BOOK IV

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. 6 – JOHN D. TAYLOR
UGI ELECTRIC STATEMENT NO. 7 – JOHN F. WIEDMAYER
UGI ELECTRIC STATEMENT NO. 8 – DAVID E. LAHOFF
UGI ELECTRIC STATEMENT NO. 9 – NICOLE M. MCKINNEY

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. 6 – JOHN D. TAYLOR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2017-2640058

UGI Utilities, Inc. – Electric Division

Statement No. 6

Direct Testimony

of

John D. Taylor, Principal Consultant
Black and Veatch Corporation

Topics Addressed: **Cost of Service**

Dated: January 26, 2018

Direct Testimony of John D. Taylor

INTRODUCTION

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

A. My name is John D. Taylor and I am employed by Black and Veatch as a Principal Consultant. My business address is 14401 Lamar Avenue, Overland Park, KS 66211.

Q. Please describe your professional background and education.

A. As a Principal Consultant with Black and Veatch I am involved in a variety of energy and utility related projects regarding matters pertaining to economics, finance, and public policy. This includes: asset divestitures, allocated class cost of service studies, rate of return, cash working capital, tax litigation, rate design analysis, auction analysts, and affiliate cost allocation. Part of my role within these projects is to conduct various analyses which take into account both accounting and financial considerations and the particular operational configuration of a company's assets. This includes studies such as: allocated class cost of service studies; valuation modeling; affiliate cost allocation; and various cost of service analyses. I have filed testimony on class cost of service studies, and statistical audit sampling. I have presented expert testimony in Indiana, Maine, Minnesota, Illinois, Delaware, Pennsylvania, British Columbia, and the Federal Energy Regulatory Commission. My educational and professional background allows me to conduct these types of analyses appropriately. I began my education studying electrical and mechanical engineering and worked for an industrial inspection company which provided me with hands on experience with electric utility assets and equipment. I received an undergraduate degree in Environmental Economics, with an emphasis in econometrics and regulatory policy. I also earned a Masters in Economics from American University in Washington, DC. A copy of my resume is provided as UGI Electric Exhibit JDT-1.

Q. What is your assignment in this proceeding?

A. UGI Utilities Inc. – Electric Division ("UGI Electric") requested Black & Veatch to conduct a fully-allocated cost of service study to determine the embedded costs of serving its various electric retail customers and support rate design efforts. In this regard, I am sponsoring the allocated class costs of service ("ACOSS") that allocates UGI Electric's costs associated with operations within the Pennsylvania Public Utility Commission ("PA PUC") jurisdiction to retail customer's rate classes. I am also supporting the class revenue increase apportionment and general guidance on the customer charges.

Q. Please summarize the content of your testimony?

A. First, I will discuss various principles of cost allocation and factors that influence the cost allocation framework; as well as, general methods and approaches used to allocate costs to customer classes. Second, I will discuss the underlying methodology and basis used in the ACOSS studies I conducted and am sponsoring. I describe the studies of relative costs and other analyses employed to apportion the various categories of plant and operation and maintenance ("O&M") expenses to the respective customer classes. I will present the class-by-class rate of return results and corresponding revenue surpluses or deficiencies from the ACOSS. Finally, I will discuss the apportionment of the rate increase to the various rate classes.

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

A. Yes. I am sponsoring Book IX labeled as UGI Electric Exhibit D – Cost of Service Study ("Exhibit D"). Exhibit D contains five sections for which an index is provided on page 2 of Exhibit D. I also am sponsoring portions of Exhibit Regs., Part IV-Rate Structure and Cost Allocation.

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

Exhibit D provides the information required under 52 Pa. Code §53.53(a)(3), and in particular Exhibit C, Part IV, Section E (1), by providing a cost of service study which fully distributes the Pennsylvania jurisdictional costs of providing retail distribution service to the various rate classes at both present and proposed rates. The studies contained in UGI Electric Exhibit D are based on costs and operating conditions for the fully projected future test year ending September 30, 2019. The exhibit provides a summary of the results, cost assignment and allocation detail, and supporting schedules showing functionalization of the costs and support for the cost allocation factors used. UGI Electric Exhibit D provides the results of studies used to functionalize and classify UGI Electric's distribution plant and support for the allocation factors. The results of these studies were applied to distribution plant data for the fully projected future test year.

OVERVIEW OF ACOSS

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

A. The purpose of the ACOSS is to allocate UGI Electric's PA PUC-jurisdictional overall adjusted test year revenues and costs to the various classes of service in a manner that reflects the relative costs of providing service to each class. This is accomplished through analyzing costs and assigning each customer or rate class its proportionate share of the utility's total revenues and costs within the test year. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility.

In order to allocate costs to the various classes, I reviewed UGI Electric's expense and plant accounts and developed studies of the relative costs of providing facilities and services for each rate class and analyzed the key factors that cause the costs to vary.

Q. Please describe the Black & Veatch Model that was used in conducting the ACOSS filed in this proceeding.

A. UGI Electric has selected the Black & Veatch Model for purposes of conducting the ACOSS in this general base rate case. The Black & Veatch Model was developed by Black & Veatch on a proprietary basis for use in its consulting engagements. The Black & Veatch Model has been used in over a dozen jurisdictions on numerous occasions to develop electric and natural gas allocated class cost of service studies.

Q. Mr. Taylor, is the preparation of a cost allocation study an exact science?

A. No, it is not. The fundamental purpose of a cost allocation study is to aid in the design of rates to be charged by identifying all of the capital and operating costs incurred by a utility to provide service to all of its customers, and then assigning or allocating those costs to individual rate classes on the basis of how those rate classes cause the costs to be incurred. This process inherently requires a substantial level of judgment and can be more accurately described as engineering/accounting art, rather than science. Although there may be not be a perfect methodology for allocating costs, there are certain fundamental and foundational principles, i.e., cost causation and consistency, which should be followed in order to produce more accurate and reasonable results. As described in further detail below, the cost allocation studies I developed follow these principles.

Q. What is the guiding principle that should be followed when performing an ACOSS?

A. The ACOSS analysis is intended to establish cost responsibility among the various customer classes the utility serves. The analysis should result in an appropriate allocation of the utility's total revenue requirement among the various customer classes. The most important theoretical principle underlying an

ACOSS is that cost incurrence should follow cost causation. In other words, the costs assigned or allocated to particular customers should be those costs that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service.

Q. What are the steps to performing an ACOSS?

A. In order to establish the cost responsibility of each customer class, initially a three step analysis of the utility's total operating costs must be undertaken. The three steps that are the predicate for an ACOSS are: (1) cost functionalization; (2) cost classification; and (3) cost allocation.

Q. Please describe cost functionalization.

A. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. UGI Electric's primary functional cost categories associated with electric distribution service include: Primary Distribution, Secondary Distribution, and Customer Accounts and Services. In addition, various categories of costs within the distribution function are assigned to separate sub-functions to the extent their costs vary in response to different customer class characteristics. Indirect costs that support these functions, such as General Plant and Administrative and General Expenses, are allocated to functions using allocation factors related to plant and/or labor ratios.

Q. Please describe cost classification.

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

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

A. *Customer Costs* are incurred to extend service to and attach a customer to the distribution system, meter electric usage, and maintain the customer's account. Customer Costs are largely a function of the number of customers served, and continue to be incurred whether or not the customer uses any electricity. They also include capital costs associated with minimum size distribution systems, services, meters, and customer billing and accounting expenses.

Demand Costs are capacity-related costs associated with plant that is designed, installed, and operated to meet maximum hourly or daily electric usage requirements, such as generating plants, transmission lines, transformers and substations, or more localized distribution facilities which are designed to satisfy individual customer maximum demands.

Energy Costs are those costs that vary with the amount of kilowatt hours ("kWh") sold to customers. However, UGI Electric's distribution costs are fixed with respect to energy usage and none of the remaining delivery service cost structure is energy-related.

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

A. Usually a determination on the classification of costs can be made simply by knowing the type of activities or assets that reside in a particular FERC account. In these instances, the account as a whole can be classified. However, for some FERC account functions it is beneficial to conduct classification studies to determine the portion of an account that is associated with each classification.

Q. Are there generally accepted methods for preparing classification studies?

A. The generally accepted methods are set forth in the National Association of Regulatory Utility Commissioners ("NARUC") Cost Allocation Manual. UGI Electric adheres to these cost allocation principles to classify its distribution capital and operating costs. The NARUC Manual (pg. 96-98) specifically states that an electric utility's distribution-related facilities are, from a design and operational basis, sized to meet the maximum kW load (demand) requirements of customers. Moreover, the NARUC Manual (pg. 89) also states that all distribution costs should be classified as either customer- or demand-related, or a combination of these two factors. To achieve this classification result, UGI

Electric's distribution capital and operating costs are functionalized into their primary and secondary voltage level components. These primary and secondary voltage level capital and operating costs are then classified based on a "minimum size system" study, which identifies the portion of those costs required to serve a customer with minimum or no load, and that portion of the costs is allocated on a customer basis. The remaining portion of the costs is allocated on a demand basis, *i.e.*, based on each rate class' maximum non-coincident peak ("NCP") demand. The non-coincident peak is the class's maximum energy demand during the year in a given hour; an hour of time that may not correspond to the system peak.

Q. Do all experts accept this classification approach?

A. No, they do not. Some experts take issue with the "minimum size system" study approach. They assert that the demand allocators produced by this type of study reflect certain equipment that may have some load-carrying capability; they suggest that the zero intercept method may produce a better result. Others contend that some portion of the fixed components, *e.g.*, poles, conductors, services, and etc., of the distribution system should be classified on an energy basis. They also assert that the customer component is overstated and the demand component is understated.

Q. Why do you support the use of the minimum size system approach?

The cost allocation methodology utilized in the minimum system studies is based on the specific design and operating characteristics of the Company's distribution system, and provides a more accurate and consistent measure of class cost responsibility than other approaches for the provision of distribution service to its customers. In other electric distribution cases for which I have developed and/or testified on an ACOSS, a similar method was employed to develop a minimum system study; notably in PPL Electric Utilities Corporation's (PPL) recent rate case at Docket No. R-2015-2469275. Further, the proposed "minimum size system" study, which is set forth in UGI Electric Exhibit D, is based on the same methodology and criteria that was accepted by this Commission in PPL's general base rate case proceeding at Docket No. R-2012-2290597.

Q. Please describe cost allocation portion of the ACOSS.

A. The final step, cost allocation, is the allocation of each functionalized and classified cost element to the rate class (or classes) that benefits from the cost. Customers generally are divided into customer classes based on the type and character of services that they require. Costs typically are allocated to these customer classes based on the number of customers and the amount of capacity required to serve the customer class. For example, much of the plant and equipment cost is related to the peak demand of the customers in each class, and these costs were accordingly allocated based on the non-coincident peak demands of the rate class. Other portions of the cost depend upon the number of customers on the system and these costs were allocated on a customer, or weighted-customer, basis.

Q. How does the cost analyst establish the fully-allocated costs related to various utility services?

A. To establish these relationships, the cost analyst must analyze a utility's electric system design, physical configuration and operations, its accounting records, and its system and customer load data. From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q. Please explain the term "direct assignment."

A. The term "direct assignment" means the assignment of costs to a specific customer or class of customers based on that customer's or class' exclusive identification with the particular plant or expense at issue. Usually, costs that are directly assigned relate to costs incurred exclusively to serve a specific customer or classes of customers. For example, FERC Account 371.5 - Installations on Customer Premises - is solely related to area lighting and, as such, is directly assigned in full to that service class. Direct assignments best reflect the cost causative characteristics of serving individual customers or classes of customers. Therefore, in performing a cost of service study, the cost analyst seeks to maximize the amount of plant and expense directly assigned to a particular customer or customer classes to avoid the need to rely upon other more generalized allocation methods. An alternative to direct assignment is an allocation methodology based on an analysis of factors that affect the relative costs of serving particular customer classes.

Q. What prompts the cost analyst to elect to perform a study of the relative costs?

A. When direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, then further analysis may be conducted to derive an appropriate basis for cost allocation. For example, in this proceeding I developed a relative cost study for meter investment costs and services.

Q. Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned to a specific customer or certain customer classes?

A. No. The nature of utility operations is characterized by the existence of facilities used jointly or commonly by multiple customers and classes. To the extent that a utility's plant and expenses cannot be directly assigned to customer classes, allocation methods must be derived to assign or allocate the remaining costs to the customer classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

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

A. As stated above, in order to allocate costs within any cost of service study, the factors that cause the costs to be incurred must be identified and understood. The availability of data for use in developing alternative cost allocation factors is also a consideration. In evaluating any cost allocation methodology, appropriate consideration should be given to whether it provides a sound rationale or theoretical basis, whether the results reflect cost causation and are representative of the costs of serving different types of customers, as well as the stability of the results over time.

ALLOCATED COST OF SERVICE STUDY

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

A. All cost of service data has been extracted from the Company's total cost of service (*i.e.*, basic rate revenue requirement) contained in this general rate case filing for the fully projected future test year ending September 30, 2019. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company and information provided by Company personnel.

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

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

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

A. The process started with each of the Company's FERC accounts which were assigned to a specific function. In some instances, the costs in an account were first split into separate functions or classifications if the costs in the account were incurred to perform more than one function, or the costs in an account varied significantly with respect to more than one factor. For example, the accounts for distribution system poles; towers and fixtures; and conductors and conduits have been separated into two functions: primary distribution and secondary distribution. In addition, these costs have been further separated into demand

and customer classifications. The functionalization and classification studies are provided as Section I of UGI Electric Exhibit D. It should be noted that the functionalization and classification of distribution plant investment and expense is based on a detailed analysis of specific UGI Electric plant records and cost data.

Q. What cost assignment and allocation method was utilized in your studies?

A. UGI Electric utilizes the class maximum non-coincident peak demand method, which is based on the highest demand imposed by each rate class on its distribution system, to allocate its demand-related distribution costs. Section II of UGI Electric Exhibit D presents the results of studies using other demand allocation methods, as required under the PA PUC's regulations. Further, the various customer based allocation factors were developed utilizing Company records and data; including a meter investment allocation study and services investment allocation study. Both are described in further detail and provided within Section II of UGI Electric Exhibit D.

ALLOCATION OF THE REVENUE INCREASE

Q. How does the Company propose to allocate the distribution rate increase in this proceeding?

A. As described by Company witness David E. Lahoff (UGI Electric Statement No. 8); in order to properly reflect the results of the class cost-of-service study, the Company is proposing to move all rate classes closer to the overall system rate of return. As shown in UGI Electric Exhibit D the current relative rate of return for the Residential Class is 30% while the remaining classes have relative rates of return in excess of 200%. As a result, the Company's allocation results in a proposed increase to the Residential Class and no net change for those rate classes with rates of return above the system average.

RS CUSTOMER CHARGE

Q. What insight does the allocated class cost of service study provide with regard to the development of the residential customer charge?

A. Black & Veatch's ACOSS model allows for the development of the total revenue requirement by functions and classifications. As such, we can see directly the revenue requirement associated with the customer classification and the respective functions that form this revenue requirement. Table 1 below provides this information for the Residential class at the proposed rate increase.

Table 1—Components of Residential Customer Related Revenue Requirement

Customer Portion of Residential Revenue Requirement		
Function	**Amount**	**Includes**
Total Customer Related Costs	**$ 20,704,273**	Distribution Facilities -
Annual Bills (Customer Count * 12)	650,160	Customer Portion & PA PUC
Unit Costs	**$ 31.84**	Direct Customer Costs

Function	**Amount**	**Includes**
Distribution Facilities - Customer Portion	**$ 8,341,735**	Distribution Primary
Annual Bills (Customer Count * 12)	650,160	Distribution Secondary
Unit Costs	**$ 12.83**	

Function	**Amount**	**Includes**
PA PUC Direct Customer Costs	**$ 12,362,538**	Meters and Services Meter Reading
Annual Bills (Customer Count * 12)	650,160	Customer Service
Unit Costs	**$ 19.01**	Billing and Collections

As can be seen in the above table, the total customer related costs of $20.7M result in a monthly customer cost of $31.84. These costs are fixed with respect to the number of customers and do not vary related to the amount of energy used nor do they vary with the amount of demand. The total of $20.7M of customer related costs is broken down between the Distribution function and PA PUC Direct Customer Costs function. The customer portion of distribution facilities within the Distribution function (totaling $8.3M above) includes costs classified as customer related through the minimum size system study for poles, overhead and underground conductor, and conduit. The PA PUC Direct Customer Costs function (totaling $12.4M above) includes costs associated with meter reading, customer service, billing and collection expenses, and costs relating to meters and services.

Q. Can you please discuss the results in Table 1 above within the context of the Company's proposed residential customer charge of $14.00 and past PA PUC precedent?

A. Yes, past PA PUC precedent defines customer related costs for inclusion in a customer charge as costs associated with meters and services and related O&M expenses, meter reading and billing and collection expenses, and meter data management systems, and related employee benefits, administrative and general expenses. The PA PUC Customer Costs function contains only these costs historically allowed by the PA PUC in a customer charge. The Company is proposing a customer charge of $14.00 which is well below the total customer costs within the PA PUC Direct Customer Costs function; a monthly customer charge of $19.01.

Q. Please describe why an increase to the customer charge is important.

A. This becomes particularly important when a customer considers different options for the generation portion of his/her bill, and also when a customer considers investments in conservation and energy efficiency. A customer's purchasing decision regarding his/her generation supply, and the decision to invest in conservation and energy efficiency, are fundamentally functions of usage. Both of those decisions can be distorted when non-usage-related fixed costs are being collected on a usage basis. Moving the collection of distribution-related fixed costs from a usage basis to a fixed charge basis will make the savings available from investments in conservation and energy efficiency clearer to customers and society. Further, this creates a clearer distinction between when energy efficiency and conservation are beneficial to a customer and when utilizing the distribution grid is beneficial. Without proper price signals the market is distorted and companies and people cannot make the proper decision on allocating their limited resources of time and money.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC EXHIBIT JDT-1

John D. Taylor

Mr. Taylor is a utility pricing expert with experience developing renewable energy tariffs, time of use rates, residential and commercial rates, and assessing the relationship between price signals and the adoption of distributed generation assets. He has supported projects involving financial analysis, regulatory support and strategy, market assessment, litigation support, and organizational and operations reviews. He has worked as the market monitor for New England ISO's capacity market, supported the negotiation of PPAs, and supported feasibility and prudence studies of generation investments. Mr. Taylor's work often involves providing support for regulatory proceedings by conducting various studies and analyses related to revenue requirements, affiliate transactions, class cost of service, and cash working capital studies. He also has experience in asset and corporate valuation, the application of real options analysis, and various risk management techniques. He has filed testimony as an expert witness on class cost of service studies and on the appropriate use of statistical analysis during audit testing. He has also been involved in the sale of generating assets as sell side advisors, supporting due diligence efforts, financial analyses, and regulatory approval processes. Prior to joining Black & Veatch Mr. Taylor held various positions with Concentric Energy Advisors and worked in the non-destructive testing industry.

PRINCIPAL CONSULTANT

Specialization:
Utility Costing and Pricing, Expert Witness Testimony, Transaction Facilitation, Revenue Requirements, Statistics, Valuation, Market Studies, Rate Case Management, Transaction Facilitation, Energy Litigation Support, Expert Testimony

Office Location
Hilton Head Island, SC

Education
- M.A., Economics, American University, 2005
- B.A., Environmental Economics, University of North Carolina at Asheville, 2004…

Year Career Started
2000

Year Started with B&V
2015

REPRESENTATIVE PROJECT EXPERIENCE

Transaction Experience

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

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

Rate Design and Regulatory Proceedings

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

- Supported the development of an allocated class cost of service study and rate design for a Midwest electric utility.
- Developed revenue requirement model to comply with a new performance based formula ratemaking process for a Midwest electric utility.
- Supported the developed of time of use rates.
- Assessed the consequences of a divestiture on the cost of service model for a New England gas distribution company.
- Analyzed and summarized allocation methodology for a shared services company.
- Constructed the cost of service model for a Texas electric distribution utility.
- Assessed the reasonableness of costs through various benchmarking efforts.
- Led the effort to collect and organize plant addition documentation for six Midwest utilities associated with the state commission's audit of rate base.
- Supported lead-lag analysis and testimony.
- Analyzed customer usage profiles to support reclassification of rate classes for a gas utility.
- Helped conduct a marginal cost analysis to support rate design testimony.
- Conducted research on performance-based ratemaking and applicable precedents.
- Conducted a regression analysis to forecast use per customer to support a rate case for a gas utility.

Litigation Support and Expert Testimony

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

- Filed testimony as an expert witness on allocated class cost of service studies.
- Filed testimony as an expert witness on the application of statistical analysis.
- Compared revenue recovery mechanisms in multiple jurisdictions in support of return on equity testimony.
- Supported affiliate cost testimony for a New England utility and for a Midwest utility.
- Supported testimony relating to the regulatory approval of assets sales and the recovery of shared services charges to regulated affiliates.
- Performed asset valuations associated with spent nuclear fuel litigation.
- Conducted research to support testimony associated with the decoupling of gas rates.

- Supported testimony and produced a discounted cash flow analysis relating to a ‘lease in lease out’ transaction in the Netherlands.
- Provided research on precedents and ratemaking theory regarding consolidated tax adjustments to support expert testimony.

Financial Analysis

Other financial analysis Mr. Taylor has conducted include:

- Modeling alternative mechanisms for the allocation of overhead costs to a nuclear plant.
- Analyzing the implications of a merchant power plant entering into a financial swap.
- Assisting with the creation of a replacement cost model used to value generation assets.
- Researching regulations associated with a foreign company establishing a U.S. natural gas marketing division.

Market Research Experience

Other market research activities Mr. Taylor has been involved with include:

- Developed distributed CNG/LNG market studies for two separate utilities and two separate competitive market participants.
- Participated in the development of a peak shaving service market study for a mid-Atlantic utility.
- Researching and creating summaries of recent pipeline projects and LNG receiving facilities.
- Conducting research on potential Caribbean investment opportunities.
- Researching market dynamics and analyzing incentive structures in several restructured states.

EXPERT WITNESS TESTIMONY PRESENTATION

- Federal Energy Regulatory Commission
- Delaware Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Main Public Service Commission
- Minnesota Public Utilities Commission
- Pennsylvania Public Utility Commission
- British Columbia Utilities Commission

UGI ELECTRIC STATEMENT NO. 7 –
JOHN F. WIEDMAYER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2017-2640058

UGI Utilities, Inc. - Electric Division

Statement No. 7

Direct Testimony of
John F. Wiedmayer, C.D.P.

Topics Addressed: **Depreciation**

Date: January 26, 2018

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I. INTRODUCTION

Q. Please state your name and address.

A. My name is John F. Wiedmayer. My business address is 1010 Adams Avenue, Audubon, Pennsylvania 19403.

Q. Are you associated with any firm and in what capacity?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") as Project Manager, Depreciation and Valuation Studies.

Q. How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since I graduated from college in June 1986.

Q. What is your educational background?

A. I have an AB Engineering degree from Lafayette College and a Master of Business Administration from the Pennsylvania State University.

Q. Do you belong to any professional societies?

A. Yes. I am a member of the National and Pennsylvania Societies of Professional Engineers and the Society of Depreciation Professionals ("SDP"). In 2005, I served as President of the SDP and was a member of the SDP's Executive Board for the years 2003 through 2007.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The SDP has established national standards for depreciation professionals. The SDP administers an examination to become certified in this field. I passed the certification exam in September 1997 and have fulfilled the requirements necessary to remain a Certified Depreciation Professional.

Q. Please outline your experience in the field of depreciation.

A. I have over 31 years of depreciation experience, which includes expert testimony in numerous cases before 13 regulatory commissions, including this Commission.

In June 1986, I was employed by Gannett Fleming as a Depreciation Engineer. I held that position from June 1986 through December 1995. In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In August 2004, I was promoted to my present position as Project Manager of Depreciation Studies. I am responsible for conducting depreciation and valuation studies, including the preparation of testimony, exhibits, and responses to data requests for submission to the appropriate regulatory bodies. My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

During the course of my employment with Gannett Fleming I have assisted in the preparation of numerous depreciation studies for utility companies in various industries. I assisted in the preparation of depreciation studies for the following telephone companies: Alberta Government Telephone, Commonwealth Telephone Company, Telus, United Telephone Company of New Jersey and United Telephone of Pennsylvania. I assisted in the preparation of depreciation studies for the following companies in the railroad industry: CSX Transportation, Union Pacific Railroad, Burlington Northern Railroad, Burlington Northern Santa Fe Railway, Amtrak, Kansas

City Southern Railroad, Norfolk & Western, Southern Railway, and Norfolk Southern Corporation.

I assisted in the preparation of depreciation studies for the following organizations in the electric industry: AmerenUE, Arizona Public Service Company, UGI Utilities, Inc. - Electric Division, Penelec, Metropolitan Edison, Orlando Utilities Commission, the City of Red Deer, Nova Scotia Power, Newfoundland Power, Owen Electric Cooperative, Bangor Hydro Electric Company, Maine Public Service Company, Michigan Electric Transmission Company, PECO, Jackson Electric Cooperative Corporation, Houston Lighting and Power, TXU Energy, Maritime Electric, Nolin Rural Electric Cooperative, AmerenCIPS, AmerenCILCO, AmerenIP, ComEd, Con Edison Company of New York, Orange and Rockland, Rockland Electric (RECO), Baltimore Gas and Electric Company (BGE), Exelon Generation and the City of Calgary - Electric System.

I assisted in the preparation of depreciation studies for the following gas companies: BGE, PECO, UGI Utilities, Inc. – Gas Division, UGI Penn Natural Gas, Inc., North Penn Gas, PFG Gas, UGI Central Penn Gas, Inc., Equitable Gas, Centra Gas Alberta, Questar Gas, Orange and Rockland, Con Edison, Dominion East Ohio, AmerenUE, AmerenCILCO, AmerenCIPS, AmerenIP, Southern Connecticut Gas and Connecticut Natural Gas.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service lives and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies.

Q. Have you previously testified on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Kentucky Public Service Commission, the Newfoundland and Labrador Board of Commissioners of Public Utilities, the Nova Scotia Utility and Review Board, the Federal Energy Regulatory Commission, the Utah Public Service Commission, the Arizona Corporation Commission, the Missouri Public Service Commission, the Illinois Commerce Commission, the Maine Public Utilities Commission, the Maryland Public Service Commission, the New York Public Service Commission, the New Jersey Board of Public Utilities and the Pennsylvania Public Utility Commission ("PA PUC" or the "Commission").

Q. Have you received any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation" and "Managing a Depreciation Study." In 2000, I became an instructor at the SDP's annual conference lecturing on "Salvage Concepts," "Depreciation Models," "Analyzing the Life of Real-World Utility Property – Actuarial Analysis," "Theoretical Reserve" and "Data Requirements for a Depreciation Study." I have been a member of the Society of Depreciation Professionals since 1996. Also, I have been part of the faculty (depreciation trainers) for the Society of Depreciation Professionals since 1999 and have prepared and presented courses on depreciation matters each year at the Society's annual conference.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony is in support of the depreciation studies conducted under my direction and supervision for the electric plant of UGI Utilities, Inc. - Electric Division ("UGI Electric" or the "Company"). I have been retained by the Company as a depreciation consultant. UGI Electric retained me to determine the book depreciation reserve as of September 30, 2019, to determine the annual depreciation expense to be included as an element of the cost of service, and to testify in support of those two determinations in this proceeding.

I am also a sponsoring witness for UGI Electric's depreciated original cost of electric plant in service included in rate base. My testimony will address my depreciation study, the appropriate depreciation reserve for ratemaking purposes, the original cost measure of value, and the appropriate annual depreciation expense to be included in the ratemaking cost of service as of September 30, 2019.

Q. Were you responsible for the preparation of any of the Company's responses to the Commission's filing regulations that were filed in support of the Company's general rate filing?

A. Yes. I am the responsible witness for the following responses to the Commission's filing requirements:

Item No.	Subject
II-D-13	Experienced and Estimated Net Salvage
V-A-1	Electric Plant in Service
V-A-2	Comparison of Calculated Reserve vs. Book Reserve
V-A-3	Projected Plant and Reserve Balances
V-B-1	Comparison of Calculated vs. Book Accruals
V-B-2	Survivor Curves and Surviving Original Cost Including Related Annual and Accrued Depreciation
V-C-1	Retirement Rate Actuarial Method of Life Analysis
V-D-1	Summary Depreciation Calculations by Account
V-D-2	Detailed Depreciation Calculations by Account and Vintage Year
V-E-1	Description of Depreciation Methods and Factors Considered in Arriving at Estimates of Service Life and Dispersion by Account

Q. Have you previously prepared comparable studies for UGI Electric and its affiliates?

A. Yes. I assisted with the preparation of testimony on depreciation matters for the Company in its last base rate proceeding at Docket No. R-00953297, and in its electric restructuring proceeding, filed in accordance with the provisions of the Electricity Generation Customer Choice and Competition Act, at Docket No. R-00973975. I have also provided testimony on depreciation matters in the prior two UGI Penn Natural Gas, Inc. ("PNG") base rate cases at Docket No. R-2016-2580030 and Docket No. R-2008-2079660, the prior two UGI Central Penn Gas, Inc. ("CPG") base rate cases at Docket No. R-2010-

2214415 and Docket No. R-2008-2079675, and the most recent base rate case for UGI Utilities, Inc. - Gas Division ("UGI Gas") filed in 2016 at Docket No. R-2015-2518438. Prior to those rate filings, I prepared exhibits for the depreciation study in UGI Gas's previous base rate case filed in 1995 at Docket No. R-00953297.

III. OUTLINE OF EXHIBITS C (FULLY PROJECTED), C (FUTURE) AND C (HISTORIC)

Q. Will you be sponsoring any exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits: UGI Electric Exhibit C (Fully Projected), UGI Electric Exhibit C (Future) and UGI Electric Exhibit C (Historic). The three exhibits are separately bound reports included in the filing and are labelled as Books VI, VII and VIII. UGI Electric Exhibit C (Fully Projected) presents the summarized depreciation calculations and supporting tables related to the fully projected future test year ending September 30, 2019 ("FPFTY"). UGI Electric Exhibit C (Future) presents summarized depreciation calculations and supporting charts and tables related to the depreciation study for the future test year ending September 30, 2018 ("FTY"). UGI Electric Exhibit C (Historic) presents the summarized depreciation calculations and supporting tables related to the historic test year ended September 30, 2017 ("HTY"). Each of the three exhibits is organized in a similar manner and each contains information and schedules supporting the amounts applicable to each test year period. UGI Electric Exhibit C (Future) contains additional information including the supporting charts and life tables related to the service life estimates.

Q. Does UGI Electric Exhibit C (Fully Projected) accurately portray the results of your depreciation study as of September 30, 2019?

A. Yes.

Q. In preparing the depreciation study, did you follow generally accepted practices in the field of depreciation?

A. Yes.

Q. Please describe the contents of the depreciation study report, UGI Electric Exhibit C (Future) and UGI Electric Exhibit C (Fully Projected).

A. The depreciation study report in UGI Electric Exhibit C (Future) consists of eight parts including charts and tables filed in the Company's most recent service life study report submitted to the PA PUC in March 2017 based on electric plant in service as of September 30, 2016. Part I, Introduction, includes statements related to the scope of and basis for the depreciation study. Part II, Estimation of Survivor Curves, presents detailed discussions of: (1) survivor curves; and (2) methods of life analysis including an example of the retirement rate method. Part III, Service Life Considerations, presents the relevant factors considered for estimating service lives. Part IV, Calculation of Annual and Accrued Depreciation, sets forth a description of: (1) the group procedures used for calculating annual and accrued depreciation; and (2) an explanation of the manner in which net salvage was incorporated in the calculations. Part V, Results of Study, includes a description of the results and summaries of the detailed depreciation calculations as of September 30, 2018. Part VI, Service Life Statistics, presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. Part

VII, sets forth the detailed depreciation calculations related to surviving original cost as of September 30, 2018. The detailed depreciation calculations present the annual and accrued depreciation amounts by account and vintage year. The remaining life annual accrual rate is also set forth in the tables of Part VII. Part VIII, Experienced and Estimated Net Salvage, contains the net salvage amortization of experienced and estimated net salvage for the fiscal years 2014 through 2018 encompassing the period October 1, 2013 through September 30, 2018.

UGI Electric Exhibit C (Fully Projected) includes: a description of the scope, basis and results of the studies; summaries of the depreciation calculations; and the detailed depreciation calculations as of September 30, 2019. The descriptions and explanations presented in UGI Electric Exhibit C (Future) are also applicable to the depreciation calculations presented in UGI Electric Exhibit C (Fully Projected). The graphs and tables related to service life presented in UGI Electric Exhibit C (Future) also support the service life estimates used in UGI Electric Exhibit C (Fully Projected) and UGI Electric Exhibit C (Historic), since the estimates are the same for all three test years.

The results of the study are set forth in Part II in UGI Electric Exhibit C (Fully Projected). Table 1, pages II-3 through II-4 of UGI Electric Exhibit C (Fully Projected), presents the estimated survivor curve, the original cost and depreciation reserve at September 30, 2019, and the calculated annual depreciation rate and amount for each account or subaccount of Electric Plant in Service. Table 2, pages II-5 through II-6 of UGI Electric Exhibit C (Fully Projected), presents the bring-forward to September 30, 2019 of the depreciation reserve as of September 30, 2018. Table 3, pages II-7 through II-8 of UGI Electric Exhibit C (Fully Projected), presents the calculation of the book depreciation amounts for the FPFTY. Table 4, page II-9 of UGI Electric Exhibit C (Fully Projected), presents the experienced and estimated net salvage for fiscal years 2015 through 2019. The amortization of net salvage is based on experienced and estimated net salvage during the period October 1, 2014 through September 30, 2019. The summary tables and detailed depreciation calculations set forth in UGI Electric Exhibit C (Fully Projected) as of September 30, 2019, are organized and presented in the same manner as those presented in UGI Electric Exhibit C (Future) as of September 30, 2018.

Q. Please outline the contents of Exhibit C (Historic).

A. UGI Electric Exhibit C (Historic) is organized like UGI Electric Exhibit C (Fully Projected). UGI Electric Exhibit C (Historic) includes: a description of the scope, basis and results of the studies; summaries of the depreciation calculations; and the detailed depreciation calculations as of September 30, 2017. The descriptions and explanations presented in UGI Electric Exhibit C (Future) are also applicable to the depreciation calculations presented in UGI Electric Exhibit C (Historic). The same depreciation methods and procedures used to calculate depreciation were used in all three test-year periods. The summary tables and detailed depreciation calculations as of September 30, 2017 are organized and presented in the same manner as those as of September 30, 2019 with two exceptions. Tables 2 and 3 presented in UGI Electric Exhibit C (Fully Projected) are not necessary and, therefore, are not presented in UGI Electric Exhibit C (Historic).

IV. THE DEPRECIATION STUDY - OVERVIEW

Q. Please describe what you mean by the term "depreciation".

A. My use of the term "depreciation" is in accord with the definition set forth in the FERC's Uniform System of Accounts at 18 C.F.R. Chapter I, Subpart C, Part 101. "Depreciation" refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation, against which the company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.

In the study that I performed, which is the basis for my testimony, I used the straight line remaining life method of depreciation, with the average service life and equal life group procedures. The annual depreciation is based on a system of depreciation accounting that aims to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of the unit, or group of assets, in a systematic and rational manner.

Q. Is the Company's claim for annual depreciation in the current proceeding based on the same methods of depreciation as were used in its most recent Annual Depreciation and Service Life Study Report filed in March 2017?

A. Yes, it is. For most plant accounts, the current claim for annual depreciation is based on the straight line remaining life method of depreciation, which has been used by the Company for many years. The depreciation methods and procedures are described further in Part II of UGI Electric Exhibit C (Future).

For General Plant Accounts 391, 393, 394, 395, 397 and 398, I used the straight line remaining life method of amortization. The annual amortization is based on amortization accounting, which distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account.

V. ORIGINAL COST MEASURE OF VALUE

Q. What is the original cost of electric plant to be included in rate base in this proceeding?

A. As of September 30, 2019, the original cost of electric plant in service is $183,333,691 as shown in column 4 of Table 1 on pages II-3 through II-4 of UGI Electric Exhibit C (Fully Projected). This amount includes $169,949,839 of Electric Plant and $13,383,852 of Other Utility Plant allocated to UGI Electric. Other Utility Plant is primarily comprised of plant assets included in Common Plant and Information Services ("IS"). The assets included in Common Plant and IS are assets that are shared and jointly used among UGI Corporation and its subsidiaries including UGI Electric. The costs related to Common Plant and IS are allocated to UGI Electric using the Modified Wisconsin Formula at 5.66 percent and 9.32 percent, respectively. In addition, the building that houses most of the IS assets, *i.e.*, the Reading Office and Service Center located on 225 Morgantown Road, is included in Account 390.1, Structures and Improvements in Gas Division. Since a portion of the building on Morgantown Road relates to IS, a portion, *i.e.*, 11.32 percent, of the cost of the building was assigned to UGI Electric.

Also, all 22.5572 percent of the Electric Division's Intangible, General and Common Plant that were included in the Company's most recent transmission rate filing before FERC were excluded from the Company's current claim in this base rate filing. The amounts allocated to Transmission Plant and excluded from electric distribution operations are shown on Table 1 of Exhibit C (Fully Projected).

VI. THE ACCRUED DEPRECIATION CLAIM

Q. Have you determined UGI Electric's accrued depreciation for ratemaking purposes as of September 30, 2019?

A. Yes. I have determined the allocated book depreciation reserve as of September 30, 2019, to be $59,711,304.

Q. Is the Company's claim for accrued depreciation in the current proceeding made on the same basis as has been used for over thirty years?

A. Yes. The current claim for accrued depreciation is the book reserve brought forward from the book reserve approved by the Commission in the last base rate proceeding.

Q. How did you determine UGI Electric's allocated book depreciation reserve as of September 30, 2018?

A. The book depreciation reserve allocated to UGI Electric as of September 30, 2018, is set forth in column 5 of Table 1 of UGI Electric Exhibit C (Future). Table 2 of UGI Electric Exhibit C (Future) presents an annual bring-forward of the book depreciation reserve as of September 30, 2017, using estimated accruals, retirements, salvage and cost of removal for the twelve months

October 2017 through September 2018. The table sets forth, by plant account, the beginning book reserve balance as of September 30, 2017, the estimated reserve activity, and the ending reserve balance as of September 30, 2018. The estimated reserve activity consists of depreciation accruals (column 3), amortization of net salvage (column 4), projected retirements (column 5), projected salvage (column 6) and projected cost of removal (column 7). Table 3 of UGI Electric Exhibit C (Future) sets forth the calculation of the estimated depreciation accruals by plant account, which is carried forward to column 3 of Table 2. The book reserve as of September 30, 2017, by plant account, shown in column 2 of Table 2 was obtained from UGI Electric's books and records.

Q. Please explain the manner in which you projected the depreciation accruals for the twelve months ended September 30, 2018.

A. The depreciation accruals for the twelve months ended September 30, 2018, by plant account, were estimated by applying the annual depreciation accrual rates calculated as of September 30, 2017, to the projected average 2018 plant balance. The average balance for the twelve months ended September 30, 2018, is computed in columns 2 through 6 of Table 3 and is based on the projected additions and retirements in columns 3 and 4.

Q. With reference to Exhibit C (Future) Table 2, column 4, please explain what you mean by "the amortization of net salvage" and explain the manner in which you projected it.

A. The amortization of net salvage is the annual provision for recovering experienced negative net salvage. This process for recognizing net salvage in the cost of service is in accordance with Pennsylvania ratemaking practice. The amortization of net salvage is based on experienced and projected net salvage for the five-year period, October 1, 2013 through September 30, 2018.

Q. Please explain the manner in which you projected retirements, salvage and removal costs that are shown in columns 4, 5 and 6 of Table 2.

A. Retirements were projected by plant account by applying the average retirement ratio, expressed as a percent of additions, i.e., 2014 through 2018, to future test year (FTY) additions for most plant accounts. For certain General Plant accounts subject to amortization accounting, retirements are recorded when a vintage is fully amortized. All units are retired per books when the age of the vintage reaches the amortization period. Therefore, all vintages that reached or exceeded the amortization period were retired during the FTY for certain General Plant accounts subject to amortization accounting. Salvage and removal costs were projected by plant account by applying the average salvage and cost of removal, expressed as a percent of retirement amounts for the five years 2014 through 2018, to the projected retirement amounts.

Q. Was the book reserve at September 30, 2019, estimated using the same methodology?

A. Yes, it was essentially the same methodology with one minor exception. The book depreciation accruals calculated for fiscal year 2019 were based on applying depreciation rates calculated as of September 30, 2018 to average monthly plant balances for purposes of calculating the book reserve as of September 30, 2019.

VII. THE ANNUAL DEPRECIATION EXPENSE CLAIM

Q. Have you determined UGI Electric's annual depreciation expense to be included as an element in the cost of service for purposes of this proceeding?

A. Yes, I have. The annual depreciation expense is $5,760,526 and consists of $5,116,978 of annual accruals to recover original cost and $643,548 of net salvage amortization. The $5,116,978 related to original cost recovery is comprised of two parts, $4,144,719 related to electric plant and $972,259 related to Other Utility Plant allocated to UGI Electric. These amounts are set forth in column 8 of Table 1 in UGI Electric Exhibit C (Fully Projected).

Q. How did you determine the annual accruals of $5,116,978?

A. The determination of annual depreciation accruals consists of two phases. In the first phase, survivor curves are estimated for each plant account or subaccount. In the second phase, the composite remaining lives and annual depreciation accruals are calculated based on the service life estimates determined in the first phase.

The determination of annual amortization amounts consists of the selection of amortization periods and the calculation of amortization amounts based on the remaining amortization period and the unrecovered cost for each vintage.

Q. Please describe the manner in which you estimated the service life characteristics for each depreciable group in the first phase of the study.

A. The service life study first compiled historical data from records related to UGI Electric's electric plant and analyzing this data to obtain historical trends of survivor characteristics. I then also obtained supplementary information from management and operating personnel concerning UGI Electric's practices and plans as they relate to plant operations, and used this data and supplementary information to form judgments of average service life characteristics.

Q. What historical data did you analyze for the purpose of estimating the service life characteristics of UGI Electric's electric plant?

A. The data consisted of the entries made by UGI Electric to record electric plant transactions during the period 1960 through 2016. The transactions included additions, retirements, transfers, acquisitions, and the related balances. I classified the data by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed.

Q. What method did you use to analyze these service life data?

A. I used the retirement rate method of life analysis. The retirement rate method is the most appropriate when aged retirement data are available because it develops the average rates of retirement actually experienced during the period of study. Other methods of life analysis infer the rates of retirement based on a selected type survivor curve.

Q. Please describe the results of your use of the retirement rate method.

A. Each retirement rate analysis resulted in a life table, which, when plotted, formed an original survivor curve. Each original survivor curve, as plotted from the life table, represents the average survivor pattern experienced by the several vintage groups during the experience band studied. Inasmuch as this survivor pattern does not necessarily describe the life characteristics of the property group, interpretation of the original curves is required in order to use them as valid considerations in service life estimation. Iowa type survivor curves were used in these interpretations. The results of the retirement rate analyses are presented in Part VI of UGI Electric Exhibit C (Future).

Q. Please explain briefly what an "Iowa type survivor curve" is and how you use it in estimating service life characteristics for each depreciable group.

A. The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type survivor curves. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. Iowa curves are the accepted survivor curves for Pennsylvania, and the remaining 49 other states, and have been for many years.

Iowa type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the qualitative outlook for future retirements.

The estimated survivor curve designations for each depreciable group indicate the average service life, the family within the Iowa system and the relative height of the mode. For example, the Iowa 36-R2.5 curve indicates an average service life of thirty-six years; a Right-skewed, or R2.5, type curve (the mode occurs after average life for right modal curves); and a relatively medium height, 2.5, for the mode (possible modes for R type curves range from 0.5 to 5).

Q. Did you physically observe plant and equipment in the field?

A. Yes. Field trips are conducted periodically in order to be familiar with the operation of the Company and observe representative portions of the plant. Field trips are conducted each time a service life study is performed. Service life study reports are submitted to the PA PUC every five years, at minimum. UGI Electric's most recent service life study report was submitted in March 2017 based on electric plant in service as of September 30, 2016. Facilities visited during field trips generally include representative substations, service centers, warehouses, and office buildings. The most recent field trip was conducted in January 2017. The specific dates and locations visited during recent field trips are listed in Exhibit C (Future) in Part III. A general understanding of the function of the plant and information with respect to the reasons for past retirements and expected causes of retirements are obtained during these field trips. This knowledge and information was incorporated in the interpretation and extrapolation of the statistical life analyses.

Q. Please describe the second phase of the process that you used in order to determine annual depreciation for ratemaking purposes.

A. After I estimated the service life characteristics for each depreciable group, I calculated annual depreciation accruals for each group in accordance with the straight line remaining life method, using remaining lives consistent with the average service life procedure for plant installed prior to 1982 and remaining lives consistent with the equal life group procedure for plant installed in 1982 and subsequent years. Summary tabulations of the survivor curve estimates and the annual accrual rates and amounts are set forth on Table 1 of UGI Electric Exhibit C (Historic), UGI Electric Exhibit C (Future) and UGI Electric Exhibit C (Fully Projected). The detailed tabulations of the depreciation calculations are presented in Part III of UGI Electric Exhibit C (Historic) and UGI Electric Exhibit C (Fully Projected) and Part VII of UGI Electric Exhibit C (Future).

Q. Please describe briefly the straight line remaining life method of depreciation that you used for depreciable property.

A. The straight line remaining life method of depreciation allocates the original cost less accumulated depreciation in equal amounts to each year of remaining service life for each vintage.

Q. Please describe briefly the average service life procedure that you used in conjunction with the straight line remaining life method for plant installed prior to 1982.

A. In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated survivor curve.

Q. Please describe briefly the equal life group procedure that you used in conjunction with the straight line remaining life method for plant installed in 1982 and in later years.

A. In the equal life group procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the composite remaining life for the surviving original cost of that vintage. The composite remaining life for the vintage is derived by weighting the individual equal life group remaining lives. In the equal life group procedure, the property group is subdivided according to service life. That is, each equal life group includes the portion of the property that experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve.

Q. Please describe briefly the amortization of certain General Plant accounts.

A. General Plant Accounts 391, 393, 394, 395, 397 and 398 include a very large number of units, but represent a very small percent of depreciable electric plant. Depreciation accounting is difficult for these assets, inasmuch as periodic inventories are required to properly reflect plant in service. Many utilities have changed to amortization accounting for general plant as a practical and reasonable solution that avoids significant accounting expenditures for such a small percent of plant.

In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, retirements are recorded when a vintage is fully amortized, rather than as the units are removed from service. That is, there is no dispersion of retirement for accounts being amortized. All units are retired per books when the age of the vintage reaches the amortization period. Amortization accounting was initiated for the Electric Division in the 1994 base rate case at Docket No. R-00932862.

VIII. ILLUSTRATION OF DEPRECIATION STUDY PROCEDURE

Q. Please illustrate the procedure followed in your depreciation study and the manner in which it is presented in UGI Electric Exhibit C (Future) using an account as an example.

A. I will use Account 368.1, Transformers, to illustrate the manner in which the study was conducted. Account 368.1 represents approximately 9 percent of the total depreciable distribution plant. As the initial step of the service life study phase, aged plant accounting data were compiled for the years 1960 through 2016. These data have been coded in the course of UGI Electric's normal recordkeeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the electric plant was placed in service. The plant additions, retirements, and other plant transactions were analyzed by the retirement rate method of life analysis.

This account includes equipment used to reduce electric voltages, primarily pole-top or pad mounted line transformers. Retirements of line transformers are primarily caused by storm damage, deterioration, fire or third-party damage, capacity or loading issues, etc. Most of the pre-1983 line transformers that contained polychlorinated biphenyls ("PCBs") have been removed. Discussions with operating and management personnel indicated that the life characteristics of transformers will be similar in the future as they have been in the past. Typical service lives for line transformers of other electric companies range from 30 to 45 years.

The life analysis was performed and the Iowa 43-S1 survivor curve was judged most appropriate for this account and is the survivor curve used for this filing. The survivor curve estimate used in the previous service life study was the Iowa 40-S1 survivor curve. The Iowa 43-S1 survivor curve is a good fit for the original curve based on the company's retirement experience for the period 1960-2016. The proposed 43-S1 survivor curve is within the range of estimates used by other electric companies and is consistent with the outlook of Company management. The original and smooth survivor curves are plotted in Part VI on page VI-9 of UGI Electric Exhibit C (Future). The original life table for the 1960-2016 experience band is set forth on pages VI-10 through VI-13.

The calculation of annual depreciation, the second phase, for the original cost of line transformers in service at September 30, 2018, is presented by vintage in Part VII on pages VII-19 through VII-21 of UGI Electric Exhibit C (Future) for Electric Plant in Service. The detailed depreciation calculations at September 30, 2019 are presented in Part III of Exhibit C (Fully Projected). The tabular presentations of the detailed depreciation calculations in Part VII of Exhibit C (Future) are similar in kind to those set forth in Part III of Exhibit C (Fully Projected). The expectancy and average life derived from the estimated survivor curve for each vintage were used to calculate the accrued depreciation by the average service life procedure for 1981 and prior vintages.

The accrued depreciation for vintages subsequent to 1981 was calculated by the equal life group procedure using the Iowa 43-S1 survivor curve. In the calculation, the surviving cost in each vintage was further subdivided, through the use of a computer program, into depreciable groups according to the expected service lives as defined by the Iowa 43-S1 survivor curve. The accrued depreciation was derived for each equal life group, based on its service life, and the totals shown for the vintages are the summations of the individually derived amounts.

The book reserve was allocated to vintages based on the calculated accrued depreciation. The remaining lives of the vintages were based on the Iowa 43-S1 survivor curve, the attained age, and the same group procedures as were used to calculate accrued depreciation. The future book accruals (original cost less allocated book reserve) were divided by the remaining lives to derive the annual depreciation accruals by vintage.

The total depreciation accrual on page VII-21 of UGI Electric Exhibit C (Future) was brought forward to column 8 of Table 1 on page V-4 of the exhibit and divided by the total original cost in column 4 in order to calculate the annual depreciation accrual rate in column 7. A similar process was used for the fully projected future test year (FPFTY).

Q. Is the procedure you described for Account 368.1 typical of that followed for most of the plant investment?

A. Yes, it is, since the straight-line method, the average service life and the equal life group procedures were used for most of the depreciable plant.

Q. Please illustrate the procedure followed for the amortization of certain General Plant accounts and the manner in which it is presented in UGI Electric Exhibit C (Future) using an account as an example.

A. I will use Account 394, Tools, Shop and Garage Equipment, to illustrate the amortization procedure. As the initial step of the amortization procedure, an amortization period of 20 years was selected based on the period during which such equipment renders most of its service, the amortization periods used by other utilities, and the service life estimate previously used for depreciation accounting.

The calculation of the annual amortization as of September 30, 2018, is presented by vintage in Part VII on page VII-55 of UGI Electric Exhibit C (Future). The calculated accrued amortization is based on the ratio of the vintage's age to the amortization period. The book reserve for vintages older than the amortization period was set equal to the original cost. The remaining book reserve was allocated to vintages based on the calculated accrued depreciation. The future book accruals or amortizations (original cost less assigned or allocated book reserve) were divided by the remaining amortization period to derive the annual amortizations by vintage.

The total amortization on page VII-55 of UGI Electric Exhibit C (Future) was brought forward to column 8 of Table 1 on page V-4 of UGI Electric Exhibit C (Future). A similar process was performed for UGI Electric Exhibit C (Fully Projected) and UGI Electric Exhibit C (Historic). That is, the calculation of the annual amortization related to the original cost of Tools, Shop and Garage Equipment in service at September 30, 2019, is presented by vintage on page III-56 of UGI Electric Exhibit C (Fully Projected) and summarized in Table 1 on page II-3.

Q. Briefly explain the methods used for the remaining portion of the depreciable plant.

A. The life span procedure was applied to major structures in Account 390. The life span procedure was used for groups such as buildings in which concurrent retirement of all property in the group is expected. The life span of both the original installation and subsequent additions is the number of years between installation and final retirement of the group. The complete details, by vintage, of the accrued depreciation and remaining life accrual calculations are set forth for each structure in Part III of UGI Electric Exhibit C (Historic) and UGI Electric Exhibit C (Fully Projected) and in Part VII of UGI Electric Exhibit C (Future).

IX. THE NET SALVAGE AMORTIZATION CLAIM

Q. Please briefly describe the accounting treatment regarding net salvage for public utilities operating in Pennsylvania.

A. In accordance with the Uniform System of Accounts and the rules for recovery of net salvage established by the Pennsylvania Superior Court in *Penn Sheraton Hotel v. Pa. P.U.C.*, 198 Pa. Super. 618, 184 A.2d 324 (1962) ("*Penn Sheraton*"), net salvage is charged to the depreciation reserve and is amortized over a five-year period beginning with the year after net salvage is actually incurred. These accounting procedures were affirmed by the Commission in PPL Gas Utilities Corporation's ("PPL Gas") most recent rate filing (Docket No. R-00061398). This procedure is consistent with how other Pennsylvania public utilities account for net salvage and is the method used in preparing the company's Annual Depreciation Reports submitted each year to the Commission.

Q. Earlier in your testimony you indicated that UGI Electric's annual depreciation expense consists, in part, of $643,548 of net salvage amortization. How did you determine that amount?

A. The $643,548 is the result of determining the five-year average of net salvage experienced and estimated during the period of October 1, 2014 through September 30, 2019. Net salvage is defined in the Uniform System of Accounts as salvage value less cost of removal. For most electric utilities, including UGI Electric, cost of removal exceeds salvage value resulting in negative net salvage. Negative net salvage is recorded to the depreciation reserve as a debit, which reduces the depreciation reserve. Charges related to the negative net salvage amortization are recorded to the depreciation reserve as a credit in the five years subsequent to the initial recording of the negative net salvage amount. Therefore, the negative net salvage amount will have been fully amortized after five years and the net effect on the depreciation reserve is zero. Detailed data related to the experienced and estimated cost of removal and salvage are presented in Part VIII of UGI Electric Exhibit C (Future) and Part IV of UGI Electric Exhibit C (Fully Projected).

Q. Do you have any other comments on the other items which you are sponsoring in this proceeding?

A. Yes. The above testimony does not describe the responses to filing requirements set forth in Items V-A-2, V-B-1 and V-B-2. In general, these responses are self-explanatory. The response to V-A-2 is a comparison of the actual and projected book depreciation reserves with the calculated accrued depreciation as of the end of the test years. The response to V-B-1 is a comparison of the calculated depreciation accruals and the book depreciation accruals related to the future and fully projected future test years. The response to V-B-2 presents the survivor curves used in the most recent prior general rate proceeding and the annual accrual rates that resulted from the use of these curves.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC STATEMENT NO. 8 – DAVID E. LAHOFF

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2017-2640058

UGI Utilities, Inc. – Electric Division

Statement No. 8

Direct Testimony of
David E. Lahoff

Topics Addressed:	**Sales and Revenues** **Rate Structure and New Riders** **Revenue Allocation and Rate Design** **Tariff Changes**

Dated: January 26, 2018

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David E. Lahoff. My business address is 2525 N. 12th Street, Suite 360, Reading, Pennsylvania 19612.

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

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

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

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

Q. Please provide your educational background.

A. I received an undergraduate degree in business from The Pennsylvania State University and a Master's Degree in Business Administration from The University of Connecticut.

Q. Please provide your professional experience.

A. In 2002, I was named Manager, Special Projects for UGI. In 2003, I became Manager, Customer Accounting Services for UGI, where my responsibilities included the administration of all customer accounting functions. Beginning in 2007, I returned to the position of Manager, Special Projects to oversee a customer information system conversion project. Following the completion of that project in 2009, I was named Manager of Rates. In 2014, I assumed the position of Senior Manager, Tariff & Supplier Administration.

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

A. Yes, I have testified in the following dockets: UGI Central Penn Gas, Inc. ("CPG") 2009 Base Rate Case, Docket No. R-2008-2079675; UGI Penn Natural Gas, Inc. ("PNG") 2009 Base Rate Case, Docket No. R-2008-2079660; UGI Gas 2009 Annual Gas Cost Filing, Docket No. R-2009-2105911; UGI Gas Petition to Implement a Purchase of Receivables Program and Merchant Function Charge, Docket No. P-2009-2145498; CPG 2011 Base Rate Case, Docket No. R-2010-2214415; UGI Gas Procurement Charge Filing, Docket No. R-2012-2314235; PNG Gas Procurement Charge Filing, Docket No. R-2012-2314224; CPG Gas Procurement Charge Filing, Docket No. R-2012-2314247; UGI Gas, PNG and CPG Growth Extension Tariff ("GET Gas") Filing, Docket No. P-2013-2356232; UGI Electric Default Service Filing, Docket No. P-2013-2357013; UGI Gas 2016 Base Rate Case, Docket No. R-2015-2518438; and PNG Base Rate case, Docket R-2016-2580030.

Q. Please describe the purpose of your testimony.

A. I will address: (1) the development of sales and revenue for the historic test year ended September 30, 2017 ("HTY"), future test year ending September 30, 2018 ("FTY"), and fully projected future test year ending September 30, 2019 ("FPFTY"); (2) UGI Electric's proposed rate structure; (3) the proposed revenue allocation and rate design; (4) the proposed Universal Service Plan ("USP") Rider; (5) UGI Electric's proposed Rate EV for electric vehicle charging stations; (6) UGI Electric's proposed Storm Expense Rider; and (7) other proposed tariff modifications.

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

A. Yes, I am sponsoring the following Exhibits: UGI Electric Exhibit DEL-1 (15 year Normal Heating and Cooling Degree Days 2000-2014), UGI Electric Exhibit DEL-2 (UGI Electric Customer Counts), UGI Electric Exhibit DEL-3 (Fully Projected Future Test Year Sales and Revenue Adjustments), UGI Electric Exhibit DEL-4 (Future Test Year Sales and Revenue Adjustments), UGI Electric Exhibit DEL-5 (Historic Test Year Sales and Revenue Adjustments), UGI Electric Exhibit DEL-6 (USP Rider Calculations), UGI Electric Exhibit DEL-7 (Rate EV calculations), and UGI Electric Exhibit DEL-8 (meter and customer costs for Rate HTP update).

II. <u>TEST YEARS' SALES AND REVENUES</u>

A. Development of FPFTY Sales and Revenues

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

A. FPFTY sales and revenues were developed by annualizing and normalizing the Company's 2019 fiscal year planned sales and revenue budget. Annualized sales were determined by developing sales and revenue adjustments reflective of annual expected use per customer and projected customer counts as of the end of the FPFTY, or September 30, 2019. UGI Electric Exhibit DEL-1 provides the development of the Company's normal degree day values which are based on the 15-year period 2000-2014. This data was used in normalizing use per customer for degree days. The Company's 15-year normal is updated every 5 years, with the most recent being that related to the 15-year period of 2000-2014.

Q. Please explain the process for developing the Company's fiscal year 2019 planned sales and revenue budget.

A. The planned sales and revenue budget was developed by the rates department with input from various UGI Electric personnel and utilized historical trends in the number of customers, sales and revenue. One of the primary drivers of the customer count forecast is the nature of the UGI Electric service territory. The service territory is very static with little to no growth in the number of customers from year to year. UGI Electric Exhibit DEL-2 provides the actual historical customer count and illustrates the relatively static nature of the service territory.

The Company developed the planned number of customers by using, as a starting point, the actual customer counts by rate class for March 2017, which was the most current month for which there was actual data at the time of the development of the budget. That March customer count is then adjusted for April based on a historical average of the monthly change between March and April. A similar adjustment is then made for each month through the end of the FPFTY, or September 2019.

The budgeted use per customer was developed using a long-term average of each month's actual usage per customer by class, which approximates a normalized value. The use per customer for residential classes was developed based on a 15-year average. Non-residential use per customer was based on average usage over time periods ranging from 8 to 14 years, depending on the rate class.

The derivation of the 2019 planned budget reflects a preliminary forecast that will be updated during 2018 as part of the normal annual budget process, which is conducted several months prior to the start of the new fiscal year. The complete budget process is described in the Direct Testimony of Company witness Stephen F. Anzaldo (UGI Electric Statement No. 2).

Q. Please describe the adjustments made to FPFTY sales and revenues for the twelve months ending September 30, 2019.

A. A summary of all adjustments made to the 2019 planned budget in order to develop FPFTY sales is shown on UGI Electric Exhibit DEL-3(a). In total, these adjustments reflect a decrease to sales of 1,783,000 kilowatt hours ("kWh"), or 0.17%, with a net downward adjustment to margin of $45,000.

Q. Please explain the "Adjustment for Customer Changes" shown on UGI Electric Exhibit DEL-3(b).

A. The "Adjustment for Customer Changes" annualizes customer counts to anticipated end-of-test-year levels based on the Company's most recent forecast for the FPFTY.

Q. How is this adjustment quantified?

A. UGI Electric Exhibit DEL-3(b) provides the calculation of the associated sales and revenue adjustments for the stated customer count decreases for Rate R, and UGI Electric Exhibit DEL-3(c) provides the calculation of the associated sales and revenue adjustments for the stated customer count increase for commercial Rate GS4. These are the two rate classes with the largest total margin dollars and represent the majority of the Company's overall margin dollars. In total, as reflected on UGI Electric Exhibit DEL-3(a), this adjustment increases sales by 287,000 kWh and increases projected revenues by $17,000. The impact to margin is an increase of $8,000.

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

A. As noted earlier, the use per customer values for the budget were based on recent actual long-term averages for the months available. As the associated average degree days for the periods associated with the budget development differ from the Company's 15-year period used to define normal degree days, or normal weather, an adjustment is necessary in order to normalize usage to the Company's 15-year normal weather. This adjustment utilizes the variance between the calculated average degree days for the periods utilized for budget development and the Company's 15-year normal degree days in order to calculate the normalizing adjustments. *See* UGI Electric Exhibit DEL-1. UGI Electric Exhibits DEL-3(d) and 3(e) show the calculation of the adjustment of the use per customer for Rate R and Commercial Rate GS4, respectively. As shown in the exhibits, this adjustment is calculated by applying the heating and cooling sensitivity per degree day to the difference between the calculated average degree days for the periods utilized for budget development and the Company's 15-year normal degree days. In total, as reflected on UGI Electric Exhibit DEL-3(a), this adjustment decreases sales by 2.1 million kWh and decreases projected revenues by $212,000. The impact to margin is a decrease of $53,000.

Q Please explain the adjustment on UGI Electric Exhibit DEL-3(f) "Adjustment for GSR."

A. The "Adjustment for GSR" annualizes the revenue from the GSR based on the December 1, 2017 GSR rate of $0.06643/kWh versus its budgeted level of $0.06214/ kWh. This GSR adjustment increases projected revenues by $2.9 million with no impact to margin.

Q Please explain the adjustment on UGI Electric Exhibit DEL-3(g) "Adjustment for CAP."

A. The "Adjustment for CAP" annualizes the revenue from the UGI Electric CAP Rider ("CAP") based on the December 1, 2017 CAP Rider rate of $0.00354/ kWh versus its budgeted level of $0.00339/ kWh. This CAP adjustment increases projected revenues by $75,000 with no impact to margin.

Q Please explain the adjustment on UGI Electric Exhibit DEL-3(h) "Adjustment for EE&C."

A. The "Adjustment for EE&C" annualizes the revenue from the UGI Electric EE&C Rider ("EE&C") based on the September 1, 2017 EE&C Rider rates of $0.00236/ kWh for Class 1 (Rates R, RWT, RTU, GS5, and the residential portion of Rates CWH, OL, SOL, and MHOL), $0.00248/ kWh for Class 2 (all non-residential rates except LP and IH) and $0.00115/ kWh for Class 3 (Rates LP and IH) versus budgeted levels by class of $0.00287/ kWh for Class 1, $0.00249/ kWh for Class 2, and $0.00335/ kWh for Class 3. This EE&C adjustment decreases projected revenues by $919,000 with no impact to margin.

Q Please explain the adjustment on UGI Electric Exhibit DEL-3(i) "Adjustment for STAS."

A. The "Adjustment for STAS" annualizes the revenue from the UGI Electric State Tax Adjustment Surcharge ("STAS") based on the October 20, 2017 rate of 1.36% versus its budgeted level of 1.57%. This STAS adjustment decreases projected revenues by $174,000 with no impact to margin.

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

Q. How were normalized and annualized sales and revenue determined for the FTY ending September 30, 2018?

A. Budgeted sales and revenues served as the starting point for the development of the normalized and annualized FTY sales and revenues shown in UGI Electric Exhibit DEL-4(a). All of the adjustments that were made in the development of the FPFTY were also made in the development of the FTY.

Q. How were normalized and annualized sales and revenue determined for the HTY ended September 30, 2017?

A. Historic sales and revenues served as the starting point for the development of the normalized and annualized HTY sales and revenues shown in UGI Electric Exhibit DEL-5(a). All of the adjustments that were made in the development of the FPFTY were also made in the development of the HTY.

III. RATE STRUCTURE

Q. Please describe the changes in rate structure proposed by the Company in this proceeding.

A. In general, the Company seeks to simplify its rate design by eliminating any existing rate schedules that are no longer deemed necessary or appropriate. In addition, the Company is proposing to reduce the number of billing blocks to one for Rate R in order to simplify billing for this rate and offset rate change impacts related to an increase in the Rate R Customer Charge.

Q. Please identify the rate schedules and rates the Company is proposing to eliminate and its basis for doing so.

A. In an effort to simplify its rate schedules, the Company is proposing to eliminate the following rate schedules:

- <u>Rate Schedule RRS - Residential Renewable Service and Rate RRTU - Residential Renewable Time of Use Service</u>. These are closed rate schedules that were only available for the duration of the 2008 and 2009 Price Application Periods. There are no customers currently being served on these rate schedules.

- Rate Schedule RWT - Residential Service Water/Space Heating. This is a closed rate schedule available only to those service locations connected prior to January 1, 1980. In addition, the only difference between the rates for Rate RWT and Rate R, the general residential rate schedule, is a slight variation in the second rate block of Rate RWT of 0.429 cents per kWh (for usage over 500 kWh but less than 1,000 kWh. The remaining rate blocks and the customer charge are identical. There are approximately 11,000 customers currently served on this rate. The Company proposes to move the residential customers served under this rate to Rate Schedule R.
- Rate Schedule RTU – Residential Time-of Use Service. There are only six customers currently being served under this rate and an analysis shows that Rate Schedule R would be more economical on average.
- Rate CWH – Controlled Off-Peak Service for Water Heating. A recent analysis by the Company shows that none of the customers currently on this rate have the required equipment to be eligible for this rate. The Company proposes to move the 32 residential customers served under this rate to Rate Schedule R – Residence Service. The 15 commercial customers would be moved to Rate Schedule GS1 - General Service, which is the general rate schedule for small commercial customers.
- Rate TE - Non-Residential Service Total Electric. This is a closed rate schedule that is available only to Customers being served under this rate prior to January 1, 1965. There are only a total of twelve customers on Rate TE. Ten would be moved to Rate GS4 – General Service (5 kW minimum) and two would be moved to Rate

LP- Large Power Service. These would be the most economical remaining rate schedules available based on a recent 12-month billing analysis.

- Rate GLP – General Lighting and Power Service. As stated in the Company's current Tariff, this rate Schedule is in the process of elimination and is available only to Customers served hereunder prior to July 29, 1970. There are now only 25 customers currently on this rate schedule. Thirteen would be moved to Rate GS4 – General Service (5 kW minimum) and twelve would be moved to Rate GS1-General Service, which would be the most economical remaining rate schedules based on a recent 12-month billing analysis.
- Rate IH – Institutional Heating Service. This is a closed rate schedule available only to customers being served on this rate prior to January 1, 1965. There are now currently only seven Customers being served under Rate IH. Two would be moved to Rate GS1, three would be moved to Rate GS4 and two would be moved to Rate LP, which would be the most economical remaining rate schedules based on a recent 12-month billing analysis.

Q. Is the Company proposing any Rider changes?

A. Yes, the Company is proposing to adopt a reconcilable USP Rider similar to that approved by the Commission for UGI Electric's affiliates UGI Gas, CPG, and PNG for recovery of USP costs.

Q. Please explain how UGI Electric currently recovers the costs of its universal service programs.

A. The current UGI Electric Customer Assistance Program ("CAP") was originally approved on June 19, 1998 at Docket No. R-00973975 and last modified on December 4, 2008 at

Docket No. P-2008-2066579. Currently, UGI Electric is permitted to recover costs, via a combination of base rate funding and a CAP Rider, for the following programs under its CAP Rider: CAP Credit (Shortfall) and External Agency Costs.

Q. Please explain how the Company proposes to recover USP costs through the revised Rider.

A. The Company is proposing to modify its recovery mechanism to mirror the recovery method established for all three of its affiliated NGDCs. Specifically, the Company is proposing to recover the following USP costs via a reconcilable USP Rider from all Rate R Customers except for those Customers enrolled in the CAP: CAP Credit (Shortfall) costs, CAP Administrative Costs, Low Income Usage Reduction Program ("LIURP") Costs, Hardship Administrative Costs and Pre-Program Arrearage ("PPA") Costs. As shown on UGI Electric Exhibit DEL-6, the proposed initial rate for the USP Rider is $0.0053 per kWh.

Q. Do you have a projection for UGI Electric's CAP enrollment for the end of FPFTY?

A. Yes. The Company projects that its CAP enrollment at September 30, 2019 will be 2,918. This projection is based on a steady increase in enrollment that the Company has experienced since a Commission-approved CAP change in September 2014 provided customers with the option to set their CAP payment at their average bill in lieu of a percentage of income.

Q. Under the revised USP Rider, does UGI Electric propose an offset to CAP credits and pre-program arrearages for the number of customers receiving credits above the projected enrollment of 2,918?

A. Yes. UGI Electric is proposing to calculate an offset to CAP credits and pre-program arrearages of 7.4%. This offset reduces the Company's recovery of CAP spending above projected enrollment to account for write-offs of bad debt that would have arguably occurred if not for CAP. As set forth in UGI Electric Exhibit DEL-6, this offset is calculated using the state-wide average write-off data for the past three years. Please see UGI Electric Exhibit F – Proposed Tariff for the proposed modifications to the USP Rider section of the Tariff.

Q. Is the Company proposing any other riders in this proceeding?

A. Yes. The Company is proposing a new Storm Expense Rider ("SER") to recover or refund certain storm damages expenses in excess of or below a base amount of $275,000 claimed in base rates. The proposed mechanism for calculating this rider is set forth in UGI Electric Exhibit F – Proposed Tariff. The adoption of this rider would provide for timely tracking of significant storm expenses which could vary significantly in relation to weather events beyond the Company's control.

Q. Is the Company proposing any new rates in this proceeding?

A. Yes, it is proposing a new Rate EV (Electric Vehicle Services) for non-residential customers who want UGI Electric to install and maintain electric vehicle ("EV") charging station equipment. The applicable rates will consist of a flat monthly charge based on the equipment costs and related maintenance expenses associated with one of three separate station types: (1) a 4,000 series charging unit (or similar); (2) a 100 series charging unit (or similar); or (3) a 250 series charging unit (or similar). See UGI Electric Exhibit DEL-7 for the development of the three proposed monthly charges. In addition to the stated monthly charges for equipment, Customers electing service under this rate will be responsible for the installation costs incurred by UGI Electric for the charging stations at their service location(s). Energy usage by the charging stations shall be billed to the customer at the applicable UGI Electric GSR or their Electric Generation Supplier's generation rate. UGI Electric believes Rate EV should promote and facilitate the adoption and utilization of EVs within its service territory. The provision of service under this rate will also help UGI Electric develop a better understanding of the potential benefits and challenges associated with serving EV requirements. Since UGI Electric has no anticipated Rate EV customers at this time, no related capital additions, associated revenues, or associated expenses have been projected in developing UGI Electric's claims in this proceeding.

IV. REVENUE ALLOCATION AND RATE DESIGN

Q. Please summarize the Company's rate design and allocation of the revenue increase ratemaking philosophy.

A. The Company's ratemaking goal is to implement reasonable rates that recover its cost of doing business.

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

A. The Company considered cost of service as the primary factor in determining revenue allocation and rate design.

Q. Please summarize how the proposed distribution revenue increase was allocated among the customer classes.

A UGI Electric is proposing to allocate the revenue increase in a manner consistent with the cost of service. In measuring cost of service, the Company relied on the cost of service studies prepared by Company witness John D. Taylor (UGI Electric Statement No. 6). The cost of service study grouped customers into four classes: (1) Residential, which includes Rate Schedules R, RWT, RTU, CWH and BLR; (2) General Service, which includes Rate Schedules GS1, GS4, GS5 and FCP; (3) Lighting, which includes all lighting rate schedules; and (4) Large Power, which includes Rate Schedule LP. As noted in Table 1 below, the current relative rate of return for Rate R is 30% while the remaining classes have relative rates of return in excess of 200%. As a result, the Company is proposing an allocation which will significantly move all rate groups approximately 80-92% toward system average rate of return, with the exception of the lighting group which will move approximately 61% toward system average rate of return. Given the significant low return of the residential group, this approach results in an allocation of the full proposed increase to the Residential Class and results in no net change for those rate classes with rates of return above the system average. Even with this revenue allocation, the residential class remains below the system average return. Table 1 below provides a summary of proposed increases and relative rates of return by customer class as shown in UGI Electric Exhibit D – Cost of Service.[1]

[1] The $9.254 million proposed increase for the residential class includes $17,225 allocated to Rate GS5, which is a general service rate that is served under residential rates. This rate applies to volunteer fire companies, non-profit senior centers, non-profit rescue squads and non-profit ambulance services

Table 1

	Total Company	Residential	General Service	Large Power	Lighting
Total Revenue Increase as Proposed	$9,254	$9,254	$0	$0	$0
Percent Total Revenue Change	10.41%	15.55%	0.00%	0.00%	0.00%
Proposed Rate of Return	8.07%	7.13%	10.69%	8.88%	17.75%
Proposed Relative Rate of Return	100%	88%	132%	110%	220%
Current Rate of Return	3.20%	0.97%	8.52%	7.28%	13.12%
Current Relative Rate of Return	100%	30%	266%	228%	410%

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

A. As evidenced by the cost of service study presented by Mr. Taylor (UGI Electric Statement No. 6), under present rates, the residential Rate R customer group is producing a return of 0.97%, as compared to a system average return of 3.20%. This translates to a current relative rate of return of 30%. As explained above, the Company allocated the full proposed rate increase to the Rate R customer group. This partially offsets the $10.3 million deficiency for the Rate R group and moves the Rate R group substantially closer to system average return. Specifically, the proposed increase will result in an overall return of 7.13% for the Rate R customer group, and a proposed relative rate of return of 88%, which results in an approximate 83% movement towards system average return (30% to 88%). At the same time, and as explained below, this proposed allocation will move commercial and industrial customer groups significantly closer to the system average return while avoiding rate decreases to these customer classes.

As to rate design, the Company is proposing a Rate R customer charge of $14.00 per month, as compared to the current charge of $5.50 per month. This proposed change moves fixed customer charges closer to the total customer costs per bill of $31.54 as identified within the cost of service studies presented in UGI Electric Exhibit D. The Company is also proposing to eliminate multiple blocks in lieu of a single block at a proposed rate of $0.03312 per kWh.

Q. Please describe the revenue allocation and rate design for the General Service customer group.

A. As evidenced by the cost of service study presented by Mr. Taylor, under present rates, the General Service customer group is producing a return of 8.52%, as compared to a system average return of 3.20%. This translates to a current relative rate of return of 266%. As a result, in allocating revenues, the Company is not proposing any decrease for this General Service group, resulting in no proposed change to the General Service customer group. This will result in an overall return of 10.7% for the General Service customer group, and a proposed relative rate of return of 132%, which results in an approximate 81% movement towards system average return (266% to 132%).

Since the Company is not allocating any increase to the General Service class, there are no proposed changes to general service Rates GS1 and GS4, other than a very slight increase to the first block for Rate GS1 to $0.04073 per kWh. This increase is to offset a variance that is created by the zeroing out of the current STAS rate of 1.36%. Embedded in that rate is 1.5% for Gross Receipts Tax ("GRT"). When the 1.36% STAS is zeroed out, it impacts the overall amount recovered for GRT and the slight adjustment to the distribution charge negates that impact. The result of that adjustment and another, related to rolling the transmission charges that are currently in base rates into the GSR, combine to reflect a total net increase for GS1 of $3,826, or essentially no change, as shown in UGI Electric Exhibit E-Proof of Revenue. Similar adjustments as those described for Rate GS1 were also made to Rate GS4 and the amount of those adjustments resulted in a negative ($3,610), or essentially no change. When looking at the combination of Rates GS1 and GS4, the combined increase is a net of $210 or again, essential no change. Rate GS5, as noted earlier, is a general service that is served under residential rates. Those proposed rates are identical to those proposed for Rate R and result in an increase of $17,225. UGI Electric Exhibit E- Proof of Revenue provides additional detail on Rate GS5.

Q. Please describe the revenue allocation and rate design for the Large Power customer group.

A. As evidenced by the cost of service study presented by Mr. Taylor, under present rates, the Large Power customer group is producing a return of 7.28%, as compared to a system average return of 3.20%. This translates to a current relative rate of return of 228%. In allocating revenues, the Company proposes to allocate none of the margin increase to the Large Power customer group. This will result in an overall return of 8.88% and a relative rate of return of 110%, which results in an approximate 92% movement towards system average return (228% to 110%). Since there is no allocated increase for Rate LP, there are no proposed changes to the rate design.

Q. Please describe the revenue allocation and rate design for the Lighting customer group.

A. As evidenced by the cost of service study presented by Mr. Taylor, under present rates, the Lighting customer group is producing a return of 13.12%, as compared to a system average return of 3.20%. This translates to a current relative rate of return of 410%. The Company proposes to allocate none of the margin increase to the Lighting customer group. This will result in an overall return of 17.75% for the Lighting customer group, and a proposed relative rate of return of 220%, which results in an approximate 61% movement towards system average return (410% to 220%). The adjustments described for Rate GS1 also apply to the lighting classes, and the impact of these adjustments, are detailed in UGI Electric Exhibit E- Proof of Revenue. When looked at in total, there is no overall increase allocated to the lighting classes

Q. Is the Company proposing any change to Rate HTP?

A. Yes. The Company has updated the rates applicable to Rate Schedule HTP to update it based on current conditions. The updated rate table consists solely of a customer charge and is based on two components, the metering costs associated with an HTP installation and the costs associated with customer service as billing using Rate LP customer costs as a proxy. The Company is proposing two different customer charges. One charge is associated with a Primary Metered service and the other charge is associated with a Secondary Metered service. UGI Electric Exhibit DEL-8 provides the calculation of these customer charges. There are no customers currently on this rate schedule and no costs or revenues have been assigned to the rate schedule in the filing.

Q. Are there any additional changes related to rate design?

A. Yes, as shown in UGI Electric Exhibit E - Proof of Revenue, the Company proposes to remove transmission related charges from base rates and will recover those related costs through the GSR. There is a $0.37 cent per kWh transmission charge applied to current rate schedules. That charge will be removed from base rates and included in the calculation of the GSR rate.

V. OTHER TARIFF MODIFICATIONS

Q. Apart from the proposed rate schedule eliminations, rider changes and Rate EV discussed above, has the Company proposed any other changes to its tariff in this proceeding?

A. Yes. A complete list of tariff modifications can be found in the List of Changes section in UGI Electric Exhibit F, Proposed Tariff No. 6. In general, the tariff changes have sought to unify, to the extent possible, the tariff provisions of UGI Electric with those of its affiliated NGDCs. For example, payment terms have been standardized across all rate schedules as proposed in Section 13-f of UGI Electric Exhibit F. These replace the currently disparate interest rate and discount terms and conditions applicable to certain tariff rate schedules today. In regard to other tariff updates, where there is no appropriate NGDC equivalent, UGI Electric has looked to the PPL Electric Utilities Corporation tariff or applicable Commission regulations for guidance. Also, the Company is proposing to eliminate certain rate discounts within Rates GS-1 and GS-4 which are applicable to certain air conditioning and space heating power use applications; where such discounts were already in process of elimination. The Company is also proposing to eliminate historic off-peak service provisions associated with Rates GS-4, LP and HTP and historic annual revenue guarantee provisions associated with Rates GS-1, LP and HTP. Lastly, the Company has restructured Rate HTP in order to more properly reflect anticipated distribution system service costs wherein these customers would receive direct 66kV service and only require either primary or secondary voltage metering equipment. Together, the proposed tariff changes have sought to simplify and clarify tariff provisions, to remove duplicative provisions, and to delete or change certain provisions that have become out-of-date because of the passage of time. Tariff organization has also been adjusted to present information in a more logical sequence.

Q. Is the Company proposing any changes to its Choice Supplier Tariff?

A. Yes. The proposed changes to the Company's Choice Supplier Tariff have been incorporated into Proposed Tariff No. 2-S and are identified in the List of Changes section. These changes can also be found in UGI Electric Exhibit F.

Q. Does this conclude your testimony?

A. Yes.

UGI ELECTRIC EXHIBIT DEL-1

UGI Utilities Inc. - Electric Division
15 Year Normal Heating Degree Days (2000-2014)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	15 Year Average
Jan	1,239	1,185	974	1,365	1,422	1,282	932	1,034	1,084	1,347	1,217	1,285	1,042	1,086	1,336	1,189
Feb	970	965	843	1,120	1,055	989	979	1,226	1,008	949	1,046	1,008	851	1,013	1,136	1,011
Mar	688	982	789	861	785	1,027	862	899	891	800	685	905	514	940	1,039	844
Apr	509	489	468	531	478	402	437	598	383	429	348	463	496	462	500	466
May	195	192	283	256	123	296	221	167	309	193	171	148	85	201	157	200
Jun	60	44	35	90	68	16	66	25	25	47	28	29	50	25	10	41
Jul	24	24	2	1	1	0	0	16	0	9	6	0	0	2	1	6
Aug	32	1	9	6	25	0	7	25	15	9	6	6	3	11	9	11
Sep	195	152	77	93	68	33	148	80	98	140	83	81	126	158	106	109
Oct	423	377	476	494	453	397	466	236	499	491	406	419	350	334	302	408
Nov	790	542	740	623	671	626	581	751	731	591	695	567	805	789	761	684
Dec	1,278	869	1,104	1,031	1,048	1,163	819	1,047	1,034	1,094	1,192	886	898	1,037	909	1,027
Totals	6,403	5,822	5,800	6,471	6,197	6,231	5,518	6,104	6,077	6,099	5,883	5,797	5,220	6,058	6,266	5,996

UGI Utilities Inc. - Electric Division
15 Year Normal Cooling Degree Days (2000-2014)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	15 Year Average
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Apr	0	9	41	2	9	6	0	4	5	41	15	14	7	4	6	11
May	39	32	19	1	86	10	32	54	9	19	80	61	72	56	30	40
Jun	108	142	138	80	75	230	92	129	154	60	183	116	127	133	152	128
Jul	85	121	262	195	138	312	264	177	224	97	305	304	308	311	214	221
Aug	109	231	237	194	130	306	175	205	86	157	209	133	194	147	139	177
Sep	54	24	74	30	33	119	8	94	71	9	91	71	61	60	71	58
Oct	0	1	10	0	0	6	0	41	0	0	0	0	2	14	9	6
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Totals	395	560	781	502	471	989	571	704	549	383	883	699	771	725	621	640

UGI ELECTRIC EXHIBIT DEL-2

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

Rate	Sept 1995	Sept 2017	Sept 2018	Sept 2019
Res-General	42,920	44,014	43,829	43,783
Res-Heating	10,389	10,341	10,347	10,369
Com-General	5,872	7,142	7,128	7,141
Com-Heating	585	336	338	334
Ind-General	136	118	119	119
Ind-Heating	45	35	35	35
Public St & Hwy Lighting	51	54	54	54
Other	5	7	7	7
Sales for Resale	2	3	3	3
Total	60,005	62,050	61,860	61,845

Note: Excludes unmetered Lighting

UGI ELECTRIC EXHIBIT DEL-3

UGI Utilities, Inc.- Electric Division
Fully Projected Future Test Year 2019 Sales and Revenues
Summary of Adjustments

	Sales (000's) KWH	Revenues ($000's)	Margin ($000's)	Reference
Budget 2019	994,438	86,243	29,490	
Adjustment for Customer Changes	287	17	8	UGI Electric Exhibit DEL-3(b)/(c)
Adjustment for Normalized Use/Customer	(2,069)	(212)	(53)	UGI Electric Exhibit DEL-3(d)/(e)
Adjustment for GSR		2,890	0	UGI Electric Exhibit DEL-3(f)
Adjustment for CAP		75	0	UGI Electric Exhibit DEL-3(g)
Adjustment for EEC		(919)	0	UGI Electric Exhibit DEL-3(h)
Adjustment for STAS		(174)	0	UGI Electric Exhibit DEL-3(i)
Fully Projected Future Test Year 2019	992,655	87,919	29,445	

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for Customer Changes
Rate R Default-Class 111

Line #	Description	[1] OCT	[2] NOV	[3] DEC	[4] JAN	[5] FEB	[6] MAR	[7] APR	[8] MAY	[9] JUN	[10] JUL	[11] AUG	[12] SEP	[13] Grand Total
1	Total Test Year 2019 Revenues (Unadjusted)	$ 2,031	$ 2,087	$ 2,545	$ 2,718	$ 2,486	$ 2,437	$ 2,100	$ 1,966	$ 2,280	$ 2,780	$ 2,807	$ 2,531	$ 28,767
2	GSR Revenues	(1,336)	(1,371)	(1,709)	(1,843)	(1,674)	(1,628)	(1,382)	(1,281)	(1,526)	(1,902)	(1,924)	(1,704)	(19,280)
3	Revenues net of GSR - Margin (Unadjusted)	$ 695	$ 716	$ 835	$ 875	$ 812	$ 808	$ 718	$ 685	$ 754	$ 878	$ 883	$ 827	$ 9,487
4	Customers in Test Year 2019 (Unadjusted)	35,259	35,317	35,358	35,385	35,396	35,403	35,321	35,258	35,240	35,226	35,221	35,221	35,300
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 0.020	$ 0.020	$ 0.024	$ 0.025	$ 0.023	$ 0.023	$ 0.020	$ 0.019	$ 0.021	$ 0.025	$ 0.025	$ 0.023	$ 0.269
6	Future Test Year 2019 Customers (Fully Adjusted)	35,221	35,221	35,221	35,221	35,221	35,221	35,221	35,221	35,221	35,221	35,221	35,221	35,221
7	Change in Customers during Future Test Year 2019 (L 6 - L 4)	(38)	(96)	(137)	(164)	(175)	(182)	(100)	(37)	(19)	(5)	-	-	(953)
8	Annualization of Margin (L 5 * L 7)	$ (1)	$ (2)	$ (3)	$ (4)	$ (4)	$ (4)	$ (2)	$ (1)	$ (0)	$ (0)	$ -	$ -	$ (21)
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 0.058	$ 0.059	$ 0.072	$ 0.077	$ 0.070	$ 0.069	$ 0.059	$ 0.056	$ 0.065	$ 0.079	$ 0.080	$ 0.072	$ 0.815
10	Annualization of Total Revenue (L 7 * L9)	$ (2)	$ (6)	$ (10)	$ (13)	$ (12)	$ (13)	$ (6)	$ (2)	$ (1)	$ (0)	$ -	$ -	$ (65)
11	Annualization of GSR Revenues (L 10 - L8)	$ (1)	$ (4)	$ (7)	$ (9)	$ (8)	$ (8)	$ (4)	$ (1)	$ (1)	$ (0)	$ -	$ -	$ (43)
12	Total UPC (Unadjusted)-KWH	515	528	659	711	646	627	533	494	590	736	744	659	7,442
13	Annualization Adjustment for Sales-MKWH (L12 * L7)/1000	(20)	(51)	(90)	(117)	(113)	(114)	(53)	(18)	(11)	(4)	-	-	(591)

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for Customer Changes
Rate Commercial GS4 Default-Class 264

Line #	Description	[1] OCT	[2] NOV	[3] DEC	[4] JAN	[5] FEB	[6] MAR	[7] APR	[8] MAY	[9] JUN	[10] JUL	[11] AUG	[12] SEP	[13] Grand Total
1	Total Test Year 2019 Revenues (Unadjusted)	$ 694	$ 670	$ 731	$ 752	$ 734	$ 747	$ 726	$ 693	$ 823	$ 884	$ 870	$ 823	$ 9,149
2	GSR Revenues	(440)	(429)	(477)	(491)	(480)	(487)	(467)	(443)	(533)	(583)	(569)	(531)	(5,930)
3	Revenues net of GSR - Margin (Unadjusted)	$ 254	$ 241	$ 254	$ 261	$ 254	$ 260	$ 260	$ 250	$ 290	$ 301	$ 301	$ 292	$ 3,218
4	Customers in Test Year 2019 (Unadjusted)	1,754	1,754	1,759	1,766	1,768	1,769	1,769	1,768	1,779	1,785	1,785	1,787	1,770
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 0.145	$ 0.137	$ 0.144	$ 0.148	$ 0.144	$ 0.147	$ 0.147	$ 0.141	$ 0.163	$ 0.169	$ 0.169	$ 0.164	$ 1.818
6	Future Test Year 2019 Customers (Fully Adjusted)	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787
7	Change in Customers during Future Test Year 2019 (L 6 - L 4)	33	33	28	21	19	18	18	19	8	2	2	-	201
8	Annualization of Margin (L 5 * L 7)	$ 5	$ 5	$ 4	$ 3	$ 3	$ 3	$ 3	$ 3	$ 1	$ 0	$ 0	$ -	$ 29
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 0.396	$ 0.382	$ 0.416	$ 0.426	$ 0.415	$ 0.422	$ 0.411	$ 0.392	$ 0.462	$ 0.496	$ 0.488	$ 0.461	$ 5.168
10	Annualization of Total Revenue (L 7 * L9)	$ 13	$ 13	$ 12	$ 9	$ 8	$ 8	$ 7	$ 7	$ 4	$ 1	$ 1	$ -	$ 82
11	Annualization of GSR Revenues (L 10 - L8)	$ 8	$ 8	$ 8	$ 6	$ 5	$ 5	$ 5	$ 5	$ 2	$ 1	$ 1	$ -	$ 53
12	Total UPC (Unadjusted)-KWH	4,188	4,053	4,463	4,607	4,454	4,585	4,344	4,139	4,885	5,252	5,181	4,882	55,033
13	Annualization Adjustment for Sales-MKWH	138	134	125	97	85	83	78	79	39	11	10	-	878

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for Usage per Customer
Rate R Default-Class 111

Line #			
1	Heating Sensitivity/HDD/cust (kWh/DD/cust)		0.3324
2	DD Variance (to 15 Year normal)		63
3	kWh/customer (L1 * L2)		20.9412
4	Customers FY19 (fully adjusted)		35,221
5	Normalizing Adj (kWh) (L3 * L4)		738
6	Revenue/kWh (L7+L8+L9+L10+L11)		0.10287
7	CAP/kWh		0.00354
8	EEC-Class 1/kWh		0.00236
9	Transmission/kWh		0.0037
10	GSR-1/kWh		0.06643
11	Distribution/kWh		0.02684
12	Revenue Adjustment (L5 * L6)	$	76
13	CAP Adjustment (L5 * L7)	$	3
14	EEC Adjustment (L5 * L8)	$	2
15	Transmission Adjustment (L5 * L9)	$	3
16	GSR Adjustment (L5 * L10)	$	49
17	Distribution Adjustment (L5 * L11)	$	20
18	Margin Adjustment (L17 less GRT)	$	19
19	Cooling Sensitivity/CDD/cust (kWh/DD/cust)		1.2761
20	DD Variance (to 15 Year normal)		(60)
21	kWh/customer (L19 * L20)		(76.566)
22	Customers FY19 (fully adjusted)		35,221
23	Normalizing Adj (kWh) (L21 * L22)		(2,697)
24	Revenue/kWh (L25+L26+L27+L28+L29)		0.10287
25	CAP/kWh		0.00354
26	EEC-Class 1/kWh		0.00236
27	Transmission/kWh		0.0037
28	GSR-1/kWh		0.06643
29	Distribution/kWh		0.02684
30	Revenue Adjustment (L23 * L24)	$	(277)
31	CAP Adjustment (L23 * L25)	$	(10)
32	EEC Adjustment (L23 * L26)	$	(6)
33	Transmission Adjustment (L23 * L27)	$	(10)
34	GSR Adjustment (L23 * L28)	$	(179)
35	Distribution Adjustment (L23 * L29)	$	(72)
36	Margin Adjustment (L35 less GRT)	$	(69)
37	Total Adjustment Summary-FY19:		
38	Normalizing Adj (kWh) (L5+L23)	$	(1,959)
39	Total Revenue Adjustment (L12+L30)	$	(202)
40	CAP Adjustment (L13+L31)	$	(7)
41	EEC Adjustment (L14+L32)	$	(5)
42	Tranmission Adjustment (L15+L33)	$	(7)
43	GSR Adjustment(L16+L34)	$	(130)
44	Distribution Adjustment(L17+L35)	$	(53)
45	Margin Adjustment (L18+L36)	$	(50)

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for Usage per Customer
Rate Commercial GS4 Default-Class 264

Line #			
1	Heating Sensitivity/HDD/cust (kWh/DD/cust)		0.8978
2	DD Variance (to 15 Year normal)		232
3	kWh/customer (L1 * L2)		208.2896
4	Customers FY19 (fully adjusted)		1,787
5	Normalizing Adj (kWh) (L3 * L4)		372
6	Revenue/kWh (L7+L8+L9+L10)		0.09356
7	EEC-Class 2/kWh		0.00248
8	Transmission/kWh		0.00162
9	GSR-1/kWh		0.06643
10	Distribution/kWh		0.02303
11	Revenue Adjustment (L5 * L6)	$	35
12	EEC Adjustment (L5 * L7)	$	1
13	Transmission Adjustment (L5 * L8)	$	1
14	GSR Adjustment (L5 * L9)	$	25
15	Distribution Adjustment (L5 * L10)	$	9
16	Margin Adjustment (L15 less GRT)	$	8
17	Cooling Sensitivity/CDD/cust (kWh/DD/cust)		2.6701
18	DD Variance (to 15 Year normal)		(101)
19	kWh/customer (L17 * L18)		(269.6801)
20	Customers FY19 (fully adjusted)		1,787
21	Normalizing Adj (kWh) (L19 * L20)		(482)
22	Revenue/kWh (L23+L24+L25+L26)		0.09356
23	EEC-Class 2/kWh		0.00248
24	Transmission/kWh		0.00162
25	GSR-1/kWh		0.06643
26	Distribution/kWh		0.02303
27	Revenue Adjustment (L21 * L22)	$	(45)
28	EEC Adjustment (L21 * L23)	$	(1)
29	Transmission Adjustment (L21 * L24)	$	(1)
30	GSR Adjustment (L21 * L25)	$	(32)
31	Distribution Adjustment (L21 * L26)	$	(11)
32	Margin Adjustment (L31 less GRT)	$	(11)
33	Total Adjustment Summary-FY19:		
34	Normalizing Adj (kWh) (L5+L21)		(110)
35	Total Revenue Adjustment (L11+L27)	$	(10)
36	EEC Adjustment (L12+L28)	$	(0)
37	Tranmission Adjustment (L13+L29)	$	(0)
38	GSR Adjustment (L14+L30)	$	(7)
39	Distribution Adjustment (L15+L31)	$	(3)
40	Margin Adjustment (L16+L32)	$	(2)

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for GSR

	OCT 2018	NOV 2018	DEC 2018	JAN 2019	FEB 2019	MAR 2019	APR 2019	MAY 2019	JUN 2019	JUL 2019	AUG 2019	SEP 2019	TOTAL
Original Budget GSR Rate FY 19	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	
Future Test Year 2019 GSR Rate	$0.06643	$0.06643	$0.06643	$0.06643	$0.06643	$0.06643	$0.06643	$0.06643	$0.06643	$0.06643	$0.06643	$0.06643	
GSR Rate Variance	$0.00429	$0.00429	$0.00429	$0.00429	$0.00429	$0.00429	$0.00429	$0.00429	$0.00429	$0.00429	$0.00429	$0.00429	
Total GSR Volumes	45,449	55,588	65,117	71,012	65,522	64,348	48,105	44,931	49,201	64,242	53,663	46,372	673,550
GSR Revenue Adjustment	$195	$238	$279	$305	$281	$276	$206	$193	$211	$276	$230	$199	$2,890

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for CAP

	OCT 2018	NOV 2018	DEC 2018	JAN 2019	FEB 2019	MAR 2019	APR 2019	MAY 2019	JUN 2019	JUL 2019	AUG 2019	SEP 2019	TOTAL
Original Budget CAP Rate FY 19	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	
Future Test Year 2019 CAP Rate	$0.00354	$0.00354	$0.00354	$0.00354	$0.00354	$0.00354	$0.00354	$0.00354	$0.00354	$0.00354	$0.00354	$0.00354	
CAP Rate Variance	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	
Total Rate R Volumes Excluding CAP volumes	31,454	35,929	48,849	54,942	51,489	49,130	38,164	31,766	34,731	41,531	41,391	37,563	496,938
Revenue Variance	$5	$5	$7	$8	$8	$7	$6	$5	$5	$6	$6	$6	$75

UGI Electric Exhibit DEL-3(h)

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for EEC

	OCT 2018	NOV 2018	DEC 2018	JAN 2019	FEB 2019	MAR 2019	APR 2019	MAY 2019	JUN 2019	JUL 2019	AUG 2019	SEP 2019	TOTAL
Original Budget EEC-Class 1 Rate FY 19	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	
Future Test Year 2019 EEC-Class 1 Rate	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	
EEC-Class 1 Rate Variance	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	
Total EEC-Class 1 Volumes	35,197	44,851	54,391	59,039	53,962	52,409	37,709	34,432	37,502	50,390	41,822	35,580	537,284
Total EEC-Class 1 Revenue Adjustment	($18)	($23)	($28)	($30)	($28)	($27)	($19)	($18)	($19)	($26)	($21)	($18)	($274)
Original Budget EEC-Class 2 Rate FY 19	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	
Future Test Year 2019 EEC-Class 2 Rate	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	
EEC-Class 2 Rate Variance	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	
Total EEC-Class 2 Volumes	12,830	15,193	13,260	14,405	13,098	14,122	11,120	12,860	13,929	19,271	13,182	11,274	164,544
Total EEC-Class 2 Revenue Adjustment	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($2)
Original Budget EEC-Class 3 Rate FY 19	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	
Future Test Year 2019 EEC-Class 3 Rate	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	
EEC-Class 3 Rate Variance	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	
Total EEC-Class 3 Volumes	23,799	22,654	23,627	25,793	23,330	24,163	23,508	23,938	25,619	25,587	25,821	24,772	292,610
Total EEC-Class 3 Revenue Adjustment	($52)	($50)	($52)	($57)	($51)	($53)	($52)	($53)	($56)	($56)	($57)	($54)	($644)
Total EEC Revenue Adjustment	($70)	($73)	($80)	($87)	($79)	($80)	($71)	($70)	($76)	($82)	($78)	($73)	($919)

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2019
($ in Thousands)

Adjustment for STAS

	Budget Revenue Excluding STAS	Customer Adj	UPC Adj	GSR Adj	CAP Adj	EEC Adj	Revised Revenue Excluding STAS	STAS Revenue @ Dec 1 Rate	STAS Revenue @ Budget Rate	STAS Adjustment
								1.36%	1.57%	
Residential	$ 56,331	$ (65)	$ (202)	$2,282	$ 75	$ (273)	$ 58,148	$ 791	$ 898	$ (107)
Commercial	$ 23,790	$ 82	$ (10)	$511	$ -	$ (410)	$ 23,963	$ 326	$ 379	$ (53)
Industrial	$ 4,153	$ -		$89	$ -	$ (236)	$ 4,007	$ 54	$ 66	$ (12)
PSHWY	$ 587	$ -		$6	$ -	$ (0)	$ 593	$ 8	$ 9	$ (1)
Other	$ 16	$ -		$ -	$ -	$ (0)	$ 16	$ 0	$ 0	$ (0)
Sales for Resale	$ 13	$ -		$1	$ -	$ (0)	$ 14	$ 0	$ 0	$ (0)
Total	$ 84,889	$ 17	$ (212)	$2,890	$75	($919)	$86,740	$ 1,180	$ 1,353	$ (174)

UGI ELECTRIC EXHIBIT DEL-4

UGI Utilities, Inc.- Electric Division
Future Test Year 2018 Sales and Revenues
Summary of Adjustments

	Sales (000's) KWH	Revenues ($000's)	Margin ($000's)	Reference
Budget 2018	992,012	86,124	29,489	
Adjustment for Customer Changes	287	18	8	UGI Electric Exhibit DEL-4(b)/(c)
Adjustment for Normalized Use/Customer	(2,068)	(212)	(53)	UGI Electric Exhibit DEL-4(d)/(e)
Adjustment for GSR		2,884	0	UGI Electric Exhibit DEL-4(f)
Adjustment for CAP		75	0	UGI Electric Exhibit DEL-4(g)
Adjustment for EEC		(917)	0	UGI Electric Exhibit DEL-4(h)
Adjustment for STAS		(173)	0	UGI Electric Exhibit DEL-4(i)
Future Test Year 2018	990,230	87,800	29,444	

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2018
($ in Thousands)

Adjustment for Customer Changes
Rate R Default-Class 111

Line #	Description	[1] OCT	[2] NOV	[3] DEC	[4] JAN	[5] FEB	[6] MAR	[7] APR	[8] MAY	[9] JUN	[10] JUL	[11] AUG	[12] SEP	[13] Grand Total
1	Total Test Year 2018 Revenues (Unadjusted)	$ 2,033	$ 2,089	$ 2,547	$ 2,720	$ 2,488	$ 2,438	$ 2,102	$ 1,967	$ 2,281	$ 2,782	$ 2,809	$ 2,533	$ 28,790
2	GSR Revenues	(1,337)	(1,373)	(1,711)	(1,845)	(1,676)	(1,630)	(1,383)	(1,282)	(1,527)	(1,903)	(1,925)	(1,705)	(19,297)
3	Revenues net of GSR - Margin (Unadjusted)	$ 696	$ 716	$ 836	$ 876	$ 812	$ 809	$ 719	$ 686	$ 754	$ 878	$ 884	$ 827	$ 9,493
4	Customers in Test Year 2018 (Unadjusted)	35,282	35,340	35,381	35,408	35,419	35,426	35,344	35,281	35,263	35,249	35,244	35,244	35,323
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 0.020	$ 0.020	$ 0.024	$ 0.025	$ 0.023	$ 0.023	$ 0.020	$ 0.019	$ 0.021	$ 0.025	$ 0.025	$ 0.023	$ 0.269
6	Future Test Year 2018 Customers (Fully Adjusted)	35,244	35,244	35,244	35,244	35,244	35,244	35,244	35,244	35,244	35,244	35,244	35,244	35,244
7	Change in Customers during Future Test Year 2018 (L 6 - L 4)	(38)	(96)	(137)	(164)	(175)	(182)	(100)	(37)	(19)	(5)	-	-	(953)
8	Annualization of Margin (L 5 * L 7)	$ (1)	$ (2)	$ (3)	$ (4)	$ (4)	$ (4)	$ (2)	$ (1)	$ (0)	$ (0)	$ -	$ -	$ (21)
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 0.058	$ 0.059	$ 0.072	$ 0.077	$ 0.070	$ 0.069	$ 0.059	$ 0.056	$ 0.065	$ 0.079	$ 0.080	$ 0.072	$ 0.815
10	Annualization of Total Revenue (L 7 * L9)	$ (2)	$ (6)	$ (10)	$ (13)	$ (12)	$ (13)	$ (6)	$ (2)	$ (1)	$ (0)	$ -	$ -	$ (65)
11	Annualization of GSR Revenues (L 10 - L8)	$ (1)	$ (4)	$ (7)	$ (9)	$ (8)	$ (8)	$ (4)	$ (1)	$ (1)	$ (0)	$ -	$ -	$ (43)
12	Total UPC (Unadjusted)-KWH	515	528	659	711	646	627	533	494	590	736	744	659	7,442
13	Annualization Adjustment for Sales-MKWH (L12 * L7)/1000	(20)	(51)	(90)	(117)	(113)	(114)	(53)	(18)	(11)	(4)	-	-	(591)

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2018
($ in Thousands)

Adjustment for Customer Changes
Rate Commercial GS4 Default-Class 264

Line #	Description	[1] OCT	[2] NOV	[3] DEC	[4] JAN	[5] FEB	[6] MAR	[7] APR	[8] MAY	[9] JUN	[10] JUL	[11] AUG	[12] SEP	[13] Grand Total
1	Total Test Year 2018 Revenues (Unadjusted)	$ 683	$ 659	$ 720	$ 741	$ 722	$ 736	$ 715	$ 682	$ 810	$ 871	$ 857	$ 811	$ 9,006
2	GSR Revenues	(433)	(422)	(470)	(484)	(472)	(479)	(459)	(436)	(524)	(574)	(560)	(523)	(5,838)
3	Revenues net of GSR - Margin (Unadjusted)	$ 250	$ 237	$ 250	$ 257	$ 250	$ 256	$ 256	$ 246	$ 285	$ 296	$ 297	$ 288	$ 3,168
4	Customers in Test Year 2018 (Unadjusted)	1,722	1,722	1,727	1,734	1,736	1,737	1,737	1,736	1,747	1,753	1,753	1,755	1,738
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 0.145	$ 0.138	$ 0.145	$ 0.148	$ 0.144	$ 0.148	$ 0.147	$ 0.141	$ 0.163	$ 0.169	$ 0.169	$ 0.164	$ 1.822
6	Future Test Year 2018 Customers (Fully Adjusted)	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755
7	Change in Customers during Future Test Year 2018 (L 6 - L 4)	33	33	28	21	19	18	18	19	8	2	2	-	201
8	Annualization of Margin (L 5 * L 7)	$ 5	$ 5	$ 4	$ 3	$ 3	$ 3	$ 3	$ 3	$ 1	$ 0	$ 0	$ -	$ 29
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 0.397	$ 0.383	$ 0.417	$ 0.427	$ 0.416	$ 0.423	$ 0.412	$ 0.393	$ 0.464	$ 0.497	$ 0.489	$ 0.462	$ 5.181
10	Annualization of Total Revenue (L 7 * L9)	$ 13	$ 13	$ 12	$ 9	$ 8	$ 8	$ 7	$ 7	$ 4	$ 1	$ 1	$ -	$ 82
11	Annualization of GSR Revenues (L 10 - L8)	$ 8	$ 8	$ 8	$ 6	$ 5	$ 5	$ 5	$ 5	$ 2	$ 1	$ 1	$ -	$ 53
12	Total UPC (Unadjusted)-KWH	4,188	4,053	4,463	4,607	4,454	4,585	4,344	4,139	4,885	5,252	5,181	4,882	55,033
13	Annualization Adjustment for Sales-MKWH (L12 * L7)/1000	138	134	125	97	85	83	78	79	39	11	10	-	878

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2018
($ in Thousands)

Adjustment for Usage per Customer
Rate R Default-Class 111

Line #			
1	Heating Sensitivity/HDD/cust (kWh/DD/cust)		0.3324
2	DD Variance (to 15 Year normal)		63
3	kWh/customer (L1 * L2)		20.9412
4	Customers FY19 (fully adjusted)		35,244
5	Normalizing Adj (kWh) (L3 * L4)		738
6	Revenue/kWh (L7+L8+L9+L10+L11)		0.10287
7	CAP/kWh		0.00354
8	EEC-Class 1/kWh		0.00236
9	Transmission/kWh		0.0037
10	GSR-1/kWh		0.06643
11	Distribution/kWh		0.02684
12	Revenue Adjustment (L5 * L6)	$	76
13	CAP Adjustment (L5 * L7)	$	3
14	EEC Adjustment (L5 * L8)	$	2
15	Transmission Adjustment (L5 * L9)	$	3
16	GSR Adjustment (L5 * L10)	$	49
17	Distribution Adjustment (L5 * L11)	$	20
18	Margin Adjustment (L17 less GRT)	$	19
19	Cooling Sensitivity/CDD/cust (kWh/DD/cust)		1.2761
20	DD Variance (to 15 Year normal)		(60)
21	kWh/customer (L19 * L20)		(76.566)
22	Customers FY19 (fully adjusted)		35,244
23	Normalizing Adj (kWh) (L21 * L22)		(2,698)
24	Revenue/kWh (L25+L26+L27+L28+L29)		0.10287
25	CAP/kWh		0.00354
26	EEC-Class 1/kWh		0.00236
27	Transmission/kWh		0.0037
28	GSR-1/kWh		0.06643
29	Distribution/kWh		0.02684
30	Revenue Adjustment (L23 * L24)	$	(278)
31	CAP Adjustment (L23 * L25)	$	(10)
32	EEC Adjustment (L23 * L26)	$	(6)
33	Transmission Adjustment (L23 * L27)	$	(10)
34	GSR Adjustment (L23 * L28)	$	(179)
35	Distribution Adjustment (L23 * L29)	$	(72)
36	Margin Adjustment (L35 less GRT)	$	(69)
37	Total Adjustment Summary-FY19:		
38	Normalizing Adj (kWh) (L5+L23)		(1,960)
39	Total Revenue Adjustment (L12+L30)	$	(202)
40	CAP Adjustment (L13+L31)	$	(7)
41	EEC Adjustment (L14+L32)	$	(5)
42	Tranmission Adjustment (L15+L33)	$	(7)
43	GSR Adjustment(L16+L34)	$	(130)
44	Distribution Adjustment(L17+L35)	$	(53)
45	Margin Adjustment (L18+L36)	$	(50)

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2018
($ in Thousands)

Adjustment for Usage per Customer
Rate Commercial GS4 Default-Class 264

Heating Sensitivity/HDD/cust (kWh/DD/cust)		0.8978
DD Variance (to 15 Year normal)		232
kWh/customer (L1 * L2)		208.2896
Customers FY19 (fully adjusted)		1,755
Normalizing Adj (kWh) (L3 * L4)		366
Revenue/kWh (L7+L8+L9+L10)		0.09356
EEC-Class 2/kWh		0.00248
Transmission/kWh		0.00162
GSR-1/kWh		0.06643
Distribution/kWh		0.02303
Revenue Adjustment (L5 * L6)	$	34
EEC Adjustment (L5 * L7)	$	1
Transmission Adjustment (L5 * L8)	$	1
GSR Adjustment (L5 * L9)	$	24
Distribution Adjustment (L5 * L10)	$	8
Margin Adjustment (L15 less GRT)	$	8
Cooling Sensitivity/CDD/cust (kWh/DD/cust)		2.6701
DD Variance (to 15 Year normal)		(101)
kWh/customer (L17 * L18)		(269.6801)
Customers FY19 (fully adjusted)		1,755
Normalizing Adj (kWh) (L19 * L20)		(473)
Revenue/kWh (L23+L24+L25+L26)		0.09356
EEC-Class 2/kWh		0.00248
Transmission/kWh		0.00162
GSR-1/kWh		0.06643
Distribution/kWh		0.02303
Revenue Adjustment (L21 * L22)	$	(44)
EEC Adjustment (L21 * L23)	$	(1)
Transmission Adjustment (L21 * L24)	$	(1)
GSR Adjustment (L21 * L25)	$	(31)
Distribution Adjustment (L21 * L26)	$	(11)
Margin Adjustment (L31 less GRT)	$	(10)
Total Adjustment Summary-FY19:		
Normalizing Adj (kWh) (L5+L21)		(108)
Total Revenue Adjustment (L11+L27)	$	(10)
EEC Adjustment (L12+L28)	$	(0)
Tranmission Adjustment (L13+L29)	$	(0)
GSR Adjustment (L14+L30)	$	(7)
Distribution Adjustment (L15+L31)	$	(2)
Margin Adjustment (L16+L32)	$	(2)

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2018
($ in Thousands)

Adjustment for GSR

	OCT 2017	NOV 2017	DEC 2017	JAN 2018	FEB 2018	MAR 2018	APR 2018	MAY 2018	JUN 2018	JUL 2018	AUG 2018	SEP 2018	TOTAL
Original Budget GSR Rate FY 18	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	
Future Test Year 2018 GSR Rate	$0.06643	$0.06643	$0.06643	$0.06643	$0.06643	$0.06643	$0.06643	$0.06643	$0.06643	$0.06643	$0.06643	$0.06643	
GSR Rate Variance	$0.00429	$0.00429	$0.00429	$0.00429	$0.00429	$0.00429	$0.00429	$0.00429	$0.00429	$0.00429	$0.00429	$0.00429	
Total GSR Volumes	45,342	55,484	65,012	70,906	65,419	64,236	48,019	44,839	49,095	64,114	53,562	46,281	672,311
GSR Revenue Adjustment	$195	$238	$279	$304	$281	$276	$206	$192	$211	$275	$230	$199	$2,884

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2018
($ in Thousands)

Adjustment for CAP

	OCT 2017	NOV 2017	DEC 2017	JAN 2018	FEB 2018	MAR 2018	APR 2018	MAY 2018	JUN 2018	JUL 2018	AUG 2018	SEP 2018	TOTAL
Original Budget CAP Rate FY 18	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	
Future Test Year 2018 CAP Rate	$0.00354	$0.00354	$0.00354	$0.00354	$0.00354	$0.00354	$0.00354	$0.00354	$0.00354	$0.00354	$0.00354	$0.00354	
CAP Rate Variance	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	$0.00015	
Total Rate R Volumes	31,646	36,202	49,205	55,353	51,880	49,373	38,377	31,883	34,827	41,682	41,513	37,652	499,593
Revenue Variance	$5	$5	$7	$8	$8	$7	$6	$5	$5	$6	$6	$6	$75

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2018
($ in Thousands)

Adjustment for EEC

	OCT 2017	NOV 2017	DEC 2017	JAN 2018	FEB 2018	MAR 2018	APR 2018	MAY 2018	JUN 2018	JUL 2018	AUG 2018	SEP 2018	TOTAL
Original Budget EEC-Class 1 Rate FY 18	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	
Future Test Year 2018 EEC-Class 1 Rate	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	
EEC-Class 1 Rate Variance	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	
Total EEC-Class 1 Volumes	35,199	44,855	54,389	59,039	53,959	52,416	37,720	34,446	37,512	50,406	41,839	35,597	537,376
Total EEC-Class 1 Revenue Adjustment	($18)	($23)	($28)	($30)	($28)	($27)	($19)	($18)	($19)	($26)	($21)	($18)	($274)
Original Budget EEC-Class 2 Rate FY 18	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	
Future Test Year 2018 EEC-Class 2 Rate	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	
EEC-Class 2 Rate Variance	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	
Total EEC-Class 2 Volumes	12,742	15,095	13,178	14,324	13,024	14,019	11,033	12,754	13,807	19,108	13,062	11,173	163,319
Total EEC-Class 2 Revenue Adjustment	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($2)
Original Budget EEC-Class 3 Rate FY 18	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	
Future Test Year 2018 EEC-Class 3 Rate	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	
EEC-Class 3 Rate Variance	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	
Total EEC-Class 3 Volumes	23,695	22,553	23,523	25,684	23,231	24,059	23,406	23,833	25,501	25,467	25,703	24,660	291,317
Total EEC-Class 3 Revenue Adjustment	($52)	($50)	($52)	($57)	($51)	($53)	($51)	($52)	($56)	($56)	($57)	($54)	($641)
Total EEC Revenue Adjustment	($70)	($73)	($80)	($87)	($79)	($80)	($71)	($70)	($75)	($82)	($78)	($73)	($917)

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2018
($ in Thousands)

Adjustment for STAS

	Budget Revenue Excluding STAS	Customer Adj	UPC Adj	GSR Adj	CAP Adj	EEC Adj	Revised Revenue Excluding STAS	STAS Revenue @ Dec 1 Rate 1.36%	STAS Revenue @ Budget Rate 1.57%	STAS Adjustment
Residential	$ 56,364	$ (65)	$ (202)	$ 2,283	$ 75	$ (273)	$ 58,182	$ 791	$ 898	$ (107)
Commercial	$ 23,509	$ 82	$ (10)	$ 505	$ -	$ (408)	$ 23,679	$ 322	$ 375	$ (53)
Industrial	$ 4,152	$ -	$ -	$ 89	$ -	$ (236)	$ 4,006	$ 54	$ 66	$ (12)
PSHWY	$ 719	$ -	$ -	$ 7	$ -	$ (0)	$ 726	$ 10	$ 11	$ (2)
Other	$ 16	$ -	$ -	$ -	$ -	$ (0)	$ 16	$ 0	$ 0	$ (0)
Sales for Resale	$ 13	$ -	$ -	$ 1	$ -	$ (0)	$ 14	$ 0	$ 0	$ (0)
Total	$ 84,773	$ 18	$ (212)	$2,884	$75	($917)	$86,622	$ 1,178	$ 1,351	$ (173)

UGI ELECTRIC EXHIBIT DEL-5

UGI Utilities, Inc.- Electric Division
Historic Year 2017 Sales and Revenues
Summary of Adjustments

	Sales (000's) KWH	Revenues ($000's)	Margin ($000's)	Reference
Actual 2017	950,632	81,689	27,950	
Adjustment for Customer Changes	(76)	(8)	(2)	UGI Electric Exhibit DEL-5(b)/(c)
Adjustment for Normalized Use/Customer	5,883	570	147	UGI Electric Exhibit DEL-5(d)/(e)
Adjustment for GSR		(1,085)	0	UGI Electric Exhibit DEL-5(f)
Adjustment for CAP		(63)	0	UGI Electric Exhibit DEL-5(g)
Adjustment for EEC		(851)	0	UGI Electric Exhibit DEL-5(h)
Adjustment for STAS		(63)	0	UGI Electric Exhibit DEL-5(i)
Adjusted Historic Test Year 2017	956,439	80,189	28,095	

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for Customer Changes
Rate R Default-Class 111

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
Line #	Description	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	Grand Total
1	Total Historic Year 2017 Revenues (Unadjusted)	$ 2,295	$ 2,355	$ 2,754	$ 2,822	$ 2,505	$ 2,313	$ 1,990	$ 1,808	$ 2,143	$ 2,910	$ 2,432	$ 2,484	$ 28,811
2	GSR Revenues	(1,572)	(1,620)	(1,908)	(1,937)	(1,697)	(1,519)	(1,256)	(1,123)	(1,385)	(1,974)	(1,628)	(1,781)	(19,399)
3	Revenues net of GSR - Margin (Unadjusted)	$ 723	$ 734	$ 845	$ 885	$ 809	$ 794	$ 734	$ 686	$ 758	$ 936	$ 805	$ 703	$ 9,412
4	Customers in Historic Year 2017 (Unadjusted)	35,266	35,340	35,379	35,418	35,436	35,449	35,414	35,356	35,365	35,346	35,431	35,380	35,382
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 0.021	$ 0.021	$ 0.024	$ 0.025	$ 0.023	$ 0.022	$ 0.021	$ 0.019	$ 0.021	$ 0.026	$ 0.023	$ 0.020	$ 0.266
6	Historic Year 2017 Customers (Fully Adjusted)	35,380	35,380	35,380	35,380	35,380	35,380	35,380	35,380	35,380	35,380	35,380	35,380	35,380
7	Change in Customers during Future Test Year 2017 (L 6 - L 4)	114	40	1	(38)	(56)	(69)	(34)	24	15	34	(51)	-	(20)
8	Annualization of Margin (L 5 * L 7)	$ 2	$ 1	$ 0	$ (1)	$ (1)	$ (2)	$ (1)	$ 0	$ 0	$ 1	$ (1)	$ -	$ (1)
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 0.065	$ 0.067	$ 0.078	$ 0.080	$ 0.071	$ 0.065	$ 0.056	$ 0.051	$ 0.061	$ 0.082	$ 0.069	$ 0.070	$ 0.814
10	Annualization of Total Revenue (L 7 * L9)	$ 7	$ 3	$ 0	$ (3)	$ (4)	$ (5)	$ (2)	$ 1	$ 1	$ 3	$ (4)	$ -	$ (2)
11	Annualization of GSR Revenues (L 10 - L8)	$ 5	$ 2	$ 0	$ (2)	$ (3)	$ (3)	$ (1)	$ 1	$ 1	$ 2	$ (2)	$ -	$ (1)
12	Total UPC (Unadjusted)-KWH	543	562	704	758	665	647	567	503	587	802	662	703	7,703
13	Annualization Adjustment for Sales-MKWH (L12 * L7)/1000	62	22	1	(29)	(37)	(45)	(19)	12	9	27	(34)	-	(31)

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for Customer Changes
Rate Commercial GS4 Default-Class 264

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
Line #	Description	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	Grand Total
1	Historic Test Year 2017 Revenues (Unadjusted)	$ 733	$ 691	$ 734	$ 734	$ 661	$ 675	$ 568	$ 633	$ 673	$ 786	$ 692	$ 680	$ 8,258
2	GSR Revenues	(479)	(454)	(480)	(477)	(426)	(420)	(342)	(377)	(413)	(498)	(435)	(424)	(5,223)
3	Revenues net of GSR - Margin (Unadjusted)	$ 254	$ 237	$ 254	$ 257	$ 235	$ 255	$ 226	$ 255	$ 260	$ 288	$ 257	$ 256	$ 3,035
4	Customers in Historic Year 2017 (Unadjusted)	1,733	1,718	1,719	1,701	1,702	1,705	1,709	1,711	1,694	1,707	1,713	1,709	1,710
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 0.147	$ 0.138	$ 0.148	$ 0.151	$ 0.138	$ 0.149	$ 0.132	$ 0.149	$ 0.153	$ 0.169	$ 0.150	$ 0.150	$ 1.775
6	Historic Year 2017 Customers (Fully Adjusted)	1,709	1,709	1,709	1,709	1,709	1,709	1,709	1,709	1,709	1,709	1,709	1,709	1,709
7	Change in Customers during Future Test Year 2017 (L 6 - L 4)	(24)	(9)	(10)	8	7	4	-	(2)	15	2	(4)	-	(13)
8	Annualization of Margin (L 5 * L 7)	$ (4)	$ (1)	$ (1)	$ 1	$ 1	$ 1	$ -	$ (0)	$ 2	$ 0	$ (1)	$ -	$ (2)
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 0.423	$ 0.402	$ 0.427	$ 0.431	$ 0.388	$ 0.396	$ 0.332	$ 0.370	$ 0.397	$ 0.460	$ 0.404	$ 0.398	$ 4.829
10	Annualization of Total Revenue (L 7 * L9)	$ (10)	$ (4)	$ (4)	$ 3	$ 3	$ 2	$ -	$ (1)	$ 6	$ 1	$ (2)	$ -	$ (6)
11	Annualization of GSR Revenues (L 10 - L8)	$ (7)	$ (2)	$ (3)	$ 2	$ 2	$ 1	$ -	$ (0)	$ 4	$ 1	$ (1)	$ -	$ (4)
12	Total UPC (Unadjusted)-KWH	4,041	3,815	4,262	4,467	3,939	4,261	3,675	4,065	4,232	4,875	4,232	4,479	50,344
13	Annualization Adjustment for Sales-MKWH (L12 * L7)/1000	(97)	(34)	(43)	36	28	17	-	(8)	63	10	(17)	-	(45)

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for Usage per Customer
Rate R Default-Class 111

Line #			
1	Heating Sensitivity/HDD/cust (kWh/DD/cust)		0.3733
2	DD Variance (to 15 Year normal)		670
3	kWh/customer (L1 * L2)		250.111
4	Customers FY19 (fully adjusted)		35,244
5	Normalizing Adj (kWh) (L3 * L4)		8,815
6	Revenue/kWh (L7+L8+L9+L10+L11)		0.09843
7	CAP/kWh		0.00339
8	EEC-Class 1/kWh		0.00236
9	Transmission/kWh		0.0037
10	GSR-1/kWh		0.06214
11	Distribution/kWh		0.02684
12	Revenue Adjustment (L5 * L6)	$	868
13	CAP Adjustment (L5 * L7)	$	30
14	EEC Adjustment (L5 * L8)	$	21
15	Transmission Adjustment (L5 * L9)	$	33
16	GSR Adjustment (L5 * L10)	$	548
17	Distribution Adjustment (L5 * L11)	$	237
18	Margin Adjustment (L17 less GRT)	$	226
19	Cooling Sensitivity/CDD/cust (kWh/DD/cust)		1.7055
20	DD Variance (to 15 Year normal)		(66)
21	kWh/customer (L19 * L20)		(112.563)
22	Customers FY19 (fully adjusted)		35,244
23	Normalizing Adj (kWh) (L21 * L22)		(3,967)
24	Revenue/kWh (L25+L26+L27+L28+L29)		0.09843
25	CAP/kWh		0.00339
26	EEC-Class 1/kWh		0.00236
27	Transmission/kWh		0.0037
28	GSR-1/kWh		0.06214
29	Distribution/kWh		0.02684
30	Revenue Adjustment (L23 * L24)	$	(390)
31	CAP Adjustment (L23 * L25)	$	(13)
32	EEC Adjustment (L23 * L26)	$	(9)
33	Transmission Adjustment (L23 * L27)	$	(15)
34	GSR Adjustment (L23 * L28)	$	(247)
35	Distribution Adjustment (L23 * L29)	$	(106)
36	Margin Adjustment (L35 less GRT)	$	(102)
37	Total Adjustment Summary-FY19:		
38	Normalizing Adj (kWh) (L5+L23)		4,848
39	Total Revenue Adjustment (L12+L30)	$	477
40	CAP Adjustment (L13+L31)	$	16
41	EEC Adjustment (L14+L32)	$	11
42	Tranmission Adjustment (L15+L33)	$	18
43	GSR Adjustment(L16+L34)	$	301
44	Distribution Adjustment(L17+L35)	$	130
45	Margin Adjustment (L18+L36)	$	124

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for Usage per Customer
Rate Commercial GS4 Default-Class 264

Line #			
1	Heating Sensitivity/HDD/cust (kWh/DD/cust)		1.5337
2	DD Variance (to 15 Year normal)		670
3	kWh/customer (L1 * L2)		1027.579
4	Customers FY19 (fully adjusted)		1,755
5	Normalizing Adj (kWh) (L3 * L4)		1,803
6	Revenue/kWh (L7+L8+L9+L10)		0.08927
7	EEC-Class 2/kWh		0.00248
8	Transmission/kWh		0.00162
9	GSR-1/kWh		0.06214
10	Distribution/kWh		0.02303
11	Revenue Adjustment (L5 * L6)	$	161
12	EEC Adjustment (L5 * L7)	$	4
13	Transmission Adjustment (L5 * L8)	$	3
14	GSR Adjustment (L5 * L9)	$	112
15	Distribution Adjustment (L5 * L10)	$	42
16	Margin Adjustment (L15 less GRT)	$	40
17	Cooling Sensitivity/CDD/cust (kWh/DD/cust)		6.63
18	DD Variance (to 15 Year normal)		(66)
19	kWh/customer (L17 * L18)		(437.580)
20	Customers FY19 (fully adjusted)		1,755
21	Normalizing Adj (kWh) (L19 * L20)		(768)
22	Revenue/kWh (L23+L24+L25+L26)		0.08927
23	EEC-Class 2/kWh		0.00248
24	Transmission/kWh		0.00162
25	GSR-1/kWh		0.06214
26	Distribution/kWh		0.02303
27	Revenue Adjustment (L21 * L22)	$	(69)
28	EEC Adjustment (L21 * L23)	$	(2)
29	Transmission Adjustment (L21 * L24)	$	(1)
30	GSR Adjustment (L21 * L25)	$	(48)
31	Distribution Adjustment (L21 * L26)	$	(18)
32	Margin Adjustment (L31 less GRT)	$	(17)
33	Total Adjustment Summary-FY19:		
34	Normalizing Adj (kWh) (L5+L21)		1,035
35	Total Revenue Adjustment (L11+L27)	$	92
36	EEC Adjustment (L12+L28)	$	3
37	Tranmission Adjustment (L13+L29)	$	2
38	GSR Adjustment (L14+L30)	$	64
39	Distribution Adjustment (L15+L31)	$	24
40	Margin Adjustment (L16+L32)	$	23

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for GSR

	OCT 2016	NOV 2016	DEC 2016	JAN 2017	FEB 2017	MAR 2017	APR 2017	MAY 2017	JUN 2017	JUL 2017	AUG 2017	SEP 2017	TOTAL
Historic Actual GSR Rates FY 17	$0.07403	$0.07403	$0.06593	$0.06593	$0.06593	$0.05636	$0.05636	$0.05636	$0.06214	$0.06214	$0.06214	$0.06214	
September 1 2017 Effective GSR Rate	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	$0.06214	
GSR Rate Variance	($0.01189)	($0.01189)	($0.00379)	($0.00379)	($0.00379)	$0.00578	$0.00578	$0.00578	$0.00000	$0.00000	$0.00000	$0.00000	
Total GSR Volumes	46,953	55,467	71,967	70,806	57,225	64,361	44,774	44,984	51,756	60,673	54,673	50,034	673,673
GSR Revenue Adjustment	($558)	($659)	($273)	($268)	($217)	$372	$259	$260	$0	$0	$0	$0	($1,085)

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for CAP

	OCT 2016	NOV 2016	DEC 2016	JAN 2017	FEB 2017	MAR 2017	APR 2017	MAY 2017	JUN 2017	JUL 2017	AUG 2017	SEP 2017	TOTAL
Historic Actual CAP Rates FY 17	$0.00454	$0.00454	$0.00363	$0.00363	$0.00363	$0.00294	$0.00294	$0.00294	$0.00339	$0.00339	$0.00339	$0.00339	
CAP Rate Effective September 2017	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	$0.00339	
CAP Rate Variance	($0.00115)	($0.00115)	($0.00024)	($0.00024)	($0.00024)	$0.00045	$0.00045	$0.00045	$0.00000	$0.00000	$0.00000	$0.00000	
Total Rate R Volumes Excluding CAP volumes	31,405	36,688	50,019	55,472	49,186	47,336	38,752	31,174	34,116	43,922	36,044	37,522	491,637
Revenue Variance	($36)	($42)	($12)	($13)	($12)	$21	$17	$14	$0	$0	$0	$0	($63)

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for EEC

	OCT 2016	NOV 2016	DEC 2016	JAN 2017	FEB 2017	MAR 2017	APR 2017	MAY 2017	JUN 2017	JUL 2017	AUG 2017	SEP 2017	TOTAL
Historic EEC-Class 1 Actual Rates FY 17	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00287	$0.00236	
Historic Year 2017 EEC-Class 1 Rate Effective Sept 1	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	$0.00236	
EEC-Class 1 Rate Variance	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	($0.00051)	$0.00000	
Total EEC-Class 1 Volumes	35,433	43,882	59,480	56,883	44,268	52,794	34,598	32,775	39,174	47,441	41,252	34,708	522,688
Total EEC-Class 1 Revenue Adjustment	($18)	($22)	($30)	($29)	($23)	($27)	($18)	($17)	($20)	($24)	($21)	$0	($249)
Historic EEC-Class 2 Actual Rates FY 17	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	$0.00249	
Historic Year 2017 EEC-Class 2 Rate Effective Sept 1	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	$0.00248	
EEC-Class 2 Rate Variance	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	($0.00001)	
Total EEC-Class 2 Volumes	11,781	11,793	12,793	14,288	13,222	11,826	10,365	12,300	12,596	13,235	13,690	16,845	154,734
Total EEC-Class 2 Revenue Adjustment	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($2)
Historic EEC-Class 3 Actual Rates FY 17	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	$0.00335	
Historic Year 2017 EEC-Class 3 Rate Effective Sept 1	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	$0.00115	
EEC-Class 3 Rate Variance	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	($0.00220)	
Total EEC-Class 3 Volumes	21,836	21,191	22,373	23,114	20,909	23,201	21,549	22,535	23,559	24,407	24,892	23,642	273,210
Total EEC-Class 3 Revenue Adjustment	($48)	($47)	($49)	($51)	($46)	($51)	($47)	($50)	($52)	($54)	($55)	($52)	($601)
Total EEC Revenue Adjustment	($66)	($69)	($80)	($80)	($69)	($78)	($65)	($66)	($72)	($78)	($76)	($52)	($851)

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for STAS

	Historic Revenue Excluding STAS	Customer Adj	UPC Adj	GSR Adj	CAP Adj	EEC Adj	Revised Revenue Excluding STAS	STAS Revenue @ Sep 1 Rate 0.94%	Historic Actual STAS Revenue	Adjustment
Residential	55,723	$ (2)	$ 477	$ (855)	$ (63)	$ (248)	$ 55,032	$ 517	$ 559	$ (42)
Commercial & Industrial	24,420	$ (6)	$ 92	$ (218)	$ -	$ (603)	$ 23,685	$ 223	$ 243	$ (21)
PSHWY	713	$ -	$ -	$ (10)	$ -	$ (0)	$ 703	$ 7	$ 7	$ (1)
Other	14	$ -	$ -	$ -	$ -	$ (0)	$ 14	$ 0	$ 0	$ (0)
Sales for Resale	10	$ -	$ -	$ (1)	$ -	$ (0)	$ 9	$ 0	$ 0	$ (0)
Total	$ 80,880	$ (8)	$ 570	($1,085)	($63)	($851)	$79,443	$ 747	$ 810	$ (63)

UGI ELECTRIC EXHIBIT DEL-6

UGI Utilities, Inc. - Electric Division
Universal Service Program Rider (USP) Calculation

	FY 19
Shortfall	2,000,000
CAP Administration	95,500
LIURP	124,750
Hardship	2,400
Pre-Program Arrearage	386,470
Total Expense	$ 2,609,120
Billing Determinants (KwH)	494,979,416
Proposed USP Rider	$ 0.0053

Calculation of Annual Reconciliation Adjustment related to CAP Credits and PPA

	FY 14	FY 15	FY 16	3 Year Average
Residential Low Income Write Offs	9.80%	9.80%	9.10%	9.57%
Less: Residential Write Offs	2.20%	2.30%	2.00%	2.17%
Gross Adjustment	7.60%	7.50%	7.10%	**7.40%**

UGI ELECTRIC EXHIBIT DEL-7

Development of Proposed Rate EV (Electric Vehicle services)

		250 series	100 series	4000 series	Notes :
1	Estimated Capital Investment	$ 46,920	$ 14,375	$ 7,475	Investment including Overhead @ 15%
2	% Return on Investment (ROI)	8.07%	8.07%	8.07%	Per Company's Proposed ROI
3	Annual $ ROI (prior to Income Tax)	$ 3,786	$ 1,160	$ 603	line1*line 2
4	Annual $ Revenue Requirement ROI	$ 6,475	$ 1,984	$ 1,032	line 3*1.71 (Income tax Factor)
5	Annual $ Depreciation Expense	$ 9,384	$ 2,875	$ 1,495	line 1/5 years
6	Estimated O&M Expense	$ 4,760	$ 2,405	$ 1,300	Associated Annual O&M Expense
7	Annual Revenue Requirement (Prior to GRT)	$ 20,619	$ 7,264	$ 3,827	line 4+line 5+line 6
8	Annual Revenue Requirement (Incl GRT)	$ 21,912	$ 7,719	$ 4,066	line /(1-.059) GRT @ 59 mills
9	*Monthly Tariff Charge*	*$ 1,826*	*$ 643*	*$ 339*	*line 8/12 billing months*

UGI ELECTRIC EXHIBIT DEL-8

	Development of Proposed Update to Rate HTP			
		Primary 66kV Metered	Secondary 13 kV Metered	
				Notes :
1	Estimated Capital Investment :	$ 88,720	$ 16,690	Based on internal costs estimate
2	% Return on Investment (ROI)	8.07%	8.07%	Per Company's Proposed ROI
3	Annual $ ROI (prior to Income Tax)	$ 7,159.70	$ 1,346.88	1 line*2 line
4	Annual $ Revenue Requirement ROI	$ 12,243	$ 2,303	line 3*1.71 (Income tax Factor)
5	Annual $ Depreciation Expense	$ 2,688	$ 506	33 year depreciation period (line 1 / 33)
6	Annual Revenue Requirement (Prior to GRT)	$ 14,932	$ 2,809	line 4 + line 5
7	Annual Revenue Requirement (Incl GRT)	$ 15,868	$ 2,985	line 6/(1-.059) GRT @ 59 mills
8	Meter Cost Component	$ 1,322	$ 249	line 7 / 12
9	Monthly Customer Charge component	349.47	349.47	Based on LP monthly customer cost in cost of service study as a proxy
10	Total Monthly Customer Charge	$ 1,671.78	$ 598.22	line 8 + line 9

UGI ELECTRIC STATEMENT NO. 9 –
NICOLE M. MCKINNEY

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2017- 2640058

UGI Utilities, Inc. – Electric Division

Statement No. 9

Direct Testimony of
Nicole M. McKinney

Topics Addressed: **Taxes and Tax Adjustments**

Dated: January 26, 2018

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Nicole M. McKinney. My business address is 2525 North 12th Street, Suite 360, Reading, PA, 19612-2677.

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

A. I am employed by UGI Utilities, Inc. ("UGI") as Manager of Tax and Regulatory Accounting. 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" or the "Company"), which is a certificated electric distribution company ("EDC") that are both regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your principal duties and responsibilities as Manager of Tax and Regulatory Accounting?

A. My primary duties as Manager of Tax and Regulatory Accounting include the preparation of tax data to be reported in UGI's various United States Securities and Exchange Commission and regulatory filings, as well as its various federal and state income and non-income tax return related filings. Additionally, I maintain the current and deferred income tax accrual and expense accounts, perform tax research, and assist UGI with tax matters as they arise. Additionally, I manage the reporting of the Company's various tax and accounting filings with the PUC and the Federal Energy Regulatory Commission, as well as maintain the accounting for our regulatory asset and liability accounts.

Q. Please describe your educational background and work experience.

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

Q. Have you testified previously before this Commission?

A. Yes. I have testified before this Commission in the 2016 base rate proceeding of UGI Gas at Docket No. R-2015-2518438 and the base rate proceeding of UGI Penn Natural Gas, Inc. at Docket No. R-2016-2580030.

Q. Please describe the purpose of your testimony.

A. I am providing testimony on behalf of UGI Electric. I will explain the Company's *pro forma* tax adjustments to its principal accounting exhibits for the fully projected future test year ending September 30, 2019 ("FPFTY"). I will also explain the tax adjustments made to the results of UGI Electric's historic test year ended September 30, 2017 ("HTY") and future test year ending September 30, 2018 ("FTY").

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

A. Yes. I am sponsoring the following UGI Electric Exhibits: NMM-1, NMM-2, and NMM-3. Together with other Company witnesses, I am sponsoring portions of UGI Electric Exhibit A (Fully Projected), UGI Electric Exhibit A (Future) and UGI Electric Exhibit A (Historic) that pertain to tax-related issues. These exhibits comprise UGI Electric's principal accounting exhibits for the HTY, FTY, and FPFTY. I am also sponsoring certain responses to the Commission's filing requirements and standard data requests. Each response identifies the witness sponsoring it.

Q. Ms. McKinney, does your testimony reflect the impact of the tax reform legislation, H.R. 1 of 2017, which was signed into law on December 22, 2017?

A. No, my testimony does not take into consideration the recently-enacted changes to the tax code. The Company is conducting an analysis of the impact of the tax reform legislation and will supplement the tax schedules and any testimony as needed later in this proceeding.

II. TAX ADJUSTMENTS

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

A. As explained in the direct testimony of Stephen F. Anzaldo (UGI Electric Statement No. 2), UGI Electric's principal accounting exhibit is UGI Electric Exhibit A (Fully Projected), which includes a presentation for the FPFTY ending September 30, 2019. Section D of UGI Electric Exhibit A (Fully Projected) presents necessary adjustments to budgeted levels of expense items and revenues. The *pro forma* adjustments related to taxes are summarized in Schedules D-31 through D-34. These tax adjustments are used to derive UGI Electric's *pro forma* income at present and proposed rates as set forth in Schedule A-1 of the same exhibit.

UGI Electric Exhibit A (Future) and UGI Electric Exhibit A (Historic) follow the format of UGI Electric Exhibit A (Fully Projected), but reflect data for the HTY ended September 30, 2017, and the FTY ending September 30, 2018. This information is provided in accordance with the Commission's filing requirements and provides a basis for comparing UGI Electric's FPFTY claims with actual book results from the HTY and adjusted FTY results. Section D to UGI Electric Exhibit A (Historic), Schedule D-31, and UGI Electric Exhibit A (Future), Schedule D-31 include adjustments that share the same methodology as used in Schedule D-31 of UGI Electric Exhibit A (Fully Projected).

A. TAXES OTHER THAN INCOME TAXES

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

A. TOTI consists of the Pennsylvania Utility Realty Tax (“PURTA”), the Pennsylvania Gross Receipts Tax, Pennsylvania and Local Use taxes, Social Security taxes, Federal Unemployment tax (“FUTA”), State Unemployment tax (“SUTA”) and the Company’s assessed contribution to the Pennsylvania Public Utility Commission. TOTI amounts were based on the plan year budget, as adjusted for reasonably known and measurable changes as explained by the direct testimony of Mr. Anzaldo (UGI Electric Statement No. 2). The net adjustment of ($605) is brought forward to Schedule D-3, page 2.

B. INCOME TAXES

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

A. Income tax expense for the FPFTY at present and proposed rates is set forth in UGI Electric Exhibit A (Fully Projected), Schedule D-33. Income taxes are calculated using the procedures normally followed by the Commission, including the use of debt interest synchronization, the normalization method for accelerated depreciation used in the calculation of Federal income taxes, and the flow through of accelerated depreciation benefits for state tax purposes. UGI Electric is also proposing to normalize the tax repairs expense deduction for federal tax purposes. For state tax purposes, UGI Electric proposes to flow-through the repairs tax benefit over the tax useful lives of the asset that generated the benefit, which is generally 20 years. The fully adjusted claim for the FPFTY income tax expense is shown on UGI Electric Exhibit A (Fully Projected), Schedule D-1.

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

A. The calculation of federal and state income taxes shown on Schedule D-1 lines 18 and 19 can be found on Schedule D-33. Schedule D-33 shows the calculation of *pro forma* income taxes for the FPFTY at present and proposed rates. Line 1 shows the revenue at present and proposed rates, while line 2 shows the operating expenses at present and proposed rates from Schedule D-1. Line 3 reflects operating income before debt interest is deducted, by netting line 1 from line 2. Debt interest expense is synchronized using the rate base claim from Schedule C-1, with the cost of debt and the debt component of UGI Electric's capital structure recommended in the direct testimony of Paul R. Moul (UGI Electric Statement No. 5) and shown on Schedule B-7. The resulting interest expense on line 6 is subtracted from net income before debt interest to calculate base taxable income on line 7.

In accordance with established Commission practice, lines 8 through 11 of Schedule D-33 reduce the base taxable income, for state tax purposes, by the total difference between accelerated tax depreciation shown on line 8 and the *pro forma* book depreciation shown on line 9. The statutory state corporate net income tax rate (9.99%) was then applied to determine the *pro forma* state income tax expense shown on line 13. Lines 14 through 19 show the federal income tax expense calculation at current and proposed rates, while line 20 sums the state and federal tax expense amounts before application of Deferred Federal and State Income Taxes. At lines 21 through 28, Deferred Federal and State Income Taxes are used to increase the *pro forma* income tax expense at present and proposed rates with the total calculated amount for income taxes before the application of other adjustments shown on line 29. The amounts of accelerated depreciation, cost of removal, repairs tax deduction, tax basis adjustments to plant, straight line depreciation and book depreciation used in the determination of income taxes used in this calculation are summarized on Schedule D-34.

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

A. As shown on Schedule D-33 at line 31, the *pro forma* tax expense at present rates is $0.38 million and the *pro forma* tax expense at proposed rates for the FPFTY is $3.77 million. As explained below in Section II.E, this figure is not reduced by a consolidated income tax adjustment.

C. ACCUMULATED DEFERRED INCOME TAXES

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

A. Schedule C-6 shows the FPFTY ending balance for federal ADIT at September 30, 2019. This amount is deducted from rate base. The total shown on line 8 reflects the difference in income tax expense for book and tax purposes attributable to the difference between the accelerated tax depreciation, inclusive of bonus depreciation, and straight line book depreciation on test year plant balances, net of offsets associated with contributions in aid of construction. Rate base has been further reduced by the state regulatory liability associated with our repairs tax method shown on line 6. As the state tax consequence of accelerated depreciation is flowed through, there is no associated state ADIT balance.

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

A. As shown on line 8 of Schedule C-6 and on line 6 of Schedule A-1, the ADIT offset is $27.785 million, which includes an amount related to the repairs tax method explained below in Section D.

Q. Has the calculation of the Company's ADIT rate base deduction been calculated in compliance with the normalization requirements of the Internal Revenue Code?

A. Yes. The Company's calculation properly reflects the pro-rationing concept in accordance with Treasury Regulation 1.167(l)-1(h)(6)(ii) that it must follow for ratemaking purposes to be in compliance with IRS normalization requirements. The pro-rationing concept requires that utilities pro-rate their rate base ADIT deduction to account for the time during the fully projected future test year that the ADIT for plant additions will be accrued by the company. This pro-rata calculation is required by the IRS in order for a utility company to be permitted to use accelerated depreciation and not have a normalization violation. As such, the Company reflects a pro-rationing of the ADIT associated with its FPFTY plant additions. This is in line with other public utility FPFTY presentations, including that of UGI Gas, Columbia Gas of Pennsylvania and PPL Electric Utilities Corporation. See UGI Electric Exhibit NMM-2 for the calculation of the pro-rata adjustment.

D. REPAIRS TAX METHOD

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

A. In its tax return for the year ended September 30, 2009, UGI Electric adopted a tax accounting method to expense as repairs certain items capitalized for book purposes in accordance with federal tax regulations. As a result of adopting this method, UGI Electric's federal tax expense for the year ended September 30, 2009, was reduced by $2,328,039.

UGI Electric has chosen to calculate its federal income tax expense claim, inclusive of the repairs tax deduction, consistent with normalization. As a result, the difference between using accelerated tax depreciation versus book depreciation in the calculation of federal tax expense creates accumulated deferred income tax. For state income tax purposes, solely with respect to the repairs tax deduction, UGI Electric has chosen to flow-through the repairs tax benefit over the tax useful lives of the assets generating the tax deduction. The state ADIT balance associated with the repairs tax deduction is classified as a regulatory liability, as it represents the repairs tax benefit that ratepayers have not yet received. In both the federal and state instances, the ADIT balance amortizes or unwinds over the remaining life of the asset.

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

E. CONSOLIDATED TAX BENEFITS

Q. Has the Company calculated a consolidated tax expense adjustment?

A. Yes, but not for the purpose of flowing through as a ratemaking deduction to federal income tax expense. It is my understanding that Act 40 of 2016, which added 66 Pa. C.S § 1301.1 to the Public Utility Code, prohibits the use of a consolidated tax adjustment for ratemaking purposes. However, Section 1301.1(b) requires a public utility seeking to change rates to demonstrate that it uses at least 50 percent of what would have been a consolidated tax expense adjustment under the law prior to Act 40 for reliability or infrastructure related capital investment and the other 50 percent must be used for general corporate purposes. I have included a calculation of such an adjustment using the modified effective tax rate methodology traditionally used by the Commission prior to the enactment of Act 40 as exhibit NMM-3 which indicates a consolidated tax adjustment in the amount of $41,000. In Electric Statement No. 2, Company witness Mr. Stephen F. Anzaldo discusses how the Company's capital budgets satisfy the requirements of Act 40.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC EXHIBIT NMM-1

Nicole M. McKinney, CPA

PROFESSIONAL EXPERIENCE:

UGI Utilities, Inc. Reading, PA

Manager. March 2015 – Present

- Supervise 2 direct reports
- Manage the accounting for income taxes in accordance with ASC 740 and regulated operations under ASC 980
- Provide technical accounting guidance and expertise on regulatory accounting and compliance and income tax matters
- Manage the preparation of various regulatory and income tax related filings

DENTSPLY International. York, PA

Manager. August 2012 –April 2014

- Supervised staff of 3
- Responsible for identifying deficiencies and areas of improvement for current tax and accounting processes
- Managed completion of domestic federal tax returns and income tax provision
- Performed periodic presentations to senior management regarding tax implications of various business transactions and changes in tax law
- Supervised special tax projects such as research & development tax credit study, domestic production activities deduction, and accounting method changes

ParenteBeard, LLC. Lancaster, PA

Manager. December 2010 – July 2012.

- Supervised staff of 5
- Managed client relationships for middle-market businesses to ensure satisfaction of tax and accounting needs
- Assisted in the standardization of accounting processes and working papers
- Served as the liaison between external auditors and clients to achieve efficiency and successful results in year- end audits
- Reviewed complex individual, partnership, corporate, and international federal and state tax returns
- Served as manager on the strategic tax initiative team

WTAS, LLC. Philadelphia, PA

Manager. August 2006 – November 2010.

- Supervised staff of 3+
- Managed successful consulting engagements resulting in substantial cash savings
- Developed various complex financial models for client budgetary and forecasting needs
- Prepared and reviewed various international, domestic, and state corporate and partnership tax returns

EDUCATION:

Villanova University, Villanova, PA

Master of Accountancy - May 2007

Bachelor of Science - International Business/Management & Accounting - May 2006

Summa cum Laude

Bartley Medallion of Honor

UGI ELECTRIC EXHIBIT NMM-2

UGI - Electric Division
Calculation of Pro-Rata Accumulated Deferred Income Tax
(In Thousands)

Month	A Increase to Deferred Taxes	B # of Days	C = B/365 Pro-Rata %	D = C*A Pro-Rata Incr to Deferred Taxes	Per Treas. Reg.1.167(l)-1(h)(6)(ii) Accumulated Deferred Income Tax Balance
9/30/2018					$ 26,535
10/31/2018	337	335	91.78%	309	26,845
11/30/2018	153	305	83.56%	128	26,973
12/31/2018	324	274	75.07%	243	27,216
1/31/2019	185	243	66.58%	123	27,339
2/28/2019	196	215	58.90%	115	27,454
3/31/2019	139	184	50.41%	70	27,524
4/30/2019	159	154	42.19%	67	27,591
5/31/2019	170	123	33.70%	57	27,649
6/30/2019	266	93	25.48%	68	27,716
7/31/2019	269	62	16.99%	46	27,762
8/31/2019	242	31	8.49%	21	27,783
9/30/2019	912	1	0.27%	2	**$ 27,785**

UGI ELECTRIC EXHIBIT NMM-3

UGI Utilities, Inc. - Electric Division
Calculation of Consolidated Tax Adjustment
In Thousands (000)

	Taxable Income 2014	Taxable Income 2015	Taxable Income 2016	Average	
Tax Loss Entities					
UGI Corporation	0	0	(20,139)	(6,713)	
AmeriGas Inc.	0	0	(20)	(7)	
Four Flags	0	0	0	0	
Homestead Holding	0	(16)	(126)	(47)	
UGI Asset Management	0	0	0	0	
UGI China	(274)	0	(3,868)	(1,381)	
UGI Development Company	0	(6,170)	0	(2,057)	
UGI Europe	0	0	0	0	
UGID Holding	(8)	(8)	(8)	(8)	
UGI HVAC Services	0	(1,327)	0	(442)	
UGI HVAC Enterprises	(2,485)	0	(350)	(945)	
UGI International (China)	(6)	0	(252)	(86)	
UGI LNG	(1,876)	(261)	(706)	(948)	
UGI Penn HVAC Services	0	0	(170)	(57)	
UGI Penn Natural Gas	0	0	0	0	
UGI Petroleum Products of DE	(10)	(139)	0	(50)	
UGI Properties	0	0	0	0	
United Valley Insurance	0	(339)	(3,295)	(1,211)	
Hellertown Pipeline	(29)	(23)	(2)	(18)	
Ashtola Production Company	(1)	(1)	(1)	(1)	
Total Tax Loss	(4,689)	(8,283)	(28,936)	(13,970)	
Tax Positive Entities					% of Total
AmeriGas Propane	42,408	55,822	50,168	49,466	17.0%
Petrolane Incorporated	15,856	16,679	16,801	16,445	5.7%
AmeriGas Inc.	67	449	0	172	0.1%
UGI Storage Company	3,884	7,276	6,703	5,954	2.1%
Energy Service Funding	4,349	3,788	2,576	3,571	1.2%
Hellertown Pipeline	0	0	0	0	0.0%
Homestead Holding	40	0	0	13	0.0%
McHugh Services Co.	0	0	0	0	0.0%
Newberry Holding	7,785	517	640	2,981	1.0%
UGI Asset Management	0	0	0	0	0.0%
UGI Corporation	0	2,231	0	744	0.3%
UGI Development Company	10,804	0	4,323	5,042	1.7%
UGI Enterprises	83,999	98,718	89,121	90,613	31.2%
UGI Ethanol	0	0	0	0	0.0%
UGI Europe	10,044	104,060	86,109	66,738	23.0%
UGI Hunlock Development	0	0	0	0	0.0%
UGI HVAC Services	0	0	0	0	0.0%
UGI Penn Natural Gas	4,972	34,986	(5,544)	11,471	4.0%
UGI Penn HVAC Services	553	876	0	476	0.2%
UGI Properties	391	172	28	197	0.1%
UGI Utilities	24,564	42,897	(21,909)	15,184	5.2%
UGID Holding	0	0	0	0	0.0%
United Valley Insurance	370	0	0	123	0.0%
UGI Central Penn Gas	29,238	21,902	10,388	20,509	7.1%
UGI China	0	1,192	0	397	0.1%
UGI International (China)	0	0	0	0	0.0%
Eliminations	123	353	313	263	0.1%
Subtotal Taxable Income	239,447	391,918	239,717	290,361	100.0%
Total	**234,758**	**383,635**	**210,780**	**276,391**	

Total Savings Allocated to UGI Utilities	(731)
MWF Allocation %	16.07%
Total Savings Allocated to UGI - Electric Division	(117)
Consolidated Tax Adjustment	(41)

Notes:
(1) Single-member limited liability companies, i.e. disregarded entities, have been combined with their tax-regarded parent company.
(2) Non-recurring losses have not been eliminated as would normally be done. With including the non-recurring losses, the Company is still above the spending rules, so no further analysis is required.