. Once the raw payment data was assembled, the dollar days were determined by multiplying the amount of the disbursement by either (i) the number of days from invoice date until bank clearance for wire 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), capital items, and other non-expense amounts. After these adjustments, the average of the expense lag days for each month shown on Schedule C-4, page 5, column 4, line 9 resulted in a payment lag for general disbursements of 12.56 days. The 12.56 day lag for Other Disbursements is then brought forward to Schedule C-4, page 4, line 14 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 365 to obtain the daily interest expense of $6,000 shown on line 5. That amount is then multiplied by the net payment lag, resulting in a reduction to the working capital allowance of $216,000 as shown on line 9. This amount is then included on page 1, line 2 of Schedule C-4.

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

A. This calculation is shown on page 8 to Schedule C-4. Separate calculations are made for federal income tax, state income tax, PA Property Tax and PURTA. 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.

Q. Does the working capital requirement for tax payments reflect the recent changes to the federal tax code?

A. No. We are still analyzing the impact of the tax code reform and will be resubmitting any schedules that have been impacted by the tax code reform in a later update.

Q. How was the working capital allowance for pre-payments 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 2016 through September 2017.

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

A. UGI Electric’s claim for CWC is $ 7.46 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 (ADIT)

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

A. The Company's determination of its rate base value for ADIT is shown on Schedule C-6 and is discussed in the direct testimony of Nicole McKinney (UGI Electric Statement No. 9). As noted in Ms. McKinney's testimony, the Company continues to analyze the impact of the recent federal tax code changes and will submit changes to this schedule in a later update.

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 September 30, 2017 month-end balance as shown on Schedule C-7. Act 155 of 2014 became effective December 22, 2014, and no longer permits the Company to collect deposits for customers who qualify for low-income programs. As a result, the Company's customer deposits balance has declined and now leveled off at a balance representative of future operations. For this reason, the balance at the end of the HTY was used to determine the rate base offset for customer deposits.

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

A. The customer deposit offset is $1.42 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 $1.44 million, as shown on Schedule C-1, line 7. This amount represents the balance at the end of the HTY as shown on Schedule C-8. This value is also shown on Schedule A-1, line 7.

Q. Why is the HTY balance an appropriate measure of materials and supplies for the FPFTY?

A. The balance at the end of the HTY is appropriate for two reasons. First, as a result of the 2011 Management Audit, the Company accepted the Commission's audit staff recommendation that UGI Electric increase its levels of emergency stock. Second, the Company's increasing capital expenditure plans have increased the need to stock longer lead time items to ensure these items are available when needed. These two factors have contributed to an increasing amount of materials and supplies inventory, which is reflected by the use of the HTY-end balance for this claim. UGI Electric will update this balance during the course of this proceeding.

IV. ACCOUNTING TREATMENT OF CLOUD BASED IMPLEMENTATION COSTS

Q. Ms. Mattern, what are the items included in the Company's rate base claim that are not accounted for in accordance with GAAP?

A. The Company has included the capitalization of implementation costs related to the Company's new cloud-based information assets. Under GAAP, such costs are ordinarily accounted for as operating expenses. In this case, however, the Company is requesting Commission approval to record these costs as a capital asset. The Commission approved the capitalization of such costs in the 2017 base rate case for the Company's affiliate UGI PNG at Docket No. R-2016-2580030. The Statement of Chairman Brown, accompanying the Commission order approving the settlement, specifically supported the capitalization of cloud-based computing, concluding "Permitting for the capitalization of cloud computing helps to align the interest of regulated utilities with the expectations of 21st century customers."

Q. Why is it appropriate to capitalize costs incurred to implement cloud based services?

A. Under the current GAAP accounting guidelines, the implementation costs for activities such as database preparation, including coding & testing for on premise software, is required to be capitalized, while the implementation costs for cloud basis assets are considered expenses. Cloud based assets offer many advantages to traditional on premise software such as enhanced security, reliability, and flexibility. Cloud-based assets are used by the Company to optimize various aspects of the utility service provided to its customers over, at a minimum, the life of the cloud based service agreement. Accordingly, cloud based assets provide benefits to customers over extended periods of time and not just the period in which the costs are incurred, the Company believes that the costs should be capitalized and depreciated over the life that the data bases will remain used and useful. In addition to the endorsement provided by the Commission and Chairman Brown, the appropriateness of capitalizing cloud-based computing is supported by the National Association of Regulated Utility Commissions ("NARUC"). *See, Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory*

Treatment of Cloud Computing Arrangements." Adopted by the NARUC Committee of the Whole on November 16, 2016.

Q. What cloud-based assets are included in the Company's FPFTY rate base claim?

A. The Company has included the allocable portion of the following cloud-based solutions: Successfactors, Concur, Hybris, and Field Glass. Both Successfactors and Field Glass were discussed in the 2017 PNG base rate case proceeding and are included with a 5-year amortization.

V. <u>ACCOUNTING FOR UNITE PHASE 2 COSTS</u>

Q. What is the adjustment for the UNITE Project that is shown on Schedule D-15?

A. The adjustments on Schedule D-15 relate to Phase 2 of UGI's Next Information Technology Enterprise ("UNITE") system replacement project, which will implement a new enterprise resource management ("ERP") solution. The costs include the implementation cost of the software as well as the preliminary-stage project costs and business and technology reengineering costs, including: internal labor; external consulting expense; other expenses related to the preparation of the vendor and system integrator requests for proposal, current state assessment, and costs to reengineer the business processes to adapt to the new system; and data conversion, migration and pre-implementation training costs. These costs have been recorded as expenses in accordance with US GAAP accounting standards, specifically ASC-350-40 'Internal Use Software'. However, under the FERC Uniform System of Accounts, these costs fit the definition of costs that should be capitalized once placed in service. The Company is seeking a 15-year amortization for the ERP solution.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC STATEMENT NO. 5 – PAUL R. MOUL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2017-2640058

UGI Utilities, Inc. – Electric Division

Statement No. 5

Direct Testimony

of

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

Topics Addressed: **Cost of Common Equity**
Rate of Return

Dated: January 26, 2018

UGI Utilities, Inc. – Electric Division
Direct Testimony of Paul R. Moul
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GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
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

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

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

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in 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 Electric 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 rate of return on common equity of 10.95%, which is within the range of results of the cost of equity models and includes 0.20% in recognition of the strong performance by the Company in the area of management effectiveness. My 10.95% 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. My cost of equity determination should be viewed in the context of increasing capital costs revealed by rising interest rates and the need for supportive regulation at a time of increased infrastructure improvements now underway for the Company. Moreover, as I will describe below, there will be more risk faced by the Company with the changes to tax law recently passed by the U.S. Congress and signed into law by the President on December 22, 2017. As shown on page 1 of Schedule 1, I have presented the 8.26% weighted average cost of capital for the Company, which is calculated with the September 30, 2019 fully projected future test year ("FPFTY") end capital structure ratios. 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, should establish a compensatory level of return for the use 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 that also owns UGI Central Penn Gas, Inc. and UGI Penn Natural Gas, Inc. UGIU is itself a wholly-owned subsidiary of UGI Corporation ("UGI"). As now constituted, UGIU and its subsidiaries provide natural gas distribution service to approximately 644,000 customers in 44 eastern and central Pennsylvania counties. In addition, UGIU provides electric distribution service to approximately 62,000 customers in portions of Luzerne and Wyoming Counties.

The deliveries on UGIU's electric system in 2017 were approximately 55% to residential, 33% commercial, and 12% industrial. The Company obtains its energy 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 10.95% represents a reasonable cost of equity, which is within the range of results of the cost of equity models and reflects 0.20% to recognize the strong performance of UGIU in the area of management effectiveness.

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 ten (10) 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

[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).

classified in the Electric Utility East group, (iii) are not currently the target of an announced merger or acquisition, and (iv) are not engaged in the construction of a nuclear generating plant or have not recently cancelled the construction of a nuclear generating plant. 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.

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. 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	10.55%
Risk Premium	11.25%
CAPM	11.03%
Comparable Earnings	12.55%

From these measures, I recommend a cost of equity of 10.95%, which is within the range of results reflected in the above table and also reflects 0.20% for strong management performance, as explained in the testimony of Mr. Paul Szykman.

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 10.95% rate of return on common 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 meaningful changes in the fundamentals that affect their operations, while retaining the obligation to serve under cost of service pricing that continues to dominate its business 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.

UGI 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 harden its system and expand its vegetation management practices 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.

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 three years, the Company's total capital expenditures (transmission and distribution), as shown in the table below, are expected to be $61.701 million:

Year		Construction
2017		$12,034,023
2018		$20,174,000
2019		$29,493,000
Total		$61,701,023

These expenditures represent approximately 51% ($61.701 million ÷ $120.138 million) of the Company's total net utility plant at September 30, 2017. 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. You indicated previously that the pending federal income tax law changes will add to the Company's risk. Please explain.

A. There are several major financial consequences arising from the changes in the federal income tax law that will negatively impact the Company. First, a lower federal income tax rate will lower the Company's pre-tax interest coverage that will reduce credit quality and increase risk. For example, with the marginal federal corporate income tax rate change from 35% to 21%, the pre-tax interest coverage shown on page 1 of Schedule 1 declines from 5.32 times to 4.56 times. This assumes no other changes in tax provisions that may also impact the Company's financial condition and credit quality. Second, with a lower marginal federal corporate income tax rate, the Company's return variability will increase, thereby increasing its business risk. When the federal corporate income tax rate was formerly 35%, investors only needed to absorb 65% of any changes in revenues and expenses. At a 21% federal corporate income tax rate, investors will need to absorb 79% of changes in revenues and expenses. That is to say, the reduced federal income taxes will make investor returns more variable than formerly, thereby increasing the Company's risk. Third, utilities will require more investor supplied capital to fund their construction program because the level of deferred taxes will decline and because the tax code reform eliminates bonus depreciation. This will also impact another credit metric revealed by the percentage of internally generated funds to construction. This percentage will decline with the new lower income tax rate. In response to these financial challenges caused by the new lower federal corporate income tax rate, there may be the need to reduce the percentage of debt in a utility's capital structure to respond to higher business risk and weaker credit quality measures.

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, Dominion Energy, 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 minus 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 higher than that of the Electric Group, which has an average Baa1 and BBB+ credit rating from Moody's and S&P, respectively. For the S&P Public Utilities, the average composite credit rating is A3 by Moody's and BBB+ by S&P. Many of the financial indicators which I will subsequently discuss are considered during the rating process.

Q. How do the financial data compare for 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 2012-2016. I will highlight the important categories of relative risk may be summarized as follows:

<u>Size</u>. 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.

<u>Market Ratios</u>. Historical market-based financial ratios, such as price-earnings multiples and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return for companies which exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[2]

Since UGIU's stock is not traded, there are no market ratios for the Company. The five-year average price-earnings multiple was higher for the Electric Group than for the S&P Public Utilities. The five-year average dividend yield for the Electric Group was also 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.

<u>Common Equity Ratio</u>. 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

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

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 57.0% for UGIU, 48.2% for the Electric Group, and 44.3% for the S&P Public Utilities. This shows that the financial risk of UGIU was somewhat lower than the Electric Group.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relative levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficient of variation, the greater degree of variability. During the five-year period, the coefficients of variation were 0.141 (1.8% ÷ 12.8%) for UGIU, 0.046 (0.4% ÷ 8.7%) for the Electric Group, and 0.022 (0.2% ÷ 9.2%) 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. And, as I indicated previously, the pending changes in the federal income tax law will likely make these variability statistics higher in the future.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation and taxes other than income).[33] The five-year average operating ratios were 77.3% for UGIU, 77.8% for the Electric Group, and 80.4% for the S&P Public Utilities. The operating ratio for UGIU is fairly close to the Electric Group 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

[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.

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 5.47 times for UGIU, 3.56 times for the Electric Group, and 3.15 times for the S&P Public Utilities. The higher interest coverage for UGIU suggests lower credit risk. Again, these indicators will decline prospectively with the implementation of the pending federal income tax changes.

<u>Quality of Earnings</u>. 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.

<u>Internally Generated Funds</u>. 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 85.0% for UGIU, 81.3% for the Electric Group, and 79.5% for the S&P Public Utilities. This indicates a fairly comparable risk for the Company and the reference groups. As noted previously, the IGF to construction expenditures will decline with the new lower federal income tax rate.

<u>Betas</u>. 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. <u>Value Line</u> publishes such a statistical measure of a stock's relative historical volatility to the rest of

the market.[4] A comparison of market risk is shown by the Value Line betas of .66 as the average for the Electric Group provided on page 2 of Schedule 3 and .75 as the average for the S&P Public Utilities provided on page 3 of Schedule 4.

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 the capital employed and the capital cost rates are directly identifiable. Not only does UGIU attract investor-provided capital for its utility divisions, it also does that for its subsidiaries. The circumstances of UGIU indicate that its capital structure ratios should be used for rate of return purposes for each of its utility divisions and both its utility subsidiaries.

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[4] 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.

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, 2017, the end of the historic test year. Also, shown on Schedule 5 is the UGIU capital structure estimated at September 30, 2018, the end of the future test year, and at September 30, 2019, the end of FPFTY. The changes in the Company's capital structure consist of: (i) two maturities of $20 million each in the future test year (ii) the issuance of $125 million of long-term debt in the future test year, (iii) the issuance of $150 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.

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. In each instance, the CWIP balances exceed the average amount of short-term debt. Therefore, all short-term debt is removed from the capital structure in this case.

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 45.98% long-term debt and 54.02% 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 and 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, 2017. On page 2 of Schedule 6, I have shown the estimated embedded cost rate of long-term debt at September 30, 2018. 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 4.69% forecast embedded long-term debt cost rate at September 30, 2019, 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 45.98% 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 10.95% for UGI Electric, which includes 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 return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model and assumes future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: P = D/(k-g), where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: k= D/P + g. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model.[5] My DCF results are provided on page 2 of Schedule 1 for the Electric Group. The DCF return is 10.55%.

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

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

A. The dividend yield reveals the portion of investors' cash flow that is generated by the return provided by dividend receipts. It is measured by the dividends per share relative to the price per share. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended October 2017, the monthly dividend yields are shown on Schedule 7 and reflect an adjustment to the month-end prices 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

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

own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the twelve months ended October 2017 the average dividend yield was 3.75% 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- and three-month periods were 3.62% and 3.51%, respectively. I have used, for the purpose of the DCF model, the six-month average dividend yield of 3.62% 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 investor anticipated cash flows for the Electric Group. 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 eleven basis points to the six-month average historical yield, thus producing the 3.73% 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 earnings per share growth represent the DCF model's primary focus because under the constant price-earnings multiple assumption of the model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth, including: earnings, dividends, book value, and cash flow stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors. A fundamental growth rate analysis is sometimes represented by the internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. To be complete, the internal growth rate should be modified to account for sales of new common stock -- this is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of the factors that cause book value per share to grow over time.

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

Q. How did you determine an appropriate growth rate?

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

Q. Did you consider company-specific data in your growth rate analysis?

A. Yes. As presented on Schedule 8 and Schedule 9, I have considered both historical and projected growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Electric Group. While analysts will review all measures of growth as I have done, it is earnings per share growth that influences directly the expectations of investors for utility stocks. Forecasts of earnings growth are required within the context of the DCF because the model is a forward-looking concept, and with a constant price-earnings multiple and payout ratio, all other measures of growth will mirror earnings growth. So, with the assumptions underlying the DCF, all forward-looking projections should be similar with a constant price-earnings multiple, earned return, and payout ratio.

As to the issue of historical data, investors cannot purchase past earnings of a utility, rather they are only entitled to future earnings. In addition, assigning significant weight to historical performance results in double counting of the historical data. While history cannot be ignored, it is already factored into the analysts' forecasts of earnings growth. In developing a forecast of future earnings growth, an analyst would first apprise himself/herself of the historical performance of a company. Hence, there is no need to count historical growth rates a second time, because historical performance is already reflected in analysts' forecasts which reflect an assessment of how the future will diverge from historical performance.

Schedule 8 shows the historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Electric Group. The historical growth rates were taken from the Value Line publication that provides these data. As shown on Schedule 8, the historical growth of earnings per share was in the range of -0.06% to 3.33% for the Electric Group.

Q. Did you also consider analysts' expectations of expected growth?

A. Yes. Schedule 9 provides projected earnings per share growth rates taken from analysts' five-year forecasts compiled by IBES/First Call, Zacks, Morningstar, SNL, and Value Line. IBES/First Call, Zacks, Morningstar, and SNL represent reliable authorities of projected growth upon which investors rely. The IBES/First Call, Zacks, and SNL growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Zacks, Morningstar, and SNL estimates are obtained from the Internet and are widely available to investors. First Call probably is quoted most frequently in the financial press when reporting on earnings forecasts. The Value Line forecasts also are widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries. The IBES/First Call, Zacks, Morningstar, and SNL forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on Schedule 9 for the Electric Group.

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

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

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

A. As to the five-year forecast growth rates, Schedule 9 indicates that the projected earnings per share growth rates for the Electric Group are 4.33% by IBES/First Call, 5.37% by Zacks, 6.01% by Morningstar, 5.04% by SNL and 6.06%% by Value Line. As noted earlier, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

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

A. A variety of factors should be examined to reach a conclusion on the DCF growth rate. However, certain growth rate variables should be emphasized when reaching a conclusion on an appropriate growth rate. From the various alternative measures of growth identified above, earnings per share should receive greatest emphasis. Earnings per share growth are the primary determinant of investors' expectations regarding their total returns in the stock market. This is because the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). Moreover, earnings per share (derived from net income) are the source of dividend payments and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is a forecast of earnings per share growth.[6] Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, Morningstar, and Value Line, represent a reasonable assessment of investor expectations.

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

A. The forecasts of earnings per share growth, as shown on Schedule 9, provide a range of average growth rates of 4.33% to 6.06%. Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-

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

expected growth rate of 5.75% is a reasonable estimate of investor expected growth within the array of earnings per share growth rates shown by the analysts' forecasts. Indeed, my 5.75% growth rate is obtained from the analysts' growth forecasts that cover a five-year period, which are the growth rates that investors employ for DCF purposes. Improved economic growth argues for a DCF growth rate near the high end of the range. Economic growth is expected to accelerate with the future implementation of the new federal corporate income tax provisions.

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

A. Only if the capital structure ratios are measured with the market value of debt and equity. In the case of the Electric Group, those average capital structure ratios are 42.95% long-term debt, 0.06% preferred stock, and 56.99% common equity, as shown on Schedule 10. If book values are used to compute the capital structure ratios, then a leverage adjustment is required.

Q. What is a leverage adjustment?

A. Where a firm's capitalization as measured by its stock price diverges from its book value capitalization, the potential exists for a financial risk difference, because the capitalization of a utility measured at its market value contains more equity, less debt and therefore less risk than the capitalization measured at its book value. A leverage adjustment accounts for this difference between market value and book value capital structures.

Q. Why is a leverage adjustment necessary?

A. In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes) the market-derived cost rate must be adjusted to account for this difference in financial risk. The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different than indicated by the market price (P). From the market perspective, the financial risk of the Electric Group is accurately measured by the capital structure ratios calculated from the market capitalization of a firm. If the rate setting process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the rate setting process uses a different set of ratios calculated from the book value capitalization, then further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the equity. This adjustment is developed through precise mathematical calculations, using well recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. The calculations presented in the lower panel of data shown on Schedule 10, under the heading "M&M," provides a return of 7.66% 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. In this regard, according to the Barron's issue of December 4, 2017, the major market indices' market-to-book ratios are well above unity. The Dow Jones Utility index traded at a multiple of 2.23 times book value, which is below the market multiple of other indices. For example, the S&P Industrial index was at 4.50 times book value, and the Dow Jones Industrial index was at 4.16 times book value. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of their cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they indeed exist.

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

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

A. No, it is not. The adjustment that I label as a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g), in the context of a return that applies to the capital structure used in ratemaking, which is computed with book value weights rather than market value weights, in order to arrive at the utility's total cost of equity. I specify a separate factor, which I call the leverage adjustment, but there is no need to do so other than providing identification for this factor. If I expressed my return solely in the context of the book value weights that we use to calculate the weighted average cost of capital, and ignore the familiar D/P + g expression entirely, then there would be no separate element to reflect the financial leverage change from market value to book value capitalization. As shown in the bottom panel of data on Schedule 10, the equity return applicable to the book value common equity ratio is equal to 7.66%, which is the return for the Electric Group applicable to its equity with no debt in its capital structure (i.e., the cost of capital is equal to the cost of equity with a 100% equity ratio) plus 2.89% compensation for having a 54.49% debt ratio, plus 0.00% for having a 0.08% preferred stock ratio. The sum of the parts is 10.55% (7.66% + 2.89% + 0.00%) and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I summed the 3.73% dividend yield, the 5.75% growth rate, and the 1.07% for the leverage adjustment in order to arrive at the same 10.55% (3.73% + 5.75% + 1.07%) return. I know of no means to mathematically solve for the 1.07% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 1.07% adjustment is merely a convenient way to compare the 10.55% return computed directly with the Modigliani & Miller formulas to the 9.48% return generated by the DCF model (i.e.,

$D_1/P_0 + g$, or the traditional form of the DCF -- see page 1 of Schedule 7) based on a market value capital structure. A 9.48% 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. What does your DCF analysis show?

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 rate setting process rather than the market value equity ratio related to the price of stock.

	D_1/P_0	+	g	+	*lev.*	=	k
Electric Group	3.73%	+	5.75%	+	1.07%	=	10.55%

The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant growth assumption. I should reiterate, however, that the DCF-indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market, because price-earnings multiples do not remain constant. This is one of the constraints of this model that makes it important to consider other model results when determining a company's cost of equity. In the current environment of rising interest rates, the DCF method tends to be less responsive (i.e., there is a lag) to changes in those rates. As such, other methods for measuring the cost of equity, e.g. Risk Premium and CAPM, should be emphasized because they respond promptly to change in interest rates.

RISK PREMIUM ANALYSIS

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

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on page 2 of Schedule 1. That result is 11.25%.

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 4.75% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

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

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on page 1 of Schedule 11. For the twelve months ended October 2017, the average monthly yield on Moody's index of A-rated public utility bonds was 4.06%. For the six and three-month periods ended October 2017, the yields were 3.95% and 3.88%, respectively. During the twelve-months ended October 2017, the range of the yields on A-rated public utility bonds was 3.86% to 4.27%. 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 1.13% on a twelve-month average basis, 1.10% on a six-month average basis, and 1.06% on a three-month average basis. From these averages, 1.00% represents a conservative spread for the yield on A-rated public utility bonds over Treasury bonds.

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

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe below. The Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on November 1, 2017, and a yield spread of 1.00%, derived from historical data.

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

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

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2017	Fourth	3.8%	4.5%	3.0%	1.00%	4.00%
2018	First	4.0%	4.7%	3.1%	1.00%	4.10%
2018	Second	4.2%	4.9%	3.3%	1.00%	4.30%
2018	Third	4.4%	5.1%	3.4%	1.00%	4.40%
2018	Fourth	4.5%	5.3%	3.5%	1.00%	4.50%
2019	First	4.6%	5.4%	3.6%	1.00%	4.60%

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, 2017 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
2019-2023	5.4%	6.3%	4.3%
2024-2028	5.5%	6.4%	4.5%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. By focusing more on these forecasts, a 4.75% yield on A-rated public utility bonds represents a reasonable benchmark for measuring the cost of equity in this case. In reaching my conclusion as to a prospectively yield on A-rated public utility debt, I have considered the data relied upon by investors. While the goal in this case is to arrive at a cost of equity for the FPFTY, there is a dearth of Blue Chip data for that particular period, and as such, I have considered the Blue Chip data that is available for the prospective period.

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

A. To develop an appropriate equity risk premium, I analyzed the results from 2017 SBBI Yearbook, Stocks, Bonds, Bills and Inflation. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on page 1 of Schedule 12.

Common Equity Risk Premiums		
Low Interest Rates		7.08%
Average Across All Interest Rates		5.64%
High Interest Rates		4.18%

Based on my analysis of the historical data, the equity risk premium was 7.08% when the marginal cost of long-term government bonds was low (i.e., 2.96%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.22% on average during periods of high interest rates) the spread narrowed to 4.18%. Over the entire spectrum of interest rates, the equity risk premium was 5.64% when the average government bond yield was 5.07%. With the forecast indicating an upward movement of interest rates that I described above from historically low levels, I have utilized a 6.50% equity risk premium. This equity risk premium is between the 7.08% premium related to periods of low interest rates and the 5.64% premium related to average interest rates across all levels.

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

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

$$i \quad + \quad RP \quad = \quad k$$

Electric Group 4.75% + 6.50% = 11.25%

Indeed, in an environment of rising interest rates, the Risk Premium model provides a direct reflection of the cost of equity that captures higher interest rates.

CAPITAL ASSET PRICING MODEL

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

A. The CAPM uses the yield on a risk-free interest-bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Schedule 1, the result of the CAPM is 11.03%. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 2 of Schedule 3, the average beta is 0.66 for the 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 rate setting capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line (market value) betas have been unleveraged and re-leveraged for the book value common equity ratios using the Hamada formula,[7] as follows:

[7] 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.

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

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 0.44 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 0.78 for the book value capital structure of the Electric Group. The book value leveraged beta that I will employ in the CAPM cost of equity is 0.78 for the Electric Group.

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

A. As shown on page 1 of Schedule 13, I provided the historical yields on Treasury notes and bonds. For the twelve months ended October 2017, the average yield on 30-year Treasury bonds was 2.93%. For the six- and three-months ended October 2017, the yields on 30-year Treasury bonds were 2.85% and 2.82%, respectively. During the twelve-months ended October 2017, the range of the yields on 30-year Treasury bonds was 2.78% to 3.11%. The low yields that existed during recent periods can be traced to the financial crisis and its aftermath commonly referred to as the Great Recession. The resulting decline in the yields on Treasury obligations was attributed to a number of factors, including: the sovereign debt crisis in the euro zone, concern over a possible double dip recession, the potential for deflation, and the Federal Reserve’s large balance sheet that was expanded through the purchase of Treasury obligations and mortgage-backed securities (also known as QEI, QEII, and QEIII), and the reinvestment of the proceeds from maturing obligations and the lengthening of the maturity of the Fed's bond portfolio through the sale of short-term Treasuries and the purchase of long-term Treasury obligations (also known as "operation twist"). Essentially, low interest rates were the product of the policy of the Federal Open Market Committee ("FOMC") in its attempt to deal with stagnant job growth, which is part of its dual mandate. The FOMC has ended its bond purchasing program. 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 Fed Funds rate by one-quarter percentage point. The FOMC also used this occasion to express a more aggressive approach to future increases in interest rates. In addition, the Fed has indicated that it will reduce the size of its balance sheet. FOMC has increased the fed 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. The Wall Street Journal has also reported that three one-quarter percentage point rate increases are anticipated for 2018 and two one-quarter percentage point rate increases will likely follow in each of the years 2019 and 2020. This buttresses the prospect that higher interest rates are on the horizon.

As shown on page 2 of Schedule 13, forecasts published by <u>Blue Chip</u> on November 1, 2017 indicate that the yields on long-term Treasury bonds are expected to be in the range of 3.0% to 3.6% during the next six quarters. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 4.3% from 2019 through 2023 and 4.5% from 2024 to 2028. 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 3.75% risk-free rate of return for CAPM purposes, which considers the <u>Blue Chip</u> forecasts.

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

A. As shown in the lower panel of data presented on page 2 of Schedule 13, the market premium is derived from historical data and the forecast returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on page 1 of Schedule 12. On that schedule, the market return was 11.97% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 2.96% when interest rates were low. As I describe above, interest rates are forecast to trend upward in the future. To recognize that trend, I have given weight to the average returns and yields that existed across all interest rate levels. As such, I carried over to page 2 of Schedule 13 the average large common stock returns of 11.96% (11.97% + 11.95% = 23.92% ÷ 2) and the average yield on long-term government bonds of 4.02% (2.96% + 5.07% = 8.03% ÷ 2). These financial returns rest between those experienced during periods of low interest rates and those experienced across all levels of interest rates. The resulting market premium is 7.94% (11.96% - 4.02%) based on historical data, as shown on page 2 of Schedule 13. For the forecast returns, I calculated an 11.87% DCF return for the S&P 500. Normally, I would also include the Value Line forecast data as part of the market premium calculation. But in this instance, the Value Line result of 8.78% is clearly anomalous. I say this because those forecasts are established by Value Line in a hypothesized economic environment 3 to 5 year hence. In that hypothesized economy, real GDP growth is approximately 2.5%. With the recent passage of the new federal corporate income tax law, GDP is expected to increase from that level. As such, I have suspended use of the Value Line forecast for the purpose of this case. With the forecast return of 11.87%, I calculated a market premium of 8.12% (11.87% - 3.75%) using the S&P 500 forecast data. Indeed, this forecast market premium is more in-line with historical evidence. The market premium applicable to the CAPM derived from these sources equals 8.03% (8.12% + 7.94% = 16.00% ÷ 2).

Q. Are adjustments to the CAPM 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.[8] 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) were 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 3.75% risk-free rate of return, the leverage adjusted beta of 0.78 for the Electric Group, the 8.03% market premium, and the 1.02% size adjustment, the following result is indicated.

	Rf	+	*ß*	x (	*Rm-Rf*	) +	*size*	=	*k*
Electric Group	3.75%	+	0.78	x (	8.03%	) +	1.02%	=	11.03%

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[8] See Fundamentals of Financial Management, Fifth Edition, at 623.

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 page 3 of Schedule 14. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on page 1 of Schedule 14.

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

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

A. I used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 12.7% using only the returns that were less than 20%, as shown on page 2 of Schedule 14. The average forecasted rate of return as published by Value Line is 12.4% also using values less than 20%, as provided on page 2 of Schedule 15. Using the average of these data my Comparable Earnings result is 12.55%, as shown on page 2 of Schedule 1.

CONCLUSION

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

A. Based upon the application of a variety of methods and models described previously, it is my opinion that a reasonable rate of return on common equity is 10.95% for UGI Electric, which includes 0.20% in recognition of the Company's strong performance in the area of management effectiveness. My cost of equity recommendation is obtained from a range of results (i.e., 10.25% to 12.55%) and should be considered in the context of the Company's risk characteristics, as well as the general condition of the capital markets, and the strong performance of the Company's management. 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.

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).