BOOK III

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS STATEMENT NO. 1 – PAUL J. SZYKMAN
UGI GAS STATEMENT NO. 2 – ANN P. KELLY
UGI GAS STATEMENT NO. 3 – PAUL R. MOUL
UGI GAS STATEMENT NO. 4 – PAUL R. HERBERT
UGI GAS STATEMENT NO. 5 – JOHN F. WIEDMAYER
UGI GAS STATEMENT NO. 6 – DAVID E. LAHOFF

ORIGINAL TARIFF
UGI UTILITIES, INC. – GAS DIVISION – PA P.U.C. NO. 6

DOCKET NO. R-2015-2518438

Issued: January 19, 2016 Effective: March 19, 2016

UGI GAS STATEMENT NO. 1 – PAUL J. SZYKMAN

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2015-2518438

UGI Utilities, Inc. – Gas Division

Statement No. 1

Direct Testimony of
Paul J. Szykman

Topics Addressed:	**Rate Filing Overview** **Need for Rate Relief** **UGI-1 Initiative** **UNITE Systems Improvement Initiative** **Interruptible Revenues** **Management Performance**

Dated: January 19, 2016

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

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

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

A. I am employed by UGI Utilities, Inc. ("UGI") as Vice President – Rates & Government Relations and Vice President & General Manager – Electric Utilities.

Q. Please briefly describe your responsibilities in that capacity.

A. As Vice President – Rates and Government Relations, I am responsible for all rate and governmental affairs activities for UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company"), UGI Penn Natural Gas, Inc. ("PNG"), UGI Central Penn Gas, Inc. ("CPG") and UGI Utilities, Inc. – Electric Division ("UGI Electric"). For the rates component, I oversee the areas of sales and revenue forecasting, tariff administration and compliance, Choice administration and compliance, rate administration, 1307(f) gas cost filings, electric POLR filings, 1307(e) filings and UGI's supportive gas management information technology systems and functionality.

As far as government relations are concerned, I am responsible for managing the development and implementation of the Company's strategies in federal and state legislative and regulatory arenas.

Finally, I have recently taken on management of the operations of UGI Electric. In all of these capacities, I report directly to the President and Chief Executive Officer of UGI.

Q. What is your educational and professional background?

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

Q. Have you testified previously before this Commission?

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

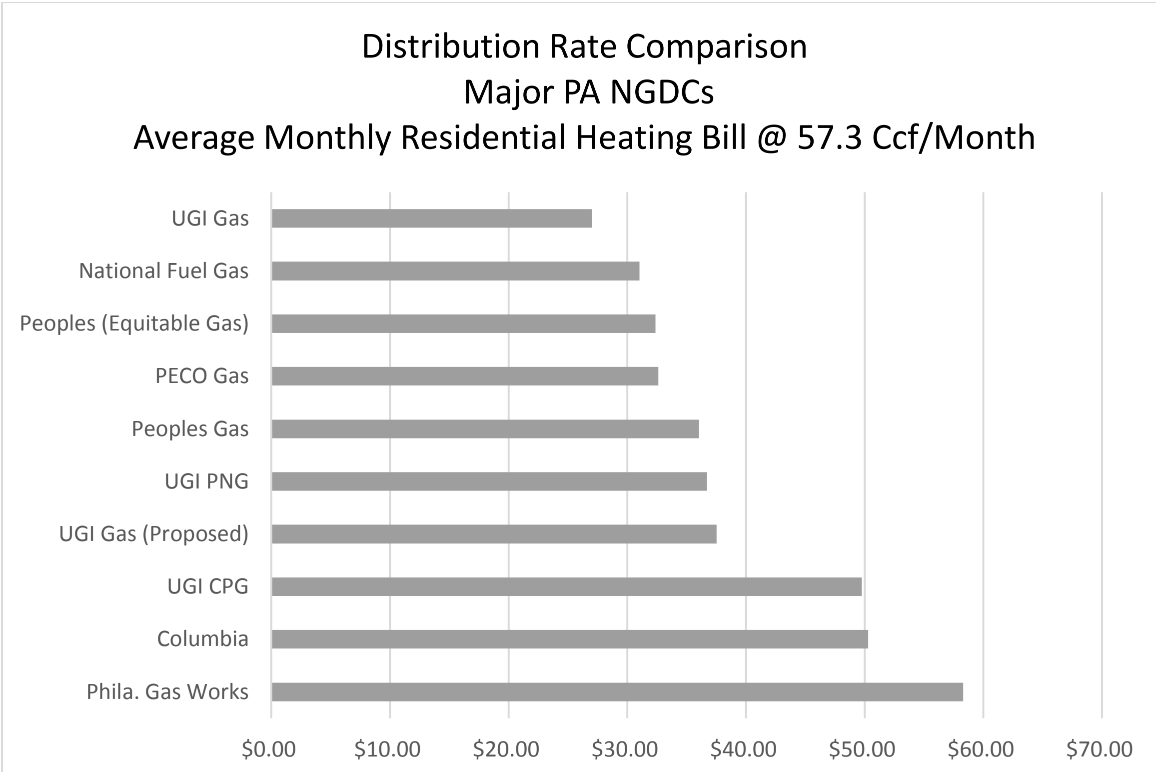
II. <u>PURPOSE OF TESTIMONY</u>

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

A. My testimony addresses several issues. First, I present an overview of the rate filing, including a brief explanation of the reasons for rate relief and an outline of the testimony of each witness in this proceeding. Second, I will describe UGI-1, which is an initiative designed to align UGI's people, processes and tools across the utility business units and identify the expected benefits from that initiative. As part of my UGI-1 discussion, I briefly discuss the UGI's Next Information Technology Enterprise ("UNITE") Initiative, which is UGI's ongoing effort to develop and implement a next generation technology solution, including a state-of-the-art customer information system ("CIS") and other work management and regulatory compliance programs, and summarize the benefits that UNITE will bring to UGI's Customers. Third, I discuss the Company's interruptible service program and how continuing value of service pricing for those customers is reasonable and appropriate. Lastly, I will summarize UGI's focus on management and its success in improving management performance. As further explained below, UGI Gas's management continues to improve service to customers through various initiatives, including, but not limited to: the UGI-1 initiative; the UNITE system improvement initiative; an accelerated infrastructure replacement plan; an innovative expansion and extension program; sustained customer growth; customer service that has generated nationally recognized customer satisfaction; implementation of recently expanded universal services offerings; development of an energy efficiency and conservation plan; and dedication to continuous safety improvement initiatives designed to keep employees, customers and property safe and reduce workplace injuries and motor vehicle accidents.

At the same time, the Company has been able to offer excellent service to customers at just and reasonable rates. A comparison of residential rates, shown in Table 1 below, illustrates that UGI Gas currently has the lowest distribution rates in the Commonwealth.

Table 1



Even if the proposed increase is approved in full, the average monthly residential heating customer bill will be 3.2% <u>lower</u> than the average bill following UGI Gas's last rate case in 1995.

Q. Are you sponsoring any exhibits in this proceeding?

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

III. OVERVIEW OF THE COMPANY'S FILING

Q. Please discuss the rate relief that UGI Gas is requesting.

A. UGI Gas is requesting an increase in its annual base rate operating revenues of $58.6 million, or 17.5 percent on a total revenue basis, with a proposed effective date of March 19, 2016. The base rate increase requested in this filing is based on a fully projected future test year ending September 30, 2017 ("FPFTY"). The Company also proposes substantial changes to its existing tariff to both harmonize the UGI Gas tariff with those previously approved by the Commission for CPG and PNG and to implement best practices and procedures. The Company also is proposing a new five-year energy conservation program, the Energy Efficiency and Conservation ("EE&C") Plan, designed to promote efficient use of natural gas. Finally, the Company is proposing a Technology and Economic Development ("TED") Rider to, among other things, provide rate flexibility needed to encourage developing technologies, and to address competitive conditions and customer preferences in seeking to expand the availability and use of the Commonwealth's abundant natural gas supplies.

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

A. The Company's current rates do not provide it with a reasonable opportunity to earn its cost of capital. Since its last rate case in 1995, UGI Gas has made over $1.0 billion in system investments, increasing the Company's rate base by over 120 percent. These investments were necessary to serve new residential and commercial customers; connect customers converting to natural gas; accelerate the replacement of aging gas plant infrastructure; upgrade and improve system segments and modernize facilities; and install and upgrade supporting information technology, all as part of growing and maintaining a safe and reliable distribution system and providing quality customer service. Over the same period, UGI Gas has adopted modest annual wage and salary adjustments and will continue to do so, where reasonable, and has experienced other general price increases for the products and services it must procure. Although UGI Gas has implemented significant cost containment measures, implemented efficiency enhancements including major strides toward integrating its operations with those of CPG and PNG, and seen substantial customer growth over time, the growth in operating and capital costs, along with experienced and anticipated declines in per customer usage, have caused UGI Gas to be unable to earn a fair rate of return on its investment, at present rate levels.

Specifically, as reflected in UGI Gas Exhibit A (Fully Projected), Schedule A-1, the Company's operations are projected to produce an overall return on rate base of 4.52%, which equates to a return on common equity of only 4.30% for the twelve months ending September 30, 2017. As explained by UGI Gas witness Paul R. Moul (UGI Gas Statement No. 3), those returns are not adequate based on applicable financial data and the risks confronted by UGI Gas. Unless UGI Gas receives the requested substantial rate relief, those returns will continue to decline and potentially jeopardize the Company's ability to attract the capital needed to make system investments that will enhance the reach and capacity of its distribution system and to replace older, obsolete facilities, each of which is prudent to ensure continued system reliability, safety, and customer service performance.

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

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

Ann P. Kelly (UGI Gas Statement No. 2) serves as Controller of UGI. Ms. Kelly addresses the Company's accounting and budgeting processes. She also presents the UGI Gas overall revenue requirement for the FPFTY, including test year revenue, rate base, and operating expense claims, and certain pro forma adjustments as set forth in UGI Gas Exhibit A (Fully Projected). Ms. Kelly also presents the Company's historic test year ("HTY"), ended September 30, 2015, and future test year ("FTY"), ending September 30, 2016, with appropriate ratemaking adjustments.

Paul R. Moul (UGI Gas Statement No. 3) is Managing Consultant of P. Moul & Associates, Inc. Mr. Moul presents expert testimony concerning the overall rate of return that UGI Gas should be afforded in order to have a reasonable opportunity to earn a fair return on its rate base investment. Mr. Moul also supports the Company's claimed capital structure, its embedded cost of debt, as well as its requested return on common equity. Schedules and work papers supporting Mr. Moul's findings are set forth in UGI Gas Exhibit B.

Paul R. Herbert (UGI Gas Statement No. 4) is President of Gannett Fleming Valuation & Rate Consultants, LLC. Mr. Herbert prepared and sponsors the Company's fully allocated cost of service studies used in this case, which are found in UGI Gas Exhibit D.

John F. Wiedmayer (UGI Gas Statement No. 5) is Project Manager at Gannett Fleming Valuation & Rate Consultants, LLC. Mr. Wiedmayer developed and supports the Company's claim for annual depreciation expense and the accumulated depreciation reserve. His studies are presented in UGI Gas Exhibit C (Fully Projected), UGI Gas Exhibit C (Future) and UGI Gas Exhibit C (Historic).

David E. Lahoff (UGI Gas Statement No. 6) is Manager – Tariff & Supplier Administration for UGI. Mr. Lahoff is responsible for all areas of the Company's rate design and revenue allocation except where I discuss interruptible service pricing in my testimony. Mr. Lahoff also addresses and sponsors related exhibits that show the proof of revenues and proposed rate design, as presented in UGI Gas Exhibit E - Proof of Revenue. Mr. Lahoff's testimony also presents the detailed supporting sales and revenue adjustments for each tariff customer class, including related models and assumptions.

Mr. Lahoff is also sponsoring UGI Gas Exhibit F, which is Original Tariff – Gas Pa. P.U.C. No. 6 (“Tariff No. 6”), which replaces current Tariff – Gas Pa. P.U.C. No. 5. Mr. Lahoff provides a summary of the proposed changes to the tariff rules, regulations, and rate schedules included in UGI Gas’s Tariff No. 6, and changes to the Choice Supplier Tariff, which is incorporated into Tariff No. 6 as Tariff No. 6-S. Mr. Lahoff also provides an explanation of the EE&C Rider, Merchant Function Rider, Universal Service Program Rider, and Growth Extension Tariff (“GET Gas”) Rider.

Robert R. Stoyko (UGI Gas Statement No. 7) is Vice President, Marketing and Customer Relations for UGI. Among the issues addressed in his testimony, Mr. Stoyko discusses the variety of risks affecting the economics of serving large firm and interruptible customers, including such variables as physical bypass and the spread between delivered natural gas prices and competing alternate fuels. Mr. Stoyko also explains and provides support for the Company’s proposed TED Rider, large customer usage projections, proposed changes to the Company’s Universal Service Program cost recovery mechanism, and implementation plans for the Company’s proposed EE&C Plan.

Thomas P. Lord (UGI Gas Statement No. 8) is Vice President & Chief

Information Officer for UGI. Mr. Lord provides a detailed explanation of the benefits of the UNITE initiative and how Phase I of UNITE, involving the implementation of a new CIS and other features, will assist the Company in improving its ability to interact with customers and improve the service provided by the Company. Mr. Lord's testimony also presents the project schedule and the important milestones that will be met to place the CIS into service during the FPFTY.

Hans Bell (UGI Gas Statement No. 9) is Vice-President Engineering & Operations Support for UGI. In his testimony, Mr. Bell discusses the Company's natural gas distribution system, its Commission-approved Long Term Infrastructure Improvement Plan ("LTIIP"), and the Company's performance against its infrastructure replacement and improvement objectives. Mr. Bell also discusses the impact of the LTIIP and other initiatives on system performance, safety, and reliability. Additionally, Mr. Bell discusses the changes to the Company workplace safety program and the favorable impact those changes have had on various employee safety performance metrics over the course of the first year those changes were in effect, fiscal year 2015. Finally, Mr. Bell addresses the Company's enhanced efforts and future plans to investigate and, where necessary, remediate sites in Pennsylvania where the Company or corporate predecessors once owned and operated manufactured gas plants in connection with gas utility operations.

Nicole McKinney (UGI Gas Statement No. 10) is UGI's Principal Tax Analyst. Ms. McKinney addresses the Company's claim for federal and state income taxes, taxes other than income taxes, the calculation of the accumulated deferred income taxes ("ADIT") offset to rate base, the ratemaking treatment of the impact of the Company's repairs tax method election on federal and state income taxes, and issues pertaining to UGI Gas's participation in a consolidated group for federal income tax purposes.

Theodore M. Love (UGI Gas Statement No. 11) is Senior Analyst of Green Energy Economics Group, Inc. Mr. Love presents the Company's proposed EE&C Plan and discusses its costs and benefits. As part of this presentation, Mr. Love also provides the results of an analysis applying the total resource cost ("TRC") test. Mr. Love also discusses the implementation schedule for the EE&C Plan.

IV. <u>UGI-1 INITIATIVE</u>

Q. Please describe the UGI-1 initiative.

A. UGI-1 is a company-wide improvement initiative focusing on people, tools and processes. UGI Gas has a history of pursuing excellent performance for its customers, employees and shareholders. Moving forward, the Company plans to build upon its strong past as it looks for ways to become an even better service provider in the future. Over the past few years, UGI Gas has experienced substantial growth opportunities as well as significant operational challenges. To act on these opportunities and to address these challenges, UGI Gas is working harder than ever to take advantage of synergies, equip employees for future success, and improve vertical and lateral communications throughout the organization. By implementing these initiatives, UGI Gas will position itself for continued growth and success and outstanding customer service.

UGI-1 includes a number of fundamental improvement efforts, including such programs as: UNITE technology improvement project; UGI's 'Making a Difference' safety improvement program; the migration of all employee computer workstations to a set of common workplace applications; the migration of all field employees to a single set of gas operations and construction processes and specifications; UGI building and grounds improvements and renovations; UGI's natural gas pipeline facility extension and betterment programs; an enhanced focus on physical and cyber security; and a range of enhanced and expanded employee development and training programs.

As a visible and public sign of these changes, the Company introduced a new logo and brand image. UGI no longer describes itself to the public as a set of entities named UGI Gas Division, UGI Penn Natural Gas, UGI Central Penn Gas, and UGI Electric Division; the company is now publically presented across all service territories as UGI Gas or UGI Electric.

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

A. The overall goal of UGI-1 is to place all of our operations on the same common set of information systems, tools, equipment, and uniform work management and performance platforms. This will allow the Company to become more efficient and effective in performing all aspects of its business, whether it is in the areas of handling calls from customers, performing billing and related activities, building a pipeline, operating and maintaining the gas distribution system, or handling emergencies. An effective and common system of performing and measuring performance among our geographically disparate service territories and segments thereof will also expedite identification of problems that can be corrected more readily or even before they happen, driving further efficiency gains and service improvements.

Fully integrating three separately regulated natural gas distribution systems (UGI Gas, CPG, and PNG) and one electric distribution system will enable the Company to ensure that costs incurred to provide service reflect a common way of doing our work. This will help eliminate differences in cost drivers among the three regulated natural gas distribution systems, to the extent feasible and where geographic or industry (natural gas versus electric) factors do not dictate the result.

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

A. There have been several improvements in the operations area. For example, UGI has made a concerted effort over the past two years to establish and implement a common methodology for rating the severity of natural gas system leaks to place all three of UGI's gas distribution systems in line with the Gas Pipeline Technology Committee standard. Now that this common rating system has been established and implemented, UGI is better situated to allocate its pipeline replacement, leak survey and repair, financial, internal labor, and contractor resources to the segments of the UGI Gas, CPG, and PNG distribution systems that require the most attention based on uniform measures of risk. This common approach to regulatory compliance has achieved significant improvements to system safety performance over the past two years, including: (i) a 20 percent system-wide reduction (11 percent for UGI Gas) in overall Class A and Class B leak inventory over the past year; (ii) a 32 percent system-wide reduction in the more critical Class B leaks (29 percent for UGI Gas); and (iii) a 17 percent system-wide reduction in hazardous Class C leaks (34 percent for UGI Gas). As discussed further in the direct testimony of Mr. Bell (UGI Gas Statement No. 9), UGI's common set of initiatives in workplace safety, Pennsylvania 1-Call, and its Distribution Integrity Management Program ("DIMP") have begun to bear fruit in terms of achieving improved safety based on measurable performance criteria.

Q. Are there examples of additional improved customer service performance?

A. Yes. In the area of natural gas line extensions, UGI is a demonstrated leader in adding new residential and commercial customers to its gas distribution system. Over the course of the past three years, UGI Gas has led Pennsylvania in adding new customers, averaging over 15,000 new residential heating and 2,000 new commercial customers per year. In fact, since the Company's last base rate case in 1995, UGI Gas has grown its customer base by 50%, or by over 120,000 customers.[1] No other gas utility in the Commonwealth has experienced such significant customer growth, and the Company's 50% customer base expansion is over 150% greater than any other gas utility growth rate during that same period. The management of customer growth of this magnitude in and of itself, while challenging, is an indicator of superior customer focus and performance in execution.

More recently, UGI's Commission-approved GET Gas Pilot Program has been nationally recognized as an innovative tariff mechanism designed to expand natural gas service to unserved and underserved areas in and around the Company's gas distribution service territory. The GET Gas program, as well as the Company's considerable growth and new construction over the past several years, is discussed further in the Direct Testimony of Mr. Stoyko (UGI Gas Statement No. 7).

In this case, the Company's proposed TED Rider and EE&C Program, as

[1] Comparison based on customers as of 12/31/14 compared to 12/31/95.

discussed in more detail below, further demonstrate the Company's commitment to expand its customer base and to do so in an effective, efficient, economic and environmentally friendly manner.

Q. Has UGI been recognized as an environmental leader?

A. Yes. As discussed in the testimony of Mr. Bell (UGI Gas Statement No. 9), UGI is nationally recognized as an environmental leader in the gas industry, as evidenced by UGI's recent selection as an "Environmental Champion" by Cogent Reports™, a division of Marketing Strategies International. The Environmental Champion status was conferred based on Environmental Dedication scores that reflect the extent consumers believe companies are supporting environmental causes, are committed to environmentally friendly energy sources, are encouraging green initiatives, and are offering tools to help customers save energy. In brief, we believe that these scores reflect UGI's advocacy in support of Combined Heat and Power ("CHP") applications, converting customers from home heating oil to natural gas, and through its management of legacy environmental sites.

In addition, as discussed in Mr. Bell's testimony (UGI Gas Statement No. 9), UGI Gas has undertaken an expanded program to remediate the environmental conditions at a number of sites in Pennsylvania formerly used to manufacture gas for consumption by its customers. By joining with its affiliated gas companies, CPG and PNG, in this effort, UGI Gas is now taking more aggressive steps to address the environmental concerns presented by these former manufactured gas plant sites.

Q. Why is the Company proposing an energy efficiency and conservation program?

A. UGI Gas's proposal is consistent with its environmental effort and approach towards customer service. The EE&C Plan will provide customers with a financial incentive to install higher efficiency gas burning appliances and equipment. The resulting reduction in consumption will provide savings to customers who take advantage of the program, as well as environmental benefits and downward pressure on natural gas prices to the benefit of all customers. Moreover, UGI Gas believes key elements of the EE&C Plan that focus on the most efficient use of energy resources, including greater CHP and direct use natural gas applications, can be a key element of the Commonwealth's compliance with the U.S. Environmental Protection Agency's Clean Power Plan. A more detailed discussion of this program and its benefits is provided in the testimony of Mr. Love (UGI Gas Statement No. 11).

Q. Has the Company undertaken any recent initiatives to assist low income customers to afford their natural gas service?

A. UGI Gas recently received approval from the Commission to implement several new components to its Universal Service Programs that should assist low income customers, including: eliminating the maximum level of low income customers that can be served under the Company's Customer Assistance Program ("CAP"), formerly the Low Income Self Help Program ("LISHP"); and increasing the level of expenditures under its Low Income Usage Reduction Program ("LIURP") to $1.1 million.

While the Company is not proposing to change any of the terms and conditions related to any of its recently approved Universal Service Programs, it is anticipating growth in CAP participation and is proposing to adopt a cost recovery mechanism identical to those it has already implemented at CPG and PNG.

Q. You mentioned earlier in your testimony the Company's UNITE initiative as part of UGI-1. Please discuss.

A. As noted earlier, UNITE stands for UGI's Next Information Technology Enterprise. As discussed in the direct testimony of Mr. Lord (UGI Gas Statement No. 8), UNITE is a multi-phased, multi-year project designed to replace and update UGI's core, non-financial computer systems including the Customer Information System ("CIS"), Work Management System, Asset Management System and Mobile Data Management System. In its first phase, UGI's two aging CISs will be replaced with one state-of-the-art system. Having a common CIS for all four of its utility business (UGI Gas, UGI Electric, CPG, and PNG) will allow UGI to develop and apply a common set of processes so that it can maximize the efficiency of rendering service to its customers at a reasonable cost. This initiative will allow 1,200 of our employees system wide to provide safer and more reliable service in the field and to address other concerns related to billing and affordability of service. Importantly, this new system will also support key Choice customer business processes, including seamless moves, instant connects and 3-day switching, as may be required. UNITE will address a number of objectives including: reducing operational risks related to the age of certain applications where there is no vendor support and the people who know the systems best are retiring; improving operational capabilities with new "scalable" technology platforms; standardizing and reducing the number of systems and duplicate processes across UGI; improving business information to make more informed business decisions; and gaining efficiency related to process and system integration.

Q. Has the Company made other efforts to make the Company's service more economic for its customers?

A. Yes. UGI Gas has implemented a series of portfolio changes that allow it, and Natural Gas Suppliers serving Choice customers on the UGI Gas system to maximize the purchase of natural gas from the Marcellus and Utica Shale sources. While the majority of UGI Gas's natural gas purchases were from the Gulf region in 1995, today nearly all of UGI Gas's natural gas purchases are physically sourced from Marcellus and Utica Shale sources. The impact related to shale gas on pricing has been significant; while UGI Gas had a purchased gas price of $13.62/Mcf in September 2008, the current purchased gas price is $4.27/Mcf. This 69% reduction in gas costs not only represents the significant impact shale production has had on natural gas pricing nationwide, but it also demonstrates the impact of UGI Gas's efforts to focus on creating value for its customers.

V. <u>INTERRUPTIBLE REVENUES</u>

Q. Please explain the Company's proposal relative to revenues received under its Interruptible Service rates.

A. As explained in the testimony of Mr. Stoyko (UGI Gas Statement No. 7), the construction of natural gas distribution systems is very capital intensive. However, unlike some other utility services, natural gas is subject to competition from alternative fuels, direct customer bypass and locational competition, and there are no uses for natural gas for which there are no other viable energy alternatives. Competition from alternative energy sources is particularly acute for UGI Gas's largest customers, and for those with installed alternate fuel capabilities. UGI Gas currently provides interruptible gas service to approximately 320 customers, comprising over 40 percent of annual system throughput, under contracts voluntarily entered into that have rates based on the alternatives available to such customers, whether that is an alternate fuel option, an alternative natural gas solution, *i.e.*, physical bypass, or a locational alternative, *i.e.*, moving production to a different facility with lower energy costs.

As a result of the capital-intensive nature of natural gas distribution systems, it benefits all customers if costs can be shared over the largest possible customer base. However, due to the market risks presented by customers with installed alternate fuel capabilities served under interruptible rate schedules, UGI Gas generally does not make distribution system investments to serve such interruptible loads given the threat that such investments could be stranded under changing market conditions. To reflect this business reality, Mr. Herbert presents two cost of service studies: one of which allocates main costs via the average and excess method outlined by Mr. Herbert, and one which allocates no main costs to interruptible customers. The Company has based its revenue allocation and rate design for firm customers based on the average of the results of these two cost of service studies, while continuing to price interruptible customers based on market conditions. This approach properly reflects both cost of service and value of service principles and provides a balanced and reasonable basis for setting rates.

Specifically, UGI Gas proposes to continue its past practice in which it (1) establishes the overall revenue requirement and revenue allocation for firm customers based on cost of service, and (2) charges interruptible service customers value of service prices and retains or absorbs any difference between cost of service and value of service pricing between rate cases.

This approach to the interruptible market provides the proper incentives to ensure the Company will strive to maximize the amount of revenues that can be achieved from interruptible service customers under higher risk and unpredictable market conditions over time. It also recovers system costs over the largest possible customer base, provides for greater rate stability to all classes, can defer the need for future base rate relief, and will shield firm customers from the possible adverse ratemaking consequence associated with the higher risk interruptible market. In my view, this approach produces a better outcome for all customers as compared to the alternatives of not offering interruptible service or offering it under an alternate pricing structure that is not value based. UGI Gas's longstanding success in avoiding the need for base rate relief is, in significant part, the result of this rate design approach and can be expected to provide similar future benefits as well.

Q. Please explain how value of service pricing assists the Company in managing its business risk.

A. Value of service pricing, to the extent that the Company can charge rates above a proxy cost of service that allocates reasonable mains investment to interruptible customers, provides the Company with an additional source of revenue to maintain a return on investment for the total enterprise that meets the expectations of its shareholders in return for assuming the risks of the associated revenue requirement offset. In years where temperatures are warmer than normal, revenue generated from the interruptible market helps UGI Gas to earn a more stable return. Similarly, as weather becomes colder than normal, firm usage increases and interruptible usage and related revenue declines as distribution capacity becomes constrained and interruptions are implemented for this market segment. Moreover, as usage per customer in our core market has declined over time, and is expected to continue to decline, having interruptible revenue, which may contribute to earning a reasonable return, will assist to support necessary capital attraction at reasonable rates. By doing so, customers may benefit by being exposed to fewer base rate increases and benefit from the resulting lower rates. Having value of service based interruptible revenues is one of the important reasons UGI has not required base rate relief for over 20 years and has still been able to fund needed capital projects and provide outstanding service to customers.

Q. Please discuss how value of service pricing provides a source of capital for use in the Company's capital improvement program.

A. The revenue generated from interruptible customers provides greater cash flows that are available for the Company to finance its operations. These increased cash flows would not be available if interruptible rates were determined strictly on cost of service principles.

Q. Why is value of service pricing appropriate for the interruptible market?

A. Value of service pricing is appropriate for two principal reasons. First, interruptible customers have competitive alternatives and are capable of choosing those alternatives and leaving the UGI system at any time. It is reasonable under these circumstances, in the Company's view, to charge these customers competitive prices because they have competitive alternatives. Cost of service pricing is more appropriate and indeed is designed for regulated monopoly conditions, which by definition do not exist where customers have competitive alternatives. Strict cost of service pricing is not appropriate where a customer group has verified competitive alternatives for gas service and can leave the utility system at any time.

Second, and relatedly, interruptible customers have the option to become firm customers and take service under a cost-based firm service rate if they choose to do so, and to the extent that the system has sufficient capacity to allow for a conversion to firm service or if they contribute sufficient capital to finance the investment necessary to render firm service. In fact, UGI Gas has had interruptible customers elect the firm service conversion option in recent years; in particular, customers have elected to convert as the real and perceived risk associated with cold weather interruptions and operational realities have been experienced over the last two colder-than-normal winter periods.

In summary, the Company's proposal to provide a fixed offset to revenue requirement, which is equal to the proxy cost of service for the interruptible market in exchange for assuming the ongoing risks related to serving this competitive market under value of service pricing, properly reflects both cost of service and value of service pricing principles, properly reflects the competitive alternatives available to interruptible customers, and provides important benefits to all customers that would not be available under strict cost of service principles.

VI. STRONG MANAGEMENT EFFECTIVENESS AND PERFORMANCE

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

A. UGI Gas has focused on a number of areas that demonstrate the quality and effectiveness of UGI Gas's current management performance and its management's focus on safe, reliable, and outstanding service, as well as a strong commitment to growth. These management efforts include:

- An accelerated infrastructure replacement plan focused on replacing all remaining cast-iron and bare steel mains, as further explained in the testimony of Hans G. Bell (UGI Gas Statement No. 9). UGI Gas already is a leader in the Commonwealth, as its distribution system is comprised of the highest percentage of contemporary mains. See Table 2 below. Moreover, as shown in UGI Gas's LTIIP filed in accordance with Act 11, the Company projects that it will eliminate all UGI system cast-iron mains by February 2027 and all bare steel mains by September 2041. The Commission approved this filing on July 31, 2014, at Docket No. P-2013-2398833. UGI Gas has just concluded its second year of the 5-year LTIIP and is ahead of the schedule established by the LTIIP.

Table 2

Percent Contemporary Main (PA NGDCs)	
UGI Gas	86%
UGI PNG	84%
PECO	83%
UGI CPG	82%
Columbia	77%
National Fuel	77%
Peoples	69%
PGW	35%

- Developing an innovative expansion and extension program (GET Gas), which will invest $25 million in UGI Gas's service territory as part of a total $75 million commitment across the UGI companies to reach new customers in unserved and underserved areas. UGI's GET Gas program has been highlighted nationwide at American Gas Association events and has been called a model program.
- Proposing to implement a new rider, the TED Rider, to facilitate non-commercial customers with large up-front payments for line extensions, as further described in the direct testimony of Robert R. Stoyko (UGI Gas Statement No. 7).
- Managing record growth and managing to increase overall customer counts by over 50% since UGI Gas's last base rate case in 1995. This growth rate by UGI Gas is the highest among all natural gas distribution companies across the Commonwealth during the same period. UGI Gas's new customer additions have continually helped to provide incremental

revenues, which have helped defer the need for rate relief since 1995.

- Winning the J.D. Power award for customer satisfaction among utilities in two of the last 3 years, and has won it a total of 7 times since the start of the J.D. Power award for utility customer satisfaction as further explained in the testimony of Robert R. Stoyko (UGI Gas Statement No. 7).
- Significantly expanding its universal services offerings since its last rate case in 1995. As further explained in the testimony of Robert R. Stoyko (UGI Gas Statement No. 7), UGI Gas now has over 8,000 participants in its CAP and has committed to fund its LIURP program at an increased level of $1.1 million annually.
- Developing and implementing numerous safety improvement initiatives to reduce injuries and motor vehicle accidents, as further explained in the testimony of Hans G. Bell (UGI Gas Statement No. 9). These initiatives include a First Move Forward policy, a 360-degree "cone" policy, a "Making a Difference" safety program, use of dash-cams to record and review incidents or close-calls, Smith Driving School training, an annual Safety Summit involving all employees, establishing safety committees for root cause review, and Company-wide education and appropriate employee coaching and engagement tracks.
- Focusing on increasing spend with Minority and Women-Owned Businesses ("MWBEs"). Since 2011, UGI has increased MWBE spending significantly, increasing Women-Owned spending by over 100% and

Minority-Owned spending by over 400%. UGI's overall MWBE spending of 11.6% ranks above the utility industry average of 11.4%, as published in the 2012 Supplier Diversity Program Performance study conducted by nationally recognized CAPS Research.

- Launching a Company-wide initiative, UGI-1, which is aligning UGI's people, processes and tools to drive additional efficiencies and effectiveness across the organization, including the implementation of new state-of-the-art customer information, work management and other supportive systems.
- Undertaking the UNITE Project to further improve customer service. As explained in the direct testimony of Thomas N. Lord (UGI Gas Statement No. 8), the UNITE Project is a multi-year, multi-phased information system modernization project. Phase 1 of the Project entails the development and implementation of a new CIS to replace our two legacy mainframe CIS systems. This new CIS will harmonize the two systems and provide increased functionality and improved customer service.
- Proposing to implement an EE&C Plan. The EE&C Plan is a comprehensive portfolio of energy efficiency and conservation programs that was designed to assist customers save energy through various cost-effective measures. The full contents of the EE&C Plan are described in detail in the direct testimony of Theodore M. Love (UGI Gas Statement No. 11).

In addition to these management efforts, it should be noted that UGI Gas has been able to provide excellent service to customers at just and reasonable rates. The above-described initiatives, as well as those described by the other witnesses, UGI Gas will continue to improve service to customers.

It also should be noted that, as shown earlier, current UGI Gas residential distribution rates are the lowest in the Commonwealth. Further, even if UGI Gas's proposed residential rates are implemented, the average monthly bill for a residential heating customer will be 3.2% lower today than the average bill following the Company's last base rate case in 1995. Comparatively, the price for many household consumer products has increased significantly over that same time period. Tables 3 and 4 below, provide that comparison.

Table 3

Household Items			
	Price ($) September 1995	**Price ($) November 2015**	**Percent Increase**
Pound of White Bread[1]	0.81	1.41	74%
Dozen of Grade A Large Eggs[1]	0.96	2.66	179%
Gallon of Whole Milk[1]	2.46	3.30	34%
Postage Stamp[2]	0.32	0.49	53%

[1] *Source:* U.S. Bureau of Labor Statistics, *Consumer Price Index-Average Price Data*

[2] *Source:* United States Postal Service, *Rates for Domestic Letters Since 1863*

Table 4

UGI Average Monthly Bill			
	Amount ($) September 1995	**Amount ($) January 2016 (Proposed)**	**Percent Change**
Residential Heating	64.01	61.97	-3.2%

The Company believes that the management efforts described above and the other improvements described by the UGI Gas witnesses in this proceeding, as well as the Company's provision of service at reasonable rates, support an additional upward adjustment to the Company's rate of return in recognition of its management effectiveness.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS EXHIBIT PJS-1

PAUL J. SZYKMAN

VICE PRESIDENT – RATES & GOVERNMENT RELATIONS
VICE PRESIDENT & GENERAL MANAGER – ELECTRIC UTILITIES

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

Previous testimony before the Pennsylvania Public Utility Commission at the following Dockets:

- R-00932927,
- R-00016376,
- R-00016376C0002,
- P-00032043,
- P-00032054,
- R-00049422,
- R-00050539,
- R-00061502,
- R-00072334,
- R-00072335,
- R-2008-2039284,
- R-2008-2039417,
- R-2008-2079675,
- R-2008-2079660,
- R-2009-2105911,
- R-2009-2105904,
- R-2009-2105909, and
- R-2010-2214415.

UGI GAS STATEMENT NO. 2 – ANN P. KELLY

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2015-2518438

UGI Utilities, Inc. – Gas Division

Statement No. 2

Direct Testimony of
Ann P. Kelly

Topics Addressed:	**Rate Base**
	Operating Revenues and Expenses

Dated: January 19, 2016

I. INTRODUCTION

Q. Please state your name and business address.

A. Ann P. Kelly, 2525 North 12th Street, Reading, Pennsylvania 19612-2677.

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

A. I am employed by UGI Utilities, Inc. ("UGI") as Controller. UGI is a subsidiary of UGI Corporation ("UGI Corp."). UGI has two separate operating divisions: UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company") and UGI Utilities, Inc. – Electric Division.

Q. What are your responsibilities as Controller?

A. I would note that the position of Chief Financial Officer of UGI became vacant during the preparation of this base rate case filing, and that I had taken on many of the responsibilities of that position on an interim basis, assuming overall responsibility for the finance and accounting functions for UGI and its wholly-owned subsidiaries, UGI Penn Natural Gas, Inc. ("PNG") and UGI Central Penn Gas, Inc. ("CPG"). My duties currently include accounting, accounts payable and cash remittance functions for these distribution companies and the coordination of these functions with the Chief Financial Officer of UGI Corp. I am also currently responsible for supervising the preparation and submission of financial, accounting, and related regulatory filings with the Pennsylvania Public Utility Commission ("PUC"), Federal Energy Regulatory Commission ("FERC"), the United States Securities and Exchange Commission ("SEC") and the United States Internal Revenue Service ("IRS").

Q. What is your educational background?

A. I received a Bachelor's degree in accounting with a minor in economics from Ohio Wesleyan University in 1992, and a Master's degree with a concentration in finance from Villanova University in 2000.

Q. Please describe your professional experience.

A. I began my professional career as a fund accountant for Dean Witter Intercapital and then worked as an auditor for Price Waterhouse LLC. I then spent ten years at Radnor Holdings Corporation, rising to the position of Treasurer, where I performed various finance-related functions, including consolidation and corporate reporting, external financial reporting, cash management and treasury. I then spent five years working for Exelon Corporation entities, where my positions included: Director of Financial Planning and Analysis for Exelon Generation; Director, Office of the President, for Exelon Generation's Power Team; Director of Finance Operations for PECO Energy Company; and finally Director, Risk Control for Exelon Generation. After two years away from the utility industry, I assumed my current position with UGI on December 15, 2014.

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

A. Yes, I presented testimony before the PUC in *Petition of PECO Energy Company for Approval of its Smart Meter Technology Procurement and Installation Plan* at Docket No. M-2009-2123944.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Gas. First, I will provide an overview of the principal accounting exhibits used to support UGI Gas's claims in this proceeding (Part II). Second, I will explain UGI Gas's accounting and budgeting processes (Part III). Finally, I will address UGI Gas's revenue requirement for the fully projected future test year ending September 30, 2017 ("FPFTY"), including its principal accounting exhibits, rate base claims, operating expenses claims, and certain *pro forma* adjustments (Part IV).

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

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

II. <u>OVERVIEW OF PRINCIPAL ACCOUNTING EXHIBITS</u>

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

A. UGI Gas Exhibit A (Fully Projected) is the revenue requirement for the FPFTY ending September 30, 2017, including principal accounting exhibits, rate base claims, operating expenses claims, and certain *pro forma* adjustments. The FPFTY information is derived from UGI Gas's operating and capital budgets for the 12 months ending September 30, 2017. UGI Gas Exhibit A (Future) is the principal accounting exhibit for the future test year ending September 30, 2016 ("FTY"), including certain *pro forma* adjustments. The FTY information is derived from UGI Gas's operating and capital budgets for the 12-

month period ending September 30, 2016. UGI Gas Exhibit A (Historic) is the principal accounting exhibit for the historic test year ended September 30, 2015 ("HTY"), with appropriate ratemaking adjustments. The HTY information is derived from the book accounting data for the 12-months ended September 30, 2015. The FTY and HTY schedules are provided as a benchmark for comparison with the FPFTY claim, which as explained above is the basis for UGI Gas's proposed revenue increase.

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

A. UGI Gas's claims in this case are based on UGI Gas Exhibit A (Fully Projected), which includes a presentation for the FPFTY ending September 30, 2017. This presentation is comprised of four sections:

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

Section B includes basic accounting data extracted primarily from UGI Gas's financial, accounting, operating and capital budgets, and other records. This data includes a balance sheet, a statement of net operating income and test year revenues, a schedule of expense items by cost element, and a tax expense calculation. Also included are schedules showing UGI Gas's embedded cost of debt, year-end capital structure and overall claimed rate of return.

Section C provides the elements of UGI Gas's rate base claim and how each element of that claim is derived. UGI Gas's rate base includes utility plant in service, gas storage inventory, cash working capital, materials and supplies inventory, and offsets for accumulated depreciation, accumulated deferred income taxes, and customer deposits.

Section D presents UGI Gas's revenues and expenses on a *pro forma* ratemaking basis. Necessary adjustments to budgeted levels of expense items and revenues are summarized in Schedules D-1 through D-2 and detailed in the remaining schedules. The resulting FPFTY expense and revenue levels are shown on Schedule D-3, and were used to establish UGI Gas's *pro forma* income at present and proposed rates as set forth in Schedule A-1.

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

A. UGI Gas Exhibits A (Historic) and A (Future) follow the format of UGI Gas Exhibit A (Fully Projected), but reflect data for the fiscal year ended September 30, 2015, and the fiscal year ending September 30, 2016, respectively. This information is provided to comply with the Commission's filing requirements, and provides a basis for comparing our FPFTY claims with actual and projected results from the HTY and FTY, respectively.

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

A. This data is derived from the UGI Gas's books and records, and capital and operating budgets. UGI Gas Exhibit A (Future) is based on adjusted budgeted data for the year ending September 30, 2016. UGI Gas Exhibit A (Historic) is based on adjusted experienced data for the year ended September 30, 2015.

III. ACCOUNTING AND BUDGET PROCESS

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

A. The accounting records of UGI Gas are kept in accordance with generally accepted accounting principles ("GAAP") and the FERC's Uniform System of Accounts as required under the provisions of 52 Pa. Code § 59.42. The Company also maintains a continuing property records system in accordance with the requirements of 52 Pa. Code § 59.47.

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

A. Yes. The books and records of UGI Gas are audited by its internal auditors and its external auditor, Ernst & Young, LLP. They are also subject to audit by the PUC.

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

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

Q. What process does UGI Gas follow to assure that property reflected in its plant accounts is used and useful?

A. UGI Gas requires field personnel to create a record when property is placed into service or retired. The information from these records is then transferred through accounting entries into the appropriate UGI Gas plant property accounts, subject to review by authorized individuals, who must approve the entries. The process employed by UGI

Gas is the same as that employed by PNG and CPG, and its integrity has been reviewed by internal and external auditors.

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

A. UGI Gas's fiscal year begins on October 1 and ends on September 30 of the following year. Preparation of the UGI Gas Operating Budget for the subsequent fiscal year begins during the spring, *i.e.*, the budget for the October 1, 2015 through September 30, 2016 fiscal year was prepared in the spring of 2015.

The revenue portion of the budget is a joint effort between the Marketing and Rates Departments. The Marketing Department provides customer growth and attrition information by customer class along with specific large commercial and industrial sales and revenue budget projections. The Rates Department develops normalized usage per customer for core customer classes, annualized sales and total revenues. The number of customers by customer class is determined using a wide range of factors, including trends in usage, the level of applications and inquiries for service from existing customers, new construction, the cost of competing fuels, and shifts in type of residence and customer mix. Usage per customer is developed by reviewing the most recent year's usage trends adjusted to normal weather conditions, the price of competitive fuels relative to natural gas, and current and anticipated levels of operation. The budgeted number of customers and usage per customer are combined to produce monthly budgeted sales. The revenue budget is calculated by applying tariff rates for each customer class to budgeted sales, plus an adjustment for unbilled revenue. The sales and revenue budget is then reviewed with and approved by senior management.

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

The final Operating Budget is then submitted to the President of the Company for his review and approval, and to the Board of Directors for its review and approval. Each element of the UGI Gas Operating Budget is formulated by personnel responsible for that aspect of the operation and who will be held accountable for the accuracy of their forecasts. The first and primary use of the Operating Budget is as a working tool for the management and planning of the business.

The UGI Gas Capital Budget is prepared in conjunction with the Operating Budget. Operating personnel in each functional area prepare a detailed list of capital projects. Each project is identified, described and justified along with a breakdown of the costs associated with it. These projects are presented to senior management, which reviews them in terms of priorities, capital availability, and strategic alignment with the operating budget. After due consideration, the Capital Budget is set and presented, along with the Operating Budget, to senior management in a series of review meetings. Additional information concerning the factors considered in establishing the UGI Gas Capital Budget is provided in the direct testimony of Hans G. Bell (UGI Gas Statement No. 9).

With the passage of Act 11 of 2012, UGI Gas has also instituted a process for establishing an Operating Budget and Capital Budget for an additional fiscal year in the future, *i.e.*, the FPFTY. This process is the same as outlined above; however, the starting point for the additional year is the FTY budget. Since the FTY budget is based on normalized weather conditions, no additional revenue normalizing adjustments are made. FTY amounts are then adjusted for salary and personnel increases, known incremental programs and expense needs, and inflation. For the capital budget, known capital projects are included based on the process described above, and also described in the direct testimony of Hans G. Bell (UGI Gas Statement No. 9). Additional assumptions also are made for emergent new business and other capital expenditures based on past experience and current trends.

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

A. UGI Gas incurs costs for services provided by UGI Corporation, UGI Utilities, and other affiliated companies, in accordance with affiliated interest arrangements authorized by the Commission. All costs which can be identified as pertaining exclusively to an operating unit are billed directly to that unit. Those costs which cannot be directly associated with the operation of an individual operating unit are allocated to the various companies benefiting from the service by a formula internally referred to as the Modified Wisconsin Formula ("MWF"). The MWF achieves an equitable distribution of common expenses based on the relative activity and size of each operating unit to the total of all operating units. Activity is measured by total revenues and total operating expenses and size is measured by tangible net assets employed (excluding acquisition goodwill).

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

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

Q. How is this budget information used to support UGI Gas's claims in this proceeding?

A. This budget information is the starting point for UGI Gas's claims, and is adjusted as appropriate to reflect new information gained since the completion of the budgeting process and through application of other appropriate ratemaking principles.

IV. FULLY PROJECTED FUTURE TEST YEAR

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

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

A. FULLY PROJECTED FUTURE TEST YEAR REVENUE REQUIREMENT

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

A. This calculation is shown at a summary level on Schedule A-1, column 4 of UGI Gas Exhibit A (Fully Projected). Lines 1-9 summarize the *pro forma* measure of value (rate base). Lines 10-20 show *pro forma* revenues at present rates, *pro forma* expenses, taxes at present rates, *pro forma* net operating income at present rates, and the calculated rate of return at present rates. Lines 21-23 show the increase in net operating income required to permit UGI Gas to earn its required overall rate of return of 8.17%. Application of the Gross Revenue Conversion Factor ("GRCF") on line 24 establishes the revenue increase shown on line 25 needed to generate that net operating income. Column 5 of Schedule A-1 shows the level of the revenue increase and the increase in expenses associated with the revenue increase. Column 6 of Schedule A-1 shows the revenue, expenses, and rate base at proposed rates, as well as the resulting rate of return of 8.17%.

Q. What is the overall requested increase in revenue?

A. The overall requested increase in revenue is $58.56 million. This represents the difference between the *pro forma* FPFTY revenue requirement of $393.2 million and the annual level of operating revenues of $334.7 million under existing rates. These figures are shown on line 13 of Schedule A-1 of UGI Gas Exhibit A (Fully Projected).

B. RATE BASE

Q. With reference to UGI Gas Exhibit A (Fully Projected), please explain how UGI Gas's rate base was determined.

A. UGI Gas's rate base presentation is shown in UGI Gas Exhibit A (Fully Projected), Schedule C-1. Schedule C-1 summarizes the UGI Gas rate base values for the FPFTY. Column 2 indicates the schedule upon which the calculation of each of the rate base elements is found. Columns 4-6 show the amounts at present and proposed rates, respectively. UGI Gas's total FPFTY rate base claim -- net of deductions for accumulated deferred income taxes, customer deposits, and customer advances -- is $923.7 million. Except where otherwise noted, I will describe each of these rate base elements in greater detail below.

1. Utility Plant in Service

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

A. UGI Gas's claim for utility plant in service represents the sum of the closing plant balances as of September 30, 2015, and budgeted plant additions for the years ending

September 30, 2016 and September 30, 2017, less budgeted FTY and FPFTY plant retirements.

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

A. This schedule includes 9 pages and presents UGI Gas's FPFTY claim of $1.65 billion for gas utility plant in service on page 2, column 2, line 64. Gas utility plant enables UGI Gas to provide gas service to its customers.

Q. How was the gas utility plant in service amount of $1.65 billion, shown on Schedule C-2, page 2, column 2, line 64 determined?

A. As noted above, this amount is based on the *pro forma* balance as of September 30, 2017. The amount includes: (1) utility plant in service as of September 30, 2015 and (2) budgeted capital expenditures expected to close to plant for the 12-month periods ending September 30, 2016 and 2017, less plant retirements during the same period.

Q. Please describe what information is shown on Schedule C-2, page 3.

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

Q. What information is included on Schedule C-2, pages 4-7?

A. Columns 2 and 3 on these pages show the gas plant in service balances for 2016 and 2017 based on the budget, plus the amount of plant additions budgeted as of the end of the FPFTY. Column 4 represents various plant adjustments and column 5 provides the adjusted FPFTY plant balance.

Q. Please explain the nature of the adjustments in column 4 on schedule C-2, pages 4-5.

A. For budgeting purposes, all common plant is recorded on the records of UGI Gas. However, common plant is also used for UGI Electric, PNG and CPG. The adjustment reduces common plant assets by the amount allocated to affiliated companies.

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

A. Pages 8-9 of Schedule C-2 provide actual and projected plant retirements. Retirements for most plant accounts were projected by plant account by applying the average retirement rate, as a percent of additions, for the five years 2010 through 2015, to the FPFTY and FTY plant additions. For certain General Plant accounts subject to amortization accounting, retirements are recorded when a vintage is fully amortized. For these accounts, all units are retired per books when the age of the vintage reaches the amortization period.

2. Accumulated Depreciation

Q. Please explain how UGI Gas determined its rate base value for accumulated depreciation.

A. UGI Gas started with accumulated depreciation as of September 30, 2015, added the budgeted level of depreciation expense for the FTY and FPFTY, and calculated the impact of the FTY and FPFTY plant retirements and a provision for net salvage as shown on Schedule C-3. The depreciation rates and test year expense levels are discussed in the direct testimony of John F. Weidmayer (UGI Gas Statement No. 5), with the underlying FPFTY depreciation analysis provided in UGI Gas Exhibit A (Fully Projected).

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

A. UGI Gas's accumulated depreciation claim is shown on Schedule C-3 of UGI Gas Exhibit A (Fully Projected). This schedule, containing 11 pages, presents the accumulated provision for depreciation as of September 30, 2017, distributed among the various FERC accounts. The total amount for accumulated depreciation, $448.7 million, is summarized on pages 1-2 to this schedule. That amount is reflected on line 2 of the measure of value summary on Schedule C-1.

Page 3 shows the *pro forma* FPFTY level of accumulated depreciation distributed to the various plant categories. Pages 4-5 show the details of the accumulated depreciation by FERC account for 2016 and 2017 based on budget plus adjustments to arrive at the FPFTY balance. Pages 8-9 show the negative net salvage amortization by FERC account. Pages 10-11 include the salvage amounts for the FPFTY. All of these amounts are included in the FPFTY accumulated depreciation calculations. The amortization of negative net salvage was calculated using a 5-year amortization schedule in accordance with Commission precedent.

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

A. Yes. Similar to the plant assets shown on Schedule C-2, the accumulated depreciation must also be reduced by the accumulated depreciation on common assets allocated to affiliated companies. These adjustments are shown in column 3 on Schedule C-3, page 3 and column 4 on Schedule C-3, pages 4 and 5.

3. Cash Working Capital

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

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

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

A. Page 2 summarizes the derivation of UGI Gas's revenue collection lag and overall expense payment lag. The revenue lag days are shown on line 1 and the expense lag days are shown for each component on lines 3-5. The net lag in the collection of revenue is 25.48 days as shown on line 8. This number is then multiplied by the average daily operating expense balance on line 9 to arrive at a base CWC amount of $15.723 million. The average daily expense balance of $617,000 shown on line 9 is determined by dividing the total *pro forma* annual operating expenses, excluding uncollectible accounts expenses of $225.361 million, as shown on line 6 of column 2, by the number of days in a year, or 365. I will describe the other components of the CWC claim when I discuss the related schedules.

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

A. The total revenue lag days (line 23) were determined by dividing the annual revenue billed during the year (line 18, column 3) by the average month-end accounts receivable balances for the thirteen months ended September 30, 2015 (line 17, column 2). This results in an accounts receivable turnover rate of 9.82 (line 19, column 4), which is equivalent to 37.17 lag days (line 20, column 5) (365 divided by 9.82 accounts receivable turnover rate). As shown on lines 20-23, the payment portion of the revenue lag is added to (1) the 2.69 day lag between the meter reading day and the day bills are sent out and recorded as revenue and accounts receivable by the Company and (2) the 15.21 day service lag, which is the time from the mid-point of the service period until the meter reading date. This calculation results in a total revenue lag of 55.07 days.

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

A. The mid-point of the service period is equal to the number of days in an average service month (365 days divided by 12, or 30.42 days) divided by two (15.21 days).

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

A. This calculation is shown on page 4 of Schedule C-4, lines 1-6. The payroll amounts shown there reflect the payroll for the FPFTY, which is shown on Schedule D-7. The lag periods for union and non-union payroll are shown separately on page 4 of Schedule C-4, lines 1-2 with the same bi-weekly pay period.

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

A. This calculation is shown on page 6 of Schedule C-4, and is based on a review of gas purchases during the 12-month period of October 2014 through September 2015. The total dollar amount of gas purchased during this period was $6.977 million, and the average payment lag equaled 36.71 days. The payment lag was determined using the midpoint of the service payment for each of the payments and the payment date for each, averaged over the 12-month study period.

Q. How was the Other Expense payment lag, shown on Schedule C-4, page 4, line 14, calculated?

A. The calculation of this lag is shown on page 5 of Schedule C-4. The average payment lag for all remaining expenses was derived from data over four months, as shown in more detail on page 5 of Schedule C-4. A list of all cash disbursements during each of these months was used in a format that shows the payee, the invoice date, the amount of the disbursement, the date the payment was made, the account to which the disbursement was charged and other data associated with the disbursements. As shown on page 5, lines

1-8, each month's listing contained numerous cash disbursements. Once the raw payment data was assembled, the dollar days were determined by multiplying the amount of the disbursement by either (i) the number of days from invoice date until bank clearance for wire payments, or (ii) the number of days from the invoice date until check date, plus seven days for payments made by check. Disbursements were eliminated if they were included in another calculation (*e.g.*, gas commodity purchases), capital items, and other non-expense amounts. After these adjustments, the average of the expense lag days for each month shown on Schedule C-4, page 5, column 4, line 9 resulted in a payment lag for general expenses of 27.44 days. The 27.44 day lag for Other Disbursements is then brought forward to Schedule C-4, page 4, line 14 and Schedule C-4, page 2, column 3, line 5.

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

A. The calculation of this amount is shown on Schedule C-4, page 7. This calculation measures the lag associated with the payment of interest on outstanding debt. The *pro forma* annual interest expense shown on line 4 is divided by 365 to obtain the daily interest expense of $52,000 shown on line 5. That amount is then multiplied by the net payment lag, resulting in a reduction to the working capital allowance of $1.871 million, as shown on line 9. This amount is then included on page 1, line 2 of Schedule C-4.

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

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

Q. How was the working capital allowance for pre-payments derived?

A. That amount is calculated on page 9 of Schedule C-4 and represents the thirteen-month average of actual pre-paid amounts for each month ended from September 2014 through September 2015.

Q. What is the total amount of the Company's cash working capital claim?

A. UGI Gas's claim for CWC is $18.648 million. This amount is shown on Schedule C-4, page 1, line 5; Schedule C-1, line 4; and on Schedule A-1, column 4, line 4.

4. Gas Storage Inventory

Q. Please explain how the rate base value for gas storage inventory was determined.

A. Gas stored underground represents gas volumes stored in facilities or in storage fields owned by interstate pipeline or storage companies with whom UGI Gas contracts for capacity. As is typical for most natural gas distribution systems, UGI Gas purchases storage gas throughout the year for use primarily during the winter heating season. UGI Gas's claim for gas storage inventory is based on a 13-month historical average book value as shown on Schedule C-5. The average monthly gas inventory balance for the FPFTY is $21.730 million, as shown on Schedule C-5, line 16, column 4. This amount is also used in Schedule C-1, line 5 and Schedule A-1, column 4, line 5.

5. Accumulated Deferred Income Taxes (ADIT)

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

A. The Company's determination of its rate base value for ADIT is shown on Schedule C-6 and is discussed in the direct testimony of Nicole McKinney (UGI Gas Statement No. 10).

6. Customer Deposits/Advances for Construction

Q. Please explain how the rate base value for customer deposits and advances for construction were determined.

A. Customer deposits and advances for construction are customer-sourced funds that offset the need for UGI Gas to provide capital. UGI Gas's claim for customer deposits is based on the September 30, 2015 month-end balance as shown on Schedule C-7. Act 155 of 2014 became effective December 22, 2014, and no longer permits the Company to collect deposits for customers who qualify for low income programs. As a result, the Company has experienced a declining balance in customer deposits. For this reason, the balance at the end of the FTY was used to determine the rate base offset for customer deposits.

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

A. The customer deposit offset is $14.517 million as shown on Schedule C-1, line 7 and on Schedule A-1, line 7.

Q. What is the rate base claim for Customer Advances In Aid of Construction?

A. The offset claim for customer advances in aid of construction is $0 since the Company did not have any such balances for the 13-month period ending September 30, 2015.

7. Materials and Supplies Inventory

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

A. UGI Gas maintains various materials and supplies in inventory for use in its operations. Its claim for those items is $4.212 million, as shown on Schedule C-1, line 8. This amount represents the balance at the end of the HTY as shown on Schedule C-8. This value is also shown on Schedule A-1, line 8.

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

A. The balance at the end of the HTY is appropriate for two reasons. First, as a result of the 2011 Management Audit, the Commission recommended that UGI Gas increase its levels of emergency stock. Second, the Company's increasing capital expenditure plans have increased the need to stock longer lead time items, such as certain sizes of pipe, to ensure it is on hand when needed. These two factors have contributed to an increasing amount of materials and supplies inventory, and is the reason for why a HTY-end balance is an appropriate basis for the claim.

C. REVENUES AND EXPENSES

Q. How were revenues at present rates determined?

A. Revenues at present rates were determined by adjusting the budgeted revenues to reflect the anticipated change in the number of customers, the projected change in existing customer usage, changes in heating degree days from that used in the budget and other *pro forma* adjustments. The net effect of these adjustments is shown in UGI Gas Exhibit A (Fully Projected), Schedule D-5, and is discussed in the direct testimony of David E. Lahoff (UGI Gas Statement No. 6).

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

A. UGI Gas's principal accounting exhibit is UGI Gas Exhibit A (Fully Projected), which includes a presentation for the FPFTY ending September 30, 2017. Section D of UGI Gas Exhibit A (Fully Projected) presents UGI Gas's claims and necessary adjustments to budgeted levels of expense items and revenues. The *pro forma* adjustments related to expense are summarized in Schedules D-3 and D-6 through D-34. These expense adjustments are used, in part, to derive UGI Gas's *pro forma* income at present and proposed rates as set forth in Schedule D-1.

UGI Gas Exhibits A (Historic) and A (Future) follow the format of UGI Gas Exhibit A (Fully Projected), but reflect data for the appropriate test years ending September 30, 2015 and 2016. This information is provided in an effort to comply with the Commission's filing requirements and provides a basis for comparing our FPFTY claims with prior results.

1. Summary

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

A. Schedule D-1 presents a summary income statement that includes UGI Gas's claimed gas revenues, expenses, and taxes at present and proposed rate levels. The direct testimony of David E. Lahoff (UGI Gas Statement No. 6) addresses the presentation of *pro forma* revenues, adjustments thereto, and the supporting schedules. Schedule D-1 also shows the proposed revenue increase of $58.564 million on line 5 in column 2.

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

A. As shown on column 3, line 20, this amount is $75.467 million. This represents a $33.692 million increase from the level under current rates ($41.775 million), as shown on line 20 in column 1 of Schedule D-1.

Q. Please describe Schedule D-2.

A. Schedule D-2 shows the development of the various line items found on Schedule D-1. Column 2 contains the Company's budgeted level of revenues and expenses for the 12 month period ending September 30, 2017. Column 3 shows adjustments to the column 2 figures, where applicable, to reflect various annualization and/or normalization adjustments. Column 4 is the sum of columns 2-3. The amount of the revenue increase and related expenses are shown in column 5 with the resulting revenues and expenses at proposed rates shown in column 6.

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

A. Yes. The derivation of the various column 3 revenue adjustments are included in UGI Gas Exhibit A (Fully Projected) in summary fashion on Schedule D-3, page 1, lines 1-14, and then listed by individual adjustment on Schedule D-5. Customer charge and distribution rate revenue adjustments for each customer class are shown on lines 1-5. Gas Cost revenue adjustments for each customer class are shown on lines 6-10 and details of other revenue adjustments are shown on lines 11-14. Details for each revenue adjustment are shown in Schedules D-5 (including supporting schedules D-5a and D-5b) and D-6 and discussed in the direct testimony of witness David E. Lahoff (UGI Gas Statement No. 6). Regarding *pro forma* expenses, the derivation of the various adjustments are summarized individually on pages 1-2 of Schedule D-3, lines 17-55. The details for these adjustments are found in Schedules D-4 through D-31.

2. Operating Expense

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

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

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

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

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

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

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

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

Q. Schedule D-3 to UGI Gas Exhibit A (Fully Projected) shows an adjustment to Gas Costs in column 2. Please discuss this adjustment.

A. The detail for this adjustment is shown in Schedule D-6. This adjustment is designed to reduce purchased gas cost expense by the same amount of the gas cost revenue adjustment recommended in the direct testimony of David E. Lahoff (UGI Gas Statement No. 6) and as shown on Schedule D-5, column 3, lines 7-12. UGI Gas recovers its gas costs on a dollar for dollar basis with no profit through an automatic adjustment clause mechanism pursuant to Section 1307(f) of the Public Utility Code. Therefore, the reduction in purchased gas costs of $34.331 million equals the reduction in gas cost revenue as recommended by Mr. Lahoff. Thus, the purchased gas cost expense has no effect on net operating income.

Q. Please discuss the Company Use of Fuel adjustment shown on Schedule D-4.

A. Schedule D-4 removes the cost of fuel used in operations. This consists of the cost of gas used in Company operations, including that used to heat buildings and operate city gate station heaters. This cost is being removed since it is recovered through Purchased Gas Cost rates and retainage rates charged to transportation customers.

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

A. Schedule D-7 shows a $379,000 increase to budgeted salaries and wages to reflect end of FPFTY operating conditions. This adjustment annualizes payroll expense and is distributed among the various cost accounts. Page 2 shows the development of this adjustment.

Q. Please describe the annualization adjustment.

A. This adjustment annualizes the effect of wage increases for unionized, exempt and non-exempt employees that will take place during the FPFTY. Schedule D-7, page 2, line 2 reflects the increase percentages for each classification of employee. Lines 3 through 6 indicate the percentage of the year for which the salaries and wages increases are not reflected in the budget.

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

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

Q. Please explain the Environmental expense adjustment shown on Schedule D-8.

A. As explained in the direct testimony of Hans G. Bell (UGI Gas Statement No. 9), UGI Gas historically has accounted for its environmental remediation expenses associated with the remediation of Pennsylvania manufactured gas plants as a component of its annual cost of removal. As such, these expenses were recorded in UGI Gas's accumulated reserve for depreciation and reversed through the annual calculation of the amortization of net salvage. However, UGI Gas is now proposing to include such expenses in its projected expenses and remove them from its accumulated reserve for depreciation. Since the UGI Gas budget did not include this expense, an adjustment is necessary. This will align the recovery of such expenses with the method of cost recovery previously adopted for CPG and PNG and other Pennsylvania gas utilities.

Q. How does UGI Gas propose to account for in-state manufactured gas plant remediation cost going forward?

A. Since these costs can vary significantly from year-to-year, UGI Gas is requesting permission in this proceeding to record on its books the difference between the expense allowance for in-state manufactured gas plant remediation costs authorized in this proceeding, and actual expense incurred for this purpose, as a regulatory asset or liability, subject to recovery or refund in future base rate proceedings where the prudency of actual expenditures can be reviewed. This treatment should protect customers from over-recoveries and the Company from under-recoveries for this non-revenue producing and non-expense reducing category of expense.

Q. Please discuss Schedule D-9, which shows an adjustment for additional employees.

A. The adjustment for employee additions shown in Schedule D-9 is made up of four parts. The first is to add $0.735 million representing the salaries for seventeen incremental positions in UGI's IT department to support UGI's new customer information system ("CIS") described in the direct testimony of Thomas N. Lord (UGI Gas Statement No. 8). The total salary for these positions was multiplied by the allocation factor attributable to UGI Gas using the Modified Wisconsin Formula as these positions will support the CIS for the gas and electric divisions of UGI Utilities, Inc., and its two gas utility subsidiaries. The second adjustment is to add $0.696 million representing the salaries of ten new supervisors for UGI Gas. Based on a recent span of control analysis it was determined the ten new supervisor positions are required to appropriately support the field division. The third adjustment is to add $170,000 to increase field wages due to increased competition in UGI Gas's area for qualified utility field resources. The final adjustment in the amount of $0.317 million is to add five additional security management resources and cyber security support positions. The salaries for these security resources were also multiplied by the UGI Gas allocation factor since these positions will support all of UGI Utilities, Inc. Each of these adjustments represents changes made since the FPFTY budget was completed.

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

A. Lines 1 through 3 show the total amount of the $1.256 million rate case expense UGI Gas expects to incur in this case. That amount is then normalized over the anticipated two-year period between the filing of rate cases to establish a normal level of rate case expense of $628,000. Since the rate case expense will be incurred in the FTY, no amount for rate case expense is included in the FPFTY budget. The FPFTY budget therefore was increased by $628,000 to reflect a normal level of rate case expense. We believe that UGI will make regular rate case filings every two years going forward given the significant capital investments it has committed to make in accordance with its PUC-approved Long-Term Infrastructure Improvement Program.

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

A. Schedule D-11 adjusts the budgeted uncollectible accounts expense. Lines 1 through 4 of Schedule D-11 develop this adjustment by showing a ratio that represents the three-year average rate of uncollectible accounts expense for the fiscal years 2013 to 2015. This ratio is used to adjust the amount of uncollectible expense in the budget to conform to the three-year average for the charge-offs. The resulting 1.669% percent ratio shown on line 4 in column 5 is applied on line 7 to the *pro forma* revenues at present rates to calculate the *pro forma* uncollectible accounts expense of $5.561 million shown in column 4 on line 7. This results in a decrease in the level of uncollectibles for the FPFTY from the budgeted amount as shown on line 5. The 1.669% percent figure is then applied to determine the level of uncollectible accounts expense at *pro forma* proposed rates through the gross revenue conversion factor, as shown in column 3, line 2 of Schedule D-35.

Q. What is the adjustment for the UNITE Project that is shown on Schedule D-13

A. The adjustments on Schedule D-13 relate to UGI's Next Information Technology Enterprise ("UNITE") system replacement project, as described in the direct testimony of Thomas N. Lord (UGI Gas Statement No. 8), and are broken into three parts. Part one on lines 1-5 represents preliminary-stage project costs and business and technology reengineering costs including internal labor, external consulting expense and other expenses related to the preparation of the vendor and system integrator requests for proposal, current state assessment, and costs to reengineer the business processes to adapt to the new system, as well as data conversion, migration and pre-implementation training costs. These costs have been recorded as expenses in accordance with US GAAP accounting standards, specifically ASC-350-40 *'Internal Use Software'*. However, under the FERC Uniform System of Accounts, these costs fit the definition of costs that should be capitalized once placed in service. The costs in lines 1-4 on Schedule D-13 represent the costs related to these expenses that were included as expenses in the UGI Gas 2017 budget. The company is proposing an adjustment to reduce expenses by $1.040 million on line 5 of Schedule D-13 since these costs are included in the plant additions listed on Schedule C-2.

Q. Is the $1.040 million adjustment calculated on Schedule D-13 the total amount of these types of costs that are included in Plant Additions?

A. No, the $1.040 million adjustment only represents the costs that were included in the 2017 budget for UGI Gas. There are additional preliminary stage and business reengineering costs that were incurred in 2014 and 2015 and are expected to be incurred in 2016 that will also be included in plant additions. The total amount of these costs is $6.7 million. Of this amount $3.1 million is related to the Company's new CIS and the portion of these costs allocated to UGI Gas is included in plant additions.

Q. What is the second part of the adjustment on Schedule D-13?

A. The second part of the adjustment related to the UNITE project reflects additional call center resources that will be required to maintain the Company's level of customer service during the conversion to UGI's new CIS. The amount of $1.034 million in column 2 line 6 of Schedule D-13 represents the total cost to UGI Utilities, multiplied by the allocation factor to determine the costs attributable to UGI Gas. UGI Gas proposes to amortize and recover these costs over three years.

Q. What is the third part of the adjustment on Schedule D-13?

A. The third part of the adjustment on Schedule D-13 relates to the difference in annual licensing and maintenance fees for the new CIS system and the existing CIS systems. Line 7 of Schedule D-13 represents the portion of the estimated licensing and maintenance fees of the new CIS system based on vendor quotes that will be allocated to UGI Gas. The amount on line 8 is the projected maintenance fees for the existing CIS system which is included in the 2017 budget. The difference between these amounts, shown on line 9, is the adjustment to reflect the new CIS system licensing and maintenance costs.

Q. Please explain the adjustment for Post-Retirement expense that is shown on Schedule D-14.

A. As shown in Schedule D-14, this adjustment is made up of two components. The first part of the Other Post-Employment Benefits ("OPEB") adjustment on lines 1-2 removes the current budgeted expenses for OPEB of $2.374 million. This is the amount that UGI Gas is collecting in current rates. In accordance with regulatory accounting standards, this amount is reflected as an expense to eliminate any profit or loss resulting from the difference between OPEB expenditures and the amounts recovered in rates. The difference between the amount collected and the expense incurred is recorded as a regulatory asset or liability to later be collected from or returned to ratepayers. UGI Gas currently funds its OPEB expenditures through a voluntary employees' beneficiary association ("VEBA") trust that is in an overfunded status. Due to the overfunded status, no contributions are expected to be made and therefore the Company is not including any amount of the OPEB expenditures in its claim. Since there is no claim for OPEB, the amount in the budget should be removed.

Q. What is the second component of the OPEB adjustment on Schedule D-14?

A. The second component of the OPEB adjustment on lines 3-5 relates to the over collection of OPEB expenses since the last UGI Gas rate case. The Company has accumulated an over collection in the amount of $10.399 million over the 22 years since its last rate case, net of the PUC-approved re-direction of certain OPEB funding to fund a portion of CAP program costs, as described in the direct testimony of Robert R. Stoyko (UGI Gas Statement No. 4). UGI Gas proposes to return this overcollection to customers over 20 years, *i.e.*, to return $0.520 million annually to customers over a similar time period that the current recovery mechanism has been in place.

Q. Why is 20 years an appropriate amount of time over which to refund these costs to the ratepayers?

A. This refund period is consistent with the 20-year time period established in the Commission's Policy Statement at 52 Pa. Code § 69.351 regarding recovery of the OPEB costs that investor-owned utilities deferred after the adoption of Statement of Financial Account Standards (SFAS) No. 106.

Q. Please explain the adjustment to pension expense on Schedule D-14.

A. This adjustment is needed to increase the pension expense from budgeted levels. The budgeted pension expense was determined on prior period estimates. The updated estimate is based on a more recent actuarial calculation and reflects the cash to be contributed to the plan, reduced by the percentage of pension expenses that have historically been capitalized. The amounts reflected in the calculation for the pension adjustment include those directly attributable to the UGI Gas pension in addition to the portion of the UGI Corporate pension expense that is included in the corporate expenses allocated to UGI Gas.

Q. Please discuss the *pro forma* adjustment on Schedule D-15 for Injuries and Damages.

A. The amount of expense incurred for injuries and damages in any one year can vary based on the quantity and severity of the claims. The budgeted amount for injuries and damages is shown on line 5 of Schedule D-15. This amount is compared to the three-year average injuries and damages expenses of $2.821 million calculated on lines 1-4 to arrive at a reduction in injuries and damages expense of $93,000 on line 6.

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

A. The Company budgeted the full amount of the anticipated expenses for the American Gas Association and the Energy Association of Pennsylvania in membership expenses. A portion of these expense relate to lobbying activities and should not be included in UGI Gas's membership expense claim. The amounts on lines 7 and 8 of Schedule D-15 represent the percentage of expenses for lobbying activities based on the HTY applied to the budgeted expenses for each organization. Line 9 on Schedule D-15 shows the total adjustment to remove lobbying expenses in the amount of $16,000.

Q. Please explain the adjustment for Licensing of New Software shown on Schedule D-15.

A. Since the budget was developed for 2017, the Company has determined that there is a need for two new software systems to support the business. Both of these systems will be cloud-based and incur annual licensing fees. The first system is a contractor management system for $350,000 per year and the second is a customer relationship management software for $262,000 per year. These systems are expected to be implemented during the FTY and costs are based on vendor supplied quotes.

Q. Please explain the adjustment for insurance premiums on Schedule D-15.

A. Subsequent to preparation of the budget, UGI Corporation obtained cyber security insurance for all of its subsidiaries effective for the FTY. The $83,000 shown on line 13 of Schedule D-15 is the portion of this insurance that is allocated to UGI Gas. It is anticipated that UGI Corporation will continue to procure this insurance each year beyond the FTY, so an adjustment to FPFTY expenses also is appropriate.

Q. What adjustment is shown on Schedule D-15?

A. The Company is in the process of implementing additional corrosion control activities at an annual cost of $300,000, which was not included in the 2016 or 2017 budgets. These programs are necessary to ensure compliance with all regulations and to ensure proper system integrity is maintained. The adjustment on line 14 of Schedule D-15 will add these expenses to the FPFTY.

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

A. This adjustment is needed to reflect the expense related to UGI Gas's Universal Service programs previously subject to recovery through UGI Gas base rates, as described in the direct testimony of Robert R. Stoyko (UGI Gas Statement No. 7), but which will be recovered through UGI Gas's Universal Service Surcharge on a prospective basis, consistent with the recovery method for such expenses approved for PNG and CPG.

Q. Please explain the adjustment for Energy Efficiency and Conservation ("EE&C") Programs shown on Schedule D-19.

A. This adjustment is needed to reflect the incremental expense related to the Company's EE&C Program, which is discussed in the direct testimony of Theodore M. Love (UGI Statement No. 11). The expenses are divided into two categories: rebate costs and the costs of administering the program. As the EE&C Program is dependent on receiving authorization from the PUC in this proceeding, it was not included in the FPFTY budget. As shown in Schedule D-19, the total for these two cost categories is $2.659 million. The derivation of this amount is discussed in Mr. Love's direct testimony.

3. Depreciation Expense

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

A. UGI Gas's depreciation study is set forth in UGI Gas Exhibit A (Fully Projected) and shows the determination of *pro forma* depreciation expense. This study uses the FPFTY ending September 30, 2017 plant in service and the applicable depreciation rates, service lives, and procedures. A summary of the budgeted depreciation expense and adjustments thereto is found in UGI Gas Exhibit A (Fully Projected), Schedule D-21, and is further explained in the direct testimony of John F. Wiedmayer (UGI Gas Statement No. 5).

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

A. UGI Gas witness Wiedmayer presents the depreciation analysis that serves as the foundation of the depreciation adjustment. The adjustment for depreciation expense of $1.119 million set forth on Schedule D-21, page 2, column 3, is designed to annualize budgeted FPFTY depreciation expense in order to calculate an entire year's worth of depreciation on plant in service as of the end of the FPFTY, ending September 30, 2017. This schedule also shows an increase to the net negative salvage amortization of $1.183 million. The total annualized depreciation expense for the FPFTY, net of costs charged to clearing accounts and net salvage amortization, is $43.190 million. The total adjustment for depreciation expense, net of the increase to the negative salvage amortization of $1.674 million, is shown on Schedule D-3, page 2, column 10, line 54.

4. Payroll Taxes

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

A. Schedule D-31 contains the details for taxes other than income adjustments. The adjustment on line 2 removes the capital stock tax in the amount of $316,000 as the capital stock tax is set to phase out by the end of the FPFTY. The adjustments to the payroll tax expenses on lines 4-6 are calculated by multiplying the ratio of tax expense to payroll expense included in the FPFTY budget by the amount of the payroll adjustment derived in Schedule D-7 to produce an adjustment to the amount of social security, Federal Unemployment Tax (FUTA) and State Unemployment Tax (SUTA) expense in the amount of $178,000. The calculation of these adjustments is shown in more detail on Schedule D-32.

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

A. Schedule D-35 shows the calculation of the Gross Revenue Conversion Factor used on Schedule A-1 to calculate the level of revenues required to achieve the net operating income required to generate the rate of return supported by the direct testimony of Paul R. Moul (UGI Gas Statement No. 3). These additional revenues are required to recognize that uncollectible accounts expense vary with the level of revenue, and to recognize the additional state and federal income taxes attributable to the proposed rate increase.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS STATEMENT NO. 3 – PAUL R. MOUL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2015-2518438

UGI Utilities, Inc. – Gas Division

Statement No. 3

Direct Testimony of
Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

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

Dated: January 19, 2016

UGI Utilities, Inc. - Gas Division
Direct Testimony of Paul R. Moul
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GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
CE	Comparable Earnings
DCF	Discounted Cash Flow
FERC	Federal Energy Regulatory Commission
g	Growth rate
IGF	Internally Generated Funds
IRPA	Interest Rate Protection Agreement
LDC	local distribution companies
Lev	Leverage modification
LIBOR	London Interbank Offered Rate
LT	Long Term
OCI	Other Comprehensive Income
P-E	Price-earnings
PUC	Public Utility Commission
r	represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Return on the market
RP	Risk Premium
s	Represents the new common shares expected to be issued by a firm
s x v	Represents external growth
S&P	Standard & Poor's
UGIU	UGI Utilities, Inc.

GLOSSARY OF ACRONYMS AND DEFINED TERMS

ACRONYM	DEFINED TERM
UGI	UGI Corporation
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value
ytm	Yield to maturity

DIRECT TESTIMONY OF PAUL R. MOUL

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

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

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

Q. What is the purpose of your testimony?

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

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

A. My conclusion is that the Company should be afforded an opportunity to earn an 8.17% overall rate of return which includes an 11.00% rate of return on common equity. My 11.00% rate or return on common equity is established using capital market and financial data relied upon by investors when assessing the relative risk, and hence cost of capital for the Company.

My overall rate of return recommendation is determined by using the weighted average cost of capital. This approach provides a means to apportion the return to each class of investor. The calculation of the weighted average cost of capital requires the selection of appropriate capital structure ratios and a determination of the cost rate for each capital component. The resulting overall cost of capital when applied to the Company's rate base will provide a level of return which will compensate investors for the use of their capital. My overall cost of capital recommendation is set forth below and is shown on page 1 of Schedule 1.

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	40.30%	5.07%	2.04%
Short-Term Debt	5.15%	2.58%	0.13%
Common Equity	54.55%	11.00%	6.00%
Total	100.00%		8.17%

This overall rate of return is applicable to the September 30, 2017, fully projected future test year and the period that the Company's proposed rates will be effective.

Q. What factors have you considered in the determination of the Company's cost of equity in this proceeding?

A. The Company is a division of UGI Utilities, Inc., a wholly-owned subsidiary of UGI Corporation ("UGI" or the "Parent Company"). The Company provides natural gas distribution service to approximately 370,000 customers in fifteen eastern and south central Pennsylvania counties. Since its last rate case, the Company has added 100,000, or 55 percent more new customers and during this time the Company's utility plant in service has more than doubled. The Company's service territory contains several production centers for basic industries involved in steel and aluminum manufacturing and fabrication chemicals, and food processing. Throughput to on-system customers in 2015 was represented by approximately 20% to residential customers, approximately 22% to commercial customers, and approximately 58% to industrial customers. The significant portion of the Company's throughput to industrial customers makes the Company a much higher risk utility as compared to the Gas

Group. In addition, average usage for residential heating customers has declined by more than 30 per cent since the Company's last base rate case in 1995. UGI Utilities obtains its natural gas supplies from producers and marketers and has transportation arrangements through connections to five interstate pipelines. The Company has storage arrangements for natural gas inventory. UGI Utilities, Inc. also provides electric delivery service, through its Electric Division, to approximately 62,000 customers in portions of Luzerne and Wyoming Counties. UGI Utilities, Inc. is also the parent company of two natural gas distribution utilities, UGI Penn Natural Gas, Inc. and UGI Central Penn Gas, Inc.

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

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence, the cost of equity for a natural gas utility, such as the Company. In this regard, I have relied on four well recognized measures: the Discounted Cash Flow ("DCF") model, the Risk Premium analysis, the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings approach. By considering the results of a variety of approaches, I determined that 11.00% represents a reasonable cost of equity, which is consistent with well recognized principles for determining a fair rate of return.

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

A. The rate of return utilized by the Commission to set rates must be sufficient to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to raise capital on reasonable terms.

The return that I propose fulfills these established standards of a fair rate of return set forth by the landmark Bluefield and Hope cases.[1] That is to say, my proposed rate of return is commensurate with returns available on investments having corresponding risks.

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

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed for my proxy group of eight (8) natural gas companies. The proxy group consists of natural gas companies that: (i) are engaged in the natural gas distribution business, (ii) have publicly-traded common stock, (iii) are contained in The Value Line Investment Survey, and (iv) are not currently the target of a merger or acquisition. From the natural gas utilities covered by the basic service of Value Line, I excluded four companies. The eliminations were: AGL Resources due to the announced acquisition of it by Southern Company, NiSource Inc. due to its sizable electric operations and recent separation of the former natural gas pipeline/storage operations, Piedmont Natural Gas due to the announced acquisition of it by Duke Energy Corp., and UGI Corp. due to its diversified businesses consisting of six reportable segments, including propane, two international LPG segments, natural gas utility, energy services, and electric generation. The companies in the proxy group are identified on page 2 of Schedule 3. I will refer to these companies as the "Gas Group" throughout my testimony.

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

A. I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not measured separately the cost of equity for the

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

individual companies within the Gas Group, because the determination of the cost of equity for an individual company has become increasingly problematic. The use of average data for a portfolio of companies reduces the effect that anomalous results for an individual company may have on the rate of return determination. By employing group average data, rather than individual companies' analysis, I have helped to minimize the effect of extraneous influences on the market data for an individual company.

Q. Please summarize your cost of equity analysis.

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

DCF	10.40%
Risk Premium	11.50%
CAPM	11.37%
Comparable Earnings	11.65%

From these measures, I recommend a cost of equity of 11.00%. My recommendation is on the conservative side for UGI Gas because it is based on the Gas Group that does not have the Company's high risk attributes related to its high level of industrial throughput. It does provide recognition of the performance of the Company's management. Mr. Szykman's testimony in UGI Gas Statement No. 1 demonstrates that the Company ranks high in customer service and management effectiveness. Indeed, UGI Utilities has had the lowest residential rates in Pennsylvania for several years and will continue to have lower than average rates even with the proposed rate levels. In recognition of its outstanding performance, the Company should be granted an opportunity to earn an 11.00% rate of return on common equity. The 11.00% rate of return on common equity provides recognition of the strong performance of the Company's management and is well within the range of the market-based measures (i.e., DCF, RP and CAPM) of the cost of equity and the Comparable Earnings book value method that extends up to 11.65%. To obtain new capital to support an expanded construction program and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements. Along these lines, the Company is spending considerable amounts of capital on main replacements and that this will put a strain on performance in the short run. In recognition of its performance, the Company should be granted an opportunity to earn an 11.00% rate of return on common equity. Such return will help promote natural gas usage in Pennsylvania and its associated positive economic and environmental effects. I note that my recommendation does not reflect any adjustment for the greater risk faced by UGI due to its higher than average sales to industrial customers.

NATURAL GAS RISK FACTORS

Q. What factors currently affect the business risk of the natural gas utilities?

A. Gas utilities face risks arising from competition, economic regulation, the business cycle, and customer usage patterns. Today, they operate in a more complex environment with time frames for decision-making considerably shortened. Their business profile is influenced by market-oriented pricing for the commodity distributed to customers and open access for the transportation of natural gas for customers.

Natural gas utilities have focused increased attention on safety and reliability, the expansion of shale gas induced price benefits and issues, and on conservation and energy efficiency. In order to address these issues and to comply with new and pending pipeline safety regulations, natural gas companies are now allocating more of their resources to addressing aging infrastructure issues and extension and expansion requests, which have led to increased external capital requirements.

Q. Does the Company face competition in its natural gas business?

A. Yes. The Company's close proximity to the Marcellus shale production area provides additional risk for it compared to the companies in the Gas Group. Natural gas generally faces significant competition from alternative energy sources. The Company faces direct competition from electricity, fuel oil, and propane in its service territory. Propane and fuel oil have an advantage because they are not inhibited by regulatory constraints when conducting their marketing activities. This situation is unlike that of UGI Utilities, where specific thresholds must be satisfied for system expansions, and where promotional activities are constrained. The Company also faces the risk associated with throughput to interruptible customers whose deliveries are influenced by global oil prices.

Q. Are there specific factors influencing the Company's risk profile?

A. Yes. The Company's risk profile is strongly influenced by throughput delivered to industrial customers. Industrial customers represent approximately 56% of throughput, but these customers represent only 0.4% of total customers. Moreover, the Company's top nine customers represent 45% of total throughput. Electric generation, manufacturing, chemicals, and food processing are among these customers. Steel and aluminum manufacturing and fabrication face a number of challenges including international competition, increased costs, and fluctuating demand for its products. Industrial sales are generally higher in risk than sales to other classes of customers. Success in this segment of the Company's market is subject to (i) the business cycle,

(ii) the price of alternative energy sources, and (iii) pressures from alternative providers. Moreover, external factors can also influence the Company's sales to these customers which face competitive pressures on their own operations from other facilities outside the Company's service territories.

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

A. With customer demand for the Company's service at high levels, the Company is faced with the requirement to invest in new facilities to meet growth and to maintain and upgrade existing facilities in its service territory. To maintain safe and reliable service to existing customers, the Company must invest to upgrade existing facilities. The Company has approximately 11% of its distribution mains constructed of unprotected steel and cast iron pipe as of year-end 2014. The Company also has approximately 6% of its services constructed of unprotected steel. The continuing costs for upgrading the Company's pipe system will elevate the level of construction expenditures. In the situation where additional capital investment is required to serve new customers, supportive regulation represents a necessary prerequisite for the Company to actually achieve a fair rate of return and attract new capital on reasonable terms.

For the future, the Company estimates that its construction expenditures will be:

	Capital Expenditures		
	Gas Division	Electric Division	Total
2016	$ 194,100,000	$ 12,500,000	$ 206,600,000
2017	196,800,000	11,700,000	$ 208,500,000
2018	124,500,000	9,600,000	$ 134,100,000
2019	116,000,000	9,800,000	$ 125,800,000
	$ 631,400,000	$ 43,600,000	$ 675,000,000

During the 2016-2019 period, gross construction expenditures will represent an approximate 63% increase (65% for gas and 43% for electric) in net utility plant, including construction work in progress, from the level at September 30, 2015.

Q. Is the Company's risk also affected by the substantial decline in usage per customer?

A. Yes. Despite adding a substantial number of new customers, usage per residential heating customer has declined by more than 30 percent since the Company's last base rate case in 1995. Company analysis indicates that this decline with continue, particularly with the implementation of a new energy conservation plan. This plan will provide many benefits to customers and to the public, but can be expected to further reduce customer usage.

Q. How should the Commission respond to the issues facing the natural gas business and in particular UGI Gas?

A. The Commission should recognize the issues listed above when deciding the rate of return issue in this case. In particular, the Company has abnormal risks associated with its large throughput to industrial customers. It should also be recognized that base rates for the Company's gas customers have not been changed in twenty-one years. Another risk is declining usage per customer discussed in the testimony of Company witness Mr. David Lahoff (UGI Gas Statement No. 6).

FUNDAMENTAL RISK ANALYSIS

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

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors which bear upon investors' assessment of overall risk. The qualitative factors that bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. For this purpose, I have compared UGI Utilities to the S&P Public Utilities, an industry-wide proxy consisting of all types of public utility endeavors, and the Gas Group.

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

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

Q. What companies comprise your Gas Group?

A. My Gas Group obtained from the Value Line publication consists of the following companies: Atmos Energy Corp., Chesapeake Utilities Corp., Laclede Group, New Jersey Resources Corp., Northwest Natural Gas, South Jersey Industries, Inc., Southwest Gas Corp., and WGL Holdings, Inc.

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

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

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

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

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

A. The broad categories of financial data that I will discuss are shown on Schedule 2, 3 and 4. The data cover the five-year period 2010-2014. I will highlight the important categories of relative risk may be summarized as follows:

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

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

Since UGI Utilities' stock is not traded, there are no market ratios for the Company. The five-year average price-earnings multiple for the Gas Group was fairly similar to that of the S&P Public Utilities. The five-year average dividend yields were

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

somewhat lower for the Gas Group as compared to the S&P Public Utilities. The average market-to-book ratios were somewhat higher for the Gas Group than the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has low financial risk, while a firm with a low common equity ratio has high financial risk. The five-year average common equity ratios, based on permanent capital based on book value, were 54.9% for UGI Utilities, 57.6% for the Gas Group, and 45.3% for the S&P Public Utilities. This shows that the financial risk of UGI Utilities was slightly higher than that of the Gas Group.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relative levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficient of variation, the greater degree of variability. During the five-year period, the coefficients of variation were 0.105 (1.4% ÷ 13.3%) for UGI Utilities, 0.058 (0.6% ÷ 10.4%) for the Gas Group, and 0.102 (1.0% ÷ 9.8%) for the S&P Public Utilities. These comparisons show substantially higher earnings variability for the Company compared to the Gas Group and slightly higher earnings variability for the Company compared to the S&P Public Utilities, thus signifying higher risk.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation and taxes other than income).[3] The five-year average operating ratios were 80.4% for UGI Utilities, 88.3% for the Gas

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

Group, and 81.3% for the S&P Public Utilities. The lower average operating ratio for UGI Utilities suggests somewhat lower risk.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average pre-tax interest coverage (excluding AFUDC) was 5.11 times for UGI Utilities, 4.90 times for the Gas Group, and 3.19 times for the S&P Public Utilities. The somewhat higher interest coverage for UGI Utilities suggests slightly lower credit risk.

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

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to construction expenditures was 117.4% for UGI Utilities, 90.0% for the Gas Group, and 87.5% for the S&P Public Utilities. The Company's levels of IGF have declined in recent years as its construction expenditures have increased. This indicates a changing risk profile for the Company that points to higher risk prospectively.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities. Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market.[3] A comparison of market risk is shown by the Value Line betas of .78 as the average for the Gas Group provided on page 2 of Schedule 3 and .77 as the average for the S&P Public Utilities provided on page 3 of Schedule 4.

Q. Please summarize your risk evaluation of UGI Utilities and the Gas Group.

A. The investment risk of UGI Utilities parallels that of the Gas Group in certain respects. In certain regards, principally related to its small size, large throughput to industrial customers, slightly lower common equity ratio, and more variable earned returns, UGI Utilities has somewhat higher risk traits. UGI Utilities has lower risk as shown by its lower operating ratio and higher interest coverages. The Company's credit quality is comparable to the Gas Group. Its IGF to construction has been trending downward as construction expenditures have increased, which shows more risk prospectively. On balance, the cost of equity for the Gas Group would understate the Company's cost of equity for this case.

RECOMMENDED CAPITAL STRUCTURE RATIOS

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

A. In the situation where the operating public utility raises its own long-term debt directly in the capital markets, as is the case for UGI Utilities, it is proper to employ the capital structure ratios and senior capital cost rates of the regulated public utility for rate of return purposes. In that case, the property and earnings of the operating public utility forms the basis of the capital employed and the capital cost rates are directly identifiable. Since the Gas Division of UGI Utilities does not obtain its capital

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

independently, I have employed the consolidated capital structure ratios of the Company to calculate the rate of return for this case. Not only does UGI Utilities attract investor-provided capital for its gas and electric divisions, it also does that for its regulated gas distribution subsidiaries, UGI Penn Natural Gas, Inc. and UGI Central Penn Gas, Inc. The circumstances of UGI Utilities indicate that the capital structure ratios of the Company should be used for rate of return purposes for both its utility divisions and its subsidiaries.

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

A. Yes. Schedule 5 presents UGI Utilities capitalization and related capital structure at September 30, 2015, the end of the historic test year. Also shown on Schedule 5 is the UGI Utilities capital structure estimated at September 30, 2016, the end of the future test year, and at September 30, 2017, the end of the fully forecast test year. The changes in the Company's capital structure consist of: (i) maturities of three series of debt consisting of $247 million in the future test year (ii) one maturity of $20 million in the fully forecast test year, (iii) the issuance of two series of long-term debt totaling $300 million in the future test year, (iv) the issuance of $100 million of long-term debt in the fully forecast test year, and (v) the Company's projection of retained earnings at the end of the future and fully forecast test years.

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

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

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

A. The accumulated OCI must be eliminated from the capital structure for rate setting purposes. OCI arises from a variety of sources, including: minimum pension liability

("MPL"), foreign currency hedges, unrealized gains and losses on securities available for sale, interest rate swaps, and other cash flow hedges. The accumulated OCI for the Company has its roots in the MPL and interest rate hedges associated with the future issuance of long-term debt. A MPL entry must be recorded on the balance sheet when the present value of the pension benefit earned by employees exceeds the market value of trust fund assets. It should be noted that the Company records the change related to prior service cost and actuarial valuations as a regulatory asset for the portion of pension attributable to its retirees and employees that are part of its regulated utility operations. The amount in the accumulated OCI is just related to the portion attributable to employees of UGI Corporation and non-utility subsidiaries. That is to say, the accumulated OCI associated with MLP is not related to utility operations. The interest rate hedges, as they affect OCI, must also be removed because they have been reflected in the forecast of interest rates used to calculate the embedded cost of debt in the future and fully forecast test years.

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

A. Since ratemaking is prospective, the rate of return should reflect known conditions which will exist during the period of time the proposed rates are to be effective. I will adopt the Company's capital structure ratios at the end of the fully forecast test year of 40.30% long-term debt, 5.15% short-term debt, and 54.55% common equity. These ratios are with the ranges indicated for the Gas Group. These capital structure ratios are the best approximation of the mix of capital the Company will employ to finance its rate base during the period new rates are in effect. For the purpose of calculating the short-term debt ratio, the Company uses a twelve-month average for ratesetting purposes. This approach conforms to the seasonal nature of short-term debt related to stored gas inventory. This procedure has been used by the Commission frequently for gas distribution utilities when calculating capital structure ratios. I have removed from the short-term debt balances the bridge financing associated with long-term debt maturities that occurred prior to the refinancing of those amounts with subsequent issues of long-term debt. This process in necessary to avoid double-counting for interim debt used to meet maturities before they are refinanced.

EMBEDDED COST OF DEBT

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

A. Consistency requires that the embedded senior capital cost rates of UGI Utilities must be used for developing a fair rate of return. It is essential that the cost rate of long-term debt is related to the same proportion of senior capital employed to arrive at the capital structure ratios. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is due to the fact that the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Schedule 6, I have computed the actual embedded cost rate of long-term debt at September 30, 2015. On page 2 of Schedule 6, I have shown the estimated embedded cost rate of long-term debt at September 30, 2016. And on page 3 of Schedule 6, the embedded cost of long-term debt is shown for the fully forecast test year. The development of the individual effective cost rates for each series of long-term debt, using the cost rate to maturity technique, is shown on page 4 of Schedule 6. The cost rate, or yield to maturity, is the rate of discount that equates the present value of all future interest and principal payments with the net proceeds of the bond.

I will adopt the 5.07% forecast embedded long-term debt cost rate at September 30, 2017, as shown on page 3 of Schedule 6. This rate is related to the amount of long-term debt shown on Schedule 5 which provides the basis for the 40.30% long-term debt ratio.

Q. What cost rate have you assigned to the short-term debt?

A. The cost of short-term debt for UGI Utilities is comprised of two components. They consist of: (i) London Interbank Offered Rate ("LIBOR") and (ii) a margin or spread to recognize the risk associated with UGI Utilities' credit quality. For this case, I have used the Blue Chip Financial Forecasts that shows a forecast LIBOR rate of 1.7% in the first quarter of 2017. Blue Chip does not publish LIBOR forecasts for subsequent quarters of 2017. For the spread associated with UGI Utilities' credit quality, the margin charged to UGI Utilities is 0.875%. In total, the cost of short-term debt is 2.575% (1.7% + 0.875%) reflecting the two components listed above.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe the process you employed to determine the cost of equity for the Company.

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

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As I describe below, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and arrived at a cost of equity of 11.00% for the Company.

DISCOUNTED CASH FLOW

Q. Please describe your use of the Discounted Cash Flow approach to determine the cost of equity.

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model and assumes future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: P = D/(k-g), where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: k= D/P + g. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model.[4] My DCF results are provided on page 2 of Schedule 1 for the Gas Group. The DCF return is 10.40%.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that

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

include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

Q. Please explain the dividend yield component of a DCF analysis.

A. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended October 2015, the monthly dividend yields are shown on Schedule 7 and reflect an adjustment to the month-end prices to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the twelve months ended October 2015, the average dividend yield was 3.18% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three-month periods were 3.24% and 3.17%, respectively. I have used, for the purpose of the DCF model, the six-month average dividend yield of 3.24% for the Gas Group. The use of this dividend yield will reflect current capital costs, while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investor anticipated cash flows for the Gas Group. I have adjusted the six-month average dividend yield in three different, but generally accepted, manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Schedule 7. This adjustment adds ten basis points to the six-month average historical yield, thus producing the 3.34% adjusted dividend yield for the Gas Group.

Q. Please explain the underlying factors that influence investor's growth expectations.

A. As noted previously, investors are interested principally in the future growth of their investment (i.e., the price per share of the stock). Future earnings per share growth represent the DCF model's primary focus because under the constant price-earnings multiple assumption of the model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth, including: earnings, dividends, book value, and cash flow stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors. A fundamental growth rate analysis is sometimes represented by the internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. To be complete, the internal growth rate should be modified to account for sales of new common stock -- this is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of the factors that cause book value per share to grow over time.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilizes at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time.

Q. Did you assume a non-constant growth rate in your analysis?

A. No. I acknowledge that growth can also be expressed in multiple stages, but there is no need to do so in this case. As my subsequent analysis will reveal, my growth rate determination provides a constant growth rate that is sustainable given the fundamentals currently affecting the industry. For example, infrastructure rehabilitation adds to the growth of rate base that will provide the foundation for future growth that is consistent with the constant growth rate.

Q. What investor-expected growth rate is appropriate in a DCF calculation?

A. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner. In my opinion, all relevant growth rate indicators using a variety of techniques must be evaluated when formulating a judgment of investor-expected growth.

Q. What company-specific data have you considered in your growth rate analysis?

A. As presented on Schedules 8 and 9, I have considered both historical and projected growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. While analysts will review all measures of growth as I have done, it is earnings per share growth that influences directly the expectations of investors for utility stocks.[5] Forecasts of earnings growth are required within the context of the DCF because the model is a forward-looking concept, and with a constant price-earnings multiple and payout ratio, all other measures of growth will mirror earnings growth. So with the assumptions underlying the DCF, all forward-looking projections should be similar with a constant price-earnings multiple, earned return, and payout ratio.

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

Schedule 8 shows the historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. The historical growth rates were taken from the Value Line publication that provides these data. As shown on Schedule 8, the historical growth of earnings per share was in the range of 4.25% to 5.81% for the Gas Group.

Q. What is presented in Schedule 9?

A. Schedule 9 provides projected earnings per share growth rates taken from analysts' forecasts compiled by IBES/First Call, Reuters, Zacks, Morningstar, SNL, and Value

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

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

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

A. Yes. In fact, it illustrates that the infinite form of the DCF model contains an unrealistic assumption. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investor expected return. The growth in the price per share will equal the growth in earnings per share absent any change in price-earnings ("P-E") multiple -- a necessary assumption of the DCF. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, conforms with the type of analysis that influences the actual total return expectation of investors. Moreover, academic research focuses on five-year growth rates as they influence stock prices. Indeed, if investors really required forecasts which extended beyond five years in order to properly value common stocks, then I am sure that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of investors. The absence of such a publication is proof that investors do not require infinite forecasts in order to purchase and sell stocks in the marketplace.

Q. What does Schedule 9 show as the projected growth rates?

A. As to the five-year forecast growth rates, Schedule 9 indicates that the projected earnings per share growth rates for the Gas Group are 5.12% by IBES/First Call, 6.11% by Reuters, 5.47% by Zacks, 4.80% by Morningstar, 5.28% by SNL, and 7.06% by Value Line. The Value Line projections indicate that earnings per share for the Gas Group will grow prospectively at a more rapid rate (i.e., 7.06%) than the dividends per share (i.e., 4.88%), which translates into a declining dividend payout ratio for the future. As noted earlier, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

Q. What conclusion have you drawn from these data regarding the applicable growth rate to be used in the DCF model?

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

The forecasts of earnings per share growth, as shown on Schedule 9, provide a range of average growth rates of 4.80% to 7.06%. Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 6.25% is a reasonable estimate of investor expected growth within the array of earnings per share growth rates shown by the analysts' forecasts. As I indicated above, the fundamentals for UGI Utilities, including its significant new investment in infrastructure rehabilitation, point to a higher growth rate.

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

A. Only if the capital structure ratios are measured with the market value of debt and equity. In the case of the Gas Group, those average capital structure ratios are 33.06% long-term debt, 0.12% preferred stock, and 66.82% common equity, as shown on

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

Schedule 10. If book values are used to compute the capital structure ratios, then an adjustment is required.

Q. Please explain why.

A. If regulators use the results of the DCF (which are based on the market price of the stock of the companies analyzed) to compute the weighted average cost of capital with a book value capital structure used for ratesetting purposes, those results will not reflect the higher level of financial risk associated with the book value capital structure. Where, as here, a stock's market price diverges from a utility's book value, the potential exists for a financial risk difference, because the capitalization of a utility measured at its market value contains more equity, less debt and therefore less risk than the capitalization measured at its book value.

This shortcoming of the DCF has persuaded the Commission to adjust the cost of equity upward to make the return consistent with the book value capital structure. Provisions for this risk difference were made by the Commission in the following cases:

Date	Company	Docket Number	Basis Points
January 10, 2002	Pennsylvania-American Water Co.	Docket No. R-00016339	60 basis points
August 1, 2002	Philadelphia Suburban Water Co.	Docket No. R-00016750	80 basis points
January 29, 2004	Pennsylvania-American Water Co.	Docket No. R-00038304 (affirmed by the Commonwealth Court on November 8, 2004)	60 basis points
August 5, 2004	Aqua Pennsylvania, Inc.	Docket No. R-00038805	60 basis points
December 22, 2004	PPL Electric Utilities Corp.	Docket No. R-00049255	45 basis points
February 8, 2007	PPL Gas Utilities Corp.	Docket No. R-00061398	70 basis points

In order to make the DCF results relevant to the capitalization measured at book value (as is done for ratesetting purposes) the market-derived cost rate cannot be used without modification.

Q. Please continue with your discussion of the calculation of the leverage adjustment.

A. The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield

(D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different than indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market capitalization of a firm. If the ratesetting process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the ratesetting process uses a different set of ratios calculated from the book value capitalization, then further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the equity. This adjustment is developed through precise mathematical calculations, using well recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. The calculations presented in the lower panel of data shown on Schedule 10, under the heading "M&M," provides a return of 8.30% when applicable to a capital structure with 100% common equity.

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

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

Further, as noted previously, the relatively high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on equity that differs from their cost of equity. Stock prices above book value are common for utility stocks, and indeed the stock prices of non-regulated companies exceed book values by even greater margins. In this regard, according to the Barron's issue of November 23, 2015, the major market indices' market-to-book ratios are well above unity. The Dow Jones Utility index traded at a multiple of 1.74 times book value, which is below the market multiple of other indices. For example, the S&P Industrial index was at 3.75 times book value, and the Dow Jones Industrial index was at 3.26 times book value. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of their cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they indeed exist.

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

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

A. No, it is not. The adjustment that I label as a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g), in the context of a return that applies to the capital structure used in ratemaking, which is computed with book value weights rather than market value weights, in order to arrive at the utility's total cost of equity. I specify a separate factor, which I call the leverage adjustment, but there is no need to do so other than providing identification for this factor. If I expressed my return solely in the context of the book value weights that we use to calculate the weighted average cost of capital, and ignore the familiar D/P + g expression entirely, then there would be no separate element to reflect the financial leverage change from market value to book value capitalization. As shown in the bottom panel of data on Schedule 10, the equity return applicable to the book value common equity ratio is equal to 8.30%, which is the return for the Gas Group applicable to its equity with no debt in its capital structure (i.e., the cost of capital is equal to the cost of equity with a 100% equity ratio) plus 2.09% compensation for having a 44.61% debt ratio, plus 0.01% for having a 0.18% preferred stock ratio. The sum of the parts is 10.40% (8.30% + 2.09% + 0.01%) and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I summed the 3.34% dividend yield, the 6.25% growth rate, and the 0.81% for the leverage adjustment in order to arrive at the same 10.40% (3.34% + 6.25% + 0.81%) return. I know of no means to mathematically solve for the 0.81% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.81% adjustment is merely a convenient way to compare the 10.40% return computed directly with the Modigliani & Miller formulas to the 9.59% return generated by the DCF model based on a market value capital structure. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

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

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

	D_1/P_0	+	g	+	*lev.*	=	k
Gas Group	3.34%	+	6.25%	+	0.81%	=	10.40%

The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant growth assumption. As described previously, the risk of UGI Gas exceeds that of the Gas Group due to the high proportion of throughput to the Company's industrial customers. As such, the DCF result for the Gas Group shown above would understate the required equity return for the Company. I should reiterate, however, that the DCF-indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market, because price-earnings multiples do not remain constant. This is one of the constraints of this model that makes it important to consider other model results when determining a company's cost of equity.

RISK PREMIUM ANALYSIS

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

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on page 2 of Schedule 1. That result is 11.50%. As with other models used to determine the cost of equity, the Risk Premium approach has its limitations, including potential imprecision in the assessment of the future cost of corporate debt and the measurement of the risk-adjusted common equity premium.

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

A. In my opinion, a 5.00% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

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

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on page 1 of Schedule 11. For the twelve months ended October 2015, the average monthly yield on Moody's index of A-rated public utility bonds was 4.06%. For the six and three-month periods ended October 2014, the yields were 4.32% and 4.31%, respectively. During the twelve-months ended October 2015, the range of the yields on A-rated public utility bonds was 3.58% to 4.40%. Page 2 of Schedule 12 shows the long-run spread in yields between A-rated public utility bonds and long-term Treasury bonds. As shown on page 3 of Schedule 12, the yields on A-rated public utility bonds have exceeded those on Treasury bonds by 1.23% on a twelve-month average basis, 1.34% on a six-month average basis, and 1.41% on a the three-month average basis. From these averages, 1.25% represents a reasonably conservative spread for the yield on A-rated public utility bonds over Treasury bonds.

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

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe below. The Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on November 1, 2015, and a yield spread of 1.25%, derived from historical data.

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

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

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2015	Fourth	4.0%	5.2%	2.9%	1.25%	4.15%
2016	First	4.2%	5.3%	3.1%	1.25%	4.35%
2016	Second	4.4%	5.4%	3.3%	1.25%	4.55%
2016	Third	4.6%	5.6%	3.5%	1.25%	4.75%
2016	Fourth	4.7%	5.7%	3.6%	1.25%	4.85%
2017	First	4.9%	5.8%	3.8%	1.25%	5.05%

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

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its June 1, 2015 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2017-2021	5.9%	6.7%	4.8%
2022-2026	6.1%	6.9%	5.0%

The longer term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near term forecasts. By focusing more on the near term forecasts, a 5.00% yield on A-rated public utility bonds represents a conservative benchmark for measuring the cost of equity in this case.

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

A. To develop an appropriate equity risk premium, I analyzed the results from Stocks, Bonds, Bills and Inflation ("SBBI") 2015 Classic Yearbook published by Ibbotson Associates that is part of Morningstar. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on page 1 of Schedule 12.

<u>Common Equity Risk Premiums</u>

Low Interest Rates	7.36%
Average Across All Interest Rates	5.69%
High Interest Rates	3.98%

Based on my analysis of the historical data, the equity risk premium was 7.36% when the marginal cost of long-term government bonds was low (i.e., 3.00%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.28% on average during periods of high interest rates) the spread narrowed to 3.98%. Over the entire spectrum of interest rates, the equity risk premium was 5.69% when the average government bond yield was 5.12%. With the forecast indicating an upward movement of interest rates that I described above from historically low levels, I have utilized a 6.50% equity risk premium. This equity risk premium is between the 7.36% premium related to periods of low interest rates and the 5.69% premium related to average interest rates across all levels.

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

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

	i	+	*RP*	=	*k*
Gas Group	5.00%	+	6.50%	=	11.50%

CAPITAL ASSET PRICING MODEL

Q. What are the features of the CAPM as you have used it?

A. The CAPM uses the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Schedule 1, the result of the CAPM is 11.37%. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 2 of Schedule 3, the average beta is 0.78 for the Gas Group.

Q. What betas have you used in the CAPM determined cost of equity?

A. The betas must be reflective of the financial risk associated with the ratesetting capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line (market value) betas have been unleveraged and releveraged for the book value common equity ratios using the Hamada formula,[7] as follows:

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

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

where ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.59 for the Gas Group if it employed no leverage and was 100% equity financed. Those calculations are shown on Schedule 10 under the section labeled “Hamada” who is credited with developing those formulas. With the unleveraged beta as a base, I calculated the leveraged beta of 0.90 for the book value capital structure of the Gas Group. The book value leveraged beta that I will employ in the CAPM cost of equity is 0.90 for the Gas Group.

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

A. As shown on page 1 of Schedule 13, I provided the historical yields on Treasury notes and bonds. For the twelve months ended October 2015, the average yield on 30-year Treasury bonds was 2.83%. For the six- and three-months ended October 2015, the yields on 30-year Treasury bonds were 2.97% and 2.90%, respectively. During the twelve-months ended October 2015, the range of the yields on 30-year Treasury bonds was 2.46% to 3.11%. The low yields that existed during recent periods can be traced to the financial crisis and its aftermath commonly referred to as the Great Recession. The resulting decline in the yields on Treasury obligations was attributed to a number of factors, including: the sovereign debt crisis in the euro zone, concern over a possible double dip recession, the potential for deflation, and the Federal Reserve’s large balance sheet that was expanded through the purchase of Treasury obligations and mortgage-backed securities (also known as QEI, QEII, and QEIII), and the reinvestment of the proceeds from maturing obligations and the lengthening of the maturity of the Fed’s bond portfolio through the sale of short-term Treasuries and the purchase of long-term Treasury obligations (also known as “operation twist”). Essentially, low interest rates were the product of the policy of the FOMC in its attempt to deal with stagnant job growth, which is part of its dual mandate. The FOMC has ended its bond purchasing program. And, at its December 16, 2015 meeting, the Federal Open Market Committee increased the federal funds rate range by 0.25 percentage points. The prospect exists that future increases in the federal funds rate will likely occur.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on September 1, 2015 indicate that the yields on long-term Treasury bonds are expected to be in the range of 2.9% to 3.8% during the next six quarters. The longer term forecasts described previously show that the yields on 30-year Treasury bonds will average 4.8% from 2017 through 2021 and 5.0% from 2022 to 2026. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a 3.75% risk-free rate of return for CAPM purposes, which considers not only the Blue Chip forecasts, but also the recent trend in the yields on long-term Treasury bonds.

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

A. As shown in the lower panel of data presented on page 2 of Schedule 13, the market premium is derived from historical data and the Value Line and S&P 500 returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on page 1 of Schedule 12. On that schedule, the market return was 12.21% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 3.00% when interest rates were low. As I describe above, interest rates are forecast to trend upward in the future. To recognize that trend, I have given weight to the average returns and yields that existed across all interest rate levels. As such, I carried over to page 2 of Schedule 13 the average large common stock returns of 12.14% (12.21% + 12.07% = 24.28% ÷ 2) and the average yield on long-term government bonds of 4.06% (3.00% + 5.12% = 8.12% ÷ 2). These financial returns rest between those experienced during periods of low interest rates and those experienced across all levels of interest rates. The resulting market premium is 8.08% (12.14% - 4.06%) based on historical data, as shown on page 2 of Schedule 13. For the forecast returns, I calculated a 12.03% total market return from the Value Line data and a DCF return of 8.24% for the S&P 500. With the average forecast return of 10.14% (12.03% + 8.24% = 20.27% ÷ 2), I calculated a market premium of 6.39% (10.14% - 3.75%) using forecast data. The market premium applicable to the CAPM derived from these sources equals 7.24% (6.39% + 8.08% = 14.47% ÷ 2).

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

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. As the size of a firm decreases, its risk and required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms.[8] Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled “Equity and the Small-Stock Effect,” it was demonstrated that the CAPM could understate the cost of equity significantly according to a company’s size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) were in excess of those shown by the simple CAPM. In this regard, the Gas Group has a market-based average equity capitalization of $2,235 million. The mid-cap adjustment of 1.10%, as revealed on page 3 of Schedule 13, would be warranted at a minimum.

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

Q. What CAPM result have you determined?

A. Using the 3.75% risk-free rate of return, the leverage adjusted beta of 0.90 for the Gas Group, the 7.24% market premium, and the 1.10% size adjustment, the following result is indicated.

	Rf	**+**	***ß***	***x (***	***Rm-Rf***	***) +***	***size***	**=**	***k***
Gas Group	3.75%	+	0.90	x (	7.24%	) +	1.10%	=	11.37%

COMPARABLE EARNINGS APPROACH

Q. How have you applied the Comparable Earnings approach in this case?

A. The Comparable Earnings approach determines the equity return based upon results from non-regulated companies. It is the oldest of all rate of return methods, having been around for about one-century. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return. In order to identify the appropriate return, it is necessary to analyze returns earned (or realized) by other firms within the context of the Comparable Earnings standard. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided.

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

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

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

Q. How have you implemented the Comparable Earnings Approach?

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

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

Q. What data have you used in your Comparable Earnings analysis?

A. I have used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 11.2% using only the returns that were less than 20%, as shown on page 2 of Schedule 14. The average forecasted rate of return as published by Value Line is 12.1% also using values less than 20%, as provided on page

2 of Schedule 14. Using the average of these data my Comparable Earnings result is 11.65%, as shown on page 2 of Schedule 1.

CONCLUSION ON COST OF EQUITY

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

A. Based upon the application of a variety of methods and models described previously, it is my opinion that the rate of return on common equity is 11.00%. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method. In conclusion, the Company is entitled to an 11.00% rate of return on common equity so that it can compete in the capital markets, be compensated for its risk profile, and be recognized for the outstanding performance of the Company's management. As I indicated previously, the range of the cost of equity derived from the results for the Gas Group is 10.40% to 11.65%. Looking just to the market based methods (i.e., DCF, RP and CAPM), the midpoint of that range is 10.95% using DCF (i.e., 10.40%) as the bottom and RP (i.e., 11.50%) as the top. The 11.00% cost of equity that I am proposing provides minimal recognition for the Company's management effectiveness and does not reflect any adjustment for the higher risk associated with the Company's large throughput to its industrial customers.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

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

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

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

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

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

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

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

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

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

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

UGI GAS STATEMENT NO. 4 – PAUL R. HERBERT

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2015-2518438

UGI Utilities, Inc. – Gas Division

Statement No. 4

Direct Testimony of
Paul R. Herbert

Topics Addressed: **Cost of Service Allocation**

Date: January 19, 2016

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION
DOCKET NO. R-2015-2518438

RE: UGI UTILITIES, INC. - GAS DIVISION

DIRECT TESTIMONY OF PAUL R. HERBERT

Q. Please state your name and business address.

A. My name is Paul R. Herbert. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. By whom are you employed?

A. I am employed by Gannett Fleming Valuation and Rate Consultants, LLC.

Q. Please describe your position with Gannett Fleming Valuation and Rate Consultants, LLC., and briefly state your general duties and responsibilities.

A. I am President. My duties and responsibilities include the preparation of accounting and financial data for revenue requirement and cash working capital claims, the allocation of cost of service to customer classifications, and the design of customer rates in support of public utility rate filings.

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

A. Yes. I have testified before the Pennsylvania Public Utility Commission, the New Jersey Board of Public Utilities, the Public Utilities Commission of Ohio, the Public Service Commission of West Virginia, the Kentucky Public Service Commission, the Iowa State Utilities Board, the Virginia State Corporation Commission, the Illinois Commerce Commission, the Tennessee Regulatory Authority, the California Public

Utilities Commission, New Mexico Public Regulation Commission, the Delaware Public Service Commission, Arizona Corporate Commission, the Connecticut Department of Public Utility Control, the Idaho Public Utilities Commission, the Hawaii Public Utilities Commission, and the Missouri Public Service Commission concerning revenue requirements, cost of service allocation, rate design and cash working capital claims. A list of the cases in which I have testified is provided at the end of my direct testimony.

Q. What is your educational background?

A. I have a Bachelor of Science Degree in Finance from the Pennsylvania State University, University Park, Pennsylvania.

Q. Would you please describe your professional affiliations?

A. I am a member of the American Water Works Association and serve as a member of the Management Committee for the Pennsylvania Section. I am also a member of the Pennsylvania Municipal Authorities Association. In 1998, I became a member of the National Association of Water Companies as well as a member of its Rates and Revenue Committee.

Q. Briefly describe your work experience.

A. I joined the Valuation Division of Gannett Fleming Corddry and Carpenter, Inc., predecessor to Gannett Fleming Valuation and Rate Consultants, LLC, in September 1977, as a Junior Rate Analyst. Since then, I have advanced through several positions and was assigned the position of Manager of Rate Studies on July 1, 1990. On June 1, 1994, I was promoted to Vice President and on November 1, 2003, I was promoted to Senior Vice President. On July 1, 2007, I was promoted to my current position as President.

While attending Penn State, I was employed during the summers of 1972, 1973 and 1974 by the United Telephone System - Eastern Group in its accounting department. Upon graduation from college in 1975, I was employed by Herbert Associates, Inc., Consulting Engineers (now Herbert Rowland and Grubic, Inc.), as a field office manager until September 1977.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Utilities, Inc. - Gas Division ("UGI Gas" or the "Company"). I will explain the cost of service allocation study

COST OF SERVICE ALLOCATION STUDY

Q. What is the purpose of the cost of service allocation study?

A. The purpose of the study is to allocate the total cost of service to the several service classifications. I have prepared two cost of service studies that I will describe later as well as summary schedules that present a simple average of the two studies. The studies provide a basis for determining the extent to which the revenues to be derived from each classification are commensurate with the cost of serving that classification.

Q. Have you prepared a cost of service study for UGI Utilities, Inc. in a prior case?

A. No. However, I prepared the cost of service studies in the UGI Penn Natural Gas, Inc. rate case at Docket No. R-2008-2079660 and the UGI Central Penn Gas, Inc. rate cases at Docket Nos. R-2008-2079675 and R-2010-2214415. In 2006, at Docket No. R-00061398, I prepared the cost of service study for PPL Gas Utilities Corporation, the predecessor of UGI Central Penn Gas, Inc.

Q. What method of cost allocation was used in the studies?

A. I used the Average and Extra Demand Method (Average/Excess), which is described in UGI Gas Exhibit D and in the text, "Gas Rate Fundamentals", published by the American Gas Association's Rate Committee.

Q. Please describe the difference in the two cost of service studies presented for this proceeding.

A. The first study presented in Exhibit D, allocates mains investment to the interruptible class on the basis of average daily volumes (excluding excess capacity). The second study presented in Exhibit D-1, does not allocate any mains investment (except for directly assigned mains for one customer) to the interruptible class. Exhibit D-2 presents the simple average of the two studies in the summary Schedule A-2 as well as the rate of return schedules under present and proposed rates in Schedules B-2 and C-2, respectively.

Q. Please describe UGI Gas Exhibit D.

A. UGI Gas Exhibit D titled, "Cost of Service Allocation Study as of September 30, 2017," is the first cost of service allocation study prepared for UGI Gas in support of its claims in this proceeding. It sets forth the results of the study based on the projected costs and conditions for the fully projected future test year for the twelve months ending

September 30, 2017 ("FPFTY"). The data in the exhibit include a description of the methods and procedures used in the study, the allocations of cost of service and measure of value, the factors on which the allocations were based and an analysis of customer costs.

Q. Please outline the procedure that you followed in the first cost allocation study.

A. The detailed allocation of costs to cost functions and service classifications is presented in Schedule E, pages 10 through 13, of UGI Gas Exhibit D. Gas costs are excluded from the amounts in Schedule E in order to develop costs by function and classification related to the delivery of gas.

In the detailed allocation, the items of cost, which include operating expenses, depreciation expense, taxes, and income available for return, are identified in column 1 of Schedule E. The cost of each item, shown in column 3, is allocated to the several service classifications: Residential (R and RT), Non-Residential (N and NT), Delivery Service (DS), Large Firm Delivery Service (LFD), Extended Large Firm Delivery Service (XD), and Interruptible Service (XD-I, IS and IL).

The allocation factor codes entered in column 2 enable one to determine the specific basis for the allocation of each item. The factor codes refer to the information presented in Schedule F, beginning on page 14, of the exhibit.

Q. Please explain the allocation of some of the large cost items in the study.

A. Referring to some of the larger delivery cost items, transmission costs and costs associated with measuring and regulating stations were allocated partly on the basis of average daily volumes and partly on the basis of demand in excess of average, or extra demand, inasmuch as the function of these facilities is to meet peak requirements.

The costs related to distribution mains were first directly assigned to XD-Firm and XD-Interruptible customers based on an analysis of the mains and the proportion thereof serving each individual XD customer. The methods and procedures used to determine the portion of mains directly assigned to XD customers were provided by Company personnel. The remaining cost of mains was separated into small mains (2-inch and smaller) and large mains (over 2-inch). Small mains were allocated to the Rate R, N, DS, a portion of LFD, and small Interruptible (IS) classes based on the average and extra capacity demand for each classification. Only 19% of the LFD consumption was used for the allocation of small mains, inasmuch as only 19% of the customers utilize mains that are 2-inch and smaller. Large mains were allocated in the same manner except only the volumes for XD-Firm and XD-I customers were excluded.

Customers under Rate XD were excluded from the allocation of small and large distribution mains since XD customers were directly assigned the cost of mains serving them, as explained above. Interruptible volumes were removed from the extra capacity calculations as these volumes can be curtailed during periods of peak demand.

Costs related to service lines in Account 380 were allocated to classes, after a direct assignment to each of the XD customers, based on the cost of service lines by size and the number of customers in each class. Costs related to meters in Account 381 and the associated house regulators were allocated to the R, N, DS, and Interruptible service classifications on the basis of the cost of meters for each class and the number of customers. Costs related to industrial measuring and regulating in Account 385, after a direct assignment to XD customers, were allocated to the N, LFD and Interruptible

Service classes based on the cost of measuring and regulating equipment assigned to each class.

Q. Please explain the allocation of uncollectible accounts and customer assistance expenses.

A. Uncollectible accounts associated with the gas cost portion are allocated consistent with the recovery of such costs through the Merchant Function Charge (Rider D). The remaining uncollectible account cost is recovered based on an analysis of write-offs. Costs associated with customer assistance programs are allocated directly to the residential class.

Q. Please describe the allocation of customer accounting costs and the remaining cost of service elements.

A. Customer accounting costs were allocated to service classifications on the basis of the number of customers. Administrative and general costs were allocated on the basis of the allocated direct operation and maintenance costs, excluding gas production expenses those costs being allocated.

Annual depreciation accruals were allocated on the basis of the function of the facilities represented by the depreciation expense for each depreciable plant account. Similarly, certain taxes other than income taxes, income taxes and income available for return were allocated on the basis of allocated rate base, including the original cost less accrued depreciation of utility plant in service and other rate base elements.

Q. What are the results of the cost of service allocation study?

A. The results of the cost of service allocation set forth in Schedule E are brought forward and summarized in Schedule D. The total cost of service by classification in Schedule D is then brought forward to Schedule A (without gas costs), columns 2 and 3, where these results are compared to the *pro forma* revenues under present rates (columns 4 and 5) and proposed rates (columns 6 and 7). The proposed change in revenue under proposed rates and the percent change are shown in columns 8 and 9 of Schedule A. Please refer to the direct testimony of Paul Szykman (UGI Gas Statement No. 1) and the direct testimony David Lahoff (UGI Gas Statement No. 6) for an explanation of the proposed rate design and revenue distribution.

Q. Did you prepare a schedule showing the rate of return by classification?

A. Yes. Schedule B sets forth the rate of return by classification under present rates, and Schedule C shows the rate of return by classification under proposed rates.

Q. Did you prepare an analysis of customer costs?

A. Yes. I prepared a fully allocated customer cost analysis and a direct customer cost analysis. Both analyses of customer costs are presented in Schedule G of UGI Gas Exhibit D.

Q. Please explain the analysis of customer costs as set forth in UGI Gas Exhibit D.

A. The customer costs were determined by allocating the cost of service to cost functions and to service classifications. The volumetric and customer functional costs were determined by an allocation of the total cost of service to these functions in Schedule E of UGI Gas Exhibit D. The customer costs were further allocated to the R, N, DS, LFD, XD, and Interruptible Service classifications in the same schedule. The factors that were the bases for the allocation to cost functions and the allocation of customer costs to classifications are presented in Schedule F. A summary of the customer costs and the development of the costs per customer per month are presented in Schedule G.

Q. Did you prepare an analysis of costs related to the demand charge for rate LFD and XD Service?

A. Yes. The analysis of costs related to the demand charges for LFD and XD Service is presented in Schedule H of UGI Gas Exhibit D.

Q. Please explain the analysis of the LFD and XD Service costs related to demand charges as set forth in UGI Gas Exhibit D.

A. The costs related to LFD and XD Service demand charges were determined by the allocation of certain fixed costs, depreciation, taxes and return to these classifications. The allocation was performed in Schedule E. A summary of the allocated costs and the development of the unit demand costs are presented in Schedule H.

Q. Please describe the second cost of service study in Exhibit D-1.

A. The second cost of service study presented in Exhibit D-1 is the same as the first study except for the allocation of mains investment. The second study does not allocate any mains investment to the interruptible class except for the directly assigned mains identified for the large XD-Interruptible customer. As a result of this change in allocation of mains investment, composite allocation factors also change.

Q. What is the rationale for not allocating any mains investment to the interruptible class?

A. The rationale for not allocating mains investment to interruptible customers is based on the cost allocation premise that costs should be allocated based on the design of the system facilities. The distribution system was designed to meet peak day requirements for firm customers only. Interruptible customers would have no usage on the design peak day as their volumes would be curtailed. The Company's investment in mains would be the same whether or not there were interruptible customers on the system. Therefore, allocating all mains investment to firm customers is reasonable.

Q. Please summarize the results of the second cost of service study.

A. The results of the second cost of service allocation (Exhibit D-1) set forth in Schedule E-1 are brought forward and summarized in Schedule D-1. The total cost of service by classification in Schedule D-1 is then brought forward to Schedule A-1 (without gas costs), columns 2 and 3, where these results are compared to the pro forma revenues under present rates (columns 4 and 5) and proposed rates (columns 6 and 7). The proposed change in revenue under proposed rates and the percent change are shown in columns 8 and 9 of Schedule A-1. Schedule B-1 and Schedule C-1 present the rate of return by classification under present rates and proposed rates, respectively.

Q. Please explain Exhibit D-2.

A. Exhibit D-2 presents the simple average of the cost allocation studies from Exhibits D and D-1. Exhibit D-2 sets forth the summary of the average cost or service by classification in Schedule A-2 (columns 2 and 3) compared to revenues under present and proposed rates, as well as the rate of return based on the average cost of service allocation under present rates in Schedule B-2 and under proposed rates in Schedule C-2.

Q. Does that conclude your direct testimony?

A. Yes, it does.

LIST OF CASES IN WHICH PAUL R. HERBERT TESTIFIED

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
1.	1983	Pa. PUC	R-832399	T. W. Phillips Gas and Oil Co.	Pro Forma Revenues
2.	1989	Pa. PUC	R-891208	Pennsylvania-American Water Company	Bill Analysis and Rate Application
3.	1991	PSC of W. Va.	91-106-W-MA	Clarksburg Water Board	Revenue Requirements (Rule 42)
4.	1992	Pa. PUC	R-922276	North Penn Gas Company	Cash Working Capital
5.	1992	NJ BPU	WR92050532J	The Atlantic City Sewerage Company	Cost Allocation and Rate Design
6.	1994	Pa. PUC	R-943053	The York Water Company	Cost Allocation and Rate Design
7.	1994	Pa. PUC	R-943124	City of Bethlehem	Revenue Requirements, Cost Allocation, Rate Design and Cash Working Capital
8.	1994	Pa. PUC	R-943177	Roaring Creek Water Company	Cash Working Capital
9.	1994	Pa. PUC	R-943245	North Penn Gas Company	Cash Working Capital
10.	1994	NJ BPU	WR94070325	The Atlantic City Sewerage Company	Cost Allocation and Rate Design
11.	1995	Pa. PUC	R-953300	Citizens Utilities Water Company of Pennsylvania	Cost Allocation and Rate Design
12.	1995	Pa. PUC	R-953378	Apollo Gas Company	Revenue Requirements and Rate Design
13.	1995	Pa. PUC	R-953379	Carnegie Natural Gas Company	Revenue Requirements and Rate Design
14.	1996	Pa. PUC	R-963619	The York Water Company	Cost Allocation and Rate Design
15.	1997	Pa. PUC	R-973972	Consumers Pennsylvania Water Company - Shenango Valley Division	Cash Working Capital
16.	1998	Ohio PUC	98-178-WS-AIR	Citizens Utilities Company of Ohio	Water and Wastewater Cost Allocation and Rate Design
17.	1998	Pa. PUC	R-984375	City of Bethlehem - Bureau of Water	Revenue Requirement, Cost Allocation and Rate Design
18.	1999	Pa. PUC	R-994605	The York Water Company	Cost Allocation and Rate Design
19.	1999	Pa. PUC	R-994868	Philadelphia Suburban Water Company	Cost Allocation and Rate Design
20.	1999	PSC of W.Va.	99-1570-W-MA	Clarksburg Water Board	Revenue Requirements (Rule 42), Cost Allocation and Rate Design
21.	2000	Ky. PSC	2000-120	Kentucky-American Water Company	Cost Allocation and Rate Design
22.	2000	Pa. PUC	R-00005277	PPL Gas Utilities	Cash Working Capital
23.	2000	NJ BPU	WR00080575	Atlantic City Sewerage Company	Cost Allocation and Rate Design
24.	2001	Ia.St Util Bd	RPU-01-4	Iowa-American Water Company	Cost Allocation and Rate Design
25.	2001	Va. St. Corp	PUE010312	Virginia-American Water Company	Cost Allocation and Rate Design
26.	2001	WV PSC	01-0326-W-42T	West-Virginia American Water Company	Cost Allocation And Rate Design
27.	2001	Pa. PUC	R-016114	City of Lancaster	Tapping Fee Study
28.	2001	Pa. PUC	R-016236	The York Water Company	Cost Allocation and Rate Design
29.	2001	Pa. PUC	R-016339	Pennsylvania-American Water Company	Cost Allocation and Rate Design
30.	2001	Pa. PUC	R-016750	Philadelphia Suburban Water Company	Cost Allocation and Rate Design
31.	2002	Va.St.CorpCm	PUE-2002-00375	Virginia-American Water Company	Cost Allocation and Rate Design
32.	2003	Pa. PUC	R-027975	The York Water Company	Cost Allocation and Rate Design
33.	2003	Tn Reg.Auth	03-	Tennessee-American Water Company	Cost Allocation and Rate Design
34.	2003	Pa. PUC	R-038304	Pennsylvania-American Water Company	Cost Allocation and Rate Design
35.	2003	NJ BPU	WR03070511	New Jersey-American Water Company	Cost Allocation and Rate Design
36.	2003	Mo. PSC	WR-2003-0500	Missouri-American Water Company	Cost Allocation and Rate Design
37.	2004	Va St.CorpCm	PUE-200 -	Virginia-American Water Company	Cost Allocation and Rate Design
38.	2004	Pa. PUC	R-038805	Pennsylvania Suburban Water Company	Cost Allocation and Rate Design
39.	2004	Pa. PUC	R-049165	The York Water Company	Cost Allocation and Rate Design
40.	2004	NJ BPU	WRO4091064	The Atlantic City Sewerage Company	Cost Allocation and Rate Design
41.	2005	WV PSC	04-1024-S-MA	Morgantown Utility Board	Cost Allocation and Rate Design
42.	2005	WV PSC	04-1025-W-MA	Morgantown Utility Board	Cost Allocation and Rate Design
43.	2005	Pa. PUC	R-051030	Aqua Pennsylvania, Inc.	Cost Allocation and Rate Design

LIST OF CASES IN WHICH PAUL R. HERBERT TESTIFIED

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
44.	2006	Pa. PUC	R-051178	T. W. Phillips Gas and Oil Co.	Cost Allocation and Rate Design
45.	2006	Pa. PUC	R-061322	The York Water Company	Cost Allocation and Rate Design
46.	2006	NJ BPU	WR-06030257	New Jersey American Water Company	Cost Allocation and Rate Design
47.	2006	Pa. PUC	R-061398	PPL Gas Utilities, Inc.	Cost Allocation and Rate Design
48.	2006	NM PRC	06-00208-UT	New Mexico American Water Company	Cost Allocation and Rate Design
49.	2006	Tn Reg Auth	06-00290	Tennessee American Water Company	Cost Allocation and Rate Design
50.	2007	Ca. PUC	U-339-W	Suburban Water Systems	Water Conservation Rate Design
51.	2007	Ca. PUC	U-168-W	San Jose Water Company	Water Conservation Rate Design
52.	2007	Pa. PUC	R-00072229	Pennsylvania American Water Company	Cost Allocation and Rate Design
53.	2007	Ky. PSC	2007-00143	Kentucky American Water Company	Cost Allocation and Rate Design
54.	2007	Mo. PSC	WR-2007-0216	Missouri American Water Company	Cost Allocation and Rate Design
55.	2007	Oh. PUC	07-1112-WS-AIR	Ohio American Water Company	Cost Allocation and Rate Design
56.	2007	Il. CC	07-0507	Illinois American Water Company	Customer Class Demand Study
57.	2007	Pa. PUC	R-00072711	Aqua Pennsylvania, Inc.	Cost Allocation and Rate Design
58.	2007	NJ BPU	WR07110866	The Atlantic City Sewerage Company	Cost Allocation and Rate Design
59.	2007	Pa. PUC	R-00072492	City of Bethlehem – Bureau of Water	Revenue Requirements, Cost Alloc.
60.	2007	WV PSC	07-0541-W-MA	Clarksburg Water Board	Cost Allocation and Rate Design
61.	2007	WV PSC	07-0998-W-42T	West Virginia American Water Company	Cost Allocation and Rate Design
62.	2008	NJ BPU	WR08010020	New Jersey American Water Company	Cost Allocation and Rate Design
63.	2008	VaStCorpCom	Pue-2008-00009	Virginia American Water Company	Cost Allocation and Rate Design
64.	2008	Tn. Reg. Auth.	08-00039	Tennessee American Water Company	Cost Allocation and Rate Design
65.	2008	Mo PSC	WR-2008-0311	Missouri American Water Company	Cost Allocation and Rate Design
66.	2008	De PSC	08-96	Artesian Water Company, Inc.	Cost Allocation and Rate Design
67.	2008	Pa PUC	R-2008-2032689	Penna. American Water Co. – Coatesville Wastewater	Cost Allocation and Rate Design
68.	2008	AZ Corp. Com.	W-01303A-08-0227 SW-01303A-08-0227	Arizona American Water Co. - Water - Wastewater	Cost Allocation and Rate Design
69.	2008	Pa PUC	R-2008-2023067	The York Water Company	Cost Allocation and Rate Design
70.	2008	WV PSC	08-0900-W-42T	West Virginia American Water Company	Cost Allocation and Rate Design
71.	2008	Ky PSC	2008-00250	Frankfort Electric and Water Plant Board	Cost Allocation and Rate Design
72.	2008	Ky PSC	2008-00427	Kentucky American Water Company	Cost Allocation and Rate Design
73.	2009	Pa PUC	2008-2079660	UGI – Penn Natural Gas	Cost of Service Allocation
74.	2009	Pa PUC	2008-2079675	UGI – Central Penn Gas	Cost of Service Allocation
75.	2009	Pa PUC	2009-2097323	Pennsylvania American Water Co.	Cost Allocation and Rate Design
76.	2009	Ia St Util Bd	RPU-09-	Iowa-American Water Company	Cost Allocation and Rate Design
77.	2009	Il CC	09-0319	Illinois-American Water Company	Cost Allocation and Rate Design
78.	2009	Oh PUC	09-391-WS-AIR	Ohio-American Water Company	Cost Allocation and Rate Design
79.	2009	Pa PUC	R-2009-2132019	Aqua Pennsylvania, Inc.	Cost Allocation and Rate Design
80.	2009	VaStCorpCom	PUC-00059	Aqua Virginia, Inc.	Cost Allocation (only)
81.	2009	Mo PSC	WR-2010-0131	Missouri American Water Company	Cost Allocation and Rate Design
82.	2010	VaStCorpCom	2010-00001	Virginia American Water Company	Cost Allocation and Rate Design
83.	2010	Ky PSC	2010-00036	Kentucky American Water Company	Cost Allocation and Rate Design
84.	2010	NJ BPU	WR10040260	New Jersey American Water Company	Cost Allocation and Rate Design
85.	2010	Pa PUC	2010-	T.W. Phillips Gas and Oil Co.	Cost Allocation and Rate Design
86.	2010	Pa PUC	2010-2166212	Pennsylvania American Water Co. - Wastewater	Cost Allocation and Rate Design
87.	2010	Pa PUC	R-2010-2157140	The York Water Company	Cost Allocation and Rate Design
88.	2010	Ky PSC	2010-00094	Northern Kentucky Water District	Cost Allocation and Rate Design
89.	2010	WV PSC	10-0920-W-42T	West Virginia American Water Co.	Cost Allocation and Rate Design
90.	2010	Tn Reg Auth	10-00189	Tennessee American Water Company	Cost Allocation and Rate Design
91.	2010	Ct PU Rg Ath	10-09-08	United Water Connecticut	Cost Allocation and Rate Design
92.	2010	Pa PUC	R-2010-2179103	City of Lancaster-Bureau of Water	Rev Rqmts, Cst Alloc/Rate Design

LIST OF CASES IN WHICH PAUL R. HERBERT TESTIFIED

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
93.	2011	Pa PUC	R-2010-2214415	UGI Central Penn Gas, Inc.	Cost Allocation
94.	2011	Pa PUC	R-2011-2232359	The Newtown Artesian Water Co.	Revenue Requirement
95.	2011	Pa PUC	R-2011-2232243	Pennsylvania-American Water Co.	Cost Allocation and Rate Design
96.	2011	Pa PUC	R-2011-2232985	United Water Pennsylvania Inc.	Demand Study, COS/Rate Design
97.	2011	Pa PUC	R-2011-2244756	City of Bethlehem-Bureau of Water	Rev. Rqmts/COS/Rate Design
98.	2011	Mo PSC	WR-2011-0337-338	Missouri American Water Company	Cost Allocation and Rate Design
99.	2011	Oh PUC	11-4161-WS-AIR	Ohio American Water Company	Cost Allocation and Rate Design
100.	2011	NJ BPU	WR11070460	New Jersey American Water Company	Cost Allocation and Rate Design
101.	2011	Id PUC	UWI-W-11-02	United Water Idaho Inc.	Cost Allocation and Rate Design
102.	2011	Il CC	11-0767	Illinois-American Water Company	Cost Allocation and Rate Design
103.	2011	Pa PUC	R-2011-2267958	Aqua Pennsylvania, Inc.	Cost Allocation and Rate Design
104.	2011	Va St Com	2011-00099	Aqua Virginia, Inc.	Cost Allocation
105.	2011	Va St Com	2011-00127	Virginia American Water Company	Cost Allocation and Rate Design
106.	2012	Tn RegAuth	12-00049	Tennessee American Water Company	Cost Allocation and Rate Design
107.	2012	Ky PSC	2012-00072	Northern Kentucky Water District	Cost Allocation and Rate Design
108.	2012	Pa PUC	R-2012-2310366	Lancaster, City of – Sewer Fund	Cost Allocation and Rate Design
109.	2012	Ky PSC	2012-00520	Kentucky American Water Co.	Cost Allocation and Rate Design
110.	2013	WV PSC	12-1649-W-42T	West Virginia American Water Co.	Cost Allocation and Rate Design
111.	2013	Ia St Util Bd	RPU-2013-000_	Iowa American Water Company	Cost Allocation and Rate Design
112.	2013	Pa PUC	R-2013-2355276	Pennsylvania American Water Co.	Cost Allocation and Rate Design
113.	2013	Pa PUC	R-2012-2336379	The York Water Company	Cost Allocation and Rate Design
114.	2013	Pa PUC	R-2013-2350509	City of DuBois – Bureau of Water	Cost Allocation and Rate Design
115.	2013	Pa PUC	R-2013-2390244	City of Bethlehem – Bureau of Water	Cost Allocation and Rate Design
116.	2014	Pa PUC	R-2014-2418872	City of Lancaster – Bureau of Water	Cost Allocation and Rate Design
117.	2014	Pa PUC	R-2014-2428304	Borough of Hanover	Cost Allocation and Rate Design
118.	2014	Va St Com	2014-00045	Aqua Virginia, Inc.	Cost Allocation
119.	2015	NJ BPU	WR15010035	New Jersey American Water Company	Cost Allocation and Rate Design
120.	2015	Pa PUC	R-2015-2462723	United Water PA	Cost Allocation and Rate Design
121.	2015	WV PSC		West Virginia American Water Company	Cost Allocation and Rate Design
122.	2015	Id PUC	UWI-W-15-01	United Water Idaho Inc.	Pro Forma Revenues

UGI GAS STATEMENT NO. 5 – JOHN F. WIEDMAYER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2015-2518438

UGI Utilities, Inc. – Gas Division

Statement No. 5

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

Topics Addressed: **Depreciation**

Date: January 19, 2016

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DIRECT TESTIMONY OF

JOHN F. WIEDMAYER

DOCKET NO. R-2015-2518438

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 a Bachelor of Arts degree in Engineering 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 29 years of depreciation experience, which includes expert testimony in numerous cases before 12 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, 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, Maritime Electric, Nolin Rural Electric Cooperative, AmerenCIPS, AmerenCILCO, AmerenIP, 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., 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, and AmerenIP.

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 and the Pennsylvania Public Utility 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."

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 gas plant of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company"). I have been retained by the Company as a depreciation consultant. UGI Gas retained me to determine the book depreciation reserve as of September 30, 2017, 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 Gas's depreciated original cost of gas 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, 2017.

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 items in UGI Gas Exhibit I:

Item No.	Subject
I-A-3	Description of Depreciation Methods and Factors Considered in Arriving at Estimates of Service Life and Dispersion by Account
I-A-4	Survivor Curves and Surviving Original Cost Including Related Annual and Accrued Depreciation
I-A-5	Comparison of Calculated Reserve vs. Book Reserve
I-A-6	Survivor Curves and Annual Accrual Rates
I-A-7	Cumulative Depreciated Original Cost by Vintage Year
I-A-17	Net Salvage

Q. Have you previously prepared comparable studies for UGI Gas?

A. Yes. I provided testimony on depreciation matters for the Company in a prior UGI Penn Natural Gas ("PNG") base rate case at Docket No. R-2008-2079660 and the prior two UGI Central Penn Gas ("CPG") base rate cases at Docket No. R-2010-2214415 and Docket No. R-2008-2079675. 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 attaching and sponsoring the following exhibits: UGI Gas Exhibit C (Fully Projected), UGI Gas Exhibit C (Future) and UGI Gas Exhibit C (Historic). UGI Gas Exhibit C (Fully Projected) presents the summarized depreciation calculations and supporting tables related to the fully projected future test year ending September 30, 2017 ("FPFTY"). UGI Gas 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, 2016 ("FTY"). UGI Gas Exhibit C (Historic) presents the summarized depreciation calculations and supporting tables related to the historic test year ended September 30, 2015 ("FTY"). 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 Gas Exhibit C (Future) contains additional information including the supporting charts and life tables related to the service life estimates.

Q. Does UGI Gas Exhibit C (Fully Projected) accurately portray the results of your depreciation study as of September 30, 2017?

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 Gas Exhibit C (Future) and UGI Gas Exhibit C (Fully Projected).

A. The depreciation study report in UGI Gas Exhibit C (Future) consists of eight parts including charts and tables filed in the Company's most recent service life study report submitted in 2012. 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, 2016. 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, 2016. 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 years 2012 through 2016.

UGI Gas 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, 2017. The descriptions and explanations presented in UGI Gas Exhibit C (Future) are also applicable to the depreciation calculations presented in UGI Gas Exhibit C (Fully Projected). The graphs and tables related to service life presented in UGI Gas

Exhibit C (Future) also support the service life estimates used in UGI Gas Exhibit C (Fully Projected) and UGI Gas Exhibit C (Historic), inasmuch as the estimates are the same for all three test years.

The results of the study are set forth in Part II in UGI Gas Exhibit C (Fully Projected). Table 1, pages II-3 through II-4 of UGI Gas Exhibit C (Fully Projected), presents the estimated survivor curve, the original cost and depreciation reserve at September 30, 2017, and the calculated annual depreciation rate and amount for each account or subaccount of Gas Plant in Service. Table 2, pages II-5 through II-6 of UGI Gas Exhibit C (Fully Projected), presents the bringforward to September 30, 2017, of the depreciation reserve as of September 30, 2016. Table 3, pages II-7 through II-8 of UGI Gas Exhibit C (Fully Projected), presents the calculation of the book depreciation amounts for the FPFTY. Table 4, pages II-9 through II-10 of UGI Gas Exhibit C (Fully Projected), presents the experienced and estimated net salvage for fiscal years 2013 through 2017. The amortization of net salvage is based on experienced and estimated net salvage during the period October 1, 2012 through September 30, 2017. The summary tables and detailed depreciation calculations set forth in UGI Gas Exhibit C (Fully Projected) as of September 30, 2017, are organized and presented in the same manner as those presented in UGI Gas Exhibit C (Future) as of September 30, 2016.

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

A. UGI Gas Exhibit C (Historic) is organized similar to UGI Gas Exhibit C (Fully Projected). UGI Gas 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, 2015. The descriptions and explanations presented in UGI Gas Exhibit C (Future) are also applicable to the depreciation calculations presented in UGI Gas 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, 2015, are organized and presented in the same manner as those as of September 30, 2017 with two exceptions. Tables 2 and 3 presented in UGI Gas Exhibit C (Fully Projected) are not necessary and, therefore, are not presented in UGI Gas Exhibit C (Historic).

IV. <u>THE DEPRECIATION STUDY - OVERVIEW</u>

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 Uniform System of Accounts prescribed for Class A and Class B Natural Gas Companies. "Depreciation" refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas 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, requirements of public authorities and the exhaustion of natural resources.

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 Report filed in March 2015 and service life study filed in March 2012?

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 over thirty years. The depreciation methods and procedures are described further in Part II of UGI Gas 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. <u>ORIGINAL COST MEASURE OF VALUE</u>

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

A. As of September 30, 2017, the original cost of gas plant in service is $1,649,567,804 as shown in column 3 of Table 1 on pages II-3 through II-4 of UGI Gas Exhibit C (Fully Projected). This amount includes $1,591,515,234 of Gas Plant and $58,052,570 of Other Utility Plant allocated to Gas Division. 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 the divisions at UGI Corporation including UGI Gas. The costs related to Common Plant and IS are allocated to Gas Division at 15.36 percent and 48.83 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 relates to IS, a portion of the cost attributable to the other three utility divisions was deducted from the Reading Office and Service Building.

VI. THE ACCRUED DEPRECIATION CLAIM

Q. Have you determined UGI Gas's accrued depreciation for ratemaking purposes as of September 30, 2017?

A. Yes. I have determined the allocated book depreciation reserve as of September 30, 2017, to be $448,735,746.

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 proceeding.

Q. How did you determine UGI Gas's allocated book depreciation reserve as of September 30, 2016?

A. The book depreciation reserve allocated to Gas Division as of September 30, 2016, is set forth in column 4 of Table 1 of UGI Gas Exhibit C (Future). Table 2 of UGI Gas Exhibit C (Future) is an annual bringforward of the book depreciation reserve as of September 30, 2015, using estimated accruals, retirements, salvage and cost of removal for the twelve months October 2015 through September 2016. The table sets forth, by plant account, the beginning book reserve balance as of September 30, 2015, the estimated reserve activity, and the ending reserve balance as of September 30, 2016. 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 Gas 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, 2015, by plant account, shown in column 2 of Table 2 was obtained from UGI Gas's books and records.

Q. Please explain the manner in which you projected the depreciation accruals for the twelve months ended September 30, 2016.

A. The depreciation accruals for the twelve months ended September 30, 2016, by plant account, were estimated by applying the annual depreciation accrual rates calculated as of September 30, 2015, to the projected average 2016 plant balance. The average balance for the twelve months ended September 30, 2016, 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 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 net salvage during the preceding five-year period, October 1, 2010 through September 30, 2015.

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, for the five years 2011 through 2015, to FTY and FPFTY 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, as a percent of retirement amounts, for the five years 2011 through 2015, to the projected retirement amounts.

Q. Was the book reserve at September 30, 2017, 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 2017 were based on applying the depreciation rate to average monthly plant balances for purposes of calculating the book reserve as of September 30, 2017.

VII. THE ANNUAL DEPRECIATION EXPENSE CLAIM

Q. Have you determined UGI Gas'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 $43,825,948 and consists of $38,830,444 of annual accruals to recover original cost and $4,995,504 of net salvage amortization. These amounts are set forth in column 6 of Table 1 in UGI Gas Exhibit C (Fully Projected).

Q. How did you determine the annual accruals of $38,830,444?

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 consisted of: compiling historical data from records related to UGI Gas's gas plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning UGI Gas's practices and plans as they relate to plant operations; and interpreting the above data 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 Gas's gas plant?

A. The data consisted of the entries made by UGI Gas to record gas plant transactions during the period 1960 through 2011. 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 Gas 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 35-R2 curve indicates an average service life of thirty-five years; a Right-skewed, or R, type curve (the mode occurs after average life for right modal curves); and a relatively low height, 2, 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 Pennsylvania Public Utility Commission ("PA PUC") every five years, at minimum. UGI Gas's most recent service life study report was submitted in March 2012. Facilities visited during field trips, generally include representative city gate stations, district regulating stations, service centers, etc. The most recent field trip was conducted over 3 days in December 2011. 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 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 Gas Exhibit C (Historic), UGI Gas Exhibit C (Future) and UGI Gas Exhibit C (Fully Projected). The detailed tabulations of the depreciation calculations are presented in Part III of UGI Gas Exhibit C (Historic) and UGI Gas Exhibit C (Fully Projected) and Part VII of UGI Gas 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.

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 gas 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. All units are retired per books when the age of the vintage reaches the amortization period.

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 Gas Exhibit C (Future) using an account as an example.

A. I will use Account 376.1, Mains – Primarily Steel, to illustrate the manner in which the study was conducted. Account 376.1 represents 14 percent of the total depreciable gas plant. As the initial step of the service life study phase, aged plant accounting data were compiled for the years 1960 through 2011.

These data have been coded in the course of UGI Gas's normal recordkeeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the gas 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 primarily cathodically-protected, steel mains, although some bare steel mains are still in service. The Iowa 72-R2.5 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 also the Iowa 72-R2.5 survivor curve. The Iowa 72-R2.5 survivor curve is an excellent fit for the original curve based on the company's retirement experience for the period 1960-2011. The proposed 72-R2.5 survivor curve is within the range of estimates used by other gas companies and is consistent with the outlook of company management. The original and smooth survivor curves are plotted in Part VI on page VI-7 of UGI Gas Exhibit C (Future). The original life table for the 1960-2011 experience band is set forth on pages VI-8 through VI-10.

The calculation of annual depreciation, the second phase, for the original cost of steel mains in service at September 30, 2016, is presented by vintage in Part VII on pages VII-19 through VII-21 of UGI Gas Exhibit C (Future) for Gas Plant in Service. The detailed depreciation calculations at September 30, 2017 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 72-R2.5 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 72-R2.5 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 72-R2.5 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 Gas Exhibit C (Future) was brought forward to column 7 of Table 1 on page V-4 of the exhibit and divided by the total original cost in column 3 in order to calculate the annual depreciation accrual rate in column 6. A similar process was used for the FPFTY.

Q. Is the procedure you described for Account 376.1 typical of that followed

for most of the plant investment?

A. Yes, it is, inasmuch as the straight line method and 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 Gas 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, 2016, is presented by vintage in Part VII on page VII-72 of UGI Gas 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-72 of UGI Gas Exhibit C (Future) was brought forward to column 7 of Table 1 on page V-4 of UGI Gas Exhibit C

(Future). A similar process was performed for UGI Gas Exhibit C (Fully Projected) and UGI Gas 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, 2017, is presented by vintage on page III-72 of UGI Gas 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 Gas Exhibit C (Historic) and UGI Gas Exhibit C (Fully Projected) and in Part VII of UGI Gas 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 Gas's annual depreciation expense consists, in part, of $4,995,504 of net salvage amortization. How did you determine that amount?

A. The $4,995,504 is the result of determining the five-year average of net salvage experienced and estimated during the period of October 1, 2012 through September 30, 2017. Net salvage is defined in the Uniform System of Accounts as gross salvage less cost of removal. For most gas utilities, including UGI Gas, cost of removal exceeds gross salvage 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 Gas Exhibit C (Future) and Part IV of UGI Gas 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 I-A-5, I-A-6, and I-A-7. In general, these responses are self-explanatory. The response to I-A-5 is a comparison of the actual and projected book depreciation reserve with the calculated accrued depreciation as of the end of the historic and future test years. The response to I-A-6 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. The response to I-A-7 is the cumulative depreciated original cost by installation year as of the end of the test years. The amounts requested in response to I-A-7 are set forth in UGI Gas Exhibit C (Historic) and UGI Gas Exhibit C (Future) in the section titled “Cumulative Depreciated Original Cost”.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS STATEMENT NO. 6 – DAVID E. LAHOFF

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2015-2518438

UGI Utilities, Inc. – Gas Division

Statement No. 6

Direct Testimony of
David E. Lahoff

Topics Addressed: **Test Years Sales/Revenues**
Rate Structure
EE&C Rider
USP Rider
Revenue Allocation and Rate Design
GET Gas Reporting
Tariff Changes

Dated: January 19, 2016

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David E. Lahoff. My current 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 by UGI Utilities, Inc. ("UGI") as Manager, Tariff & Supplier Administration.

Q. Please provide your educational background.

A. I received an undergraduate degree in business from The Pennsylvania State University and a Masters 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 Manager, Tariff & Supplier Administration.

Q. What are your current areas of responsibility?

A. My current responsibilities include (1) all aspects of tariff and rate administration, including interactions with natural gas suppliers under our natural gas supplier tariffs, (2) revenue planning and (3) oversight of UGI's gas management system.

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 Utilities, Inc. – Gas Division ("UGI Gas" or the "Company") 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; and UGI Utilities, Inc. - Electric Division Default Service Filing, Docket No. P-2013-2357013.

Q. Please describe the purpose of your testimony.

A. I will address: (1) development of the historic test year ended September 30, 2015 ("HTY"), future test year ending September 30, 2016 ("FTY"), and fully projected future test year ending September 30, 2017 ("FPFTY"), sales and revenues, including use per customer adjustments due to energy savings from the proposed Energy Efficiency and

Conservation ("EE&C") Plan; (2) rate structure, including elimination of certain rate schedules, and the new EE&C Rider and Universal Service Program ("USP") Rider; (3) revenue allocation and rate design; (4) update to the GET Gas Pilot Program; and (5) 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 Gas Exhibit DEL-1 (15 year normal heating degree days); UGI Gas Exhibit DEL-2 (Multi-year Normal Trend of use per customer – residential and non-residential); UGI Gas Exhibit DEL-3 (FPFTY Sales and Revenue Adjustments); UGI Gas Exhibit DEL-4 (FTY Sales and Revenue Adjustments); UGI Gas Exhibit DEL-5 (HTY Sales and Revenue Adjustments); UGI Gas Exhibit DEL-6 (Detail of Usage per Customer by Class as shown on UGI Gas Exhibit DEL-3); UGI Gas Exhibit DEL-7 (Calculation of EE&C Rider); UGI Gas DEL-8 (Calculation of the USP Rider and the Adjustment to Annual USP Reconciliation); UGI Gas Exhibit DEL-9 (Rate NNS calculation); UGI Gas Exhibit DEL-10 (Rate MBS calculation); UGI Gas Exhibit DEL-11 (Recalculation of GPC); UGI Gas Exhibit DEL-12 (Recalculation of MFC percentages); UGI Gas Exhibit DEL-13 (Recalculation of GET Surcharge); UGI Gas Exhibit DEL-14 (Calculation of GET Gas Revenues); and Schedules D-5A and D-5B of UGI Gas Exhibit A. I am also sponsoring those responses to the Commission's filing requirements and standard data requests where my name is indicated as the sponsoring witness.

II. SALES AND REVENUES

A. Development of FPFTY Sales and Revenues

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

A. FPFTY sales and revenues were developed by annualizing and normalizing the Company's 2017 fiscal year planned sales and revenue budget, adjusted to reflect the most recently available growth forecast. Annualized sales were determined by developing sales and revenue adjustments reflective of projected customer counts and annual expected use per customer as of September 30, 2017 for a full twelve- month period by reviewing historic usage data and applying regression analysis techniques. Both the Company's 2017 fiscal year planned sales and revenue budget and the Company's FPFTY reflect normal heating degree days of 5,214 based upon an average over a fifteen year period ending December 31, 2014. UGI Gas Exhibit DEL-1 provides the supporting calculation of the normal degree days utilized.

Q. Is the use of average temperature data for a fifteen-year period consistent with the methodology used by PNG and CPG for calculating normal heating degree days in previous base rate cases?

A. Yes. PNG used a fifteen-year period to develop normal heating degree days in its 2009 base rate case, and CPG used this methodology in its 2009 and 2011 base rate cases.

Q. Please explain the process for developing the Company's fiscal year 2017 planned sales and revenue budget.

A. The planned sales and revenue budget is a joint effort of the Marketing and Rates Departments, with Marketing providing customer growth and attrition information by customer class along with specific large commercial and industrial sales and revenue budget projections. The Rates Department develops normalized usage per customer for core customer classes, annualized sales and total revenues. The budget process is described in the direct testimony of Company witness Ann P. Kelly (UGI Gas Statement No. 2).

In developing sales and revenues, the Vice President, Marketing and Customer Relations, with input and assistance from other marketing employees, budgets the number of customers by class. Various factors are considered in developing customer budgets, including: the trend in losses and conversions to and from other energy sources; the level of applications and inquiries for service, new construction activity; current and projected economic factors; and the costs of competing fuels. The usage per customer reflected in the planned 2017 budget was developed by carrying forward the same levels of usage per customer derived for the fiscal year 2016 budget, which were developed using normalized twelve-month trends for the period ending March 2015 incorporating historic actual weather and actual usage per customer class, to develop projected customer usage under normal weather conditions. Planned budgeted numbers of customers and usage per customer for these customer classes are then combined to produce planned budgeted sales. Sales are allocated by month, and appropriate rates or rate blocking are applied to derive planned budgeted revenues. Sales and revenues related to large contract customer classes are developed by the Marketing Department on a customer specific basis using customer input where appropriate.

The derivation of the 2017 planned budget reflects a preliminary forecast which will be subsequently updated during 2016 as part of the normal budget process, which is conducted several months prior to the start of the new fiscal year. The methodology applied to develop normalized FPFTY use per customer, FTY use per customer, and HTY use per customer is the same for all three periods. In particular, the methodology used is appropriate for ratemaking purposes given the longer term period over which new rates are likely to be in effect as compared to the Company's typical budget, which is shorter term in nature.

Q. Please describe the adjustments made to FPFTY year sales and revenues for the twelve months ending September 30, 2017.

A. A summary of all adjustments made to the 2017 planned budget in order to develop FPFTY sales is shown on UGI Gas Exhibit DEL-3(a). In total, these adjustments reflect a reduction to sales of 5,606 MMcf and a reduction to revenue of $68.5 million.

Q. Please explain the "Adjustment for Customer Changes" shown on UGI Gas 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. In particular, this adjustment includes a net increase of 977 residential heating customers and a net increase of 161 non-residential heating customers.

Q. How is this adjustment quantified?

A. UGI Gas Exhibit DEL-3(b) provides the calculation of the associated sales and revenue adjustments for the stated customer count increases. In total, as reflected on UGI Gas Exhibit DEL-3(a), this adjustment increases sales by 0.093 MMcf and increases projected revenues by $0.8 million, inclusive of revenues for recovery of purchased gas costs (“PGC”) and exclusive of transportation customer adjustments discussed separately below.

Q. Please explain your next adjustment, “Adjustment for Annualized Use/Customer.”

A. The “Adjustment for Annualized Use/Customer” annualizes usage per customer to projected end of year test levels based on a twenty-one year regression analysis of actual usage and degree day information for the period from January 1995 through September 2015, and forecasts end of FPFTY use per customer conditions using the regression results along with normal heating degree days. The results can be seen in UGI Gas Exhibit DEL-3(c), resulting in a net sales decrease of 4.34 MMcf and a net revenue decrease of $33.1 million, inclusive of revenues for recovery of PGC and exclusive of transportation customer adjustments discussed separately below.

Q. Why did UGI Gas utilize a regression period of twenty one years?

A. Utilizing this approach provides a large enough sample set of data to smooth out short-term variations and capture the underlying long-term use per customer trend in order to more accurately project usage per customer during the period rates are likely to be in effect. Please see UGI Gas Exhibits DEL-2(a) and DEL-2(b), which contain graphs that illustrate the long-term usage trend for the Company’s core residential and commercial heating customers, and clearly show that, although there are short-term fluctuations which occur in certain periods, the values consistently revert to the long-term trend observed over this twenty-one period. In developing the data, the Company utilized an econometric regression model that incorporates four independent variables: use per customer, heating degree days, lagged heating degree days and time trend. While use per customer and heating degree days capture annualized usage factors based on projected annualized customer changes and weather defined by a normal standard, the time trend variable of this regression captures trends underlying changes in usage per customer over time. These trends can be varied, but as a comprehensive variable, "trend" will capture the impacts of conservation items and measures, including, but not limited to: (1) regular appliance replacements; (2) accelerated appliance replacements; (3) high-efficiency appliance installations; (4) setback thermostat installations; (5) modifications to new and existing buildings that are designed to decrease energy consumption; and (6) changes in consumer usage behavior due to other economic influences. Given the number of variables that can influence customer usage over time, and the difficulty in identifying, quantifying and tracking all variables over time, the use of a trend variable can be used to provide a comprehensive indicator of usages trends, which can then be used to forecast for a future period.

Q. Is the econometric model you described the same as the model utilized in the 2009 PNG, and 2009 and 2011 CPG base rate cases?

A. The econometric model uses the same set of variables, but uses twenty one years of data, as opposed to five years of data. In their base rate cases, CPG and PNG did not have access to as much historical data as the Company has in this proceeding. Therefore, CPG and PNG had to use a more abbreviated historical period. The twenty-one years of history are useful in identifying clear trends which should be evaluated for rate making purposes.

Q. Do the adjustments to use per customer for the FPFTY include the impact of Company's proposed EE&C Plan?

A. Yes. As part of its base rate filing, the Company is proposing to implement an EE&C Plan. The energy savings associated with the program will primarily occur in residential and small commercial customer usages. UGI Gas Exhibit DEL-3(m) shows the summary energy savings by Rates R, RT, N and NT, based on the five-year average annual savings for the program. The exhibit also contains the energy savings impact on a use per customer basis. The incremental impact on use per customer for Rates R and RT is 0.5 Mcf, and the incremental impact on use per customer for Rates N and NT is 1.5 Mcf. These incremental reductions in use per customer are included in the calculation of adjusted use per customer for the FPFTY. The buildup for the overall energy savings is addressed in the direct testimony of Company witness Theodore M. Love (UGI Gas Statement No. 11). This adjustment decreases total sales by 0.22 MMcf and reduces revenue by $1.5 million.

Q. Please explain the adjustment titled "Adjustment for Transport Changes" as shown on UGI Gas Exhibit DEL-3(a), 3(b), 3(b)1, 3(c), and 3(c)1.

A. The "Adjustment for Transport Changes" is the summation of several adjustments made for the Company's transportation customers for the FPFTY. This adjustment reduces projected sales by 1.1 MMcf and decreases revenues by $2.35 million, as shown in summary on UGI Gas Exhibit DEL-3(a) and detailed on UGI Gas Exhibits DEL-3(b), 3(b)1, 3(c) and 3(c)1 The adjustment for large transportation customers was developed by UGI Gas marketing personnel following their review of individual large customer accounts and market segments. It reflects anticipated increases or reductions from original fiscal year 2017 planned budget levels in the sales and revenues for these accounts. Changes in customer counts for small transportation customer classes have been developed from UGI Gas marketing forecasts for counts at the end of the FPFTY, and associated usage per customer for the small transportation customer groups were included within the 21-year regression analysis. See UGI Gas Exhibit DEL-6 for details on use per customer by class.

Q. Please explain the "Adjustment for PGC" shown on UGI Gas Exhibit DEL-3(a).

A. The "Adjustment for PGC" shown in summary on UGI Gas Exhibit DEL-3(a) represents an annualization of the FPFTY PGC revenues using the PGC rate in effect as of December 1, 2015 for the FPFTY period. UGI Gas Exhibit DEL-3(d) provides the calculations for this adjustment. This adjustment decreases PGC revenues for the FPFTY by $11.32 million.

Q. Please explain the three adjustments "Adjustment for MFC," "Adjustment for LISHP," and "Adjustment for GPC" shown in summary on UGI Gas Exhibit DEL-3(a).

A. The "Adjustment for MFC" annualizes Company's Merchant Function Charge ("MFC") revenues for the FPFTY based on the MFC surcharge rate in effect as of December 1, 2015. The "Adjustment for LISHP" annualizes Company's USP surcharge revenues for the FPFTY based on the Low Income Self Help Program ("LISHP") Rider rate in effect as of December 1, 2015. The "Adjustment for GPC" annualizes the Gas Procurement Cost ("GPC") revenues to reflect the volume variance to the original fiscal year 2017 planned budget. The MFC Adjustment decreases projected revenues by $184,000; the LISHP adjustment increases revenues by $2.0 million; and the GPC adjustment decreases revenues by $171,000. Additional details for these three adjustments are provided on UGI Gas Exhibits DEL-3(e), 3(f) and 3(g).

Q Please explain the "Adjustment for Interruptible."

A. The "Adjustment for Interruptible" annualizes the Company's interruptible revenues for the FPFTY at the level of revenue based on a proxy cost of service of $4.9 million. The methodology for this proxy cost of service is discussed by UGI Gas witnesses Paul J. Szykman (UGI Gas Statement No. 1) and Paul R. Herbert (UGI Gas Statement No. 4). In total, the Interruptible Adjustment decreases revenues by $15.7 million.

Q. Please explain the three adjustments shown on UGI Gas Exhibit DEL-3(a): "Adjustment for Transportation Service Revenues," "Adjustment for Excess Take" and "Adjustment for Rate N Minimum."

A. The "Adjustment for Transportation Service Revenues," detailed in UGI Gas Exhibit DEL-3(i), reflects the proposed elimination of the following capacity release and transportation service related fees: Pooling Fees, System Access Fees and Information Service Fees. It also assumes a zero level for Supply Transfer Fees given the very low level of transfer activity in prior years and the proposal to move a transaction base fee, rather than a volumetric based fee. The adjustments for transportation service revenues reduce revenue by $6.7 million. The "Adjustment for Excess Take," detailed in UGI Gas Exhibit DEL-3(j), reflects the assumption that customers will evaluate new service elections as part of the implementation of new tariff rates, and will make the necessary adjustments to avoid

Excess Take penalties in the FPFTY year. The Excess Take adjustment reduces revenue by $600,000.

The "Adjustment for Rate N Minimums," detailed in UGI Gas Exhibit DEL-3(l), reflects the proposed elimination of Rate N minimum bill requirements. The Rate N minimum adjustment reduces revenue by $1.3 million.

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

A. The "Adjustment for STAS" zeros out the current UGI Gas State Tax Adjustment Surcharge ("STAS") from its current level of (0.55%). The STAS adjustment increases projected revenues by $1.8 million.

Q Please explain the adjustment on UGI Gas Exhibit DEL-3(n) "Adjustment for GET Gas."

A. The "Adjustment for GET Gas" reflects a reduction in GET Gas revenues primarily due to the higher than forecasted number of customers that are choosing to pay the GET Gas charge upfront as a lump sum instead of monthly, which eliminates the revenue from the return on investment portion of the monthly GET Gas charge. The revised revenues were developed by annualizing the projected payments in September 2017. This adjustment reduced revenues by $238,000.

Q. Do the adjusted FPFTY revenues exclude revenues related to off-system sales?

A. Yes.

Q. Do the FPFTY revenues exclude revenues associated with the proposed discontinued tariff fees?

A. Yes. As discussed in the section on Tariff Changes, the Company is proposing to eliminate a number of tariff fees to improve customer satisfaction and simplify its tariff administration, and has adjusted "Other Gas Revenues" by the amount of the fees associated with the elimination of the tariff charges. This adjustment of Other Gas Revenues reduces Other Gas Revenues by $3.3 million, as shown on UGI Gas Exhibit A (Fully Projected), Schedule D-5B.

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

Q. How were annualized and normalized sales and revenue determined for the FTY ending September 30, 2016?

A. Budgeted sales and revenues serve as the starting point for the development of the annualized and normalized FTY sales and revenues shown in UGI Gas Exhibit DEL-4(a). All of the adjustments that were made in the development of the FPFTY, with the exception of the adjustment related to the proposed EE&C program, were also made in the development of the FTY.

Q. How were annualized and normalized sales and revenue determined for the HTY ended September 30, 2015?

A. Historic sales and revenues serve as the starting point for the development of the annualized and normalized HTY sales and revenues shown in UGI Gas Exhibit DEL-5(a). The adjustments that were made in the development of the HTY were substantially the same as the adjustments made in the development of the FTY.

III. RATE STRUCTURE

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

A. The Company has not had a base rate proceeding in over twenty years. In general, the Company seeks to update and more closely align its tariff and rate schedules with those of PNG and CPG, who have had more recent base rate proceedings, and to simplify its rate design by eliminating a number of existing rate schedules that are no longer necessary or appropriate.

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

A. The Company is proposing to eliminate the following rate schedules and PGC rates:

- <u>Rate BD (Business Development Rate)</u> – This is a retail (*i.e.*, a non-transportation) rate schedule designed for higher volume customers willing to execute a service agreement with the Company for a Daily Contract Requirement of not less than 50 Mcf. Rate BD customers also qualify for a PGC ("PGC 2") rate that has separate demand and commodity components, which was initiated by the Company in 1993 to make PGC retail service more attractive to higher volume customers. As the retail natural gas market has matured, however, all of the Company's Rate BD customers have migrated to transportation rate schedules, so the Company is proposing to eliminate this rate. Also, there is no comparable rate schedule in the tariffs of PNG and CPG.

- Rate PV (Propane Vaporization Service) – Under this rate, the Company would vaporize propane as an agent for any Commercial or Industrial customer of the Company served under other rate schedules, where the customer provided suitable commercial grade propane fuel to the Company for vaporization. The Company is proposing to eliminate this rate because there are no customers currently using it and there is no prospect of any future use. Also, there is no comparable rate schedule in the tariffs of PNG and CPG.
- Rate SS (Storage Service) – Under this rate schedule, the Company would provide storage capacity on an agency basis when suitable gas or other fuel is supplied by the customer. This rate schedule was developed and implemented before the Federal Energy Regulatory Commission ("FERC") established the capacity release mechanism as the sole means, with certain limited exceptions, for making FERC-jurisdictional pipeline and storage capacity available to third parties. The Company is proposing to eliminate this rate because there currently are no customers served under this rate, and it is not clear whether this service could be provided in any event under current FERC rules. Also, there is no comparable rate schedule in the tariffs of PNG and CPG.
- Rates IL (Interruptible Service – Large Volume) and IS (Interruptible Service – Small Volume) – The Company is proposing to merge these two rate schedules into a new Rate IS (Interruptible Service). Since interruptible service is priced against the cost of alternative fuel options, there is little difference between these two rate

schedules other than minimum bill requirements, which will be combined into a new unified minimum bill requirement under the Company's proposed new Rate IS, along with applicable retainage requirements. The proposed Rate IS is also consistent with the Rate IS rate schedules in the tariffs of PNG and CPG.

- Rate CIAC (General Service – Commercial and Industrial Air Conditioning) – This is a retail rate available to commercial or industrial customers using gas for air conditioning purposes. PGC 2 rates apply to Rate CIAC usage. The Company is proposing to eliminate this rate, which was adopted at a time when it was thought that gas air-conditioning would develop into a significant market and when there were more significant differences in costs between PG 1 and PGC 2. As there currently are only 17 customers on this rate, these customers will be migrated to full year service under Rates N (General Service – Non-Residential) or NT (General Service – Non-Residential – Transportation). While PNG and CPG have a comparable rate schedule in their tariffs, the Company anticipates that they will seek to eliminate these rate schedules in the future.
- Rate CT (General Service – Commercial and Industrial Air Conditioning – Transportation) – This is the comparable transportation rate for commercial or industrial customers using gas for air conditioning purposes. The Company is also proposing to eliminate this rate schedule because there are only four customers served under the rate schedule, all of whom will now be served under Rate NT (General Service – Non-Residential - Transportation). While PNG and CPG have a comparable rate schedule in their tariffs, the Company anticipates that they will seek to eliminate these rate schedules in the future.

- PGC 2 – Given the proposed elimination of Rate Schedules BD and CIAC, the only Rate Schedules to which its PGC 2 rate is applicable, the Company is also proposing to eliminate its PGC 2 rate and serve all retail customers subject to its PGC rates under a single PGC rate.
- Rate EC (Environmental Conversion Rider) – This rider permits a discount to customers converting from an alternate fuel where the customer (1) permanently retires storage tanks or other equipment for the utilization of alternative energy supplies and (2) incurs a "demonstrated economic penalty" because of its conversion to gas. The Company proposes to eliminate this rider because the Company anticipates that it will not have any customers utilizing this rider at the time the proposed tariff changes become effective and future considerations for customers may now be made under the proposed Technology and Economic Development ("TED") Rider.
- Rate CDS (Cogeneration Delivery Service) – This Rate is available to customers who wish to use gas to; (a) generate electricity and/or (b) produce a combination of mechanical and heat energy where mechanical energy production represents no less than 25% of total energy output. A customer must have an indicated gas usage of at least 3,000 Mcf per year. The Company is proposing to eliminate this rate due to the minimal number of customers on this rate. There are only 2 customers currently on this rate. In addition, there is no comparable rate at PNG or CPG. The Company proposes to move these customers to Rate LFD, which would be the most appropriate rate schedule given their size and load profile, and to the extent

required, utilize the proposed TED Rider to preserve the economic substance of the existing service agreements currently available under Rate CDS.

Q. How does the Company propose to effectuate the changes resulting from these rate eliminations?

A. If the Company's proposed rate schedule and PGC 2 rate deletions are approved by the Commission, the Company will: (1) tender new Rate IS service agreements to existing Rate IS and IL customers that, to the extent possible under the Commission's ruling, will preserve the economic substance of the existing service agreements for their remaining term; (2) contact each existing Rate CIAC and CT customer to help them select an alternative rate schedule, and if no decision is made, move the customer to Rate N (the Company cannot automatically move a customer to Rate NT since the customer must select an alternate supplier in order to receive service under Rate NT); (3) contact the two Rate CDS customers and provide them with their comparative rate information in order to help them select an alternative rate schedule; (4) move all existing PGC 2 customers to the new unified PGC rate; and (5) roll any remaining PGC 2 rate over/under collection, which is anticipated to be very small, into the new unified PGC rate E-factor.

Q. Is the Company proposing any additional rates or riders?

A Yes, the Company is proposing a new rider to recover the costs associated with the implementation of its proposed EE&C Plan. In addition, the Company is proposing to replace its current LISHP Rider with a USP Rider. Finally, the Company is proposing a new TED Rider , which is discussed in the direct testimony of Robert R. Stoyko (UGI Gas Statement No. 7).

Q. Please describe the calculation of the proposed EE&C Rider.

A. The Company is proposing to establish an EE&C Rider, which will appear as a separate line item on customer bills, to recover program costs related to the Company's proposed EE&C Plan for fiscal years 2017-2021, as described in the testimony of Company witness Theodore M. Love (UGI Gas Statement No. 11). The EE&C Rider will be computed separately for each of the following two customer classes: (i) Residential customers served under Rate Schedules R and RT (ii) Non-Residential customers served under Rate Schedules N, NT, DS, and LFD. The initial proposed EE&C Rider rates, as developed in UGI Gas Exhibit DEL-7 are:

- Residential Rates R and RT: $0.0778/Mcf.
- Non-Residential Rates N, NT, DS, LFD: $0.0278/Mcf.

The EE&C Rider will apply to all customers served under the rate schedules identified above and the EE&C Rider revenues shall be subject to the STAS.

Q. Please describe the calculation of the proposed USP Rider.

A. The Company is not proposing any policy or procedural changes to its current, recently-approved Universal Service and Energy Conservation Plan. The Company is, however, proposing to modify its recovery mechanism of USP costs to mirror the Commission-approved reconcilable riders currently in place at CPG and PNG. As a result, the Company's LISHP Rider will be replaced by the proposed USP Rider. The initial proposed

USP Rider surcharge is $0.2927 per Mcf, as calculated in UGI Gas Exhibit DEL-8. In conjunction with the proposed USP Rider, the Company is also proposing to modify the tariff section for the annual reconciliation of the proposed USP Rider to include an adjustment for amounts granted to the number of participants receiving Customer Assistance Program ("CAP") credits and preprogram arrearage in excess of 10,000. The adjustment related to CAP credits and preprogram arrearage will be equal to 8.48%. The adjustment is based on the 3-year average of the difference between the gross write-off percentage for low-income customers identified by UGI Gas's system and the gross write off percentage for all other residential customers, adjusted for write-off recoveries. See UGI Gas Exhibit DEL-8 for the calculation of this adjustment. See UGI Gas Exhibit F – Proposed Tariff for the proposed modifications to the USP Rider section of the tariff. Further, see the direct testimony of Company witness Robert R. Stoyko (UGI Gas Statement No. 7) for the participation levels.

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. Rate schedules are generally designed to reflect movement toward class cost of service and to be competitive with prices of alternate energy sources, including bypass. Our rates and rate design seek to achieve efficient utilization of the Company's facilities and natural gas supplies.

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

A. The Company considered both cost of service and value of service as the primary factors in determining revenue allocation and rate design. Other factors that were considered include competition, historic rate patterns, supply conditions, impacts upon customers, the local economy, the nature of our territory, the needs of our customers, utilization of facilities, and public acceptance of rate forms and changes.

Q. Did the Company consider customer migration between rate classes in allocating the proposed rate increase?

A. Yes. The Company has conducted an analysis of customers in Rate Schedules N and NT with annual volumes of 3,000 Mcf or more, and all Rate Schedule DS customers to determine which rate schedule would be the most economical under proposed rates, and has assigned these customers to their most economical rate schedule based on proposed rates for the purposes of projecting anticipated revenues.

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

A Except for Rates XD and IS, whose rates are negotiated and established under their current service agreements, overall UGI Gas is proposing to move applicable rate classes above the system average rate of return at present rates approximately halfway toward cost of service, subject to the following conditions: (1) rate classes that are above the system average rate of return at present rates will receive an increase less than the system average distribution increase; and (2) the rate increase for rates classes that are below the system average rate of return at present rates will not exceed 150% of the system average increase.

In measuring cost of service, the Company relied on the cost of service studies prepare by Company witness Paul R. Herbert (UGI Gas Statement No. 4). In developing the allocations for interruptible service, Mr. Herbert presented two cost of service studies to establish a range of reasonableness. One study included an allocation of distribution main costs to the interruptible rate class, and a second study did not allocate any distribution main costs to the interruptible rate class. The Company then used an average of these two methods as the basis for allocating the proposed revenue increase. Table 1 below provides a summary of the proposed allocation of the increase and the relative class rates of return at present and proposed rates.

Table 1 COMPARISON OF RELATIVE RATES OF RETURN

Rate	% Increase (without gas costs)	Relative ROR- present rates	Relative ROR- proposed rates	Change in relative ROR	% change in relative ROR
R	39.90%	0.16	0.61	0.45	54%
N	22.70%	1.3	1.09	-0.21	-70%
DS	9.30%	3.28	2.14	-1.14	-50%
LFD	7.00%	6.4	3.7	-2.7	-50%
Total	26.60%	1.00	1.00	0	

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. Herbert, under present rates, the residential Rate R customer group (Rates R and RT) is producing a return of 0.71%, as compared to a system average return of 4.52%. This translates to a relative rate of return of 0.16 compared to the system average. In allocating revenues, the Company proposes to allocate $43.3 million of the revenue increase to the Rate R customer group in order to move it closer toward cost of service. This increase will result in an overall return of 5.01%

for the Rate R customer group, compared to the proposed system average of 8.17%, and a relative rate of return of 0.61.

As to rate design, the Company is proposing a Rate R customer group customer charge of $17.50 per month, as compared to the current charge of $8.55 per month, to better reflect the customer component of customer service. The Company also is proposing to replace the current declining block structure with a single block volumetric charge of $3.0123 per Mcf.

Q. Please describe the revenue allocation and rate design for the small commercial Rate N customer group.

A. For the small commercial Rate N customer group (Rates N and NT), current rates are producing a return of 5.89% with a relative rate of return 1.30. UGI Gas proposes to allocate $12.5 million of the revenue increase to the Rate N customer group in order to move the Rate N customer group closer toward cost of service. This increase will result in an overall return of 8.93% or a relative rate of return of 1.09.

As to rate design, the Company is proposing a Rate N customer group customer charge of $32.00 per month, as compared to the current charge of $8.55 per month, to better reflect the customer component of customer service. The Company also is proposing to replace the current declining block structure with a single block volumetric charge of $3.6932 per Mcf.

Q. Please describe the revenue allocation and rate design for the Rate DS.

A. For Rate DS, the applicable transportation rate for small to medium sized customers, current rates are producing a return of 14.86%, with a relative rate of return of 3.28. The Company proposes to allocate approximately $982,000 of the revenue increase to the Rate DS customers in order to move the Rate DS class closer toward cost of service. This increase will result in an overall class return of 17.48% or a relative rate of return of 2.14, by moving Rate DS by 50% toward a unity relative rate of return value.

As to rate design, the Company is proposing to maintain the current Rate DS monthly customer charge of $290.00 per month. The Company also is proposing to replace the current declining block structure with a single block volumetric charge of $2.9121 per Mcf.

Q. Please describe the revenue allocation and rate design for the Rate LFD.

A. For Rate LFD, the applicable transportation rate for medium to large sized customers, current rates are producing a return of 28.96%, with a relative rate of return of 6.40. The Company proposes to allocate approximately $1.75 million of the proposed revenue increase to the Rate LFD customers in order to move this customer class toward cost of service. This increase will result in an overall return of 30.22% or a relative rate of return of 3.70, by moving Rate LFD by 50% toward a unity relative rate of return.

As to rate design, the Company is proposing to maintain the current Rate LFD monthly customer charge of $700 per month. The Company also is proposing to replace the current declining block structure with a single block volumetric charge of $1.2133 per Mcf. The Company also is proposing a demand charge of $5.45/Mcfd to assist with system planning.

Q. Please describe the revenue allocation and rate design for the Rate XD.

A. For Rate XD, the rates for this class are based on current contracts as negotiated between the Customer and the Company given competitive considerations, the Company is not proposing any change to present rates.

Q. Please describe the revenue allocation and rate design for the Rate IS.

A. Rate IS, the applicable interruptible rate schedule for commercial and industrial customers, is an opportunistic rate schedule that is based on the relative price of natural gas versus alternative fuels or other customer alternatives. As such, the Company is at risk for those revenues if circumstances change, and there is no guarantee that current revenue levels will be achieved in the future, particularly considering the recent changes in the interruptible market over the past few years, such as declining price spreads and an increase in the number of interruptions in the winter season. These changes, if they continue, could lead to a substantial decline in interruptible revenue for the Company. For example, the NYMEX price for crude oil has declined from approximately $65 per barrel to under $40 as of December 2015. As a result, the NYMEX futures price spread between natural gas and number 2 heating oil has dropped from $18.08/MMBTU as recently as February 2014 to $7.43/MMBTU as of December 2015, a 59% decline. Since interruptible rates are based on prices for alternate fuels, the decline in price spreads could impact future contract negotiations and potentially lead to a decline in interruptible revenues. In addition to changes in price spreads, there has also been an escalation in the number of actual interruptions experienced by the interruptible rate class, due to weather and system constraints, that could change perceptions of the relative reliability of interruptible service and lead to customers taking additional actions. For example, customers could lock in heating oil inventories to ensure a continuation of operations during potential gas interruptions and then use that inventory of oil during the heating season instead of gas, even during periods when there is no interruption simply because the customer owns the oil.

As a result of the at-risk nature of the interruptible revenues and the market changes discussed above, the Company is reflecting, as a proxy, a level of interruptible revenue in its revenue allocation that is based on a cost of service allocation methodology, or $4.9 million. The Company assigned to the interruptible class an amount based approximately on the midpoint of the calculated results from two separate cost of service studies, one which allocated a portion of distribution mains to interruptible customers and one which did not allocate any mains costs to interruptible customers. The implied overall rate of return under these assumptions is 7.93% or a relative rate of return of 0.97. Please see the direct testimony of Paul J. Szykman (UGI Gas Statement No. 1) for additional detail on the Company's proposal on value of service pricing to the interruptible market and the treatment of revenues received under its Interruptible Service rates. Also see the direct testimony of Paul R. Herbert (UGI Gas Statement No. 4) for additional discussion of the cost of service allocation methodology.

Q. Please describe Rate NNS (No Notice Service) and any changes to this rate that the Company is proposing.

A. Rate NNS is a daily balancing service offered by the Company that is patterned after Rate NNS as offered at PNG and CPG. It provides an alternate election of a daily balancing tolerance for transportation customers, allowing a customer to optionally elect a balancing tolerance greater than the standard basic balancing provided by the Company. A customer is able to make a Rate NNS election up to its DFR (Daily Firm Requirement) contract demand level and pay only for the level chosen. The Company is proposing to update the tariffed NNS rate to reflect current conditions, while retaining the methodology used to develop the current rate.

Q. How were the proposed NNS rates developed?

A. The charge for providing service under Rate NNS is a monthly charge established using the Company's cost of interstate storage that can be utilized for balancing excess or shortfall requirements on the Company system, Columbia FSS storage. UGI Gas Exhibit DEL-9 shows the calculation of the Rate NNS charges, which were developed based on the same methodology used in the Company's last base rate case, as well as the methodology utilized by CPG and PNG in their respective last base rate cases, updated to reflect current costs and conditions. The proposed rate for unit rate for NNS is $0.0066 per Mcf compared to the current rate of $0.025 per Mcf, and the proposed NNS service per unit cost of demand is $0.1320/Mcf of demand ("Mcfd") compared to the current $0.050 per Mcf per day of elected Rate NNS.

Q. Are the revenues received from Rate NNS proposed to be credited to PGC Rates?

A. Yes, revenues from these rate schedules are proposed to be credited to the PGC Rates.

Q. Please describe Rate MBS (Monthly Balancing Service).

A. Rate MBS is a monthly balancing service offered by the Company that mirrors Rate MBS as offered at PNG and CPG. Service under Rate MBS allows transportation imbalances of up to 10% for the month to be carried forward in the customer's MBS account for excess deliveries of or receipt of shortfalls in subsequent months.

Q. How were the proposed MBS rates developed?

A. UGI Gas Exhibit DEL-10 provides the basis for the Rate MBS calculations, as well as the proposed MBS rates under Rates DS, LFD, and XD. These rates were developed based upon the Company's costs to provide Rate MBS service and follow the same rate design methodology utilized by CPG and PNG in their respective most recent base rate cases, updated for current costs and conditions. The proposed rates by rate class are as follows: Rate DS - \$0.0050/Mcf, Rate LFD - \$0.0034/Mcf, and Rate XD - \$0.0031/Mcf. These rates would replace the existing rates which currently are based on the following monthly transportation volumes:

- Under 1,500 Mcf — \$0.075/Mcf x Transported Volumes
- 1,500 – 20,000 Mcf — \$0.035/Mcf x Transported Volumes
- 20,000 – 50,000 Mcf — \$0.015/Mcf x Transported Volumes
- Over 50,000 — \$0.005/Mcf x Transported Volumes

Q. Are the revenues received from Rate MBS proposed to be credited to PGC Rates?

A. Yes, revenues from these rate schedules are proposed to be credited to the PGC.

Q Is the Company proposing to update its GPC in this proceeding?

A. Yes. The Company is proposing to revise its GPC to reflect current labor and information technology costs associated with the procurement function. The current GPC rates is $0.04/Mcf, the proposed GPC is $0.0146/Mcf. Please see UGI Gas Exhibit DEL-11 for additional details on the calculation of this rate

Q Is the Company proposing to update its MFC in this proceeding?

A. Yes. The Company is updating the percentages for the MFCs to reflect the actual uncollectible expense for the last three years. Based on this updated data, the residential MFC will remain at 2.19%, and the MFC for the commercial class will increase slightly from 0.36% to 0.47%. Please see UGI Gas Exhibit DEL-12 for additional details.

V. GET GAS PILOT PROGRAM

Q. Please briefly describe the Company's GET Gas Pilot Program.

A. The Get Gas pilot is designed to help expand natural gas distribution facilities into under-served and unserved areas of the Commonwealth by permitting customers connecting to extended facilities to pay a surcharge on their rates for a defined period of time. It was approved in a Commission Order entered on February 20, 2014, at Docket No. P-2013-2356232.

Q. Did the Commission's Order approve a comprehensive settlement that was reached in this docket?

A. Yes.

Q. Did this settlement contain any provisions addressing future base rate proceedings?

A. Yes, the GET Gas settlement provides, in pertinent part:

> *In the event that any of the UGI Companies files a general base rate case during the term of the pilot, such Company will provide information, as part of its initial filing, showing how the GET Gas surcharge rates would be adjusted to reflect changes in the following items: revenue from a base rate increase, annual sales volumes, average usage per customer for GET Gas customers, depreciation rates, weighted cost of debt, return on equity, tax rates, CAP component and Uncollectibles component. Such UGI Company further agrees that if adjustments for these items would result in a decrease in GET Gas surcharge amounts, it will propose to implement such decreased surcharge rates prospectively for both new GET Gas customers and to any remaining term of the GET Gas surcharge payment for existing GET Gas customers. In the event the adjustment would suggest an increase in GET Gas surcharges, the Signatory Parties agree not to propose any prospective increase in GET Gas surcharges. In addition, and not withstanding any update of the GET Gas surcharge, the Signatory Parties agree not to oppose the UGI Companies' full and timely recovery of and a return on reasonably incurred capital investments in GET Gas facilities that are made consistent with the terms of the pilot program approved in this proceeding or any future modifications to the program approved by the Commission. Any Signatory Party shall be free to propose how such recovery shall occur, and shall be free to propose potential recovery, in part, from non-GET Gas customers.*

Q. Has the Company presented the specified information concerning potential adjustments to GET Gas Surcharge amounts?

A. Yes, this information in shown in UGI Gas Exhibit DEL-13.

Q. Does the updated information suggest a decrease in previously approved GET Gas surcharge amounts?

A. No.

Q. Is the Company proposing any adjustments to GET Gas surcharge levels?

A. No. The Company's GET Gas Pilot Program is still relatively new and, given the small number of actual projects to date, additional information needs to be gathered over time before adjustments to the approved surcharge rates should be made.

Q **Has the Company included GET Gas related investment and GET Gas revenues in its base rate claim?**

A. Yes. The Company has included GET Gas related investment in rate base, less deductions for depreciation and the applicable principal portion of the GET Gas surcharge. The Company is also including the annualized revenue associated with the return on investment ("ROI") portion of the GET Gas surcharge and the adder for uncollectible and CAP expenses. This amount was calculated by annualizing the projected ROI portion and adder portion of the GET Gas surcharge payments for September 30, 2017, plus the adder portion associated with those GET Gas customers who elected to pay the up-front amount of the GET Gas contribution. The total annualized amount included as revenue from the GET Gas surcharge is $198,099 and is reflected on UGI Gas Exhibit DEL-14.

VI. <u>OTHER TARIFF MODIFICATIONS</u>

Q. Apart from the proposed rate schedule and PGC 2 rate eliminations 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 Gas Exhibit F – Proposed Tariff. As noted earlier in my testimony, the primary intent of the proposed changes to the UGI Gas tariff is to standardize and harmonize, where applicable, its tariff provisions with those contained in the CPG and PNG tariffs, reflect best practices, add clarify, as well as update the UGI tariff to reflect certain proposed changes to the Company's business practices. Some of the more significant changes to the current UGI Gas Tariff No. 5 are:

- **Section 3 Guarantee of Payment.** This section has been modified to align it, where applicable, with the CPG and PNG tariffs including language changes regarding minimum deposit requirements for non-residential customers.
- **Section 5 Extension Regulation**. The Extension Regulation tariff section has been modified to align it, where applicable, with the current CPG and PNG Extension Regulation tariff sections, update the methodology used to determine allowable extension investments, and clarify language regarding cost estimates, restoration obligations and daily metering obligations.
- **Section 8 Meter Reading.** This section was updated to align it, where applicable, with the PNG and CPG tariffs except for the Heating Value Correction, which will not be included in the UGI Gas proposed Tariff No. 6.
- **Section 9 Billing and Payment.** The Company is proposing to eliminate several tariff charges as part of the effort of standardizing the tariff provisions of UGI Gas, PNG and CPG. The revenues associated with these charges have been removed from the FPFTY. The CPG tariff does not contain these charges and although the PNG tariff contains some of these charges, it is the Company's intent to eliminate them in PNG's next rate case. The charges being eliminated include:

  Payment to Collector Charge, Bill History Charge, Landlord If Shut Off (LIFSO) Charge, Turn On Charge, Shut Off Charge, Set Meter Charge, and Change of Customer Charge. Additionally, the Company is proposing to increase Returned Check Fee from $20 to $35

- **Section 11 Termination or Discontinuance of Service.** This section was updated to align it, where applicable, with the CPG and PNG tariffs and to update the Reconnection Charge to $73.00, which is equivalent to the current ½ hour charge contained in the UGI Gas Tariff No. 5 and is the charge that the Company currently is applying for reconnections.
- **Section 13 1307(f) Purchased Gas Cost.** This section was updated to align it, where applicable, with the CPG and PNG tariffs, including the elimination of PGC(2), PGC credits related to transportation customer capacity releases or assignments, and the elimination of the IRC. The Company's tariff currently provides for a credit to PGC equal to the margin realized from interruptible transportation customers utilizing pipeline capacity reflected in rates established under 1307(f). This mechanism was established in October 2000, when the restructuring occurred and Choice was implemented in Pennsylvania. The Company is proposing the elimination of the Interruptible Revenue Credit ("IRC") to reflect the results of its cost of service methodology for the interruptible group, and to simplify the administration of tariffed rates for the interruptible rate schedule.
- **Section 17 General Terms for Delivery Service for Rates DS, LFD, CDS, XD And The Delivery Service Option Of IS and IL.** This section has been modified to update it for current conditions and align it, where applicable, with the current CPG and PNG General Terms for Delivery Service tariff sections. This includes: the addition of clarifying language to address a number of balancing provisions, updates and modifications to remedy language related to default or misuse of

balancing provisions, the elimination of Information Service Fees and Pooling Fees, and the modification of Supply Transfer fees that are applied on a transactional basis rather than volumetric basis.

- **Elimination of the System Access Fee From Applicable Transportation Rate Schedules.** Due to the changes in FERC rules related to capacity releases, UGI Gas is proposing to eliminate the System Access Fee. When the System Access Fee was originally adopted in 1995, FERC rules capped the rate at which capacity could be released. The System Access Fee represented the difference between the Company's weighted average cost of demand ("WACOD") and the maximum rate at which the capacity could be released, and the System Access Fee was charged to those applicable transportation rate schedules to ensure PGC customers were not a higher cost of capacity than the applicable transportation customers. FERC rules have now changed, and the Company is able to and will release capacity at its WACOD, which eliminates the need for the System Access Fee.
- **Elimination of the Total Space Conditioning ("TSC") option for Rate Schedules R & N.** TSC is available only to customers who (1) utilize natural gas as the primary energy source for space conditioning requirements – heating and cooling, (2) utilize natural gas for water heating purposes, and (3) maintain one or more additional gas appliances (range, dryer, cooktop or oven). There are relatively few customers who are receiving the discount (103 residential customers and 10 commercial customers), and the total annual discount for all applicable customers in fiscal year 2015 was only $2,039. In addition, the PNG and CPG tariffs contain no comparable rate option. Given the minimal financial impact of the TSC option

and as part of the simplification and standardization of tariffs and rate schedules, UGI Gas is proposing to eliminate the TSC option.

- **Elimination of the Standby Charge for Rate Schedules R, RT.N and NT.** The Standby Charge applies to any customer receiving service under Rates R, RT, N, or NT who utilizes natural gas as a backup, auxiliary or temporary fuel. Given the relative popularity of natural gas as a heating fuel, the vast majority of customers who use natural gas for heating do so as their primary heating fuel. So, there are very few customers utilizing natural gas as a backup fuel. As part of the simplification and standardization of tariffs and rate schedules, the Company is proposing to eliminate the Standby Charge from all applicable rate schedules. Although the CPG and PNG tariffs currently contain provisions for a standby charge, it is the Company's intent to eliminate those provisions in future base rate proceedings.
- **Elimination of Minimum Bills for Rate Schedules N & NT.** The minimum bill provision under Rates N and NT establish a minimum bill based on 3% of the average monthly use during January, February and March billing periods, regardless of actual usage. The Company is proposing to eliminate this provision to minimize customer confusion as well as standardize tariff provisions among UGI Gas, PNG and CPG to facilitate tariff administration, as the PNG and CPG tariffs do not contain a similar minimum bill provisions.
- **Modification of Rate Schedule GL.** As part of the simplification and standardization of tariffs and rate schedules, UGI Gas is proposing to modify its current gas light rate, Rate GL, to standardize it with the current CPG gas light rate.

This includes the elimination of the optional monthly maintenance charge by UGI Gas. Currently, there are no customers that have selected the optional monthly maintenance option.

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 the *pro forma* tariff, Tariff No. 6, as Tariff No. 6-S. See UGI Gas Exhibit F. The proposed modifications to the Choice Supplier Tariff are summarized below.

- **Section 4 Choice Supplier Obligations.** As noted earlier**, t**he Company is proposing to update its MFC percentages to reflect the most recent update of its uncollectible expense as a percent of revenue. As a result, the Company is also proposing to update its discount on the purchase of receivables ("POR") in conjunction with its POR Program. The uncollectible component of the residential POR discount will remain at 2.19%, and the uncollectible component of the commercial POR discount will increase slightly from 0.36% to 0.47%. The Company is proposing no change to its administrative adder for the POR Program in this proceeding, and it will remain at 0.14%. As a result, for purchased receivables, the Company shall pay participating Choice Suppliers an amount equal to 97.67% for residential amounts billed (inclusive of associated taxes) and 99.39% for non-residential amounts billed (also inclusive of taxes).
- **Section 8 Financial Security.** The reference to Call Options has been eliminated primarily because it has never been used as a financial security alternative. The Security Agreement required for suppliers who wish to utilize receivables

associated with the Company's POR Program as a partial offset to their security requirements to operate as Choice Suppliers on the Company's system has also been removed from the tariff, but will still be available as an option for Choice Suppliers.

- **Section 9 Enrollment of Customers into Rate Schedules RT and NT.** The number of days the customer has to respond to the letter of confirmation it receives from the Company was updated from 10 days to 5 days to reflect current regulations and current Company practice. Language on multiple enrollments that was not consistent with current regulations was removed.
- **Rate AG.** The Company proposes to eliminate the difference in the calculation of balancing fees between Choice Suppliers using UGI Gas capacity and Choice Suppliers using third party capacity because it is no longer applicable. The time frame for billing rate information submission was changed from 10 days to 15 days. Redundant definition language was also removed.
- **Aggregation Agreement (Pro Forma).** Redundant definitions found elsewhere in the tariff were removed. Contact information for notices and correspondence was updated. Selected sections of the Aggregation Agreement that were no longer relevant were removed.

Q. Does this conclude your testimony?

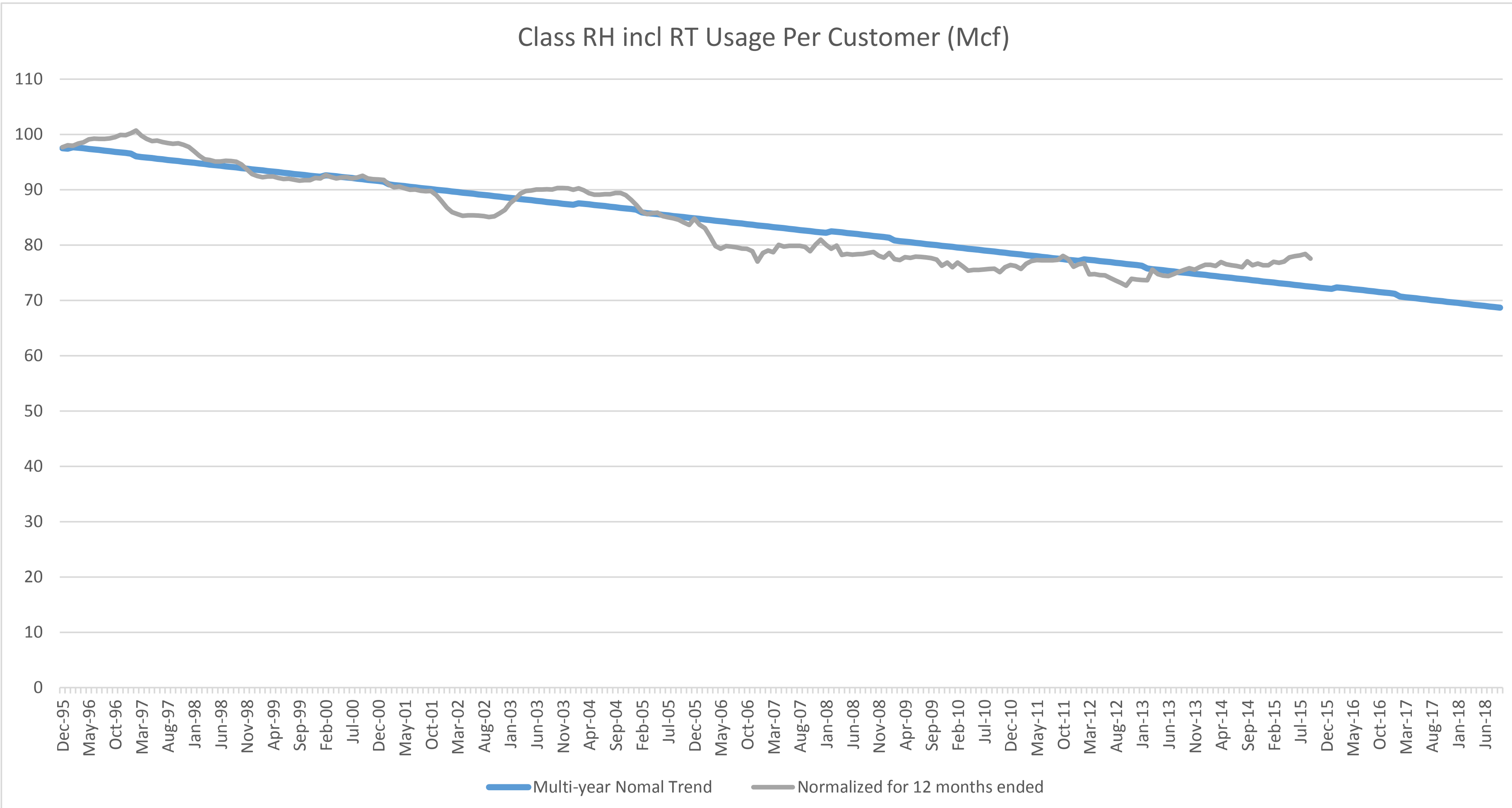
A. Yes.

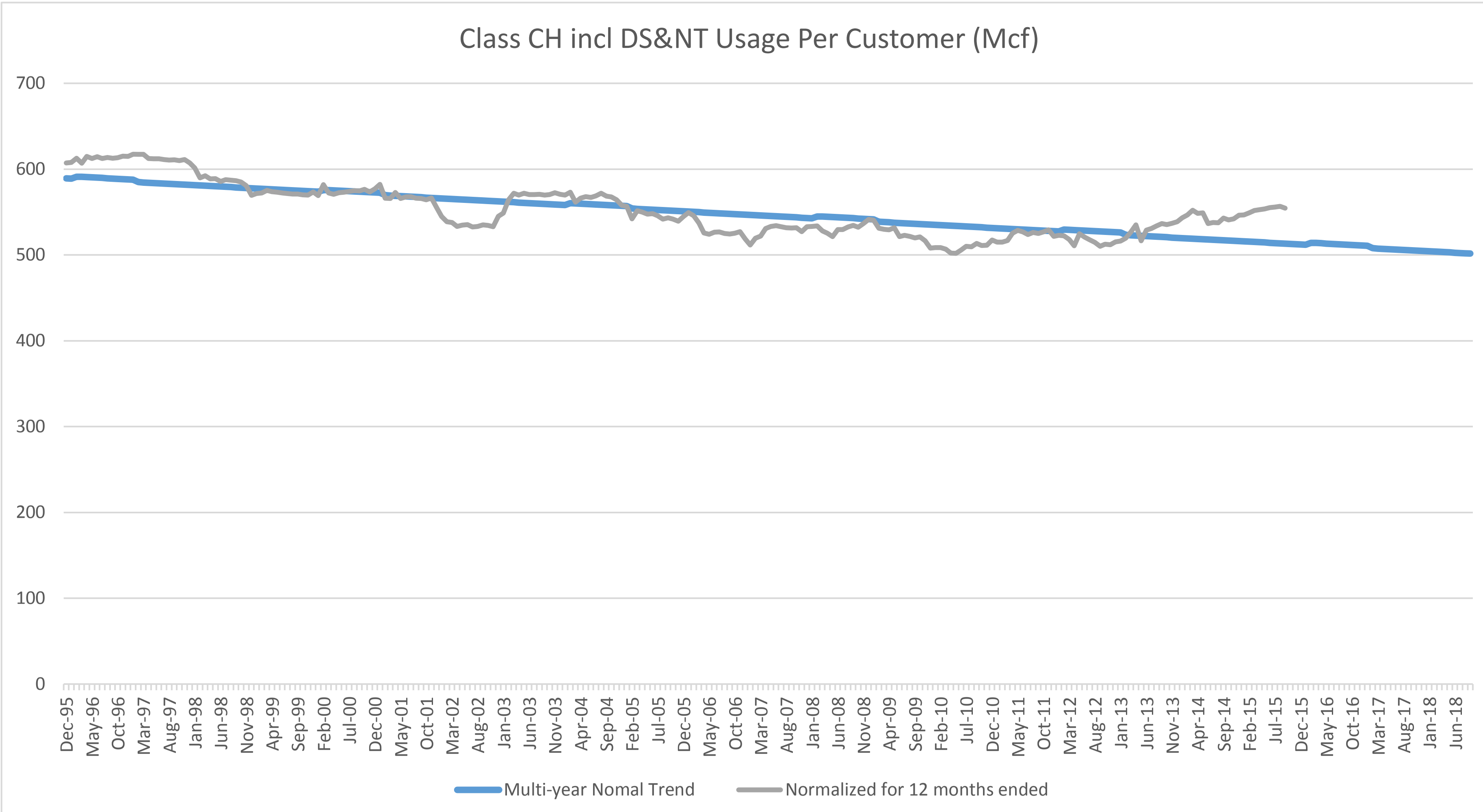
UGI GAS EXHIBIT DEL-1

UGI Utilities, Inc. Primary System
15 Year Normal Heating Degree Days (2000-2014)
Gas Day Basis - Composite Average of Allentown, Harrisburg, Lancaster, and Reading)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	15 Year Average
Jan	1,104	1,086	875	1,223	1,284	1,145	844	938	1,000	1,225	1,082	1,192	951	1,001	1,267	1,081
Feb	875	864	764	1,038	912	885	891	1,117	915	880	965	893	759	924	1,064	916
Mar	561	827	675	743	677	854	691	755	737	735	557	757	451	819	908	716
Apr	401	386	364	430	388	328	333	495	335	388	288	354	373	383	430	378
May	114	121	187	208	67	221	138	110	226	140	119	92	51	158	126	139
Jun	27	12	10	53	28	7	18	12	7	25	7	2	21	4	4	16
Jul	2	3	0	0	0	0	0	4	0	0	0	0	0	0	2	1
Aug	9	0	3	0	9	0	1	16	4	6	0	2	0	2	2	4
Sep	136	105	35	42	34	25	84	50	54	78	25	51	77	111	71	65
Oct	318	321	395	400	368	295	375	192	418	381	331	355	302	300	267	335
Nov	673	463	659	525	574	562	512	703	680	526	631	536	754	723	731	617
Dec	1,158	791	1,023	952	951	1,066	779	956	963	995	1,103	795	816	968	875	946
Totals	5,378	4,979	4,990	5,614	5,292	5,388	4,666	5,348	5,339	5,379	5,108	5,029	4,555	5,393	5,747	5,214

UGI GAS EXHIBIT DEL-2


Class RH incl RT Usage Per Customer (Mcf)
0
10
20
30
40
50
60
70
80
90
100
110
Dec-95
May-96
Oct-96
Mar-97
Aug-97
Jan-98
Jun-98
Nov-98
Apr-99
Sep-99
Feb-00
Jul-00
Dec-00
May-01
Oct-01
Mar-02
Aug-02
Jan-03
Jun-03
Nov-03
Apr-04
Sep-04
Feb-05
Jul-05
Dec-05
May-06
Oct-06
Mar-07
Aug-07
Jan-08
Jun-08
Nov-08
Apr-09
Sep-09
Feb-10
Jul-10
Dec-10
May-11
Oct-11
Mar-12
Aug-12
Jan-13
Jun-13
Nov-13
Apr-14
Sep-14
Feb-15
Jul-15
Dec-15
May-16
Oct-16
Mar-17
Aug-17
Jan-18
Jun-18
Multi-year Nomal Trend
Normalized for 12 months ended


Class CH incl DS&NT Usage Per Customer (Mcf)
700
600
500
400
300
200
100
0
Dec-95
May-96
Oct-96
Mar-97
Aug-97
Jan-98
Jun-98
Nov-98
Apr-99
Sep-99
Feb-00
Jul-00
Dec-00
May-01
Oct-01
Mar-02
Aug-02
Jan-03
Jun-03
Nov-03
Apr-04
Sep-04
Feb-05
Jul-05
Dec-05
May-06
Oct-06
Mar-07
Aug-07
Jan-08
Jun-08
Nov-08
Apr-09
Sep-09
Feb-10
Jul-10
Dec-10
May-11
Oct-11
Mar-12
Aug-12
Jan-13
Jun-13
Nov-13
Apr-14
Sep-14
Feb-15
Jul-15
Dec-15
May-16
Oct-16
Mar-17
Aug-17
Jan-18
Jun-18
Multi-year Nomal Trend
Normalized for 12 months ended

UGI GAS EXHIBIT DEL-3

Fully Projected Future Test Year 2017 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Reference
Budget 2017	127,990	398,721	
Adjustment for Customer Changes	93	761	UGI Gas Exhibit DEL-3(b)
Adjustment for Annualized Use/Customer	(4,339)	(33,064)	UGI Gas Exhibit DEL-3(c)
Adjustment for Transport Changes	(1,140)	(2,348)	UGI Gas Exhibit DEL-3(b)/(b)(1)/(c)/(c)(1)
Adjustment for PGC		(11,319)	UGI Gas Exhibit DEL-3(d)
Adjustment for MFC		(184)	UGI Gas Exhibit DEL-3(e)
Adjustment for LISHP		1,998	UGI Gas Exhibit DEL-3(f)
Adjustment for GPC		(171)	UGI Gas Exhibit DEL-3(g)
Adjustment for Interruptible		(15,721)	UGI Gas Exhibit DEL-3(h)
Adjustment for Transportation Service Revenues		(6,666)	UGI Gas Exhibit DEL-3(i)
Adjustment for Excess Take		(600)	UGI Gas Exhibit DEL-3(j)
Adjustment for STAS		1,783	UGI Gas Exhibit DEL-3(k)
Adjustment for Rate N Minimum Bill		(1,279)	UGI Gas Exhibit DEL-3(l)
Adjustment for EEC Conservation Impact	(220)	(1,484)	UGI Gas Exhibit DEL-3(m)
Adjustment for Get Gas		(238)	UGI Gas Exhibit DEL-3(n)
Fully Projected Future Test Year 2017	122,384	330,190	

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

Adjustment for Customer Changes

Line #	Description	[1] Residential-Non Htg	[2] Residential-Htg	[3] RT	[4] Commercial-Non Htg	[5] Commercial-Htg	[6] Industrial-Non Htg	[6] Industrial-Htg	[7] NT	[8] DS	[9] Transport-Other	[10] Grand Total
1	Total Test Year 2017 Revenues (Unadjusted)	$ 5,539	$ 192,862	$ 15,965	$ 3,986	$ 74,182	$ 218	$ 4,408	$ 29,230	$ 20,273	$ 52,059	$ 398,721
2	PGC Revenues	(1,959)	(98,331)	9	(2,074)	(39,467)	(119)	(2,391)	-	(4,204)	(1,738)	(150,276)
3	Revenues net of PGC - Margin (Unadjusted) (L 1 - L 2)	$ 3,579	$ 94,531	$ 15,974	$ 1,912	$ 34,716	$ 99	$ 2,016	$ 29,230	$ 16,069	$ 50,320	$ 248,445
4	Average Effective Customers in Test Year 2017 (Unadjusted)	21,308	279,008	47,688	2,208	25,238	59	470	10,287	791	613	387,670
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 0.168	$ 0.339	$ 0.335	$ 0.866	$ 1.376	$ 1.690	$ 4.288	$ 2.841	$ 20.310	$ 82.089	$ 0.641
6	Future Test Year 2017 Customers (Fully Adjusted)	20,447	279,985	47,688	2,167	25,410	54	459	10,287	818	604	387,919
7	Change in Customers during Future Test Year 2017 (L 6 - L 4)	(861)	977	-	(41)	172	(5)	(11)	-	27	(9)	249
8	Annualization of Margin (L 5 * L 7)	$ (145)	$ 331	$ -	$ (35)	$ 236	$ (8)	$ (48)	$ -	$ 545	$ (1,221)	$ (344)
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 0.260	$ 0.691	$ 0.335	$ 1.805	$ 2.939	$ 3.719	$ 9.374	$ 2.841	$ 25.624	$ 84.924	$ 1.029
10	Annualization of Total Revenue (L 7 * L9)	$ (224)	$ 675	$ -	$ (74)	$ 505	$ (17)	$ (105)	$ -	$ 688	$ (1,221)	$ 227
11	Annualization of PGC Revenues (L 10 - L8)	$ (79)	$ 344	$ -	$ (38)	$ 269	$ (9)	$ (57)	$ -	$ 143	$ -	$ 572
11	Total UPC (Unadjusted)-MCF	19.80	76.20	77.80	201.50	337.80	437.40	1,097.60	763.60	6,574.30		
12	Annualization Adjustment for Sales-MMCF (L12 * L7)	(17)	74	-	(8)	58	(2)	(12)	-	176	(858)	(589)

Notes:
Column [4] includes Com CIAC
Column [9] further detailed on CPG Exhibit PJS-4(b)(1)

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

Adjustment for Customer Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] DSO IS/IL	[5] TOTAL
1	Total Test Year 2017 Revenues (Unadjusted)	$ 17,993	$ 12,794	$ 736	$ 20,535	$ 52,059
2	PGC Revenues	(113)	(0)	(44)	(1,581)	(1,738)
3	Revenues net of PGC - Margin (Unadjusted) (L 1 - L 2)	$ 17,880	$ 12,794	$ 692	$ 18,954	$ 50,320
4	Average Effective Customers in Test Year 2017 (Unadjusted)	261	28	21	303	613
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 68.506	$ 456.935	$ 32.961	$ 62.554	$ 82.089
6	Future Test Year 2017 Customers (Fully Adjusted)	255	27	21	301	604
7	Change in Customers during Future Test Year 2017 (L 6 - L 4)	(6)	(1)	-	(2)	(9)
8	Annualization of Margin	$ (256)	$ (954)	$ -	$ (10)	$ (1,221)
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 68.940	$ 456.935	$ 35.063	$ 67.771	$ 84.924
10	Annualization of Total Revenue	$ (256)	$ (954)	$ -	$ (10)	$ (1,221)
11	Annualization of PGC Revenues (L 10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total Future Test Year 2017 UPC (Unadjusted)-MCF					
13	Annualization Adjustment for Sales-MMCF	(378)	(478)	0	(3)	(858)

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

Adjustment for Annualized Use/Customer

Line #	Description	[1] Residential-Non Htg	[2] Residential-Htg	[3] RT	[4] Commercial-Non Htg	[5] Commercial-Htg	[6] Industrial-Non Htg	[7] Industrial-Htg	[8] NT	[9] DS	[10] Large Transp-Other	[11] Reconciliation Adj.	[12] Total
1	Total FY 17 (Unadjusted) UPC-MCF	19.80	76.20	77.80	201.50	337.80	437.40	1,097.60	763.60	6,574.30			
2	Future Test Year FY 17 UPC (Fully Adjusted)-MCF	17.80	67.30	77.50	153.70	268.30	476.80	1,182.20	766.00	5,928.80			
3	Change in UPC -MCF (L 1 - L 2)	(2.00)	(8.90)	(0.30)	(47.80)	(69.50)	39.40	84.60	2.40	(645.50)			
4	Future Test Year 2017 Customers (Fully Adjusted)	20,447	279,985	47,688	2,167	25,410	54	459	10,287	818	604		387,919
5	Annualization Adjustment for Sales-MMCF (L3*L4)	(41)	(2,492)	(14)	(104)	(1,766)	2	39	25	(528)	60	22	(4,797)
6	Total Revenue Adjustment (L8 + L10)	$ (310)	$ (18,071)	$ (43)	$ (859)	$ (14,208)	$ 18	$ 312	$ 93	$ (1,214)	$ (295)	$ (302)	$ (34,878)
7	Total Unit Revenue Adjustment (L6/L5)	7.5744	7.2520	2.9858	8.2930	8.0451	8.2930	8.0451	3.7789	2.3000	(4.9092)		
8	Margin Adjustment (L5 *L9)	$ (135)	$ (7,440)	$ (43)	$ (417)	$ (6,673)	$ 9	$ 147	$ 93	$ (1,214)	$ (295)	$ (54)	$ (16,023)
9	Unit Margin Rate	3.3082	2.9858	2.9858	4.0268	3.7789	4.0268	3.7789	3.7789	2.3000	(4.9092)		
10	PGC Revenue (L5*L11)	$ (174)	$ (10,631)	$ -	$ (442)	$ (7,534)	$ 9	$ 166	$ -	$ -	$ -	$ (248)	$ (18,855)
11	PGC Unit Rate	4.2662	4.2662		4.2662	4.2662	4.2662	4.2662					

Notes:
Column (4) includes CIAC
Column (10) further detailed on UGI Exhibit DEL-4 (c)(1)
Column (11) Adjustment reflective of interdependent relationship of sequential adjustment impacts.

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

Adjustment for Annualized Usage and Annualized Rates
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] DSO IS/IL	[5] TOTAL
1	Total FY 17 (Unadjusted) UPC-MCF					
2	Future Test Year FY 17 UPC (Fully Adjusted)-MCF					
3	Change in UPC -MCF (L 1 - L 2)	0.00	0.00	0.00	0.00	0.00
4	Future Test Year 2017 Customers (Fully Adjusted)	255	27	21	301	604
5	Annualization Adjustment for Sales-MMCF	60	-	-	-	60
6	Total Revenue Adjustment	$ 39	$ (54)	$ 44	$ (323)	$ (295)
7	Unit Revenue Adjustment (L6/*L5)	0.6560	0.0000	0.0000	0.0000	(4.9092)
8	Margin Adjustment	$ 39	$ (54)	$ 44	$ (323)	$ (295)
9	Unit Margin (L8/*L5)	0.6560	0.0000	0.0000	0.0000	(4.9092)
10	PGC Revenue (L 6 - L8)	$ -	$ -	$ -	$ -	$ -

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

Adjustment for PGC

	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
Original Budget PGC 1 Rate FY 17	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	
Future Test Year 2017 PGC 1 Rate	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	
PGC 1 Rate Variance	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	
Total PGC 1 Volumes	1,445	3,089	5,201	6,415	5,308	3,919	2,093	1,012	724	635	607	726	31,174
PGC 1 Revenue Adjustment	($524)	($1,120)	($1,885)	($2,325)	($1,924)	($1,421)	($759)	($367)	($263)	($230)	($220)	($263)	($11,301)
Original Budget PGC 2 Rate FY 17	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	
Future Test Year 2017 PGC 2 Rate	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	
PGC 2 Rate Variance	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	
Total PGC 2 Volumes	2	3	2	3	0	6	1	0	1	1	1	1	19
PGC 2 Revenue Adjustment	($2)	($3)	($2)	($3)	($0)	($6)	($1)	($0)	($1)	($1)	($1)	($1)	($19)
Total PGC Revenue Adjustment	($526)	($1,123)	($1,887)	($2,328)	($1,924)	($1,426)	($760)	($367)	($263)	($231)	($221)	($264)	($11,319)

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

Adjustment for MFC

	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
Orignal Budget PGC 1 Rate FY 17	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	
Future Test Year 2017 PGC 1 Rate	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	
PGC 1 Rate Variance	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	
Total PGC 1 Volumes	1,445	3,089	5,201	6,415	5,308	3,919	2,093	1,012	724	635	607	726	31,174
Rate R %	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	
Rate N %	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	
MFC Rate R Adj Rate	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	
MFC Rate N Adj Rate	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	
Revenue Variance	($10)	($19)	($30)	($37)	($31)	($23)	($12)	($6)	($4)	($3)	($3)	($5)	($184)

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

Adjustment for LISHP

	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
Original Budget LISHP Rate FY 17	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	
Future Test Year 2017 LISHP Rate	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	
LISHP Rate Variance	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	
Total Rate R Volumes	1,426	2,639	4,142	5,059	4,277	3,216	1,741	850	472	457	450	659	25,388
Revenue Variance	$112	$208	$326	$398	$337	$253	$137	$67	$37	$36	$35	$52	$1,998

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

Adjustment for GPC

	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
GPC Rate	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	
Volume Variance to Original FY17 Budget	(174)	(512)	(733)	(937)	(828)	(636)	(309)	(106)	(6)	5	6	(31)	(4,263)
Revenue Variance	($7)	($20)	($29)	($37)	($33)	($25)	($12)	($4)	($0)	$0	$0	($1)	($171)

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

Adjustment for Interruptibles to Cost of Service

Total Future Year 2017 Revenues	20,621
Adjustment to Interruptible Revenues	(14,096)
Adjustment to IRC Revenues (PGC Revenues)	(1,626)
Fully Projected Future Test Year 2017 Interruptible Revenues	4,900

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

Adjustment for Transportation Service Revenues

	DS	LFD	DSO IS/IL	CDS	XD-I	XD-F	Total
Revenue:							
Pooling	(287)	(5)	(248)	0	0	0	(540)
System Access	(4,309)	(118)	0	0	0	0	(4,427)
Information Service	0	0	(108)	0	0	0	(108)
Supply Transfer	0	0	(4)	0	0	0	(4)
DS/PGC Credit	(1,592)	5	0	0	0	0	(1,587)
Total	(6,187)	(119)	(360)	0	0	0	(6,666)
Margin:							
Pooling	(287)	(5)	(248)	0	0	0	(540)
System Access	(1,696)	0	0	0	0	0	(1,696)
Information Service	0	0	(108)	0	0	0	(108)
Supply Transfer	0	0	(4)	0	0	0	(4)
Total	(1,983)	(5)	(360)	0	0	0	(2,348)

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

Adjustment for Excess Take Revenues

Excess Take (MCF)		(100)
$/MCF	$	6.00
Excess Take Revenue/Margin	$	(600)

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

Adjustment for STAS

	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 2017
RES. G	2	3	3	3	3	3	3	2	2	2	2	2	30
H	62	106	158	191	164	126	74	43	30	29	29	37	1,049
SUBTOTAL R	64	108	161	195	167	129	77	45	32	31	31	38	1,079
RT	7	9	12	13	11	10	7	5	4	3	4	4	88
TOTAL	71	118	173	208	179	139	84	50	35	35	34	42	1,168
COM. G	2	2	2	2	2	2	2	2	1	1	1	1	22
H	13	36	70	83	66	48	27	14	16	13	12	9	407
TSC	0	0	0	0	0	0	(0)	(0)	0	0	0	0	1
SUBTOTAL C-N	15	39	73	86	68	51	29	15	17	14	13	10	429
AC	0	(0)	0	0	0	0	0	0	0	0	0	0	0
NT	9	15	24	27	23	19	11	6	3	2	2	4	145
TOTAL	24	54	97	113	90	70	40	21	20	16	15	15	574
IND. G	0	0	0	0	0	0	0	0	0	0	0	0	1
H	1	2	3	6	5	4	1	1	0	0	0	0	23
SUBTOTAL I-N	1	2	3	6	5	4	1	1	0	0	0	0	24
NT	1	2	2	3	2	2	1	1	1	0	1	1	17
TOTAL	2	4	6	9	8	6	3	1	1	1	1	1	41
GRAND TOTAL	97	176	275	329	277	214	127	72	56	52	50	58	1,783

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

Adjustment for Rate N Minimum Bills

		Actual Fiscal Year Excess MCF's
FY10		(147)
FY11		(162)
FY12		(120)
FY13		(132)
FY14		(178)
5 YR AVG		(148)
Projected Rate N FY 17 Budget	$	8.6555
FY17 Budget Rate N Minimum Bills	$	(1,279)

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

Adjustment for EE&C Conservation Impact

UGI EE&C Plan (Version 11/20/2015)

Yearly Gas Savings by Rate Class 2017 - 2045 (Cumulative MMBtus)

Rate Class Description	Fiscal Year 2017	2018	2019	2020	2021	MMBTU 5 Year Average	BTU	MCF 5 Year Average	Customers FY17 Retail Htg & Choice Htg	EE&C UPC Conservation Adj
Residential (R/RT)	11,969	52,814	176,130	281,756	360,098	176,553	1.046	168,789	323,977	**(0.5)**
Nonresidential (N/NT)	2,800	16,271	43,980	82,275	124,938	54,053	1.046	51,676	35,122	**(1.5)**
Total	**14,769**	**69,085**	**220,110**	**364,031**	**485,037**	**230,606**		**220,465**	**359,099**	

Line #	Description	[1] Residential-Htg	[2] Res Htg-RT	[3] Commercial-Htg	[4] Com Htg-NT	[5] Industrial-Htg	[6] Ind Htg-NT	[7] Total
1	Future Test Year FY 17 UPC (Fully Adjusted)-MCF	67.30	82.00	268.30	732.20	1,182.20	2,115.30	
2	Future Test Year FY 17 UPC (Fully Adjusted-Incl EE&C Impact)-MCF	66.78	81.48	266.83	730.73	1,180.73	2,113.83	
3	Change in UPC -MCF (L 1 - L 2)	(0.5)	(0.5)	(1.5)	(1.5)	(1.5)	(1.5)	
4	End of Year Customers-Total FY 17	279,985	43,992	25,410	8,891	459	362	359,099
5	Annualization Adjustment for Sales-MMCF (L3*L4)	(146)	(23)	(37)	(13)	(1)	(1)	(220)
6	Total Revenue Adjustment (L8 + L10)	$ (1,058)	$ (68)	$ (301)	$ (49)	$ (5)	$ (2)	$ (1,484)
7	Total Unit Revenue Adjustment (L6/L5)	7.2520	2.9858	8.0451	3.7789	8.0451	3.7789	6.7309
8	Margin Adjustment (L5 *L9)	$ (436)	$ (68)	$ (141)	$ (49)	$ (3)	$ (2)	$ (699)
9	Unit Margin Rate	2.9858	2.9858	3.7789	3.7789	3.7789	3.7789	
10	PGC Revenue (L5*L11)	$ (622)	$ -	$ (159)	$ -	$ (3)	$ -	$ (785)
11	PGC Unit Rate	4.2662		4.2662		4.2662		

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

Adjustment for Get Gas Surcharge

Budget 2017	$	436
Fully Projected Future Test Year 2017	$	198
Get Gas Revenue Adjustment	$	(238)

UGI GAS EXHIBIT DEL-4

Future Test Year 2016 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Reference
Budget 2016	125,057	388,626	
Adjustment for Customer Changes	94	770	UGI Gas Exhibit DEL-4(b)
Adjustment for Annualized Use/Customer	(3,726)	(28,261)	UGI Gas Exhibit DEL-4(c)
Adjustment for Transport Changes	331	(1,699)	UGI Gas Exhibit DEL-4(b)/(b)(1)/(c)/(c)(1)
Adjustment for PGC		(11,974)	UGI Gas Exhibit DEL-4(d)
Adjustment for MFC		(196)	UGI Gas Exhibit DEL-4(e)
Adjustment for LISHP		1,946	UGI Gas Exhibit DEL-4(f)
Adjustment for GPC		(146)	UGI Gas Exhibit DEL-4(g)
Adjustment for Interruptible		(15,857)	UGI Gas Exhibit DEL-4(h)
Adjustment for Transportation Service Revenues		(6,252)	UGI Gas Exhibit DEL-4(i)
Adjustment for Excess Take		(600)	UGI Gas Exhibit DEL-4(j)
Adjustment for STAS		1,741	UGI Gas Exhibit DEL-4(k)
Adjustment for Rate N Minimum Bill		(1,279)	UGI Gas Exhibit DEL-4(l)
Adjustment for Get Gas		100	UGI Gas Exhibit DEL-4(m)
Future Test Year 2016	121,755	326,919	

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for Customer Changes

Line #	Description	[1] Residential-Non Htg	[2] Residential-Htg	[3] RT	[4] Commercial-Non Htg	[5] Commercial-Htg	[6] Industrial-Non Htg	[7] Industrial-Htg	[8] NT	[9] DS	[10] Transport-Other	[11] Grand Total
1	Total Test Year 2016 Revenues (Unadjusted)	$ 6,038	$ 186,884	$ 15,945	$ 4,146	$ 71,332	$ 240	$ 4,488	$ 29,217	$ 18,987	$ 51,349	$ 388,626
2	PGC Revenues	(2,144)	(95,587)	9	(2,163)	(38,024)	(132)	(2,536)	-	(3,757)	(1,739)	(146,075)
3	Revenues net of PGC - Margin (Unadjusted) (L 1 - L 2)	$ 3,893	$ 91,297	$ 15,953	$ 1,983	$ 33,308	$ 109	$ 1,952	$ 29,217	$ 15,230	$ 49,609	$ 242,551
4	Average Effective Customers in Test Year 2016 (Unadjusted)	23,177	269,849	47,688	2,290	24,167	65	479	10,287	744	613	379,359
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 0.168	$ 0.338	$ 0.335	$ 0.866	$ 1.378	$ 1.684	$ 4.074	$ 2.840	$ 20.475	$ 80.929	$ 0.639
6	Future Test Year 2016 Customers (Fully Adjusted)	22,297	270,805	47,688	2,248	24,351	60	467	10,287	773	602	379,578
7	Change in Customers during Future Test Year 2016 (L 6 - L 4)	(880)	956	-	(42)	184	(5)	(12)	-	29	(11)	219
8	Annualization of Margin (L 5 * L 7)	$ (148)	$ 323	$ -	$ (37)	$ 254	$ (8)	$ (49)	$ -	$ 598	$ (1,267)	$ (333)
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 0.261	$ 0.693	$ 0.334	$ 1.810	$ 2.952	$ 3.725	$ 9.367	$ 2.840	$ 25.527	$ 83.766	$ 1.024
10	Annualization of Total Revenue (L 7 * L9)	$ (229)	$ 662	$ -	$ (77)	$ 544	$ (17)	$ (114)	$ -	$ 745	$ (1,267)	$ 248
11	Annualization of PGC Revenues (L 10 - L8)	$ (81)	$ 339	$ -	$ (40)	$ 290	$ (9)	$ (64)	$ -	$ 147	$ -	$ 581
12	Total Test Year 2016 (Unadjusted)-MCF	19.80	76.20	77.80	201.50	338.50	437.40	1,138.20	763.60	6,579.40		
13	Annualization Adjustment for Sales-MMCF (L12 * L7)	(17)	73	-	(9)	62	(2)	(14)	-	192	(797)	(512)

Notes:
Column [4] includes Com CIAC
Column [10] further detailed on CPG Exhibit PJS-4(b)(1)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for Customer Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] DSO IS/IL	[5] TOTAL
1	Total Test Year 2016 Revenues (Unadjusted)	$ 17,802	$ 12,243	$ 758	$ 20,546	$ 51,349
2	PGC Revenues	(114)	0	(43)	(1,582)	(1,739)
3	Revenues net of PGC - Margin (Unadjusted) (L 1 - L 2)	$ 17,688	$ 12,243	$ 714	$ 18,964	$ 49,609
4	Average Effective Customers in Test Year 2016 (Unadjusted)	261	28	21	303	613
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 67.769	$ 437.264	$ 34.002	$ 62.588	$ 80.929
6	Future Test Year 2016 Customers (Fully Adjusted)	254	26	21	301	602
7	Change in Customers during Future Test Year 2016 (L 6 - L 4)	(7)	(2)	-	(2)	(11)
8	Annualization of Margin	$ (133)	$ (1,124)	$ -	$ (10)	$ (1,267)
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 68.207	$ 437.264	$ 36.073	$ 67.808	$ 83.766
10	Annualization of Total Revenue	$ (133)	$ (1,124)	$ -	$ (10)	$ (1,267)
11	Annualization of PGC Revenues (L 10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total Future Test Year 2016 (Unadjusted)-MCF					
13	Annualization Adjustment for Sales-MMCF	(167)	(628)	-	(3)	(797)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for Annualized Use/Customer

Line #	Description	[1] Residential-Non Htg	[2] Residential-Htg	[3] RT	[4] Commercial-Non Htg	[5] Commercial-Htg	[6] Industrial-Non Htg	[7] Industrial-Htg	[8] NT	[9] DS	[10] Large Transp-Other	[11] Reconciliation Adj	[12] Total
1	Total FY 16 (Unadjusted) UPC-MCF	19.80	76.20	77.80	201.50	338.50	437.40	1,138.20	763.60	6,579.40			
2	Future Test Year FY 16 UPC (Fully Adjusted)-MCF	17.70	68.70	77.50	161.30	272.90	476.80	1,182.20	766.00	5,978.80			
3	Change in UPC -MCF (L 1 - L 2)	(2.10)	(7.50)	(0.30)	(40.20)	(65.60)	39.40	44.00	2.40	(600.60)			
4	Future Test Year 2016 Customers (Fully Adjusted)	22,297	270,805	47,688	2,248	24,351	60	467	10,287	773	602		379,578
5	Annualization Adjustment for Sales-MMCF (L3*L4)	(47)	(2,031)	(14)	(90)	(1,597)	2	21	25	(464)	1,390	17	(2,790)
6	Total Revenue Adjustment (L8 + L10)	$ (355)	$ (14,729)	$ (43)	$ (749)	$ (12,851)	$ 20	$ 165	$ 93	$ (1,068)	$ 132	$ (53)	(29,438)
7	Total Unit Revenue Adjustment (L6/L5)	7.5744	7.2520	2.9858	8.2930	8.0451	8.2930	8.0451	3.7789	2.3000	0.0951		
8	Margin Adjustment (L5 *L9)	$ (155)	$ (6,064)	$ (43)	$ (364)	$ (6,036)	$ 10	$ 78	$ 93	$ (1,068)	$ 132	$ 34	(13,384)
9	Unit Margin Rate	3.3082	2.9858	2.9858	4.0268	3.7789	4.0268	3.7789	3.7789	2.3000	0.0951		
10	PGC Revenue (L5*L11)	$ (200)	$ (8,665)	$ -	$ (386)	$ (6,815)	$ 10	$ 88	$ -	$ -	$ -	$ (87)	(16,054)
11	PGC Unit Rate	4.2662	4.2662		4.2662	4.2662	4.2662	4.2662					

Notes:

Column (4) includes CIAC
Column (10) further detailed on UGI Exhibit DEL-4 (c)(1)
Column (11) Adjustment reflective of interdependent relationship of sequential adjustment impacts.

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for Annualized Usage and Annualized Rates
Large Transport and Interruptible Detail

		[1]	[2]	[3]	[4]	[5]
Line #	Description	LFD	XD-F	XD-I	DSO IS/IL	TOTAL
1	Total FY 16 (Unadjusted) UPC-MCF					
2	Future Test Year FY 16 UPC (Fully Adjusted)-MCF					
3	Change in UPC -MCF (L 1 - L 2)	0.00	0.00	0.00	0.00	0.00
4	Future Test Year 2016 Customers (Fully Adjusted)	254	26	21	301	602
5	Annualization Adjustment for Sales-MMCF	59	1,331	-	-	1,390
6	Total Revenue Adjustment	$ 38	$ 269	$ 7	$ (182)	$ 132
7	Unit Revenue Adjustment (L6/L5)	0.6560	0.2019	0.0000	0.0000	0.0951
8	Margin Adjustment	$ 38	$ 269	$ 7	$ (182)	$ 132
9	Unit Margin (L8/L5)	0.6560	0.2019	0.0000	0.0000	0.0951
10	PGC Revenue (L 6 - L8)	$ -	$ -	$ -	$ -	$ -

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for PGC

	OCT 2015	NOV 2015	DEC 2015	JAN 2016	FEB 2016	MAR 2016	APR 2016	MAY 2016	JUN 2016	JUL 2016	AUG 2016	SEP 2016	TOTAL
PGC 1 Rate FY 16	$4.8547	$4.8547	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	
Sept 16 PGC 1 Rate	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	
PGC 1 Rate Variance	($0.5885)	($0.5885)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	
Total PGC 1 Volumes	1,465	2,975	4,992	6,200	5,140	3,825	2,078	968	708	625	584	654	30,215
PGC 1 Revenue Adjustment	($862)	($1,751)	($1,810)	($2,247)	($1,863)	($1,386)	($753)	($351)	($257)	($227)	($212)	($237)	($11,956)
PGC 2 Rate FY 16	$4.8451	$4.8451	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	
Sept 16 PGC 2 Rate	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	
PGC 2 Rate Variance	($0.7524)	($0.7524)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	
Total PGC 2 Volumes	1	3	2	3	0	6	1	0	1	1	1	1	18
PGC 2 Revenue Adjustment	($1)	($2)	($2)	($3)	($0)	($6)	($1)	($0)	($1)	($1)	($1)	($1)	($17)
Total PGC Revenue Adjustment	($863)	($1,753)	($1,812)	($2,250)	($1,863)	($1,392)	($755)	($351)	($257)	($227)	($212)	($238)	($11,974)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for MFC

	OCT 2015	NOV 2015	DEC 2015	JAN 2016	FEB 2016	MAR 2016	APR 2016	MAY 2016	JUN 2016	JUL 2016	AUG 2016	SEP 2016	TOTAL
PGC 1 Rate FY 16	$4.8547	$4.8547	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	
Sept 16 PGC 1 Rate	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	
PGC 1 Rate Variance	($0.5885)	($0.5885)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	
Total PGC 1 Volumes	1,465	2,975	4,992	6,200	5,140	3,825	2,078	968	708	625	584	654	30,215
Rate R %	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	
Rate N %	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	
MFC Rate R Adj Rate	($0.0129)	($0.0129)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	
MFC Rate N Adj Rate	($0.0021)	($0.0021)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	
Revenue Variance	($16)	($29)	($29)	($36)	($30)	($23)	($12)	($6)	($4)	($3)	($3)	($4)	($196)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for LISHP

	OCT 2015	NOV 2015	DEC 2015	JAN 2016	FEB 2016	MAR 2016	APR 2016	MAY 2016	JUN 2016	JUL 2016	AUG 2016	SEP 2016	TOTAL
Original Budget LISHP Rate FY 16	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	
Future Test Year 2016 LISHP Rate	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	
LISHP Rate Variance	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	
Total Rate R Volumes	1,391	2,552	4,028	4,931	4,212	3,120	1,747	816	463	450	427	589	24,725
Revenue Variance	$109	$201	$317	$388	$331	$246	$137	$64	$36	$35	$34	$46	$1,946

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for GPC

	OCT 2015	NOV 2015	DEC 2015	JAN 2016	FEB 2016	MAR 2016	APR 2016	MAY 2016	JUN 2016	JUL 2016	AUG 2016	SEP 2016	TOTAL
GPC Rate	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	
Volume Variance to Original FY 16 Budget	(149)	(423)	(614)	(803)	(732)	(550)	(264)	(89)	(5)	5	6	(23)	(3,642)
Revenue Variance	($6)	($17)	($25)	($32)	($29)	($22)	($11)	($4)	($0)	$0	$0	($1)	($146)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for Interruptibles to Cost of Service

Total Future Year 2016 Revenues	20,757
Adjustment to Interruptible Revenues	(14,231)
Adjustment to IRC Revenues (PGC Revenues)	(1,626)
Total Adjusted Future Test Year 2016 Interruptible Revenues	4,900

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for Transportation Service Revenues

	DS	LFD	DSO IS/IL	CDS	XD-I	XD-F	Total
Revenue:							
Pooling	(270)	(5)	(248)	0	0	0	(523)
System Access	(4,063)	(156)	0	0	0	0	(4,219)
Information Service	0	0	(108)	0	0	0	(108)
Supply Transfer	0	0	(4)	0	0	0	(4)
DS/PGC Credit	(1,402)	4	0	0	0	0	(1,398)
Total	(5,735)	(157)	(360)	0	0	0	(6,252)
Margin:							
Pooling	(270)	(5)	(248)	0	0	0	(523)
System Access	(1,708)	(38)	0	0	0	0	(1,746)
Information Service	0	0	(108)	0	0	0	(108)
Supply Transfer	0	0	(4)	0	0	0	(4)
Total	(1,978)	(43)	(360)	0	0	0	(2,381)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MCF)		(100)
$/MCF	$	6.00
Excess Take Revenue/Margin	$	(600)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for STAS

	OCT 2015	NOV 2015	DEC 2015	JAN 2016	FEB 2016	MAR 2016	APR 2016	MAY 2016	JUN 2016	JUL 2016	AUG 2016	SEP 2016	TOTAL 2016
RES. G	3	3	3	4	3	3	3	2	2	2	2	2	33
H	63	103	151	185	158	123	74	41	29	28	28	33	1,017
SUBTOTAL R	66	106	154	189	162	126	77	44	31	30	30	35	1,050
RT	6	10	12	13	12	9	7	5	3	3	3	4	88
TOTAL	72	116	166	202	174	136	84	48	35	34	33	39	1,138
COM. G	2	2	2	2	2	2	2	2	2	1	1	1	23
H	13	37	66	80	63	46	26	13	15	12	11	9	391
TSC	0	0	0	0	0	0	(0)	(0)	0	0	0	0	1
SUBTOTAL C-N	15	39	68	82	65	49	28	15	17	14	13	10	414
AC	0	(0)	0	0	0	0	0	0	0	0	0	0	0
NT	9	16	23	27	23	18	11	6	3	3	2	4	145
TOTAL	24	55	91	109	89	67	39	21	19	16	15	14	560
IND. G	0	0	0	0	0	0	0	0	0	0	0	0	1
H	1	2	3	6	5	4	1	1	0	0	0	0	25
SUBTOTAL I-N	1	3	3	7	6	4	2	1	0	0	0	0	26
NT	1	2	2	3	3	2	1	1	0	0	0	1	17
TOTAL	2	4	6	9	8	6	3	1	1	1	1	1	43
GRAND TOTAL	99	175	263	320	271	209	126	70	55	51	49	54	1,741

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for Rate N Minimum Bills

		Actual Fiscal Year Excess MCF's
FY10		(147)
FY11		(162)
FY12		(120)
FY13		(132)
FY14		(178)
5 YR AVG		(148)
Projected Rate N FY 16 Budget	$	8.6555
FY16 Budget Rate N Minimum Bills	$	(1,279)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for Get Gas Surcharge

Budget 2016	$	108
Future Test Year 2016	$	208
Get Gas Revenue Adjustment	$	100

UGI GAS EXHIBIT DEL-5

Historic Year 2015 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	
Actual 2015	128,834	448,327	
Adjustment for Customer Changes	151	1,170	UGI Gas Exhibit DEL-5(b)
Adjustment for Annualized Use/Customer	(6,954)	(49,836)	UGI Gas Exhibit DEL-5(c)
Adjustment for Transport Changes	250	252	UGI Gas Exhibit DEL-5(b)/(c)
Adjustment for PGC		(32,247)	UGI Gas Exhibit DEL-3(d)
Adjustment for MFC		(524)	UGI Gas Exhibit DEL-3(e)
Adjustment for LISHP		(498)	UGI Gas Exhibit DEL-3(f)
Adjustment for Interruptible		(16,088)	UGI Gas Exhibit DEL-3(g)
Adjustment for Transportation Service Revenues		(7,318)	UGI Gas Exhibit DEL-3(h)
Adjustment for Excess Take		(1,112)	UGI Gas Exhibit DEL-3(i)
Adjustment for Rate N Minimum Bill		(1,517)	UGI Gas Exhibit DEL-3(j)
Historic Year 2015	122,280	340,610	

UGI Utilities, Inc.
Historic Period- 12 Months Ended September 30, 2015
($ in Thousands)

Adjustment for Customer Changes

Line #	Description	[1] (Incl RT) Residential-Non Htg	[2] (Incl RT) Residential-Htg	[3] (Incl NT) Commercial-Non Htg	[4] (Incl NT) Commercial-Htg	[5] (Incl NT) Industrial-Non Htg	[6] (Incl NT) Industrial-Htg	[7] DS	[8] Transport-Other	[9] Total
1	Total Historic Year Revenues	$ 7,893	$ 238,970	$ 6,970	$ 113,017	$ 549	$ 8,888	$ 19,927	$ 52,115	$ 448,327
2	PGC Revenues	(2,992)	(129,617)	(2,832)	(52,831)	(208)	(3,978)	(3,790)	(3,040)	(199,287)
3	Revenues net of PGC - Margin (L 1 - L 2)	$ 4,901	$ 109,353	$ 4,138	$ 60,186	$ 341	$ 4,910	$ 16,137	$ 49,074	$ 249,041
4	Average Effective Customers in Historic Year	28,835	304,799	3,359	32,135	114	857	702	608	371,409
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 0.170	$ 0.359	$ 1.232	$ 1.873	$ 2.989	$ 5.731	$ 22.982	$ 80.665	$ 0.671
6	Number of Customers at End of Year	28,031	305,598	3,352	32,420	112	836	720	606	371,675
7	Change in Customers during Historic Year (L 6 - L 4)	(804)	799	(7)	285	(2)	(21)	18	(2)	266
8	Annualization of Margin (L 5 * L 7)	$ (137)	$ 287	$ (9)	$ 535	$ (6)	$ (119)	$ 410	$ (240)	$ 721
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 0.274	$ 0.784	$ 2.075	$ 3.517	$ 4.811	$ 10.373	$ 28.379	$ 85.662	$ 1.207
10	Annualization of Total Revenue (L 7 * L9)	$ (220)	$ 626	$ (14)	$ 1,004	$ (10)	$ (216)	$ 506	$ (240)	$ 1,436
11	Annualization of PGC Revenues (L 10 - L8)	$ (83)	$ 340	$ (6)	$ 469	$ (4)	$ (97)	$ 96	$ -	$ 716
12	Total Actual (Unadjusted)-MCF	21.10	84.30	310.20	489.80	844.50	1,710.80	7,172.00		
13	Annualization Adjustment for Sales-MMCF (L12 * L7)	(17)	67	(2)	140	(2)	(36)	128	(5)	274

Notes:
Column [1] and [3] includes GL
Column [3] includes CIAC

UGI Utilities, Inc.
Historic Period- 12 Months Ended September 30, 2015
($ in Thousands)

Adjustment for Annualized Use/Customer

Line #	Description	[1] (Incl RT) Residential-Non Htg	[2] (Incl RT) Residential-Htg	[3] (Incl NT) Commercial-Non Htg	[4] (Incl NT) Commercial-Htg	[5] (Incl NT) Industrial-Non Htg	[6] (Incl NT) Industrial-Htg	[7] DS	[8] Large Transp-Other	[9] Total
1	Total FY 15 Actual UPC-MCF	21.10	84.30	310.20	489.80	844.50	1,710.80	7,172.00		
2	Fully Adjusted FY 15 UPC-MCF	18.70	72.30	280.60	408.20	820.20	1,145.60	6,568.90		
3	Change in UPC -MCF (L 1 - L 2)	(2.40)	(12.00)	(29.60)	(81.60)	(24.30)	(565.20)	(603.10)		
4	End of Year Customers-Total FY 15	28,031	305,598	3,352	32,420	112	836	720	606	371,675
5	End of Year Customers-PGC Only FY 15	24,383	262,059	2,354	23,457	70	467	-	-	312,790
6	Annualization Adjustment for Sales-MMCF (L3*L4)	(67)	(3,667)	(99)	(2,645)	(3)	(473)	(434)	561	(6,828)
7	Total Revenue Adjustment (L9 + L11)	$ (507)	$ (26,216)	$ (738)	$ (19,289)	$ (19)	$ (3,067)	$ (999)	$ 985	$ (49,850)
8	Total Unit Revenue Adjustment (L7/L6)	7.53	7.15	7.44	7.29	7.06	6.49	2.30	1.76	
9	Margin Adjustment (L6 *L10)	$ (223)	$ (10,949)	$ (400)	$ (9,997)	$ (11)	$ (1,786)	$ (999)	$ 985	$ (23,379)
10	Unit Margin Rate	3.3082	2.9858	4.0268	3.7789	4.0268	3.7789	2.30	1.76	
11	PGC Revenue (L 5/ L4)*L6*L12	$ (284)	$ (15,267)	$ (338)	$ (9,292)	$ (8)	$ (1,281)	$ -	$ -	$ (26,471)
12	PGC Unit Rate	4.8547	4.8547	4.8547	4.8547	4.8547	4.8547			

Notes:
Column (1) & (3) includes GL
Column (3) includes CIAC

UGI Utilities, Inc.
Historic Period- 12 Months Ended September 30, 2015
($ in Thousands)

Adjustment for PGC

	OCT 2014	NOV 2014	DEC 2014	JAN 2015	FEB 2015	MAR 2015	APR 2015	MAY 2015	JUN 2015	JUL 2015	AUG 2015	SEP 2015	TOTAL
PGC 1 Rate FY 15	$6.4350	$6.4350	$5.9394	$5.9394	$5.9394	$5.5663	$5.5663	$5.5663	$4.8547	$4.8547	$4.8547	$4.8547	
Sept 15 PGC 1 Rate	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	
PGC 1 Rate Variance	($1.5803)	($1.5803)	($1.0847)	($1.0847)	($1.0847)	($0.7116)	($0.7116)	($0.7116)	$0.0000	$0.0000	$0.0000	$0.0000	
Total PGC 1 Volumes	1,074	3,698	4,466	6,725	6,817	4,635	1,864	733	737	563	571	676	32,559
PGC 1 Revenue Adjustment	($1,697)	($5,844)	($4,844)	($7,295)	($7,394)	($3,299)	($1,326)	($522)	$0	$0	$0	$0	($32,220)
PGC 2 Rate FY 15	$6.1379	$6.1379	$5.9298	$5.9298	$5.9298	$5.5567	$5.5567	$5.5567	$4.8451	$4.8451	$4.8451	$4.8451	
Sept 15 PGC 2 Rate	$4.8451	$4.8451	$4.8451	$4.8451	$4.8451	$4.8451	$4.8451	$4.8451	$4.8451	$4.8451	$4.8451	$4.8451	
PGC 2 Rate Variance	($1.2928)	($1.2928)	($1.0847)	($1.0847)	($1.0847)	($0.7116)	($0.7116)	($0.7116)	$0.0000	$0.0000	$0.0000	$0.0000	
Total PGC 2 Volumes	2	2	4	5	5	4	2	1	1	1	1	1	31
PGC 2 Revenue Adjustment	($3)	($3)	($4)	($5)	($5)	($3)	($2)	($1)	$0	$0	$0	$0	($27)
Total PGC Revenue Adjustment	($1,700)	($5,847)	($4,848)	($7,300)	($7,400)	($3,301)	($1,328)	($523)	$0	$0	$0	$0	($32,247)

UGI Utilities, Inc.
Historic Period- 12 Months Ended September 30, 2015
($ in Thousands)

Adjustment for MFC

	OCT 2014	NOV 2014	DEC 2014	JAN 2015	FEB 2015	MAR 2015	APR 2015	MAY 2015	JUN 2015	JUL 2015	AUG 2015	SEP 2015	TOTAL
PGC 1 Rate FY 15	$6.4350	$6.4350	$5.9394	$5.9394	$5.9394	$5.5663	$5.5663	$5.5663	$4.8547	$4.8547	$4.8547	$4.8547	
Sept 15 PGC 1 Rate	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	
PGC 1 Rate Variance	($1.5803)	($1.5803)	($1.0847)	($1.0847)	($1.0847)	($0.7116)	($0.7116)	($0.7116)	$0.0000	$0.0000	$0.0000	$0.0000	
Total PGC 1 Volumes	1,074	3,698	4,466	6,725	6,817	4,635	1,864	733	737	563	571	676	32,559
Rate R %	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	
Rate N %	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	
MFC Rate R Adj Rate	($0.0346)	($0.0346)	($0.0238)	($0.0238)	($0.0238)	($0.0156)	($0.0156)	($0.0156)	$0.0000	$0.0000	$0.0000	$0.0000	
MFC Rate N Adj Rate	($0.0057)	($0.0057)	($0.0039)	($0.0039)	($0.0039)	($0.0026)	($0.0026)	($0.0026)	$0.0000	$0.0000	$0.0000	$0.0000	
Revenue Variance	($28)	($98)	($78)	($118)	($118)	($54)	($22)	($8)	$0	$0	$0	$0	($524)

UGI Utilities, Inc.
Historic Period- 12 Months Ended September 30, 2015
($ in Thousands)

Adjustment for LISHP

	OCT 2014	NOV 2014	DEC 2014	JAN 2015	FEB 2015	MAR 2015	APR 2015	MAY 2015	JUN 2015	JUL 2015	AUG 2015	SEP 2015	TOTAL
LISHP Rate FY 15	$0.0580	$0.0580	$0.0173	$0.0173	$0.0173	$0.0098	$0.0098	$0.0098	($0.0024)	($0.0024)	($0.0024)	($0.0024)	
Sept 15 LISHP Rate	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	
LISHP Rate Variance	($0.0604)	($0.0604)	($0.0197)	($0.0197)	($0.0197)	($0.0122)	($0.0122)	($0.0122)	$0.0000	$0.0000	$0.0000	$0.0000	
Total Rate R Volumes excl CAP	605	1,675	3,626	4,508	4,974	5,000	2,462	872	531	438	383	413	25,488
Revenue Variance	($37)	($101)	($71)	($89)	($98)	($61)	($30)	($11)	$0	$0	$0	$0	($498)

UGI Utilities, Inc.
Historic Period- 12 Months Ended September 30, 2015
($ in Thousands)

Adjustment for Interruptibles

	FY 15 Actual	Including: Interruptible Adjustments on UGI Gas Exhibit DEL-5 (c)&(h)
Total Historic Year Revenues	20,380	20,988
Adjustment to Interruptible Revenues		(13,800)
Adjustment to IRC Revenues (PGC Revenues)		(2,288)
Adjusted Historic Year Interruptible Revenues		4,900

UGI Utilities, Inc.
Historic Period- 12 Months Ended September 30, 2015
($ in Thousands)

Adjustment for Transportation Service Revenues

	DS	LFD	DSO	CDS	XD-I	XD-F	Total
Revenue:							
Pooling	(236)	(168)	(180)	(1)	(7)	(106)	(698)
System Access	(4,593)	(710)	0	(4)	0	0	(5,307)
Information Service	(47)	(208)	(78)	(2)	(4)	(40)	(379)
Supply Transfer	(3)	(0)	(4)	0	0	(2)	(9)
DS/PGC Credit	(1,148)	10	0	0	0	212	(925)
Total	(6,027)	(1,076)	(263)	(6)	(11)	64	(7,318)
Margin:							
Pooling	(236)	(168)	(180)	(1)	(7)	(106)	(698)
System Access	(2,416)	(586)	0	(4)	0	0	(3,006)
Information Service	(47)	(208)	(78)	(2)	(4)	(40)	(379)
Supply Transfer	(3)	(0)	(4)	0	0	(2)	(9)
Total	(2,702)	(963)	(263)	(6)	(11)	(148)	(4,092)

UGI Utilities, Inc.
Historic Period- 12 Months Ended September 30, 2015
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MCF)		(185)
$/MCF	$	6.00
Excess Take Revenue/Margin	$	(1,112)

UGI Utilities, Inc.
Historic Period- 12 Months Ended September 30, 2015
($ in Thousands)

Adjustment for Rate N Minimum Bills

Excess Take Mcf;s		(206)
Average FY 15 Rate N	$	7.3489
FY15 Rate N Minimum Bills	$	(1,517)

UGI GAS EXHIBIT DEL-6

Detail for Usage per Customer by Class as shown on UGI Exhibit DEL-3(c)

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**18.8**	24,143	453,888
Rate R	17.8	20,447	363,336
Rate RT	24.5	3,696	90,552

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**69.3**	323,977	22,451,606
Rate R	67.3	279,985	18,844,262
Rate RT	82.0	43,992	3,607,344

Rate RT Total	77.5	47,688	3,697,896

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**307.9**	3,172	976,659
Rate N	153.7	2,167	333,127
Rate NT	549.6	990	544,104
Rate DS	6628.5	15	99,428

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**503.6**	34,975	17,613,410
Rate N	268.3	25,410	6,816,241
Rate NT	732.2	8,891	6,509,990
Rate DS	6360.8	674	4,287,179

Industrial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**1584.3**	125	198,038
Rate N	476.8	54	25,747
Rate NT	1369.4	44	60,254
Rate DS	4149.5	27	112,037

Industrial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**1797.9**	923	1,659,462
Rate N	1182.2	459	542,630
Rate NT	2115.3	362	765,739
Rate DS	3442.1	102	351,093

Rate NT Total	766.0	10,287	7,880,086
Rate DS Total	5928.8	818	4,849,737

Detail for Usage per Customer by Class as shown on UGI Exhibit DEL-4(c)

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**18.7**	25,993	486,069
Rate R	17.7	22,297	395,517
Rate RT	24.5	3,696	90,552

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**70.6**	314,797	22,224,668
Rate R	68.7	270,805	18,617,324
Rate RT	82.0	43,992	3,607,344

Rate RT Total	77.5	47,688	3,697,896

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**305.4**	3,251	992,855
Rate N	161.3	2,248	362,581
Rate NT	549.6	990	544,104
Rate DS	6628.5	13	86,171

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**507.4**	33,876	17,188,682
Rate N	272.9	24,351	6,645,945
Rate NT	732.2	8,891	6,509,990
Rate DS	6360.8	634	4,032,747

Industrial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**1644.5**	129	212,141
Rate N	476.8	60	28,608
Rate NT	1369.4	44	60,254
Rate DS	4931.2	25	123,279

Industrial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**1825.0**	930	1,697,250
Rate N	1182.2	467	552,087
Rate NT	2115.3	362	765,739
Rate DS	3756.7	101	379,424

Rate NT Total	766.0	10,287	7,880,086
Rate DS Total	5978.8	773	4,621,621

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

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**18.7**	28,031	524,180

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**72.3**	305,598	22,094,735

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**303.2**	3,364	1,019,965
Rate N & NT	279.5	3,352	936,745
Rate DS	6935.0	12	83,220

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**513.9**	33,006	16,961,783
Rate N & NT	407.6	32,420	13,214,548
Rate DS	6394.6	586	3,747,236

Industrial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**1709.4**	134	229,060
Rate N & NT	447.5	112	50,116
Rate DS	8133.8	22	178,944

Industrial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**1862.3**	936	1,743,113
Rate N & NT	1329.6	836	1,111,563
Rate DS	6315.5	100	631,550

Rate DS Total	**6445.8**	720	4,640,949

UGI GAS EXHIBIT DEL-7

UGI Utilities, Inc. - Gas Division
Energy Efficiency & Conservation (EEC) Rider Calculation

Program Category		R/RT		Non-Residential		Total
Customer Incentives	$	471,396	$	310,856	$	782,252
Administration	$	1,108,417	$	339,349	$	1,447,765
Marketing	$	172,955	$	209,851	$	382,806
Inspections	$	16,422	$	9,262	$	25,683
Evaluation	$	-	$	20,000	$	20,000
Total Expenses	$	1,769,189	$	889,317	$	2,658,506
Billing Determinants (Mcf)		22,744,148		31,945,029		
Proposed EEC Rider 1/	$	0.0778	$	0.0278		

1/ The Non-Residential Rider will be applied to Rate Schedules N, NT, DS, and LFD

UGI GAS EXHIBIT DEL-8

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

		FY 17
Shortfall	$	3,644,703
CAP Admin	$	373,693
LIURP	$	1,100,000
Hardship	$	7,260
Pre-Program Arrearage	$	1,230,949
Total Expenses	$	6,356,605
Billing Determinants (Mcf)		21,720,661
Proposed USP Rider	$	0.2927

Calculation of Annual Reconciliation Adjustment related to CAP Credits and PPA

				3 Yr Average
	2012	2013	2014	
Residential Low Income Write Offs	13.30%	11.60%	12.80%	
less Residential Write Offs	2.30%	2.20%	3.00%	
Gross Adjustment	11.00%	9.40%	9.80%	10.07%
Less Average % of Write Offs Recovered				15.80%

Total Net Adjustment 8.48%

UGI GAS EXHIBIT DEL-9

UGI Gas
Rate NNS Calculation:

Assumptions:

1. Customer deliveries are assumed at a level daily rate.
2. A $0.11/Mcf average storage trip cost for Columbia FSS is used as a proxy.
3. A $2.54/Mcf gas cost assumption is used for the calculation of fuel costs associated with the storage trip.
4. A 14.2% load reduction on weekends is assumed, based on fiscal year 2015 actual usage for DS, LFD, and XD. (Note: Weekend Reduction Factor for DS uses 2015 actual usage from UGI Penn Natural and UGI Central Penn as a proxy since the majority of UGI Gas Rate DS customers are monthly read.

Calculation:

WD = weekday use
WE = weekend use

(5 x WD + 2 x WE) / 7 = average
WE = WD x (1 – 0.142)
WD = 1.17 x WE
(5 x (1.17 x WE) + 2 x WE) / 7 = average
(7.85 x WE) / 7 = average
0.89 x average = WE

Therefore:
Imbalance = 5 x (WD – average) + 2 x (average – WE)
= (5 x WD) - (3 x average) - (2 x WE)
= 5 x (1.17 x WE) - (3 x average) – (2 x WE)
= 3.85 x WE - 3 x average
= 3.85 x (0.89 x average) – 3 x average
= 0.43 x average

Unit Cost Calculation
= [(0.43 x average)/(7 x average)] x storage trip cost
= ((0.43) x (1/7) x storage trip cost
= 0.06 x storage trip cost =
= 0.06 x $0.11/Mcf
= $0.0066/Mcf

Per Unit of Demand Calculation
= $0.0066/Mcf x 20 = $.1320/Mcfd

UGI GAS EXHIBIT DEL-10

UGI Gas

Rate MBS Calculation:

Assumptions:

1. The average capacity charge for Columbia FSS is used as a proxy.
2. System average transportation load factor is based on 2017 Fully Projected Future Test Year usage (Rates DS, LFD, XD) divided by peak day capacity, exclusive of large power generation customers.
3. Anticipated average monthly imbalance percentage based on calculated imbalance of FY 2015 actual usage and deliveries.
4. Storage use will vary with load factor, that is, 100% load factor uses 0% storage.

Calculation:

Average capacity charge for storage: $0.3456/Dth

Average capacity charge for storage: $0.3615/Mcf
(@ 1.046 Btu/mcf)

System average transportation load factor: 52.6%

Anticipated average monthly imbalance percentage: 1.1%

Rate allocation formula by Load Factor:
[($0.3615/0.526) – ($0.3615/0.526 x Load Factor)] x 0.011

Accordingly:

Rate Schedule	Load Factor	MBS Rate
Rate DS	33.6%	$0.0050/Mcf
Rate LFD	54.4%	$0.0034/Mcf
Rate XD	58.8%	$0.0031/Mcf

UGI GAS EXHIBIT DEL-11

UGI Gas Exhibit DEL-11

UGI Utilities, Inc.

Development of the Gas Procurement Charge

Line	Labor and Benefits		UGIU Total
(1)	Gas Supply		$ 162,743
(2)	Accounting Support		$ 46,684
(3)	Internal Legal Support		$ 26,552
(4)	Regulatory Support		$ 52,520
(5)	Management Support		$ 36,062
(6)	Total Labor and Benefits Costs	(6) = (1)+(2)+(3)+(4)+(5)	$ 324,561
	Non-Labor Costs		
(7)	Outside Services- Legal Support		$ 60,000
(8)	IT O&M Expenses		$ 8,766
(9)	Costs to be recovered by GPC	(9) = (6)+(7)+(8)	$ 393,327
(10)	Sales Volumes For rates R and N (Mcf)		26,930,349
(11)	GPC rate	(11) = (9)/(10)	$ 0.0146

UGI GAS EXHIBIT DEL-12

UGI Gas Utilities, Inc. - Gas Division
Merchant Function Charge (MFC) Calculation

				Rate R/RT		Rate N/NT
Total Uncollectible Revenue Requirement	$	5,561,000				
Allocator 1/				91.86%		6.28%
Uncollectible Revenue Requirement			$	5,108,335	$	452,665
Total Proposed Revenue			$	233,347,467	$	96,316,755
MFC % 2/				2.19%		0.47%

1/ The allocator is based on a 5-year average of uncollectible expenses.
2/ The MFC will be applied to bills of customers in Rate Schedules R & N only.

UGI GAS EXHIBIT DEL-13

Recalculation of GET Surcharge

	UGI Gas
GET Investment Total	$5,000,000
Services Cost per Customer	$2,986
Mains Cost per Customer	$4,371
Number of Customers	680
Current Annual Forecast Residential GET Customers	673
Current Annual Forecast Commercial GET Customers	7
Residential Load per Customer	76.3
Commercial Load per Customer	292.2
Residential Base Revenues per Customer at Proposed Rates	$448
Commercial Base Revenues per Customer at Proposed Rates	$1,473
Base Rate Revenues	$311,438.09
Supported Investment	$1,990,750
GET Investment Recovery Need	$3,009,250
Residential Base Revenue Share	96.8%
Commercial Base Revenue Share	3.2%
Base Residential GET Monthly Customer Charge	$67.12
Annual Commercial GET Charge Needed	$2,648
Base Commercial GET Monthly Customer Charge	$12.85
Base Commercial GET Volumetric Charge	$8.54
Proposed Pre Tax WACC	13.96%
Depreciation Rate	1.680%
Residential Gross Up for CAP and Uncollectible Exp	$0.92
Commercial Gross Up for Uncollectible Exp	$0.67
Total Residential GET Monthly Customer Charge	$68.04
Total Commercial GET Monthly Customer Charge	$13.52
Total Commercial GET Volumetric Charge	$8.54
Proposed After Tax Weighted Average Cost of Capital	8.17%
Tax rate	41.49%

UGI GAS EXHIBIT DEL-14

UGI Gas Exhibit DEL-14

GET Revenues	Sep-17	**Annulaized Amount (Sept x 12)**
ROI Component of Monthly Surcharge GET Payments (interest)	$ 14,974	$ 179,685
Uncollectible & CAP Adder Component of Monthly Surcharge GET Payments	$ 431	$ 5,167
Uncollectible & CAP Adder Component of Lump Sum Upfront GET Payments	$ 1,104	$ 13,248
Total	$ 16,508	$ 198,099

BOOK IV

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS STATEMENT NO. 7 – ROBERT R. STOYKO
UGI GAS STATEMENT NO. 8 – THOMAS N. LORD
UGI GAS STATEMENT NO. 9 – HANS G. BELL
UGI GAS STATEMENT NO. 10 – NICOLE M. MCKINNEY
UGI GAS STATEMENT NO. 11 – THEODORE M. LOVE

ORIGINAL TARIFF
UGI UTILITIES, INC. – GAS DIVISION – PA P.U.C. NO. 6

DOCKET NO. R-2015-2518438

Issued: January 19, 2016 Effective: March 19, 2016

UGI GAS STATEMENT NO. 7 – ROBERT R. STOYKO

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2015-2518438

UGI Utilities, Inc. – Gas Division

Statement No. 7

Direct Testimony of
Robert R. Stoyko

Topics Addressed:	**Technology & Economic Development Rider** **Large Customer Usage Projections** **Bypass Risk** **Universal Service** **Customer Service** **Energy Efficiency & Conservation Plan**

Dated: January 19, 2016

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert R. Stoyko and my business address is 2525 North 12th Street, Reading, PA 19612-2677.

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

A. I am employed by UGI Utilities, Inc., ("UGI") as Vice President – Marketing and Customer Relations. UGI has two separate operating divisions: UGI Utilities, Inc. - Gas Division ("UGI Gas" or the "Company"), a natural gas distribution company ("NGDC"), and UGI Utilities, Inc. - Electric Division ("UGI Electric"), an electric distribution company ("EDC").

Q. What are your responsibilities as Vice President – Marketing and Customer Relations?

A. In this position, I have overall responsibility for Marketing, Sales and Customer Service for UGI, including UGI Gas and UGI Electric, and its wholly-owned NGDC subsidiaries, UGI Penn Natural Gas, Inc. ("PNG") and UGI Central Penn Gas, Inc. ("CPG"). In my testimony, UGI Gas, UGI Electric, PNG, and CPG will be referred to collectively as the "UGI Distribution Companies."

Q. Please describe your educational background and work experience.

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

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

A. Yes. In 2013, I presented testimony in a proceeding before the Pennsylvania Public Utility Commission ("Commission) in support of the Joint Petition of the UGI Distribution Companies for approval to implement the Growth Extension Tariff ("GET Gas") Pilot Programs, at Docket No. P-2013-2356232.

Q. What is the purpose of your testimony?

A. In my testimony, I will address UGI Gas's (1) proposed Technology and Economic Development ("TED") Rider, (2) changes to its Large Customer/Industrial Sales Budget, (3) adoption of the universal service program recovery mechanism of CPG and PNG, (4) customer service performance, and (5) the implementation of its Energy Efficiency and Conservation ("EE&C") Plan, which is proposed with this filing.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits: UGI Gas Exhibit RRS-1, UGI Gas Exhibit RRS-2, and UGI Gas Exhibit RRS-3. I am also sponsoring certain responses to the Commission's standard filing requirements as indicated on the master list accompanying this filing.

Q. Were these exhibits and filing requirements prepared by you or by persons under your direct supervision or control?

A. Yes.

Q. Are they true and correct to the best of your information and belief?

A. Yes.

II. TECHNOLOGY AND ECONOMIC DEVELOPMENT RIDER

Q. What is the core function of UGI Gas's distribution system?

A. The core function is to transport and distribute natural gas from sources of supply to end-use customers. In the case of UGI Gas, these sources of supply have primarily been delivery points, or the so-called "city gates", of interstate pipeline systems that connect UGI Gas's distribution system to upstream sources of supply, such as gathering systems connecting gas wells to interstate pipeline systems or gas storage facilities. Other sources of supply include liquefied natural gas and propane air peaking facilities connected to UGI Gas's system. Certain natural gas pipeline systems are or may be constructed through or in close proximity to the UGI Gas distribution system and may also be potential sources of future supply. These sources of supply can also serve as sources of supply to current or potential UGI customers who may elect to bypass UGI's distribution system and receive gas directly from these sources.

Q. What are some of the core characteristics of the natural gas distribution business?

A. Two important features of the business are (1) it is very capital intensive, which is to say that it requires substantial capital to extend natural gas distribution facilities to connect new customers, and (2) unlike some other utility services, there are no uses for natural gas for which there are not alternative substitute forms of energy.

Q. What are some of the consequences of these characteristics?

A. As a result of the capital intensive nature of the business, it has been recognized since the early days of the industry that the public interest is often best served if NGDCs are granted exclusive service territories so that system costs can be shared by the widest possible customer base in a geographic area. In return for being the sole service provider within a geographic area, however, NGDC rates are subject to rate regulation by the Commission.

Also, as a result of the capital intensive nature of the business, as well as the general nature of rate regulation, Pennsylvania NGDCs, in accordance with Commission policies, have established provisions in their tariffs incorporating economic tests for the extension of NGDC facilities. Under these tariff provisions, applicants for utility service must pay for the costs of line extensions deemed not to be economic primarily to prevent undue cost shifting to existing customers under traditional ratemaking policies. For some customers, these line extension rules may result in a requirement to make a large up-front payment, or a contribution in aid of construction ("CIAC"), for the extension of facilities. Since some customers may not be willing or able to pay large up-front contributions in return for potential long-term savings, this could create a barrier to the expansion of NGDC systems. UGI Gas's GET Gas pilot program was designed to try to address this problem for some of the applicants for UGI Gas distribution service while protecting the interests of existing customers.

Q. Does the fact that UGI Gas is the sole entity authorized by the Commission to provide natural gas distribution service in most of its service territories mean that it can dictate the costs under which it will extend it facilities or provide distribution service to all customers?

A. No. UGI Gas is subject to Commission oversight and regulation as well as competitive market forces to a larger degree than other public utilities, such as water or electric utilities. NGDC must recognize that applicants and customers have alternative options to natural gas. Businesses may choose to locate new or expanding operations elsewhere if the energy costs are attractive enough. Customer characteristics and circumstances, such as tolerance for large up-front contributions, can also vary considerably. UGI Gas will lose the applicant's or customer's business and the potential for long-term contributions towards system fixed costs if it does not have the flexibility to adjust contribution and/or distribution rates to reflect the applicant's or customer's competitive alternatives.

Q. How has the Commission historically recognized and made provision in its rate-making policies for the competitive forces UGI Gas faces?

A. The Commission has, amongst other things, afforded UGI Gas substantial latitude in negotiating contributions for extensions costing over $10,000 for non-residential applicants and customers, and has permitted the negotiating of firm XD and LFD rates and all interruptible rates within certain parameters. However, UGI Gas does not currently have such rate flexibility for firm DS and NT rates.

Q. Has such rate flexibility served the public interest and the interests of UGI Gas's customers?

A. Yes. UGI Gas has had an excellent track record of customer growth. This growth is attributable in part to UGI Gas's ability to adjust its rates within tariff-specified boundaries to meet changing competitive conditions and customer preferences. This flexibility has contributed to the expansion of UGI Gas's distribution system and the recovery of fixed costs from a larger customer base. The expansion of UGI Gas's distribution system also benefits the environment since customer conversion to natural gas generally displaces the use of less environmentally friendly energy sources.

Q. Looking forward, do you see the need for additional rate flexibility to attract new customers?

A. Yes. For example, UGI Gas is beginning to see an increased demand for service to compressed natural gas ("CNG") vehicle refueling stations. These stations may start out as low volume customers, but carry the prospect for steady incremental growth as vehicles are replaced. Often, the applicant or customer will be making a significant capital investment in vehicles and refueling equipment, and may have a low tolerance for large up-front contributions for line extensions, but would be willing to pay a higher distribution rate over time. It is also possible that UGI Gas will see the spread of smaller scale fuel cell, cogeneration facilities or gas-fired heat pump technologies that will require rate flexibility to meet competitive conditions.

Q. How does UGI Gas propose to provide this flexibility?

A. UGI Gas is proposing (1) a new rate mechanism, the "Technology & Economic Development" or "TED" Rider and (2) changes to its line extension rules for smaller volume commercial and industrial customers.

Q. Please describe the TED Rider and associated line extension rule changes.

A. The TED Rider would permit UGI Gas and an applicant or customer to negotiate a mutually acceptable rider, which could either be (1) an incremental rate over the otherwise applicable NT or DS firm service rates or an incremental rate to LFD maximum rates, or (2) a rate discount from otherwise applicable NT, DS firm service or maximum LFD rates. The flexibility within the TED Rider will allow for either (i) a larger up-front customer contribution combined with lower negotiated rates, or (ii) a lower up-front customer contribution combined with higher negotiated rates. UGI Gas also proposes to revise its line extension rules to permit the negotiation of line extension terms for all non-residential customers.

Q. Can you provide an example of how the TED Rider might be applied?

A. Yes. Say a company plans to convert its fleet of vehicles to CNG vehicles over time but initially only plans to install compression facilities sufficient to serve a small number of vehicles. This service location initially would be best served under rate NT, which does not offer rate flexibility. If the company wants a line extension constructed that will be capable of serving its future needs but does not have the budget to make a large up-front payment for the line extension, the project may not proceed. Under the proposed TED

Rider, UGI Gas and the applicant could agree to an incremental rate on top of the NT rate and a reduced CIAC to accommodate the applicant's planned CNG project.

In another instance, a transit agency contemplating a conversion to a CNG fleet might receive a grant that can cover any required CIAC and would qualify for service under Rate DS, but might need a discount off of the DS rate to make the project economically viable. Under the proposed TED rider, UGI Gas and the applicant could agree to a higher CIAC and an incremental rate reduction of the DS rate to accommodate the applicant's planned CNG project.

Q. Would the TED Rider be used to make un-economic investments?

A. No. The TED Rider will be determined and applied using an economic test consistent with UGI Gas's new business extension tariff.

Q. Are there any limits on the TED Rider?

A. Yes. The TED Rider will be applicable by request of the applicant and with approval by the company, and would be subject to the following criteria:

1. The Rider is applicable to usage associated with new gas load at competitive risk only.
2. The Rider will be applicable for a defined period outlined in the customer's TED Rider service agreement.
3. The Rider will be determined and applied using an economic test consistent with UGI Gas's new business extension tariff.

Q. Are TED Rider customers included in the fully projected test year revenue calculations?

A. No. However, due to the elimination of Rate CDS, there are two customers who will be assigned a TED Rider adjustment consistent with the rates and terms of their existing Rate CDS service agreements.

III. LARGE CUSTOMER BUDGET ADJUSTMENTS

Q. Has UGI Gas made any adjustments to its large customer budget numbers in developing its revenue requirement in this proceeding?

A. Yes, the budgeted revenue numbers have been adjusted to reflect the annualization of midyear customer additions and deletions, as well as customer data unknown at the time the 2017 budget was prepared. These adjustments are reflected in the sales and revenue exhibits included in the direct testimony of David E. Lahoff (UGI Gas Statement No. 6).

IV. UNIVERSAL SERVICE PROGRAM RECOVERY MECHANISM

A. OVERVIEW OF UNIVERSAL SERVICE PROGRAMS

Q. What universal service and low-income energy conservation programs does UGI Gas currently offer to its customers?

A. UGI Gas offers the following universal service programs: (1) the Customer Assistance Program ("CAP"), (2) the Low-Income Usage Reduction Program ("LIURP"), (3) Operation Share Energy Fund (hardship fund), and (4) the Customer Assistance and Referral Evaluation Services ("CARES") program, which includes outreach for the Low Income Home Energy Assistance Program ("LIHEAP").

Q. Has UGI Gas's universal service and low-income energy conservation plan been approved by the Commission?

A. Yes. The UGI Distribution Companies jointly filed a Universal Service and Energy Conservation Plan ("USECP") for the Three-Year Period of January 1, 2014 through December 31, 2016 at Docket No. M-2013-2371824. The USECP was approved by the Commission by three related orders entered on January 15, 2015, June 11, 2015, and September 3, 2015.

Q. Is UGI Gas proposing any changes to its Commission-approved Universal Services Programs?

A. No. UGI Gas is not proposing any changes to any of its Commission-approved universal service programs. As explained below, UGI Gas is only proposing to modify the recovery mechanism for these universal service programs.

Q. How are UGI Gas CAP costs currently recovered?

A. The Commission-approved settlement of UGI Gas's last base rate case at Docket No. R-00953297 provided, in pertinent part:

> [t]he revenue allowance includes $315,000 in administrative costs and approximately $400,000 current bill shortfall associated with the Company's pilot Low Income Self Help Program ("LISHP"). UGI shall be permitted to include arrearages forgiven and written off under the LISHP pilot in developing its uncollectible accounts expense in future proceedings if such write-offs fall within the period used to develop uncollectible accounts expense.

Thereafter, in a Commission-approved Stipulation in Settlement (the "Universal Service Restructuring Settlement") in UGI Gas's restructuring proceeding at Docket No. R-00994786 (Order entered March 14, 2001), UGI Gas agreed to ramp-up its targeted CAP participation level to 4,000 participants, and was authorized to recover $1.5 million per year in addition to its base rate allowance through a combination of available Other Post-Employment Benefits ("OPEB") funding and, if necessary, base rate increases, to cover incremental costs, subject to certain specified reductions if CAP targets were not met.

Thereafter, in an Order at Docket No. P-00052190 entered on December 1, 2005, the Commission authorized UGI Gas to increase its LISHP participation cap to 8,000 customers, to increase its LISHP discount limit from $840 to $1,146, and to establish its current LISHP Rider. As the Commission explained in its December 1, 2005 Order, CAP costs for the first 4,000 CAP participants will first be funded through the redirection of all available OPEB and LIHEAP funding, and thereafter through a LISHP tariff rider. For the initial 4,000 participants, the LISHP Rider only recovers (1) the difference between $1.5 million and available OPEB funding, to the extent available OPEB funding is less than $1.5 million, and (2) the difference between the residential sales service rate (excluding CAP customer GET Gas charges) and the LISHP rate that is in excess of $752 per CAP participant. The amount of $752 per CAP participant is a fixed amount that represents the average discount of all CAP participants at the time the LISHP Rider was implemented. For all CAP participants over 4,000, the LISHP Rider only recovers the discounts granted to CAP participants and external agency application fees for these additional participants.

Q. Please explain how LIURP costs are recovered by UGI Gas.

A. Pursuant to the Commission's Order entered June 11, 2015, at Docket No. M-2013-2371824, the UGI Gas annual LIURP budget was increased, as of January 1, 2016, from the proposed $650,000, based on 0.2 percent of jurisdictional revenues for UGI Gas, to a fixed $1.1 million. UGI Gas is precluded from recovering LIURP spending at or below $600,000 via its LISHP Rider, and is permitted to recover 50% of LIURP expenditures in excess of $600,000 up to 0.2 percent of jurisdictional revenue. However, UGI Gas is permitted to recover – subject to the $600,000 floor - all LIURP expenditures in excess of 0.2 percent of jurisdictional revenue up to the new $1.1 million budget cap.

Q. How does UGI Gas fund and recover costs associated with the Operation Share Energy Fund?

A. Most of Operation Share's funding comes from sources external to UGI Gas. However, as set forth in the 2014-2017 USECP, UGI Gas is making an annual contribution of $38,500 to the Operation Share Energy Fund and is making available another $38,500 in matching funds, whereby UGI Gas will contribute one dollar for every two dollars donated by a customer, employee, or outside source. Currently, the administrative costs of the UGI Gas Operation Share Energy Fund are included in the UGI Gas general operating budget. There currently is no reconcilable cost recovery mechanism in place.

Q. Briefly explain the CARES program, including funding of the program.

A. UGI also manages a CARES program. This program evaluates customers who are either participating or are being evaluated for participation in any one of our Low Income

Programs to identify customers in need of additional services, including services not offered by UGI Gas. Those customers identified are referred to other programs that could be beneficial to the customer. In addition to UGI Gas's CAP program, the CARES program ensures we are equipped to refer to external agencies, such as the Office of Aging and Department of Human Services when that need is identified.

B. UNIVERSAL SERVICE PROGRAM RECOVERY MECHANISM

Q. Is UGI Gas proposing any changes to the way it recovers the costs of its universal service programs?

A. Yes. UGI Gas is proposing to adopt a Universal Service Plan ("USP") Rider similar to that approved by the Commission in the most recent PNG and CPG base rate proceedings. The USP Rider would address UGI Gas's cost recovery for its CAP, LIURP, and the Operation Share Energy Fund.

Q. **Please explain how the PNG and CPG USP Riders recover the costs of those companies' universal service programs.**

A. Pursuant to the Commission-approved settlement in PNG's last base rate proceeding at Docket No. R-2008-2079660, PNG is permitted to recover costs for the following programs under its USP Rider with an annual reconciliation for costs and recoveries: (1) CAP shortfall, pre-program arrearages and external administrative costs; (2) LIURP in an annual amount of $850,000; and (3) Hardship funds in an annual amount of $5,000 (for administrative costs).

Pursuant to the Commission-approved settlement in CPG's last base rate proceeding, at Docket No. R-2008-2079675, CPG is permitted to recover costs for the following programs under its USP Rider with an annual reconciliation for costs and recoveries: (1) CAP shortfall, pre-program arrearages and external administrative costs; (2) LIURP in an annual amount of $500,000; and (3) Hardship funds in an annual amount of $3,000 (for administrative costs).

For both CPG and PNG there is an offset for CAP credits and pre-program arrearages for customers receiving shortfall credits above the enrollment projected in each of those base rate cases.

Q. Would any of UGI Gas's funding of its universal service programs change from its recently-approved 2014-2017 USECP?

A. No. UGI Gas's funding of its universal service programs would be unchanged from its recently-approved USECP. Only the recovery mechanism would change, so that each UGI Gas, CPG, and PNG would each have the same USP Rider and surcharge mechanism, with the only variations being the differing funding levels for each NDGC set by the Commission in the USECP.

Q. Do you have a projection for UGI Gas's CAP enrollment for the end of the fully-projected future test year?

A. Yes. I project that UGI Gas's CAP enrollment at September 30, 2017 will be 10,000. This projection is based on a steady increase in enrollment that we have observed since the CAP program 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. Is UGI Gas proposing an offset to CAP credits and pre-program arrearages for customers receiving shortfall credits above the projected enrollment of 10,000?

A. Yes. UGI Gas is proposing to calculate an offset to CAP credits and pre-program arrearages in the same manner as CPG and PNG.

Q. What are the projected costs of the UGI Gas's USECP at the end of the FPFTY that must be accounted for in the USP Rider surcharge?

A. These are reflected in UGI Gas Exhibit RRS-2. The direct testimony of David E. Lahoff (UGI Gas Statement No. 6) explains in greater detail how these costs will be incorporated in the surcharge applicable to non-CAP customers through the USP Rider.

V. <u>QUALITY OF SERVICE PERFORMANCE</u>

Q. How does UGI Gas evaluate its customer service performance?

A. There are several ways that UGI Gas evaluates its customer service performance. One way is through the collection of data on performance goals set by the Commission's Bureau of Consumer Services ("BCS"), which are reported annually to the Commission and published in a comprehensive report. Based on these metrics, over the past three years UGI Gas's quality of customer service has met or exceeded the Commission's requirements and, based on our information to date, 2015 metrics are also expected to meet or exceed the Commission's requirements.

Q. Are there any surveys by which UGI Gas measures its customer service performance?

A. Yes. UGI Gas participates in the JD Power Gas Utility Residential Customer Satisfaction Study.

Q. Please explain the Gas Utility Residential Customer Satisfaction Study.

A. JD Power is a global market research company. 2015 marks the fourteenth year of its Gas Utility Residential Customer Satisfaction Study, an online survey that measures residential customer satisfaction with gas utility brands across the following six factors, in order of importance: billing and payment; price; corporate citizenship; communications; customer service; and field service. Satisfaction is calculated on a 1,000-point scale.

Q. How does JD Power evaluate customer satisfaction with gas utility brands?

A. JD Power contracts with several consumer survey panels to complete the survey, with online interviews conducted for 83 gas utilities across four quarterly fielding periods for four US regions (East, Midwest, South and West), each consisting of large and mid-sized utility categories. UGI Gas is in the "Large East" region for the study. This region consists of 11 gas utilities with more than 400,000 households.

Q. How is UGI Gas judged in comparison to similarly-situated gas utilities?

A. UGI Gas is considered together with its affiliate NGDCs CPG and PNG so customer satisfaction is reported on a collective basis. The collective UGI NGDCs were the highest ranked in their region in 2013 and 2014 and were named the JD Power Award winner for this study. The UGI NGDCs came in second place in 2015. UGI Gas Exhibit RRS-3 consists of charts that depict the 2013, 2014, and 2015 customer satisfaction rankings for the 11 natural gas utilities that make up the Large East region.

Q. Are there any other ways that UGI Gas evaluates its customer service performance?

A. Yes. UGI Gas is required to report to the Commission the results of telephone transaction surveys of residential and small business customers that have recently contacted the company. The purpose of these surveys is to assess the customer's perception of the interaction with UGI Gas and fulfill reporting requirements for quality of service benchmarks and standards pursuant to Commission regulations. All EDCs and major NGDCs utilize a common survey which was developed collaboratively with the Commission. Metrix Matrix, a research firm used by all EDCs and major NGDCs for this purpose, contacts individual consumers until it meets a monthly quota of completed surveys for each company. Each year Metrix Matrix completes approximately 700 surveys for each participating utility, including UGI Gas.

In addition, each month UGI Gas randomly selects a sample of transaction records for consumers who have contacted them within the past 30 days. The following chart represents UGI Gas survey results since 2012, using a scale of 1 to 10:

	Customer Satisfaction Survey Results		
Calendar Year	**Overall Satisfaction**	**Call Rep Satisfaction**	**Field Rep Satisfaction**
2012	**8.89**	**9.35**	**9.48**
2013	**8.95**	**9.37**	**9.57**
2014	**8.82**	**9.38**	**9.48**
2015 to date	**8.93**	**9.38**	**9.5**

Our customer satisfaction survey results demonstrate excellent performance on the part of our call center staff, which is consistent with our high marks from JD Power.

Q. Is UGI Gas engaged in any programs anticipated to further improve its customer service performance?

A. Yes. UGI has undertaken UGI's Next Information Technology Enterprise ("UNITE") Project. The UNITE Project is a multi-year, multi-phased information system modernization project. Phase 1 of the Project entails the development and implementation of a new customer information system ("CIS") to replace our two legacy mainframe CIS systems. This new CIS will harmonize the two systems and provide increased functionality and improved customer service. The development and implementation of this plan is discussed in the direct testimony of Thomas N. Lord (UGI Gas Statement No. 8).

VI. ENERGY EFFICIENCY AND CONSERVATION PLAN IMPLEMENTATION

Q. Has UGI Gas proposed an Energy Efficiency and Conservation ("EE&C") Plan in this filing?

A. Yes.

Q. Please describe the Plan.

A. The full contents of the EE&C Plan are described in detail in the direct testimony of Theodore M. Love (UGI Gas Statement No. 11), senior analyst with Green Energy Economics Group, Inc. The EE&C Plan is a comprehensive portfolio of energy efficiency and conservation programs that was designed to assist customers save energy through various cost- effective measures. The EE&C Plan Rider is discussed in the direct testimony of David E. Lahoff (UGI Statement No. 6).

The following six natural gas energy efficiency programs are proposed for the five-year timeframe that will run from Fiscal Year 2017 through Fiscal Year 2021:

- Residential Prescriptive (RP)
- Nonresidential Prescriptive (NP)
- New Construction (NC)
- Residential Retrofit (RR)
- Nonresidential Retrofit (NR)
- Behavior and Education (BE)

An additional Combined Heat and Power ("CHP") program is also being proposed as a separate fuel-switching program in addition to the six programs that comprise the EE&C Plan.

Q. How will the EE&C Plan be marketed to customers?

A. The EE&C Plan will be marketed to current and prospective customers with the intent of providing relevant, cost-effective communications that will drive awareness and education regarding the UGI Gas EE&C Plan. The marketing efforts will be implemented and managed by both UGI Gas Staff and qualified Conservation Service Providers ("CSPs"). The EE&C Plan will be marketed in various ways, which may include the following:

1) <u>Company website</u> - Utilize UGI.com to inform customers of energy efficiency and conservation tips, along with applicable programs and associated customer rebates. In addition to web content, UGI may decide to leverage "how to" videos through mediums such as YouTube, etc.

2) <u>Social media</u> - Leverage social media (e.g. Twitter, Facebook, etc.) to communicate energy efficiency and conservation messages.

3) <u>Media advertising</u> - Broadcast within the UGI Gas service territory to inform customers of the benefits of energy efficiency and conservation. Advertising may include the following tactics:

   a. <u>Television</u>
   b. <u>Radio</u>
   c. <u>Newspaper/Billboards</u>
   d. <u>Event sponsorship and trade shows</u>

4) <u>Bill inserts/Newsletters</u> - Distribute energy efficiency and conservation tips to customers at a minimum on a quarterly basis. Topics may include:

   a. Seasonal energy conservation tips

b. Information on low-income assistance programs

c. Specific rebates available to Residential, Commercial, and Industrial customers

5) CSPs - Once the request for proposal ("RFP") process is finalized, UGI will partner with hired CSPs that specialize in promoting and administering energy efficiency programs. The CSPs will help identify market opportunities, promote applicable customer programs and rebates, and assist with developing relationships with various trade allies.

Q. Does that conclude your testimony?

A. Yes, it does.

UGI GAS EXHIBIT RRS-1

UGI CORPORATION

LEADERSHIP BACKGROUND PROFILE

Name Robert Stoyko Date 1/7/16
DOB 4/11/60
DOE 8/15/83
Current Position – Vice President Marketing and Customer Relations
Tenure Current Position – 3 ½ years

PROFILE

- Diverse background in Marketing, Operations and general management within the ED, PNG, CPG & GUD.
- Managerial leadership experience in both Area Operations, Marketing and other functional departments
- Strong analytical, team building and interpersonal skills

EXPERIENCE

UGI Utilities

Vice President – Marketing and Customer Relations 2012 - Present
Vice President – Northern Region/Northern Operations 2007-2012

UGI Utilities – Electric Division

Vice President – Electric Distribution 2004-2007

UGI Utilities – Gas Division

Marketing Manager 2002-2004
Manager – Customer Accounting Services 2001-2002
Lancaster Area Manager 1998-2001
Customer Relations Manager - Lehigh 1991-1998
Residential Supervisor – Reading Area 1988-1991
Financial and Cost Analyst - Rates 1984-1988
Industrial/Commercial Marketing Representative - Lancaster 1983-1984

EDUCATION

St. Joseph's University: MBA - Finance 1986-1990

Received Graduate Business Award for finishing first in the graduating class with a 4.0 GPA

Kutztown University: B.S. Business Administration 1981-1983

Graduated Cum Laude

Other : Various

AGA Sustainable Growth Committee ; Energy Solutions Center Board of Directors ; United Way Ready, Set, Read Board of Directors

UGI GAS EXHIBIT RRS-2

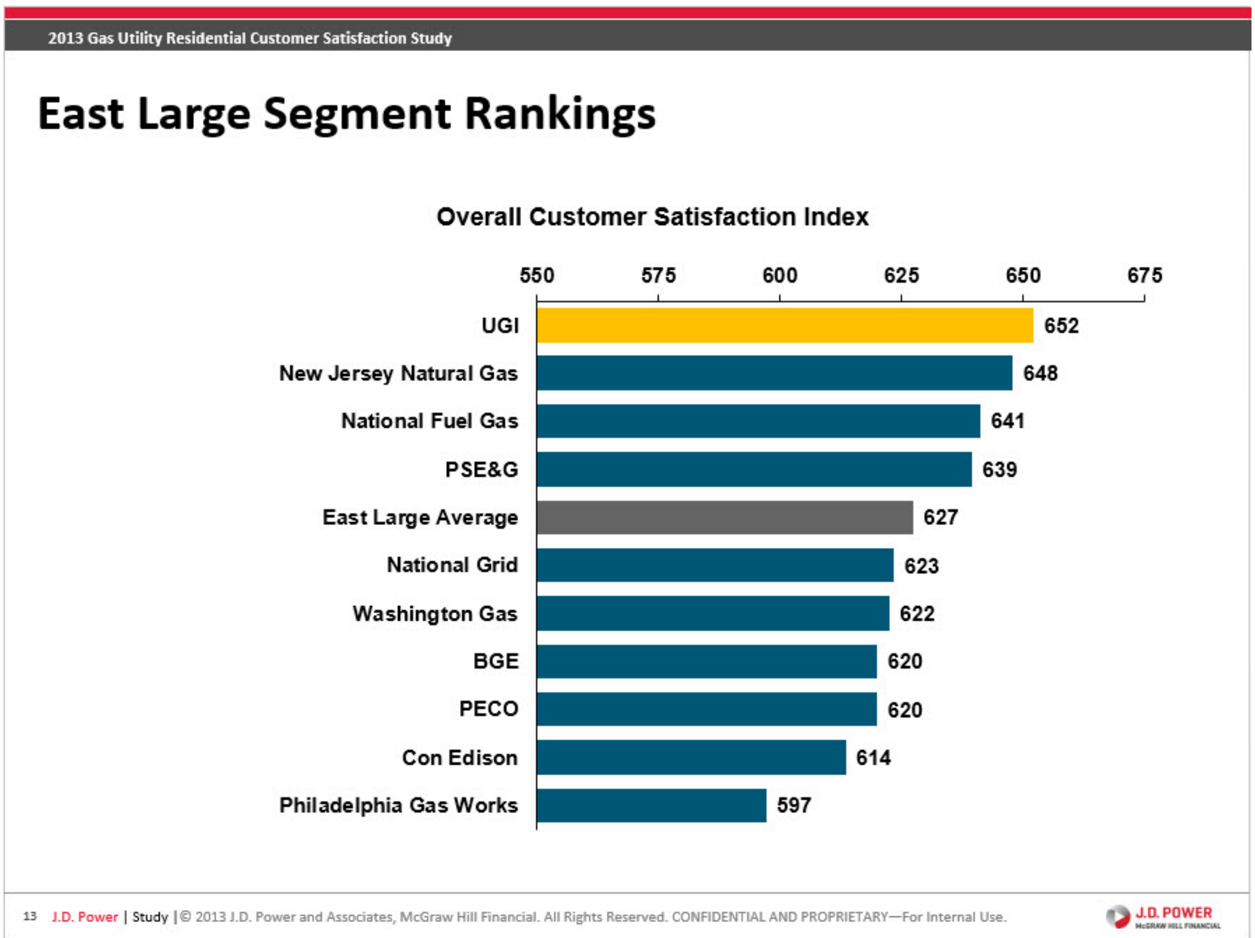
UGI GAS	FY 15	FY 16	FY 16 BRC	FY 17 BRC
	ACTUAL	BUDGET	Forecast	Forecast
CAP CREDIT	$ 3,319,960	$ 1,816,271	$ 3,644,703	$ 4,009,173
CAP ADMIN	$ 294,131	$ 348,000	$ 323,544	$ 355,899
LIURP	$ 401,077	$ 1,100,000	$ 1,100,000	$ 1,100,000
HARDSHIP	$ 7,260	$ 10,200	$ 7,970	$ 8,767
PPA	$ 930,949	$ 1,000,000	$ 1,130,949	$ 1,530,949

UGI GAS EXHIBIT RRS-3

JD Power Gas Utility Residential Customer Satisfaction Study Results

2013-2015

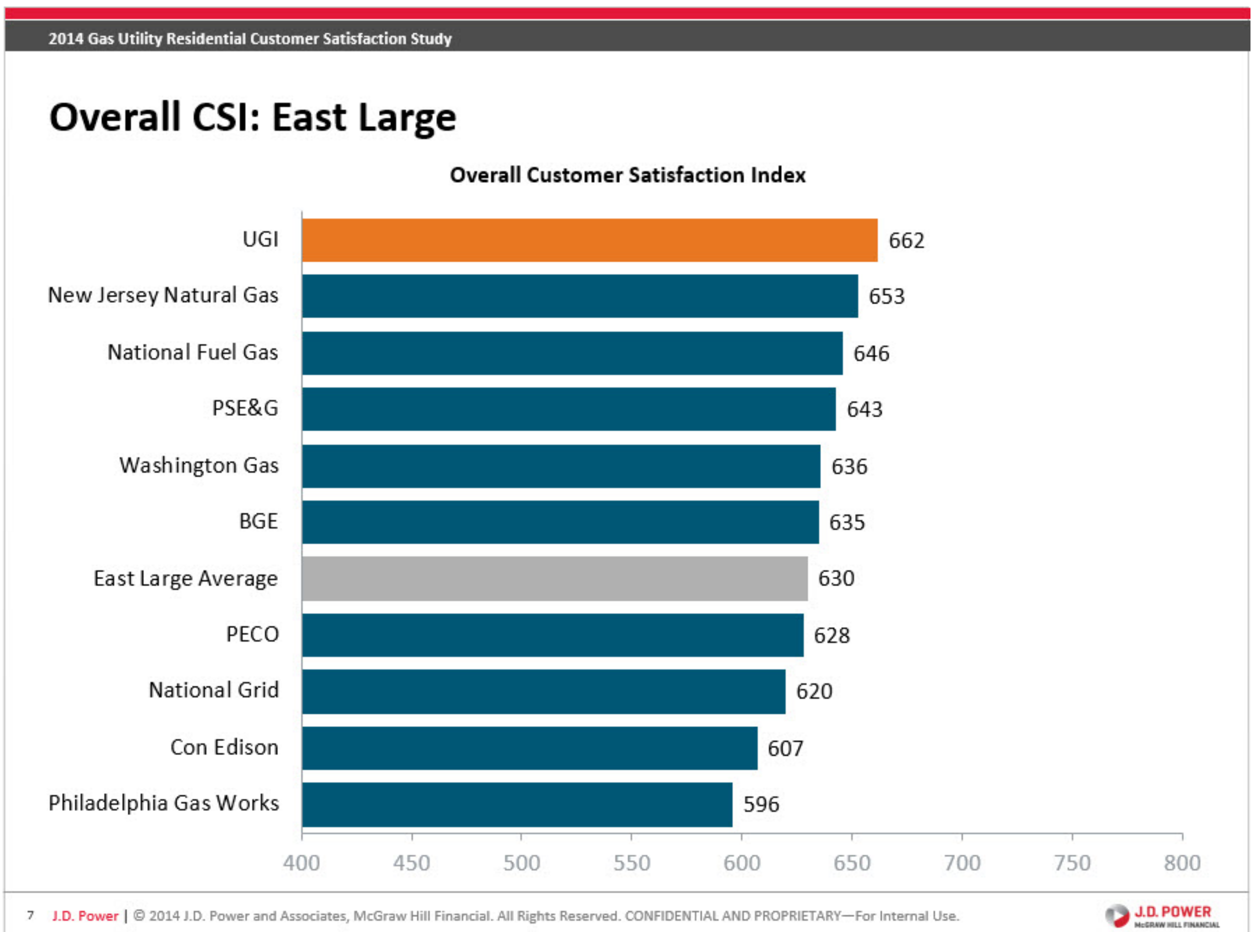
2013



JD Power Gas Utility Residential Customer Satisfaction Study Results

2013-2015

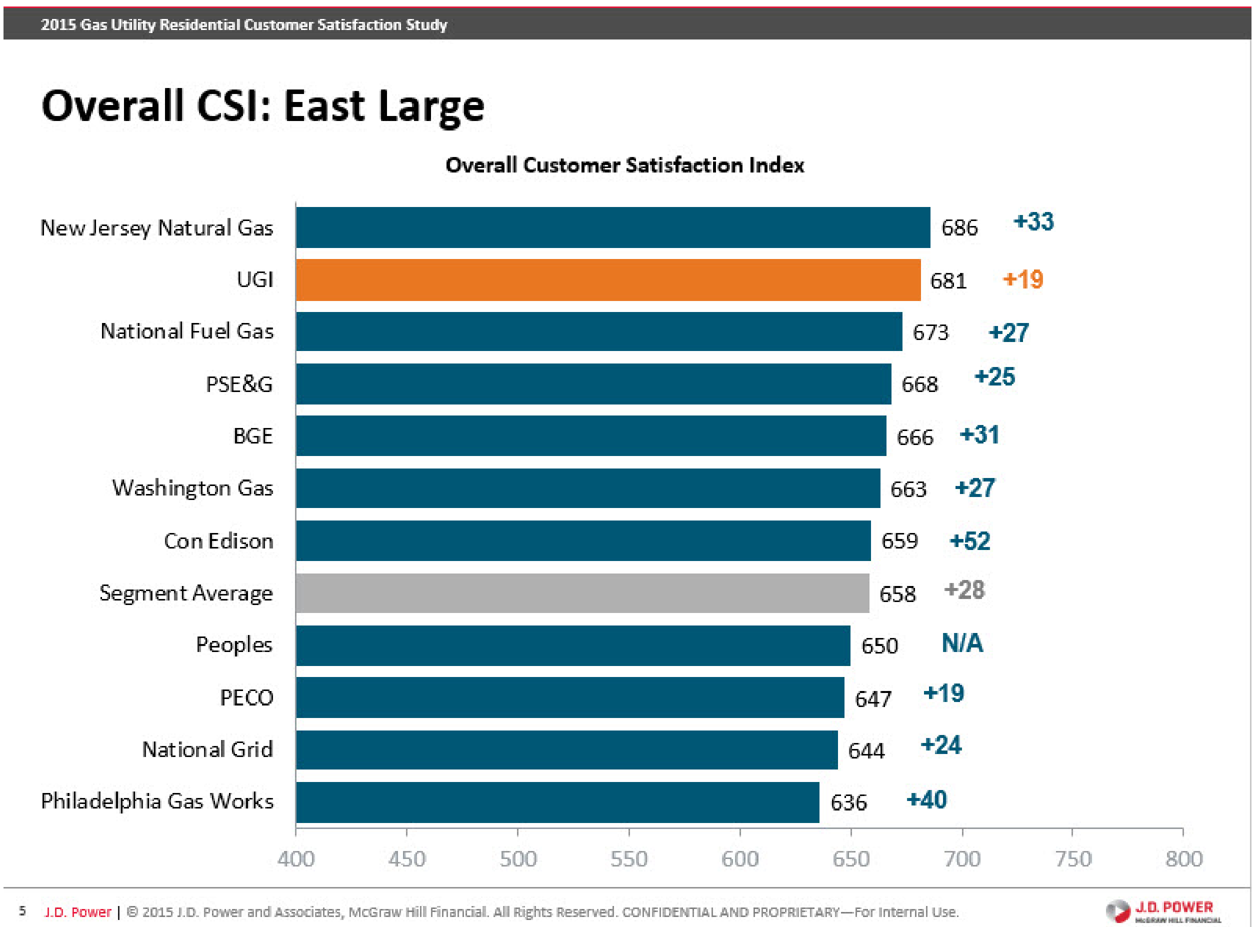
2014



JD Power Gas Utility Residential Customer Satisfaction Study Results

2013-2015

2015



UGI GAS STATEMENT NO. 8 – THOMAS N. LORD

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2015-2518438

UGI Utilities, Inc. – Gas Division

Statement No. 8

Direct Testimony of
Thomas N. Lord

Topics Addressed: **UGI's Next Information Technology Enterprise (UNITE Program)**

Dated: January 19, 2016

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Thomas N. Lord. 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 Vice President and Chief Information Officer. UGI is a subsidiary of UGI Corporation ("UGI Corp."). UGI has two separate operating divisions: UGI Utilities, Inc. - Gas Division ("UGI Gas" or the "Company") and UGI Utilities, Inc. - Electric Division.

Q. What are your principal duties and responsibilities as Vice President and Chief Information Officer?

A. I am responsible for the strategic direction and overall management of all UGI technology functions including defining, delivering, and supporting business enabling Information Technology ("IT") solutions.

Q. What is your educational background?

A. I have a Bachelor of Science, Computer Science – Queen Mary College, University of London, United Kingdom.

Q. Please describe your professional experience.

A. I am an IT professional with over 30 years' experience in defining, delivering, managing, and supporting IT solutions. Most recently, I held the position of Director, Enterprise

Architecture and Information Systems at TECO Energy, Tampa, Florida. Previously, I held senior information technology positions at Lucent Technologies, British Telecom, and Special Data Processing Corporation. My curriculum vitae is attached to this testimony as UGI Gas Exhibit TNL-1.

Q. Please describe the purpose of your testimony.

A. I am providing testimony on behalf of UGI Gas. The primary purpose of my testimony is to discuss UGI's Next Information Technology Enterprise ("UNITE") Program. I will present an overview of the UNITE Program, describe its costs and benefits, and discuss the program's schedule. As this is a multi-year, multi-phased program, I will also discuss the components of the program that will be placed into service during the fully projected future test year ending September 30, 2017 ("FPFTY"), the related capital costs, and the associated cost reductions that will occur after the UNITE Program is implemented and the existing systems are retired from service. Additionally, I will described other pending IS projects that UGI is planning to implement by the end of the FPFTY.

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

A. Yes. I am sponsoring the following exhibits attached to this testimony: UGI Gas Exhibit TNL-1, and UGI Gas Exhibit TNL-2.

II. UNITE PROGRAM

A. OVERVIEW

Q. Mr. Lord, please provide an overview of the UNITE Program.

A. As part of the UGI-1 initiative described in the direct testimony of Paul J. Szykman (UGI Gas Statement No. 1), the UNITE Program is a multi-year, multi-phased information system modernization program. Phase 1 of the Program entails the development and implementation of a new customer information system (CIS) to replace our two legacy mainframe CIS systems. Currently, UGI's 40-year old system serves the customers of UGI (both UGI Gas and UGI Electric) and UGI Penn Natural Gas, Inc., while a separate 20-year old system is used to serve the customers of UGI Central Penn Gas, Inc., with both systems operating in a legacy mainframe environment.

Phase 2 represents the modernization of our enterprise asset/work management system, which will allow for improved management of our assets, long-cycle maintenance work, mobile workforce, and contractors, as well as improvements and consolidation of our Geospatial Information System ("GIS"). Phase 3 of the UNITE Program will help us improve how we manage gas outages, engage in supply chain activities, and account for our plant investment.

Phase 1 of the UNITE Program will be implemented and in service before the end of the FPFTY. Phases 2 and 3 of the UNITE Program will not be placed in service until after the FPFTY. Accordingly, my testimony addresses only the issues pertaining to Phase 1 of the UNITE Program.

Q. Please discuss the specific activities that will be affected by the Phase 1 implementation.

A. The new CIS will transform the Company's ability to manage several aspects of its utility systems, including Contact Center (call center) Operations, scheduling service orders, and provide broader customer self-service options. In addition, the Company will have a more flexible tool that will enhance its billing functionality in order to adapt to changes in rates more readily, allow for more flexible online payment and account management features for customers, and allow the Company to better manage and track its credit and collections processes. With respect to the service orders, the new CIS will enable the Company to more efficiently and effectively communicate short-cycle service orders to field personnel. This more effective communication will both enable the field work to be performed more efficiently and allow the Company to more efficiently track the entire lifecycle of utility meters and meter-related devices from requisition, through operation and maintenance cycles, and to retirement. Further, the added functionality provided by the new CIS will enable the Company to access and validate data more efficiently, which will allow the Company to create, modify, and run business reports better than the current system allows. Finally, a new CIS is a key for the Company's data governance model in terms of ensuring appropriate retention of information required under regulatory and corporate data management models. Altogether, these changes will transform how more than 1,200 of our employees serve all 700,000 of our customers. In summary, the new CIS will allow the Company to more efficiently manage its entire meter-to-cash process, enable the Company to measure its performance more effectively, and significantly improve the service experience for customers.

Q. Why has UGI decided to undergo this CIS transformation now?

A. There are four primary reasons. First, the current CIS system presents significant business continuity concerns. Maintaining a workforce proficient in the legacy system has become increasingly challenging, with the average age of UGI-employed software developers being 57 years old. Having roots dating back to 1975, UGI's legacy mainframe system utilizes a technology that is no longer included in formal education programs and has not been for some time. With no replacement workforce being educated in the language and other technology used by the system, it is quickly becoming obsolete.

Second, while the Company currently provides excellent customer service, we believe that modernization of the CIS program will provide improved service to customers. This improvement will primarily be the result of the state-of-the-art technology that will enable customers to seek out and obtain information more quickly and efficiently, as well as enable service providers to do the same to provide better service to customers. Self-service for utility customer information now represents a key determinant of customer satisfaction. Indeed, customers now prefer low-touch, web portal, email, social media, and other means available only through modern technology. The new CIS will provide more effective and efficient technology solutions for our business processes, including processes that manage emergency situations, such as contact center, dispatch and field operations.

Third, UGI's workforce spends an inordinate amount of time completing manual tasks that can be automated with up-to-date systems. The newly automated systems will reduce the number of tasks required to be done manually. The reduction of manual tasks will improve the efficiency of the workforce to perform certain emergency, asset management, and record keeping tasks.

Fourth, the topic of CIS modernization was addressed in the most recent management audit conducted by the Bureau of Audits Pennsylvania Public Utility Commission ("PA PUC") in 2012.[1] In that report, the Bureau found the following:

> Standardization of the CIS would enable all call centers to operate in a more cost efficient manner eliminating duel processes and maintenance of two systems. Additionally, call center personnel utilization would improve with the ability to cross train personnel to handle customer service calls from any call center. Finally, if all call centers utilize one system, the UGI Utility Group will be in a position to evaluate the benefits for further consolidation of the call centers and develop one set of metrics/goals for evaluation purposes.

For all of these reasons, the Company has decided to pursue the UNITE Program.

Q. What is the total cost of the UNITE Program?

A. The total UNITE Program capital investment will be $130-$150 million. UGI Gas will be allocated $63-$73 million of the total capital costs for the UNITE Program.

Q. What is the total cost of Phase 1 of the UNITE Program?

A. As I further explain below, Phase 1 of the UNITE Program will be implemented and in service before the end of the FPFTY. The total capital cost for Phase 1 of the UNITE Program will be $88.1 million. UGI Gas will be allocated $43.0 of these Phase 1 capital costs.

[1] *See* Focused Management and Operations Report of UGI Utilities, Inc. UGI Central Penn Gas, Inc. and UGI Penn Natural Gas, Inc., Pennsylvania Public Utility Commission, Bureau of Audits, April 2012

Q. What are the expected annual maintenance costs for the new CIS system?

A. The annual cost of maintaining the new CIS system with the improved features I previously described will be $1.76 million per year. UGI Gas will be allocated $859,000 of these annual maintenance costs. The calculation of the annual operating expense adjustments is discussed in the testimony of UGI Gas witness Ann P. Kelly (UGI Gas Statement No. 2) and shown in UGI Gas Exhibit A (Fully Projected), Schedule D-13.

Q. Are there viable alternatives to replacing the existing CIS systems?

A. No. Like many system improvements, an important consideration other than the direct economic cost must be the implication of not making the investment. As discussed previously, one critical consideration is that the current CIS systems are bordering on technological obsolescence. Assuming that the old systems are not replaced, UGI would eventually no longer have a workforce capable of performing the tasks necessary to maintain the system. Without essential maintenance, the system will begin to degrade, and more manual processes and workarounds will be needed, which could seriously impact the performance of the Contact Center and customer service received by customers. Declining customer service would result in increased numbers of informal and formal complaints to the Commission, or worse. That situation, while not directly measurable in dollars and cents, would be costly to customers and present an untenable situation for the Company, the Commission, and other constituents.

B. UNITE PROGRAM PHASE 1 PROJECT SCHEDULE

Q. Please discuss the schedule that has been developed for the Phase 1 project.

A. The Company has already conducted much of the necessary preliminary work by mapping out the project, confirming essential data, developing requests for proposals, and selecting software and system integration vendors. The remaining steps include developing a complete project plan, creating the business blueprint, building the functionality, testing the functionality, and then preparing for the Go-live date and deployment. The project schedule for Phase 1 contemplates an in-service, Go-live date of September 5, 2017, at which point customers will be fully served by the new CIS system. There also will be a phase to stabilize the new CIS system with the Company's other systems. A high level chart showing the duration of each step of the project is provided in UGI Gas Exhibit TNL-2.

Q. Please explain how operations will be transitioned to the new CIS systems?

A. The Company recognizes that its employees will need to transition from the old CIS systems to the new ones over a period of time. During this transition period, we plan to bring on additional call center and other resources to provide additional call center and other coverage to help manage customer call flow during the first several months after the new CIS is placed into service. This is reasonably necessary to avoid a drop off in customer of service during the interim transition period. The anticipated cost of these additional resources required during the transition period are discussed in the testimony of UGI Gas witness Ann P. Kelly (UGI Gas Statement No. 2) and shown in UGI Gas Exhibit A (Fully Projected), Schedule D-13.

Q. Please describe the activities contemplated for each step of the Phase 1 project timeline.

A. A brief description of each of the Phase 1 project steps is described below:

- **Project Planning** includes defining of goals, objectives, and high level requirements; performing data cleansing; and defining the delivery strategy.
- **Business Blueprint** includes gathering functional requirements; creating business process blueprint; performing solution fit/gap analysis; defining application and technical architecture; analyzing training and communication needs; and continuing data cleansing.
- **Building the Functionality (Realization – Build)** contemplates creating functional and technical specifications; configuring the system; designing, building, and installing development, testing and production environments; and designing and developing a training and communications plan.
- **Testing the Functionality (Realization – Test)** consists of executing product and user tests; performing mock conversions; executing technical and performance tests; testing and piloting of training materials; and assessing business readiness.
- **Go-Live Preparation and Deployment** includes performing data conversions; and deploying applications into UGI's business functions.
- **Post Go-Live Support** stabilization of new CIS with the Company's other systems.

Q. You mentioned that UGI had already selected the vendors for the software and software integration process. When did that occur?

A. The preliminary analysis and vendor selection process for the UNITE Program began in the fall of 2014. The Company studied the experience of several other utility companies to gain an understanding of the resource requirements, cost magnitudes, and processes for developing and implementing a new customer information system. CIS vendor selection began in the Spring of 2015, with a request for proposal process, interviews, and on-site demonstrations by the two vendor finalists in July 2015. The SAP Customer

Relationship and Billing ("CRB") solution was selected due to the scoring of the SAP system against the other finalist, in terms of pricing and total cost of ownership, an evaluation of how the system satisfied various business needs (Business Evaluation), the ease in managing the system (Technical Evaluation), and how the solution met our strategic needs (Industry Strategy). Factors considered by our subject matter experts included customer management, service premise management, rates, usage, billing, account management, credit and collections, service order management, inventory management, and analytics.

In terms of selecting the system integrator, UGI also held an RFP process in which 8 vendors submitted bids. Pricing considerations and qualifications eliminated all but three of the vendors, and the three shortlisted vendors were interviewed extensively as to their proposed solutions, project approach, timeline, resource plan, and pricing. As a result of this process, Deloitte Consulting was chosen for the project.

III. OTHER IS PROJECTS

Q. Mr. Lord, are there other pending IS projects that UGI is planning to implement by the end of the FPFTY ending September 30, 2017?

A. Yes. UGI is planning to implement the following IS projects by September 30, 2017.

Workstation Refresh - the replacement of obsolete workstation equipment, which will include standardization of equipment and workstation administration. The refresh of UGI's workstations will address a number of operational and cyber security related items. Standard operating system images will be established for a greatly reduced variety of workstation equipment thereby significantly simplifying the support of the environment and its end users. In addition, the refresh will eliminate certain current cyber security gaps by removing workstation administrative privileges, implementing data at rest encryption, and enhancing remote connection capabilities.

Network Redesign - a comprehensive assessment and redesign of UGI's data/voice network to address current deficiencies and add capabilities for UNITE and other initiatives. The last comprehensive assessment/redesign was performed over five years ago. The UGI Local and Wide Area Network (LAN/WAN) redesign and upgrade will increase network capacity and resiliency. Additional bandwidth will be provided to UGI offices and remote sites to improve information systems performance and reliability. All sites with have at least a primary and backup connection to the UGI WAN. Offices critical to Customer Service and Safety (including Call Centers, Electric Division Systems Operations, and Gas Control) will have redundant physical network access paths provided by independent telecommunications vendor facilities. The new network design and equipment upgrade will ensure the UGI WAN can support planned information system enhancements.

Cyber Security Enhancements - UGI is further enhancing its cyber security capabilities. UGI will continue to deploy cyber security policies, procedures, and tools to protect utility/customer information and assets from loss, corruption, unauthorized access, use, and disclosure. Planned cyber security tools include Security Information and Event Management (SIEM), Network Access Control (NAC), End point security control, Data Loss Prevention (DLP), and host based Intrusion Detection and Prevention (IDS/IPS) solution. The enhanced security posture provided by the continued enhancement of UGI cyber security will reduce the risk of utility assets being compromised, systems degraded, or unauthorized information accessed. The procedures and tools will enable UGI to detect, contain, and quickly respond to cyber security incidents.

Telephony System Replacement - the current system is technically obsolete and will be replaced, including handsets. The current obsolete private branch exchange (PBX) voice system and handsets will be replaced. The replacement system will improve phone system reliability and call quality. The new phone system will be deployed using the enhanced UGI LAN/WAN to reduce the risk of interruption to customer calls and to reduce the possibility of the system not performing during an emergency. The new phone system will simplify deployment and management enabling problems to be quickly resolved using centralized troubleshooting.

Q. Does this conclude your direct testimony?

A. Yes, it does.

THOMAS N. LORD

SUMMARY

An Information Technology (IT) executive with strong business and technical expertise acquired from over thirty (30) years of successfully defining and executing business strategies coupled with the creation and deployment of IT solutions that align with business goals, objectives, and investments.

PROFESSIONAL EXPERIENCE

UGI UTILITIES **2015 –**

A multi-million dollar utility company, providing natural gas service throughout Pennsylvania and electric service to a number of Pennsylvanian counties.

Vice President; Chief Information Officer

Responsible for the strategic direction and overall management of all UGI Utilities IT functions including the definition, delivery, and support of business enabling IT solutions, ensuring alignment with the company's strategies.

- Establish and guide the company's technology strategy and ensure the provision of information technology solutions that are delivered so as to maximize the strategy in a manner consistent with the company's culture.
- Develop, coordinate, guide, and maintain strategic and operational IT plans in support of the overall mission and business strategy. These plans define a vision for meeting current and future information technology needs, while ensuring alignment and integration of IT with the overall vision, mission, and values of the company.
- Provide vision, strategy, tactical planning, development evaluation, and coordination of the information technology systems and solutions.
- Maintain enterprise systems architecture, defining standards and protocols for data exchange, communication, software, and interconnection of network information systems to ensure optimal performance, availability, and resilience.
- Develop, implement and test on a regular basis disaster and cyber incident recovery processes, ensuring alignment with UGI Utilities business priorities.
- Participate in the full lifecycle of IS staff development including recruitment, hiring, training, managing, coaching and terminating when appropriate. Foster a culture that promotes employee development, engagement and teamwork.

TECO ENERGY **2008 – 2015**

A multi-billion dollar utility company, providing electric service in West Central Florida, natural gas service throughout Florida and New Mexico, and coal mining operations in Kentucky and Virginia.

Director; Enterprise Architecture and Information Systems

Responsible for managing a multi-million dollar annual budget and for defining, evolving, and supporting TECO's IT solutions and ensuring alignment with the company's business strategies.

- Established a company-wide, 3-tier IT Governance Model that includes a top-tier Executive Steering Committee and uses a Portfolio Management approach to evaluating and prioritizing IT investments.
- Defined a multi-year technology consolidation and rationalization plan that is aimed at significantly reducing the number of applications and the variety of technology platforms in TECO's application portfolio.
- Led a cross-company team through the definition, selection, and Board of Director approval of SAP as TECO's Enterprise Resource Planning (ERP) platform, providing Finance and Control, Human Capital, and Supply Chain Management business capabilities.
- As the IT Program Director, managed the 18-month implementation of the ERP platform, completing on time and the overall project being under budget. The implementation won SAP's Utility Project of the year 2012.
- Participating in the definition and refinement of the company's business strategies, providing particular guidance in areas where IT can be used as a key enabler.
- Established a Business Relationship Management function that is the liaison between IT and TECO's business areas, with responsibility for being the primary point-of-contact for all IT activities.
- Guided the approach to analyze, select, acquire, and implement the trouble-tracking and resolution platform for TECO's Tampa Electric and Peoples Gas' businesses with this being one of the first cross-company solutions.
- Led the definition and implementation of a Systems Development Life-Cycle (SDLC) methodology that is used to guide and direct IT projects. A strong emphasis is placed on business process analysis to ensure full business context is captured and used to frame functionality requirements.

SPECIAL DATA PROCESSING CORPORATION **2003 – 2007**

A multi-million dollar direct marketing company specializing in optimizing clients' customer acquisition and sales opportunities.

Vice President; Chief Information Officer

Responsible for managing a multi-million dollar annual budget and for defining, evolving, and operating all aspects of Special Data Processing's IT solutions and ensuring alignment with business strategies.

- Participated in the definition and refinement of the company's business strategies, providing particular guidance in areas where IT could be a competitive differentiator and key enabler.
- Delivered business functionality in support of a single site 1,200 seat Sales Contact Center, with an additional 300 home-based sales associates. On a weekly basis the Center handled 220K inbound sales inquiries, 60K outbound sales attempts (to existing customers), and 25K Customer Service inquiries.
- Defined and created an innovate approach for processing consumer information resulting in $2+M annual savings.
- Analyzed, designed, and managed the development of functionality that established a single, consistent and consolidated, cross-enterprise view of our 100+ million consumers. Reprocessed 13 years of customer contact and sales data and established a baseline view of customer activity.
- Defined, negotiated, and contracted for an IP PBX (Cisco Call Manager), with associated voice-mail and e-mail integration, as a replacement for an existing analog PBX.
- Evaluated and conducted an initial deployment of a "thin client" desktop environment for sales associates, which would deliver a 70% reduction in equipment refresh costs.
- Created and managed a Program Management Office (PMO) that established IT request and prioritization processes and procedures to ensure appropriate focus and utilization of IT personnel and systems.
- Established an Enterprise Architecture, which included the IT Operating Model and IT personnel roles and responsibilities that were mapped to the IT methodology, encompassing the entire SDLC from Analysis through Implementation, including Maintenance.
- Created IT Application Architecture road-map that forms the basis for evolving the existing applications technology and applications and guiding new technology decisions.
- Evaluated IT operating financials and reduced annual expenditures on existing technology by 30% ($750k) while achieving technology upgrades, which included a ten-fold increase in data storage capacity and the introduction and use of "blade" servers and VMWare virtualization products.
- Reviewed and rebuilt the IT Operations group applying focus on automated system alerts that allowed greater resource availability for an enhanced Service Desk team.
- Established and executed a 90 day infrastructure stabilization plan that eliminated frequent server downtime and drastically reduced system recovery time.

LUCENT TECHNOLOGIES, INC. **1998 – 2003**

A multi-billion dollar, multi-national company specializing in the manufacture of telecommunications equipment and the delivery of associated technical services.

Director; IT Customer Relationship Solutions (2001 – 2003)

Responsible for managing a multi-million dollar annual budget allocated for the delivery of all functionality for Lucent's Customer Relationship Management (CRM) and associated Customer focused solutions.

- Led and guided the definition and evolution of Lucent's approach on Customer Relationship Management (CRM), including process and procedure definition and systems analysis, design, remote development, and global deployment.
- Delivered Sales Force Automation functionality through the implementation of Siebel Sales Enterprise software, providing business support for Account Planning, Target Account Selling, Opportunity Management, and Revenue Forecasting.
- Led the redesign of Lucent's Sales Revenue and Manufacturing Demand Forecasting processes and procedures.
- Led the rationalization of existing systems – including multiple Siebel implementations – removing functionality overlap, and consolidating systems resulting in $5M reduction in annual operating costs.

Director; IT Business Services (2000 – 2001)

Responsible for providing all IT services and solutions to Lucent's Technical Support Services business division, a multi-million dollar ($700M in fiscal year 2002) business unit that delivers technical support for all equipment manufactured by the company, which accounts for all warranty and post-warranty maintenance and management services.

- Redesigned Lucent's Technical Support Services processes and procedures, delivered systems enhancements, and implemented related business policies.
- Conducted the integration of multiple Customer Service systems into a single, globally deployed system supporting over 10,000 end-users.

Sr. Manager; IT Strategy, Architecture, & Application Development (1998 – 2000)
Responsible for defining the IT strategy and architecture and implementing essential systems and networking solutions in support of Lucent's multi-million dollar Managed Network Services business.

- Evaluated, selected, and implemented Clarify's Customer Service and Contract Management solution thereby establishing the businesses 1st integrated CRM platform. The $6.5M implementation was completed in 6 months, globally to over 800 end-users, with supporting Interactive Voice Response (IVR), Computer Telephony Integration (CTI), and Web capabilities.
- Services business IT representative on Lucent's Mergers and Acquisition team; participated in the evaluation and integration of a multiple data equipment companies including, Ascend Communication, Livingstone, Prominet Corporation, and Yurie Systems.
- Implemented the Customer and Network Operations Center in Tampa, FL, in support of the service offers, including the design and build of the Operations facility and supporting systems, network infrastructure, and business continuity environment.
- Defined and built the data-centric IT systems architecture, including full integration to Lucent's legacy systems environment. Redefined and implemented the systems and network architecture and infrastructure supporting the Remote Managed Network Service.
- Defined and implemented the IT Operating Model, Methodology, Architecture, and Strategy. An adaptation of EDS' STRADIS® SDLC methodology was created and used to guide and direct IT projects and operational activities.

PRIOR EXPERIENCE 1980 – 1998

- DMR Trecom, Inc.; IT Consulting Company (Tampa, FL); evaluated, hired, and managed IT consulting personnel and delivered a variety of IT client projects, including; data center design and build, network separation, network conversion, business continuity, IT organization definition, billing redesign, and Y2K compliance.
- British Telecom (BT); Syncordia, Global Telecommunications Outsourcing (Atlanta, GA); defined Syncordia's Service Offers. Implemented and managed the delivery of IT solutions in support of the global operating model, including operational procedures, data center design and build, network, and systems infrastructure. Telefónica de España, Network Traffic Management (Madrid, Spain); managed the design and build of Telefónica's Network Operations Centre and associated data center. Implemented modifications to BT's Network Traffic Management systems to align with Telefónica's requirements. National Network Traffic Management (Oswestry, UK); designed, developed, and implemented systems and related operational procedures and approaches for managing BT's entire UK national communications network, utilizing local and off-shore resources. Designed and built data centers for two of BT's management districts.
- Wellingham Computer Services; Accounting and Stock control system; designed and provided programming expertise, and for the production of the tax calculation and handling module of the system.
- Her Majesty's Civil Service; Census Systems; Systems Programmer responsible for providing operational support for a suite of mainframe computers and associated communications processors and networks.

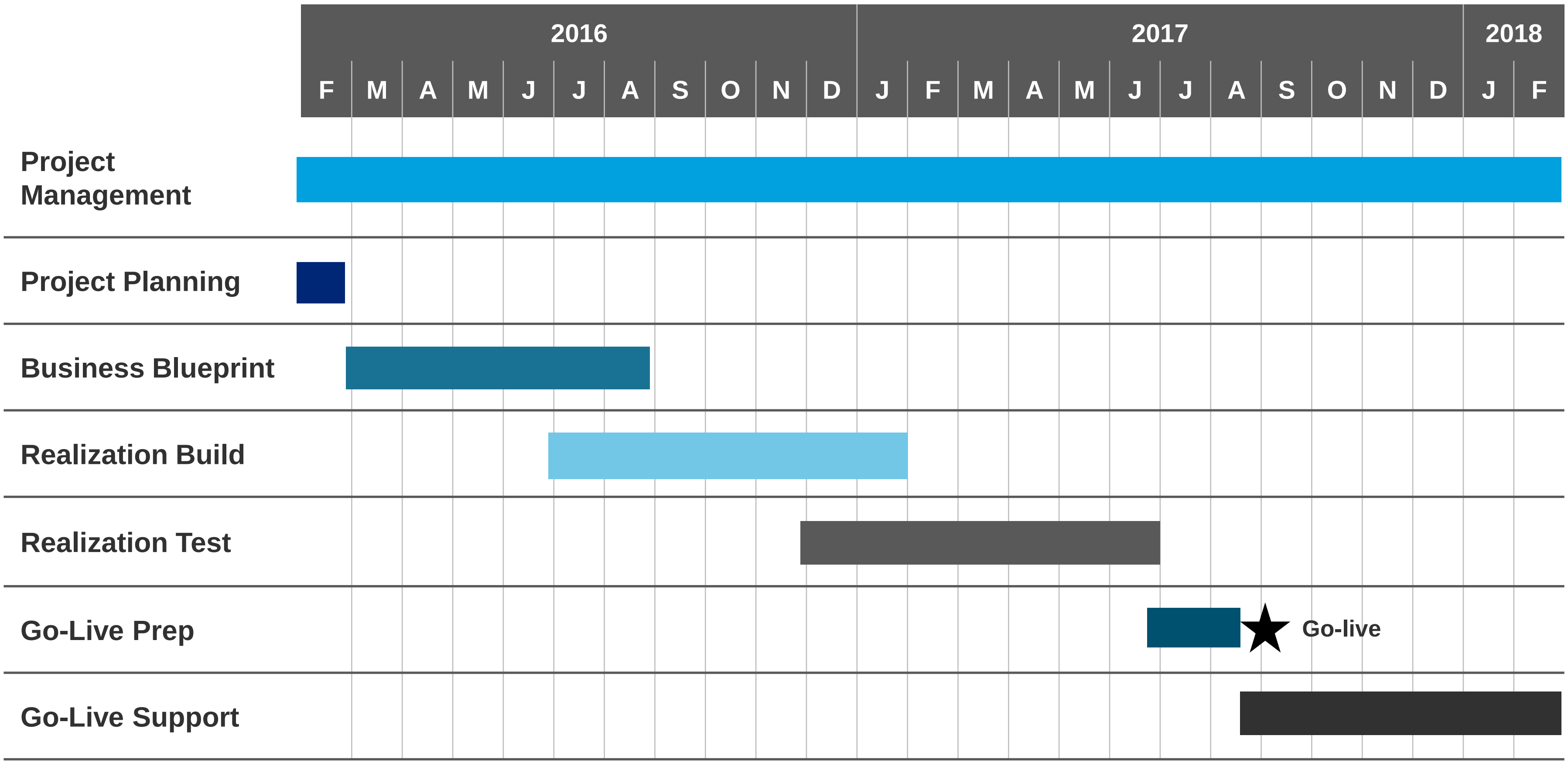
EDUCATION

B.Sc., Computer Science (Honors), Queen Mary College, University of London

TECHNICAL SKILLS

Design, Support Techniques	STRADIS, Structured Design Methodology (SDM), Flow Charting, ITIL v3 Certified
Databases	SQLServer, Oracle, Informix, Reliance, Sybase
Hardware	various, including; Hewlett Packard 9000 series, NetFrame, IBM Compatible PCs, Sun Microsystems, Tektronix workstations, Bay Networks (Nortel) LAN/WAN equipment, Cisco Systems LAN/WAN equipment, Lucent Technologies LAN/WAN equipment, SynOptics Hub, Newbridge Routers, Wellfleet Routers
Software	various, including; Clarify, Oracle, Siebel, SAP, Remedy, Cognos, BusinessObjects, Informatica, Oracle*CASE, Oracle Discoverer, Oracle JDeveloper, Oracle 10G AS Portal, ADW, IEF, BPWin, ERWin, MS Office Suite
Languages	various, including; C, C++, COBOL, Fortran77, Lisp, Pascal, Pro*C, PL/SQL, SQL, SmallTalk
Operating Environments	UNIX (HP, Sun), MS Windows NT/2000/XP/W7, OS/32, GEORGE3, VME2900

UGI UNITE Phase 1 Project Timeline



Project Kick-Off – Early-Mid February 2016 (TBD)
Blueprint – Start 2/29/16 – End 8/26/16
Realization – Start 6/27/16 – End 6/24/17
Go-Live – 9/5/2017

UGI GAS STATEMENT NO. 9 – HANS G. BELL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2015-2518438

UGI Utilities, Inc. – Gas Division

Statement No. 9

Direct Testimony of
Hans G. Bell

Topics Addressed:	**System Operations** **Capital Planning** **System Reliability and Safety** **Environmental Program and Remediation Costs**

Dated January 19, 2016

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Hans G. Bell. My business address is 2525 N. 12th Street, Reading, Pennsylvania, 19612.

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

A. I am employed by UGI Utilities, Inc. ("UGI") as Vice President of Engineering and Operations Support.

Q. What are your responsibilities as Vice President of Engineering and Operations Support?

A. As Vice President of Engineering and Operations Support, I am UGI's senior executive accountable for providing technical leadership and strategic direction to all gas utility engineering and gas technical services functions for UGI and its wholly-owned subsidiaries UGI Penn Natural Gas, Inc. ("PNG") and UGI Central Penn Gas, Inc. ("CPG"), each of which is a certificated natural gas distribution company ("NGDC"). UGI has both a Gas Division ("UGI Gas"), which is a certificated NGDC, and an Electric Division ("UGI Electric"), a certificated electric distribution company ("EDC") (collectively the "UGI Distribution Companies"). For UGI Gas, CPG, and PNG (collectively the "UGI NDGCs"), I am responsible for establishing long-term strategic infrastructure investment plans. For all of the UGI Distribution Companies I am responsible for developing and managing corresponding annual capital budgets. Under my direction is the engineering staff, which is accountable for engineering design, engineering standards, corrosion control, Distribution Integrity Management Program

("DIMP"), Transmission Integrity Management Program ("TIMP"), leak survey, mapping & records, safety, damage prevention, operator qualification, training, and environmental programs.

Q. Please describe your educational background and work experience.

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

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

A. Yes, I presented testimony in two proceedings before the Pennsylvania Public Utility Commission ("Commission") to support the petitions for approval of a Distribution System Improvement Charge ("DSIC") for PNG and CPG, at Docket Nos. P-2013-2397056 and P-2013-2398835, respectively.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Gas. In my testimony I will address the following topics: (1) UGI Gas's system operations; (2) UGI Gas's system reliability and safety record; and (3) UGI Gas's environmental program and associated environmental costs incurred by UGI Gas to address historical environmental liabilities.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following UGI Gas Exhibits: HGB-1 and HGB-2. I am also sponsoring certain responses to the Commission's standard filing requirements as indicated on the master list accompanying this filing.

II. SYSTEM OPERATIONS

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

A. UGI Gas provides natural gas service to approximately 377,000 customers in eastern and central Pennsylvania through a system consisting of approximately 5,525 miles of gas distribution mains and 117 miles of natural gas transmission mains as of December 31, 2014.[1] The UGI Gas service territory is split into two non-contiguous regions: a primary and secondary region. The primary region spans twelve counties: Franklin, Cumberland, York, Dauphin, Lebanon, Lancaster, Berks, Chester, Montgomery, Lehigh, Bucks, and Northampton and includes five of Pennsylvania's ten largest cities: Allentown, Bethlehem, Harrisburg, Lancaster and Reading; along with the suburban communities surrounding them. The secondary region spans four counties: Schuylkill, Luzerne, Carbon, and Monroe and is largely made up of rural communities with Hazleton as the largest city in that area.

Q. Is the UGI Gas service territory supplied by an interstate pipeline?

A. Yes. The primary region is supplied by the Transco pipeline (Leidy and Gulf), as well as Columbia, and Texas Eastern. The secondary region is only supplied by Transco (Leidy).

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

A. UGI Gas maintains operations centers in Bethlehem, Hazleton, Middletown, Lancaster, and Reading.

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[1] Per 2014 U.S. Department of Transportation Report reflecting mileage on December 31, 2014.

Q. How does UGI Gas staff its operations?

A. UGI Gas is a business division of UGI. As of December 15, 2015, UGI Gas had a total of 1048 full-time employees, including: 66 at UGI Electric, 832 at UGI Gas, and 140 at UGI headquarters (Information Systems, Finance, Human Resources, etc.). More than half of these employees are involved in the physical operation and maintenance of the transmission and distribution facilities, which includes the construction, operations and maintenance of mains, services and other facilities, damage prevention and safety, and pipeline regulatory compliance. A smaller number of employees work primarily to support UGI Electric operations. The remaining employees are responsible for administrative duties, marketing, customer service, and credit and collections. UGI provides various management and support services to its wholly-owned NGDC subsidiaries, CPG and PNG (*e.g.*, finance and accounting, payroll, gas supply, engineering, rates, purchasing, fleet, and information technology). UGI and its subsidiaries also benefit from management and support services provided by the parent company of UGI Corporation (*e.g.*, insurance, legal, treasury operations, and corporate governance).

III. CAPITAL PLANNING

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

A. The main areas for which UGI Gas develops capital budgets are: (1) replacement and betterment infrastructure; (2) new business; (3) facilities; (4) Information Technology; and (5) Supply. The budgeting process is further described in the direct testimony of Ann P. Kelly (UGI Gas Statement No. 2).

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

A. Replacement and betterment infrastructure is chosen for inclusion in the capital budget using a risk-based prioritization process. New business projects are chosen based on projections that in turn are informed by large known customers, and forecasts of new business, customer conversions, customer counts, and construction and development in the service territory. Facilities projects are a prioritized set of building-related projects. Information Technology ("IT") projects are selected based on need for investment in new systems and hardware and replacement of old systems and hardware. Supply projects are selected for inclusion in capital planning based on their ability to maximize the utilization of upstream interstate supply capacity and react to cost of supply, one example of which is our attempt to optimize low-cost Marcellus supply.

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

A. UGI Gas's risk-based prioritization process prioritizes the replacement of cast iron and bare steel pipe, which are most susceptible to failure from corrosion, cracks and leakage. Where other facilities that are located near projects are determined to be prone to failure, they will also be prioritized for replacement. As part of its infrastructure upgrade, UGI Gas replaces associated distribution equipment and installs additional safety and monitoring equipment that is compatible with the upgraded design. UGI Gas installs excess flow valves, will replace and potentially relocate meters, and replaces risers, meter bars, regulator stations and service regulators. UGI Gas's prioritization of projects for its capital budgets is consistent with its Long Term Infrastructure Improvement Plan

("LTIIP") for 2014-2019, approved by the Commission at Docket No. P-2013-2398833 (Opinion and Order entered July 31, 2014).

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

A. In 2013 and 2014, UGI Gas has slightly outspent its budgeted capital. In 2015, the capital spend was in alignment with the budget as shown on UGI Gas Exhibit HGB-2.

IV. <u>SYSTEM RELIABILITY AND SAFETY</u>

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

A. Due to its long operation, the UGI Gas distribution system is comprised of pipeline facilities composed of a mixture of materials indicative of the industry's technological advancement over time. Cast iron mains can be found in the oldest parts of the system. The industry then transitioned to bare steel and wrought iron piping, which were prevalent until the 1960s. The first generation of plastic piping was introduced in the early 1970s. Materials installed since the 1970s include polyethylene (PE) and coated steel piping. Overall, the UGI distribution is composed of approximately 86.4% contemporary, post-1970s, materials. This ratio is among the highest of local distribution companies in Pennsylvania.

Q. Please discuss UGI Gas's main replacement program.

A. UGI Gas's main replacement program constitutes a large part of its capital budget. UGI Gas has been identifying and repairing, improving, or replacing its distribution infrastructure on an accelerated basis. As I stated above, UGI Gas has a Commission-approved LTIIP. The LTIIP commits UGI Gas to the replacement of all of its approximately 347 miles of cast iron pipelines over a 13-year period ending in February 2027, and all of its approximately 392 miles of bare steel and wrought iron pipelines over a 28-year period ending September 2041. UGI Gas also committed to replacing gas service lines and moving inside regulators to outside on a planned basis in conjunction with the replacement of the mains to which they are connected. These projects are "DSIC-eligible," meaning that they meet the requirements for recovery in a DSIC. As of December 31, 2014, the remaining mileage of UGI Gas cast iron main declined to 279 miles, and bare steel and wrought iron main declined to 362.5 miles. The 2015 Calendar year figures will be available February 28, 2016 in UGI Gas's annual distribution report.

Q. Does UGI Gas track capital investment associated with these DSIC-eligible main replacements?

A. Yes. Though UGI Gas does not currently have a Commission-approved DSIC, UGI Gas has been tracking DSIC-eligible capital placed in service per calendar year and reporting that information to the Commission on a voluntary basis in its Annual Asset Optimization Plan ("AAOP").

Q. Has UGI Gas so far met its main replacement goals set by its LTIIP?

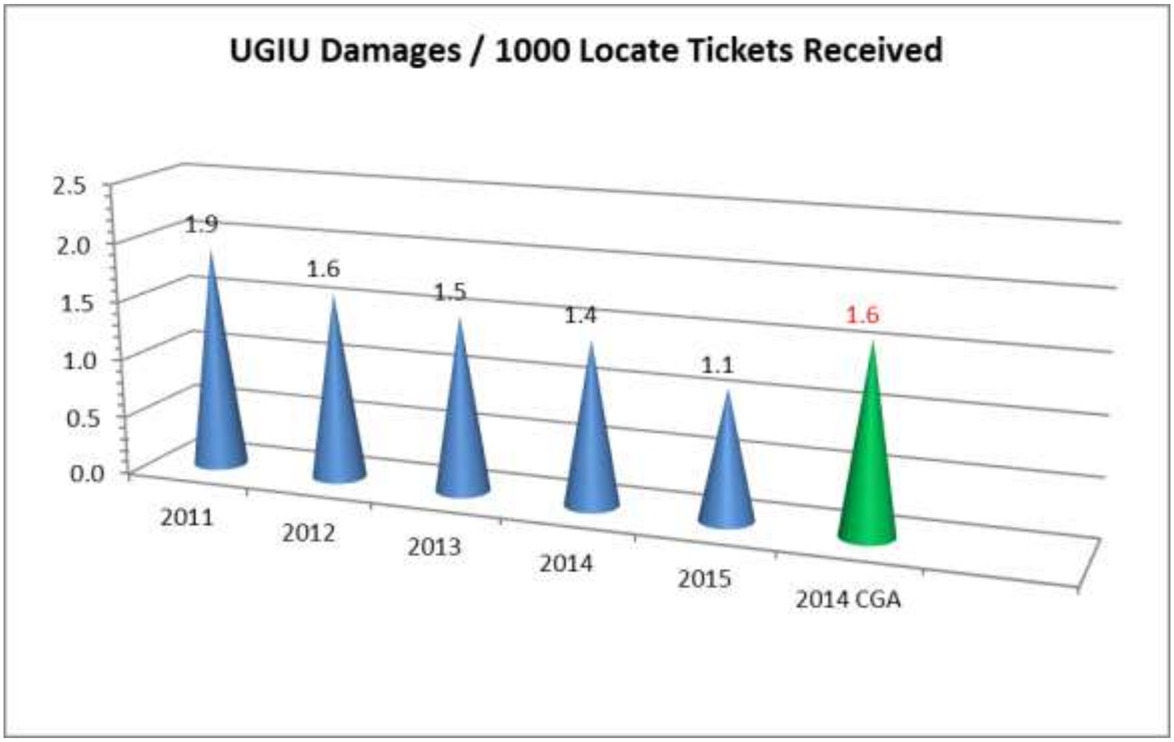
A. Yes. The UGI Gas replacement plan included replacement of approximately 33 miles of combined cast iron and bare steel mains for 2014, with a combined total goal of 62 miles of cast iron and bare steel replacement for all of the UGI NGDCs. As stated in the UGI Gas AAOP, approved by the Commission's Bureau of Technical Utility Services ("TUS") on April 1, 2015 at Docket No. M-2015-2469626, the UGI NGDCs exceeded their combined total 2014 goal by replacing 62.6 miles of cast iron, bare steel, and wrought iron mains. UGI Gas in particular exceeded its goal by replacing 40.4 miles of cast iron, bare steel, and wrought iron mains in 2014. For calendar year 2015, the UGI NGDCs expect to meet or exceed the total main replacement quantities as set forth in the current AAOP.

Q. What is UGI Gas's capital investment associated with these main replacements for 2014 and 2015?

A. In calendar year 2014, DSIC-eligible capital investment for UGI Gas was $59 million, which significantly exceeded UGI Gas's minimum target of $51.2 million. In 2015, UGI Gas again anticipates exceeding the minimum target as set forth in the AAOP. Actual 2015 investment placed into service will be provided in the annual update to the AAOP.

Q. Please discuss UGI Gas's efforts to reduce the level of damage to its pipeline facilities that is caused by third parties.

A. UGI Gas directs significant resources towards damage prevention programs and achieves very favorable results. For the fiscal year ended September 30, 2015, UGI Gas posted an excavation damage rate of 1.1 damages per 1,000 locates received, a rate significantly below industry averages and among the lowest in Pennsylvania. UGI Gas has consistently demonstrated favorable performance in minimizing third party damages as shown below:



* The 2014 CGA is the national damage rate taken from the Common Ground Alliance DIRT Report for 2014, which is available at: www.cga-dirt.com.

Notably, this rate represents a 21% improvement over the prior year during a period in which the number of locate tickets increased by nearly 9%. Efforts contributing to the damage prevention metrics are a robust public awareness program, systematic outreach to project owners and excavators, and root cause analysis of instances of excavation damage. Additionally, UGI is an active participant in the Pennsylvania One Call System where UGI Gas employee Eric Swartley serves on the board of directors.

Q. How are leaks classified on the UGI Gas System?

A. UGI Gas classifies underground leaks as “A”, “B”, and “C”, with “C” being the most severe. An “A” leak is an underground leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous. “B” leaks are underground leaks that are recognized as being non-hazardous at the time of detection, but justify a scheduled repair based on a probable hazard. "C" leaks are underground leaks that represent an existing or probable hazard to persons or property, and require immediate repair or continuous action until the conditions are no longer hazardous.

Q. Has UGI Gas undertaken efforts to reduce leaks on its system?

A. Yes.

Q. Please discuss UGI Gas's efforts to reduce system leaks.

A. UGI Gas has developed consistent specifications for standardized leak classification criteria based on ANSI Z380.1, the Guide for Gas Transmission, Distribution and Gathering Piping Systems, produced by the Accredited Standards Committee ("ASC") Z380 Gas Piping Technology Committee ("GPTC"). The adoption of the GPTC based leak standard made classification criteria more stringent and resulted in an increase in the number of leaks repaired. As of October 31, 2015, the total number of pending leaks on the UGI Gas system has decreased by 11% as compared to the prior prior-year period. Over a five-year time period, which aligns with the leak survey frequency of the full distribution system, the inventory of pending leaks has decreased by more than 43%. Given the severe colder than normal winters of 2013-2014 and 2014-2015, the reductions in leak inventory over this time period is a significant accomplishment. By having a stricter leak standard and fewer leaks, overall system safety has improved.

Another metric indicative of UGI Gas's system integrity is the number of repaired leaks per mile of distribution main. UGI Gas had 0.3 repaired leaks per mile of distribution main in 2014. Only National Fuel Gas and wholly-owned subsidiaries UGI PNG and UGI CPG ranked lower for this metric.

As a part of the DIMP, UGI Gas will regularly re-assess all system risks and leakage trends to determine if additional or accelerated actions are required to further reduce system leaks.

Q. How is UGI Gas's performance in the area of gas odor response rate?

A. UGI Gas performs very well in the timeliness of emergency response to gas odor complaints. For the year ended September 30, 2015, UGI Gas posted an emergency response rate where 96.79% of the time a first responder arrived on premise within 45 minutes of receipt of an odor call. This performance is better than industry averages and is attributable to factors such as staffing levels and after-hours coverage. It should be noted that UGI Gas sets performance goals on a 45 minute response whereas most other distribution companies' goals are based on a one hour response target.

Q. In your opinion does UGI Gas have a good history of employee safety?

A. Yes. The UGI Distribution Companies have a collectively-managed safety program whose safety statistics are reported on a combined basis. The UGI Distribution Companies have made some recent improvements in employee safety as measured by recordable injury rates and motor vehicle accident rates. For the fiscal year ended September 30, 2015, the companies posted an OSHA recordable incident rate of 2.89, a 31% reduction over the prior year, approximately 12% better than the 2014 industry average rate of 3.27. In terms of motor vehicle accident rates, the companies posted a rate of 7.66 accidents per million miles driven, a 15% reduction over the prior year, but approximately comparable to the 2014 industry average rate of 7.70 accidents per million mile driven.

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

A. The UGI Distribution Companies have undertaken significant efforts to build a safety-centric culture to better support and enhance employee safety. Encouraging a safety culture is fundamental to driving safety performance. Some of the strategies implemented to build safety culture include performing detailed accident reviews, holding an Employee Safety Summit and implementing enhancements to the employee safety incentive program.

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

A. Supervisory engagement in post-accident reviews ensures consistency in assessing causal factor trends and in implementing enterprise wide process improvements. Following each accident or injury, supervisors review and document the circumstances of the accident with the employee noting any contributing factors. On a monthly basis, supervisors of employees involved in an accident or personal injury participate in a conference call to review the circumstances surrounding each instance. The calls help drive supervisor accountability for safety performance and provide visibility to any underlying trends. Additionally, metrics on work group safety performance are incorporated into each supervisor's annual performance review.

Q. Please discuss the UGI Employee Safety Summit.

A. In April 2015, just prior to the seasonal ramp up in construction activity, a broad cross-functional group of over 450 employees participated in the first ever full day safety summit. The event included a wide variety of safety education sessions covering topics such as dog bite prevention, electrical safety, and distracted driving. Employee feedback was overwhelmingly positive. Building upon the success of the initial event, in fiscal years 2016 and 2017 new groups of employees will be invited to extend attendance to the full employee population over a 3 year period. Going forward, additional employee-developed content will be emphasized to further cultivate employee ownership of and responsibility for safety.

Q. Please describe the UGI Safety Incentive Program.

A. In 2015, the employee safety incentive program was re-designed to emphasize individual employee engagement in safety. Known as "Making a Difference," the enhanced program rewards employees for supporting safety culture through actions such as demonstrating positive safety behaviors, leading safety meetings, reporting safety issues, or participating in safety education. In fiscal year 2015, 5,490 individual recognition cards were redeemed along with 406 peer-nominated safety award nominations. Advantages of the program include simplicity of administration, customization of reward redemptions, visibility of acknowledgement, and creation of constructive competition around advancing safety.

V. ENVIRONMENTAL

Q. Please discuss the environmental program at UGI Gas.

A. The environmental group at UGI Gas is focused on both environmental compliance programs for current operations and on addressing historical environmental liabilities. With respect to ongoing compliance activities, UGI Gas has a mercury regulator removal program in its primary service area. Service locations with mercury regulators are identified through canvass, and by training meter read and service personnel to recognize mercury regulators when encountered. The mercury regulators are removed and replaced with spring-loaded regulators. The program has already completed its activities in the service area surrounding Lehigh, and is ongoing in Reading, Harrisburg, and Lancaster. UGI Gas also has a program that changes out heater fluid from ethylene glycol to an environmentally-friendly, biodegradable propylene glycol. UGI Gas has also been a partner in the United States Environmental Protection Agency's ("EPA") voluntary Natural Gas STAR program since the program's inception in 1993. Natural Gas STAR provides a framework to encourage partner companies to implement methane emissions reducing technologies and practices, and document their voluntary emission reduction activities. As discussed earlier in my testimony, UGI Gas places significant emphasis on reducing system leaks for both safety and environmental reasons.

Q. Are there any other significant environmental programs at UGI Gas?

A. Yes, there is also our manufactured gas plant ("MGP") program. As a company with a history of providing gas service for more than 100 years, UGI Gas has some sites in its service territory that were formerly used for the purpose of producing manufactured gas from coal for distribution to utility customers. UGI Gas works to remediate these MGP sites to address any environmental site conditions due to the former manufactured gas operations.

Q. What types of costs does UGI Gas incur with respect to addressing MGP site conditions?

A. UGI Gas incurs costs attributed to site investigations, remediation, and site restoration. There also may be costs incurred to obtain an environmental covenant at the site to prevent certain uses of the site, and miscellaneous costs, as applicable, associated with transferring the site to a third party (such as with a dedication for public use) once the site has been restored.

Q. What is UGI Gas's projected spending on the MGP program?

A. UGI Gas has developed a plan to spend $3-5 million per year as of the end of the fully projected future test year ending September 30, 2017 ("FPFTY"). This plan is predicated on a significant increase to UGI Gas's historic level of investigation and remedial activity to address environmental concerns at former MGP sites. UGI Gas's plans will be conducted in a manner that is consistent with Pennsylvania Department of Environmental Protection ("PA DEP") and EPA regulations and requirements.

Q. Please describe UGI Gas's accounting for MGP costs.

A. Historically, UGI Gas has accounted for its environmental remediation expenses as a component of its annual cost of removal. As such, these expenses were recorded in UGI

Gas's accumulated reserve for depreciation and reversed through the annual calculation of the amortization of net salvage.

Q. Is UGI Gas proposing an alternative treatment for MGP costs in the future?

A. Yes. The treatment of MGP costs is addressed in the direct testimony of Ann P. Kelly (UGI Gas Statement No. 2).

Q. **For which sites is UGI Gas currently incurring costs to address its liability for historical MGP operations?**

A. There are three UGI Gas MGP sites for which the Company is currently incurring costs. These sites include the former Columbia MGP Site in Columbia, Pennsylvania, the former Allentown MGP Site in Allentown, Pennsylvania, and the former Mount Joy MGP Site in Mount Joy, Pennsylvania.

Q. What is UGI Gas's goal for restoration of the MGP sites?

A. UGI Gas strives to restore each site so that it constitutes a beneficial reuse and becomes an asset to the community. With respect to the Mount Joy MGP Site, for example, we have proposed to develop a portion of the restored site as a public park for use by the residents of Mount Joy Borough.

Q. What future activities has UGI Gas planned to address MGP impacts?

A. UGI Gas plans to take an approach that is consistent with the approach historically embraced by its subsidiary utilities CPG and PNG. CPG and PNG each have a multi-site

Consent Order and Agreement ("COA") with PA DEP that govern remedial activities on the former MGP sites listed in the COAs. CPG and PNGs activities under the COA are closely monitored by the PA DEP. A total of 33 sites are listed under the two COAs – 22 under the CPG COA and 11 under the PNG COA. In accordance with the COAs, CPG and PNG are each required to either obtain a certain number of points per calendar year based on defined eligible remedial activities or make expenditures in an amount equal to an annual environmental cost cap of $1.75 million for CPG and $1.1 million for PNG.

UGI Gas has identified a number of former MGP sites that were previously used to render gas service to customers in Pennsylvania. UGI Gas, while currently not under a COA approved by the PA DEP, has developed a remedial plan for its former MGP sites that contemplates an expenditure of approximately $3-5 million per year over the next several years on PA DEP monitored activities.

Q. Has UGI Gas been recognized for its environmental stewardship?

A. Yes. A 2015 survey by Cogent Reports™, a division of Market Strategies International, included UGI among 36 utility companies nationwide that were named "Environmental Champions." Cogent surveyed more than 25,000 residential electric, natural gas, and combination utility customers of the 125 largest U.S. companies. Our high ranking in this survey demonstrates that our customers recognize our commitment to the environment.

Additionally, in 2012, UGI, and UGI Gas's current Environmental Manager Anthony Rymar received the Pennsylvania Environmental Council's Governor's Award for Environmental Excellence. We were nominated for the award by PA DEP staff. In bestowing the award, the Pennsylvania Environmental Council recognized Mr. Rymar and UGI as consistently exhibiting a management philosophy that assures former manufactured gas plants are remediated to a level that protects human health and the environment while ensuring sites are beneficially re-used.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS EXHIBIT HGB-1

Hans G. Bell, P.E.

hbell@ugi.com

Summary

Engineering executive with 20 years of broad experience in gas transmission and distribution operations including engineering design, asset integrity management, regulatory compliance, capital budgeting, and project management.

Education

Keller Graduate School of Management, Chicago, Illinois

Masters of Business Administration*, Graduated with Distinction, 2000*
Concentration in Finance

University of Illinois, Champaign, Illinois

Bachelor of Science in Civil Engineering*, 1996*
Concentration in Construction Management

Experience

UGI Utilities, Reading, Pennsylvania

Vice President, Engineering and Operations Support *2013- Present*

Senior engineering leader responsible for establishing technical strategy and executing infrastructure programs to ensure safe, reliable, and cost effective natural gas service for a utility serving more than 600,000 customers in Pennsylvania and Maryland.

- Accountable for accelerated infrastructure replacement programs, capital budgeting (~$300M), contractor management, corrosion control, damage prevention, employee safety, engineering design, transmission & distribution integrity, regulatory compliance, training, and all related technical support functions
- Accountable for planning and execution of annual cast iron / bare steel replacement program covering > 62 miles per year
- Primary regulatory witness and author for Long Term Infrastructure Improvement Plans
- Responsible for management and development of professional and technical support staff of over 110 employees

AGL Resources, Naperville, Illinois

Over 17 years at AGL Resources (Nicor Gas) I advanced through positions of increasing responsibility beginning at entry level and concluding as Managing Director of Engineering.

Managing Director, Engineering *2012-2013*

- Accountable for Engineering Design, Land Management, and System Planning supporting gas transmission, storage, and distribution operations spanning 11 states serving over 4.5 million customers
- Managed capital budgets of >$200M including budget development, variance reporting, and project prioritization
- Accountable for oversight of right of way acquisitions in advance of major pipeline projects
- Developed long term investment plans for infrastructure replacement, optimization, and growth

Assistant Vice President Engineering & Chief Engineer *2011- 2012*

- Accountable for all gas utility engineering support departments with over 50 professional and technical staff including Engineering Design, Transmission Integrity, Distribution Integrity, System Planning, Geographic Information Systems, Measurement, and Technical Services (Lab)
- Accountable for Transmission & Distribution Integrity Management compliance, audits, plans, program management, and project portfolio optimization

- Accountable for Engineering Design and project management for distribution, storage, and transmission projects from initial scope, detailed design, cost estimates, sourcing, and contract negotiation
- Managed multiple interdisciplinary project teams executing complex multi-million dollar storage and transmission projects
- Managed regulatory relationships with State (ICC) and Federal Pipeline Safety Agencies (PHMSA). Provided technical support to incident investigations
- Developed strategic approaches to addressing pipeline safety legislation including MAOP affirmation
- Developed engineering integration plans for AGL Resources– Nicor Gas merger including, organizational design, critical process mapping, accountabilities, budgeting, and staffing

General Manager System Integrity & Chief Engineer *2007 - 2011*

- Responsible for management of multiple departments including Engineering, Transmission Integrity, Distribution Integrity, System Planning, and Geographic Information Systems
- Responsible for development and management of infrastructure capital budgets of approximately $65 million
- Managed contracts with engineering consulting firms for pipeline design, construction, survey, and professional services
- Implemented a Distribution Geographic Information System including database design, data conversion of over 34,000 miles of distribution pipe, and deployment of a mobile GIS application to all front line workers

Manager Engineering Design *2004- 2007*

- Responsible for managing departmental capital budget in excess of $20 million annually
- Provided project management oversight to pipeline projects from concept, feasibility, budgeting, approval, planning, design and implementation
- Maintained engineering consultant relationships and negotiated service contracts
- Implemented process improvements including development of Geographic Information System (GIS) based map distribution application
- Managed pipeline construction projects, negotiated construction contracts, resolved permitting issues, and delivered project approval presentations

Project Manager – Transmission Pipeline Integrity *2003 –2004*

- Responsible for development and implementation of pipeline integrity management program to maintain regulatory compliance with the Pipeline Safety Act of 2002
- Managed GIS conversion project for 1150 mile natural gas transmission system
- Developed risk management program for prioritization of pipeline integrity assessments in high consequence areas
- Determined pipeline assessment project schedules including long term operating expense and capital budgets

Region Manager – Distribution *2001 – 2003*

- Manager responsible for construction and maintenance activities of gas distribution utility
- Managed projects involving main installations, service installations, and leak repairs
- Measured and tracked performance of 50 personnel against productivity and safety benchmarks
- Coordinated response to emergencies including gas leaks and pipeline breaks

Supervisor of Distribution Planning *2000 - 2001*

- Supervised staff of six engineers in distribution planning department
- Coordinated hydraulic modeling studies of 34,000 mile natural gas distribution system serving over 2 million customers
- Recommended capital improvement projects required to maintain uninterrupted reliable peak day service throughout entire natural gas distribution network
- Coordinated long range planning studies and forecasts used to develop capital budgets

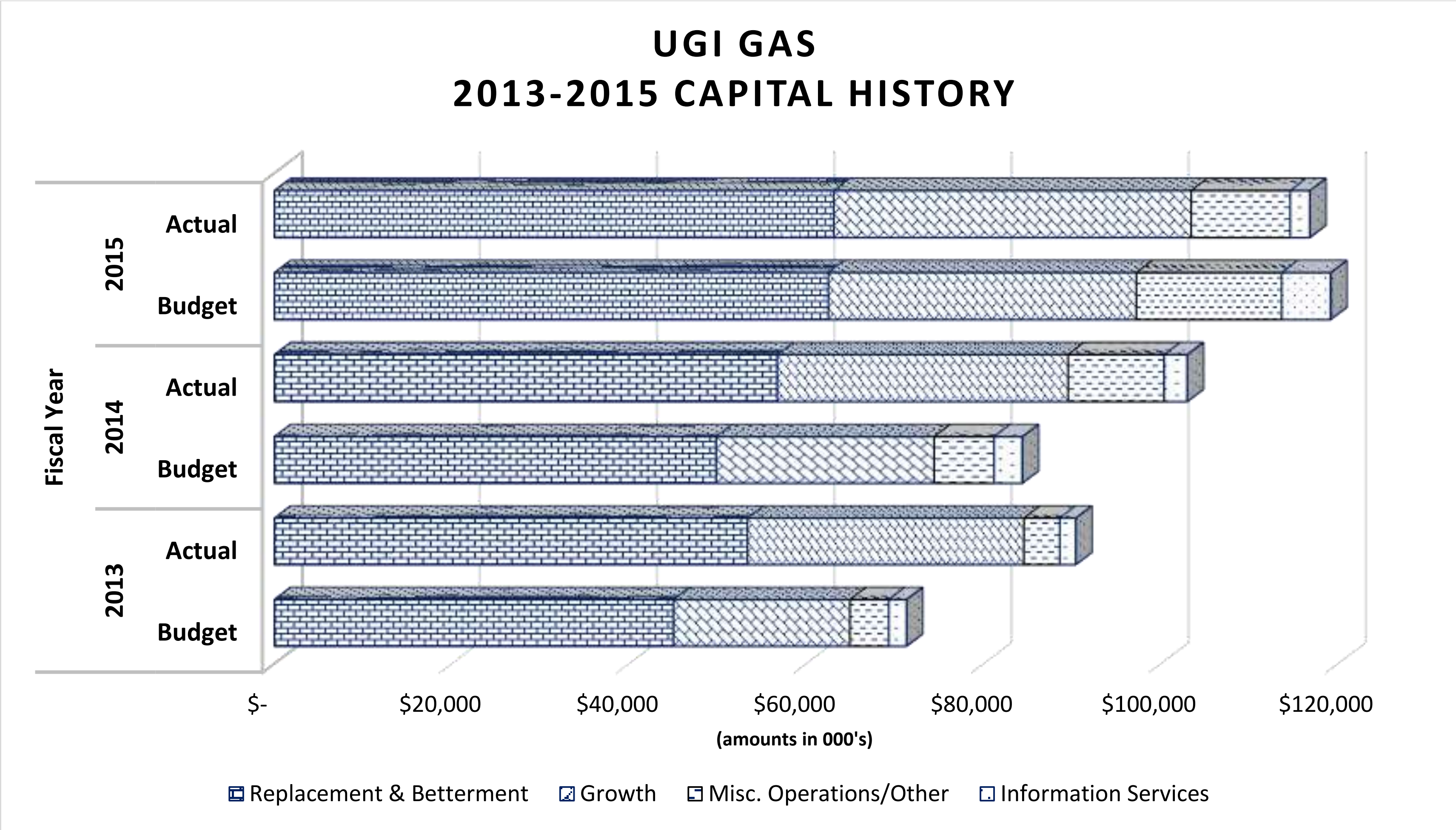
Project Engineer *1996 –2000*

- Managed pipeline construction and maintenance projects, supervised inspectors and company maintenance crews
- Designed plans for installation and revision of gas distribution facilities
- Reviewed highway improvement plans and worked with state transportation engineers to resolve utility conflicts

Professional Affiliations

- Licensed Professional Engineer, State of Illinois, License # 62054443
- Member Society of Gas Operators – 2015 to present
- American Gas Association Bronze Award of Merit 2012
- Member American Gas Association Leadership Council
- Chair American Gas Association Distribution & Transmission Engineering Committee 2012 - 2013
- Speaker at PHMSA Distribution Integrity Management Workshop 2011
- Co-chair of Southern Gas Association Distribution Engineering Committee 2007-2010

UGI GAS EXHIBIT HGB-2


UGI GAS
2013-2015 CAPITAL HISTORY
Fiscal Year
2015
Actual
Budget
2014
Actual
Budget
2013
Actual
Budget
$-
$20,000
$40,000
$60,000
$80,000
$100,000
$120,000
(amounts in 000's)
Replacement & Betterment
Growth
Misc. Operations/Other
Information Services

UGI GAS STATEMENT NO. 10 – NICOLE M. MCKINNEY

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2015-2518438

UGI Utilities, Inc. – Gas Division

Statement No. 10

Direct Testimony of
Nicole M. McKinney

Topics Addressed: **Taxes and Tax Adjustments**

Dated: January 19, 2016

7135779v4

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 Principal Tax Analyst. UGI is a subsidiary of UGI Corporation ("UGI Corp."). UGI has two separate operating divisions: UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company") and UGI Utilities, Inc. – Electric Division.

Q. What are your principal duties and responsibilities as Principal Tax Analyst?

A. My primary duties as the Principal Tax Analyst 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.

Q. What is your educational background?

A. I received a Bachelor of Business Administration in International Business and Management with a minor in Accounting from Villanova University in 2006. In

2007, I completed a Master's Degree of Accountancy from Villanova University. I am also a Certified Public Accountant.

Q. Please describe your professional experience.

A. I began my career with Andersen Tax (formerly known as WTAS, LLC) in 2006. In 2010, I joined Baker Tilly Virchow Krause, LLP (formerly known as ParenteBeard, LLC) as a manager in their middle-market tax practice where I managed tax compliance engagements, and international and special tax projects. From 2012-14, I worked as the Federal Domestic Tax Manager for Dentsply International Inc., overseeing the U.S. federal tax compliance and income tax accounting processes. In March of 2015, I began working as the Principal Tax Analyst for UGI.

Q. Please describe the purpose of your testimony.

A. I am providing testimony on behalf of UGI Gas. I will explain the Company's pro forma tax adjustments to its principal accounting exhibits for the fully projected future test year ending September 30, 2017 ("FPFTY"). I will also explain the tax adjustments made to the results of UGI Gas's historic test year ended September 30, 2015 ("HTY") and future test year ending September 30, 2016 ("FTY").

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

A. Yes. Together with other Company witnesses, I am sponsoring portions of UGI Gas Exhibit A (Fully Projected), UGI Gas Exhibit A (Future) and UGI Gas Exhibit

A (Historic) that pertain to tax-related issues. These exhibits comprise UGI Gas's principal accounting exhibits for the HTY, FTY, and FPFTY. I am also sponsoring certain responses to the Commission's filing requirements and standard data requests. Each response identifies the witness sponsoring it.

II. <u>TAX ADJUSTMENTS</u>

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

A. As explained in the direct testimony of Ann P. Kelly (UGI Gas Statement No. 2), UGI Gas's principal accounting exhibit is UGI Gas Exhibit A (Fully Projected), which includes a presentation for the FPFTY ending September 30, 2017. Section D of UGI Gas Exhibit A (Fully Projected) presents necessary adjustments to budgeted levels of expense items and revenues. The pro forma adjustments related to taxes are summarized in Schedules D-31 through D-34. These tax adjustments are used to derive UGI Gas's pro forma income at present and proposed rates as set forth in Schedule A-1 of the same exhibit.

UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic) follow the format of UGI Gas Exhibit A (Fully Projected), but reflect data for the HTY ended September 30, 2015, and the FTY ending September 30, 2016. This information is provided in an effort to comply with the Commission's filing requirements and provides a basis for comparing UGI Gas's FPFTY claims with actual book results from the HTY and adjusted FTY results. Section D to UGI Gas Exhibit A (Historic), Schedule D-31, and UGI Gas Exhibit A (Future), Schedule D-31 include adjustments that share the same methodology as used in Schedule D-31 of UGI Gas Exhibit A (Fully Projected).

A. TAXES OTHER THAN INCOME TAXES

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

A. TOTI amounts were based on the plan year budget, as adjusted for reasonably known and measurable changes to various payroll and other taxes, as well as other changes due to changes in headcount as supported by the direct testimony of Ann P. Kelly (UGI Gas Statement No. 2). Specifically, TOTI includes an adjustment for the planned phase out of the capital stock tax in the 2016 tax year. These adjustments are shown on UGI Gas Exhibit A (Fully Projected), Schedule D-31. The net adjustment of ($138,000) 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 Gas 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 Gas is also proposing to normalize the tax repairs expense deduction for both federal and state tax purposes. The fully adjusted claim for the FPFTY income tax expenses is shown on UGI Gas Exhibit A (Fully Projected), Schedule D-1.

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

A. The calculation of federal and state income taxes 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 Gas's capital structure recommended in the direct testimony of Paul R. Moul (UGI Gas Statement No. 3) 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 expenses 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. Line 30 reflects a decrease to total tax expense for the amortization of the Company's Investment Tax Credit, while line 31 reflects the total combined income tax expense after this adjustment. 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. Has the Company reduced federal income tax expense through application of a consolidated tax expense adjustment?

A. No. The company does not believe that such an adjustment is appropriate. However, in the event a consolidated tax adjustment is adopted by the Commission, we have included a calculation of such an adjustment using the modified effective tax rate methodology traditionally used by the Commission in the response to filing requirement II-A-26.

Q. Why did the Company not include a consolidated tax adjustment in the calculation of its income tax expense shown in UGI Gas Exhibit A (Fully Projected)?

A. The Company did not include a consolidated tax adjustment in UGI Gas Exhibit A (Fully Projected) primarily due to two reasons. First, while the Company recognizes the legal precedent requiring a utility to reduce its income tax expense by a proportionate share of certain tax losses experienced by non-utility members of a consolidated tax group, we do not believe that it is appropriate to do so as a matter of sound ratemaking policy considering the overwhelming precedent that holds that utilities may not establish their ratemaking revenue requirements by including the costs of their unregulated affiliates in utility rates. As the Company has no expectation that its customers should bear the income requirement of its non-utility affiliates as an increase to our utility revenue requirement, our customers should have no expectation that our rates should be reduced by tax losses generated from the income of our non-utility affiliated business enterprises. Second, I note that there is legislation pending that would effectively eliminate the consolidated tax savings adjustment that may be enacted by the end of the FPFTY.

Q. Please describe the consolidated tax adjustment calculation shown in the response to filing requirement II-A-26.

A. The consolidated tax adjustment shown in the response to filing requirement II-A-26 is calculated in accordance with Commission practice using the modified effective tax rate method. Under this method, tax losses for existing non-regulated companies in the consolidated group are aggregated with and allocated to the companies (both regulated and non-regulated) with taxable income in proportion to their taxable income.

The consolidated tax adjustment shown in the response to filing requirement II-A-26 was calculated using a three-year average of UGI's income and the UGI Corp. consolidated group's taxable income that encompasses the years 2012 to 2014. Companies that are no longer part of the consolidated group, that are not expected to have recurring losses, or that will exit the consolidated group during the test year were eliminated from this calculation. For each of the three years, the adjusted tax losses of non-regulated corporations in the UGI Corp. consolidated group were summed, and a portion was allocated to UGI's operations based on the proportion of the UGI taxable income to all corporations (regulated and non-regulated) with positive taxable income. Once the allocation percentage was determined, it was applied to the losses of the consolidated loss companies, and from that figure UGI's percentage of the consolidated taxable income was used to derive the loss allocable to UGI for each of the three years in the analysis. The average of these losses was then allocated between UGI Gas and UGI Electric based on the proportionate share of each entity's taxable income from the most recently filed federal income tax return, fiscal year ended September 30, 2014. The allocation to UGI Gas is $181,000.

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

A. As shown on Schedule D-33 at line 31, the pro forma tax expense at present rates is $13.962 million and the pro forma tax expense at proposed rates for the FPFTY is $37.856 million. Again, 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, 2017. This amount is deducted from rate base. The total shown on line 7 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 8. As the state tax consequence of accelerated depreciation is flowed through, there is no associated state ADIT balance.

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

A. As shown on line 9 of Schedule C-6 and on line 6 of Schedule A-1, the ADIT offset is $307.196 million, which includes an amount related to the repairs tax method explained below.

D. REPAIRS TAX METHOD

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

A. In its tax return for the year ended September 30, 2009, UGI 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's (both UGI Gas and UGI Electric operating divisions) federal tax expense for the year ended September 30, 2009, was reduced by $25,463,817.

UGI 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 has also chosen to calculate its state income tax expense consistent with normalization. The state ADIT balance associated with the repairs tax deduction is classified as a regulatory liability. In both the federal and state instances, the ADIT balance amortizes or unwinds over the remaining life of the asset. By accounting for the Repairs Tax Method in this way, the repairs tax deduction flows through to ratepayers over the same period that the related assets would have been capitalized and depreciated for tax purposes.

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

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS STATEMENT NO. 11 – THEODORE M. LOVE

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2015-2518438

UGI Utilities, Inc. – Gas Division

Statement No. 11

Direct Testimony of
Theodore M. Love
(Green Energy Economics Group, Inc.)

Topics Addressed: **Energy Efficiency & Conservation Plan and Total Resource Cost Implementation**

Dated: January 19, 2016

I. INTRODUCTION

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

A. My name is Theodore M. Love, and I am the Senior Analyst and Data Scientist at Green Energy Economics Group, Inc. ("GEEG"), an energy consulting firm founded in 2005. My office address is 147 South Oxford Street, Brooklyn, New York.

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

A. My testimony is submitted on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas").

Q. Please briefly describe your qualifications.

A. I have been involved in the review and preparation of both gas and electric energy efficiency plans, as well as potential studies and cost-effectiveness analysis, in nearly a dozen states, two Canadian Provinces, and China, since I began working with GEEG in 2007. Most relevant to this proceeding, I have been advising Philadelphia Gas Works ("PGW") on their energy efficiency activities since August 2008. My full resume is attached as UGI Gas Exhibit TML-1.

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

A. Yes. In 2015, I presented testimony on behalf of PGW in support of the continuation of their demand-side management ("DSM") gas programs for a second five-year phase under Docket No. P-2014-2459362.

Q. What is the purpose of your testimony?

A. I will be describe the development of the UGI Gas Energy Efficiency and Conservation Plan ("EE&C Plan" or "the Plan"), provide an overview of the programs proposed under the Plan, and provide details on the Plan's benefits and costs.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

- UGI Gas Exhibit TML-1 – Resume of Theodore M. Love; and
- UGI Gas Exhibit TML-2 – UGI Gas's Five Year Energy Efficiency & Conservation Plan.

Q. Please summarize your testimony.

A. In Section II, I explain why it is appropriate and important for UGI Gas to implement natural gas energy efficiency and conservation programs. I also give an overview of the proposed programs and how they were developed. In Section III, I discuss the benefits, costs and staging of the proposed portfolio of programs. Section IV provides a summary of each of the proposed programs. Finally, I provide my conclusions and recommendations in Section V.

UGI Gas proposes to invest $24.8 million in real 2015 dollars in energy efficiency programs over the next five years and, if implemented, expects to reduce natural gas consumption by 7,385 Billion British thermal units ("BBtus") over the lifetime of the installed measures. The energy efficiency programs provide UGI Gas customers with present value of total resource benefits of $53.9 million at cost of $30.6 million, including participant investments, for a net benefit to customers of $23.2 million with a

Total Resource Cost ("TRC") benefit-cost ratio ("BCR") of 1.76. The proposed Combined Heat and Power ("CHP") Program is projected to cost $2.8 million in real 2015 dollars over the five-year period. This investment would lead to a 25,591 BBtu reduction in net primary energy usage over the lifetime of the installed CHP units, and avoid the emission of approximately 101,000 tons of carbon dioxide per year by the end of the five-year period. The CHP program provides $44.6 million in net total resource benefits with a BCR of 1.60. Combined, the energy efficiency programs and CHP Program provide $67.9 million in net total resource benefits with an overall TRC BCR of 1.65.

II. OVERVIEW AND BACKGROUND

Q. Why is it appropriate for UGI Gas to implement energy efficiency and conservation programs?

A. Improving efficiency and addressing climate change in all end uses of our energy resources is an increasingly important part of this nation's energy, economic, and environmental policy goals. Over the past decade numerous nationwide initiatives have focused on improving efficiency, including large portions of funding from the American Recovery and Reinvestment Act of 2009 ("ARRA") to the Clean Power Plan ("CPP") ruling recently issued by the United States Environmental Protection Agency ("US EPA"). In Pennsylvania, the General Assembly has embraced this view by the passage of Act 129, of 2008[1] ("Act 129") that mandates, among other things, the implementation of electric distribution company ("EDC") programs, funded by ratepayers, to promote

[1] Act 129 of 2008, P.L. 1592, 66 Pa.C.S §§ 2806.1 and 2806.2.

electric energy conservation and efficiency improvements. Phase II of Act 129 was approved in 2012, and Phase III of Act 129 was approved in June of 2015, central to which is the continuation of mandatory electric efficiency programs. This reaffirmation of support for Act 129 confirms the value that utility-facilitated electric efficiency provides to the residents of Pennsylvania. A similar undertaking by natural gas distribution companies ("NGDCs") is expected to have similar beneficial impacts.

Furthermore, PGW has been successfully operating a voluntary portfolio of natural gas energy efficiency programs for the past five years. These programs have resulted in over 260 BBtus in incremental annual gas savings and a present value of TRC net benefits of $5.7 million from inception through August 31, 2014. PECO also offers customers rebates for energy efficiency furnaces through their Smart Gas Efficiency Upgrade program, and Peoples Natural Gas has committed to the preparation of an EE&C Plan by the end of 2016.[2]

Altogether, over 30 years of program experience across North America, as well as many years of activity in Pennsylvania, proves that large-scale energy efficiency and conservation investment portfolios can be effectively and cost-effectively administered by the distribution utilities responsible for delivering energy service.

Q. Will the Plan, if implemented, benefit UGI Gas's customers?

A. Yes, it will. Section 1.3 of the EE&C Plan (UGI Gas Exhibit TML-2) describes the goals of the portfolio as the following:

[2] Settlement in Docket Nos. A-2013-2353647, A-2013-2353649, A-2013-2353651 before the Pennsylvania Public Utility Commission.

- Help customers save energy cost-effectively through a holistic approach to energy efficiency and conservation.
- Avoid lost opportunities and provide deep levels of savings.
- Provide a wide range of services for UGI Gas's diverse customer base.
- Contribute to the economic welfare of its customers and Pennsylvania.

UGI Gas is proposing to spend $24.8 million in real 2015 dollars towards energy efficiency programs, an investment that will return a present value of total resource net benefits of $23.2 million and save customers 7,385 BBtus of gas over the lifetime of measures installed. For the CHP program, an investment of $2.8 million in real 2015 dollars is projected to return present value total resource benefits of $44.6 million. Furthermore, the program should avoid approximately 101,000 tons of carbon dioxide emissions per year by the end of the five-year period, which I expect to be countable towards Pennsylvania's CPP goals.

Q. How was the Plan developed?

A. As described in Section 1.4 of UGI Gas Exhibit TML-2, the Plan was developed in three stages. The first stage involved the characterization of measure costs, savings, and cost-effectiveness of eligible measures. An achievable scenario was developed for each of the cost-effective measures for the second stage. Finally, the programs were designed and staged to meet budget goals and follow best practices in program and portfolio design.

Q. What kinds of efficiency opportunities does UGI Gas's EE&C Plan target?

A. UGI Gas plans to implement a comprehensive portfolio of six natural gas efficiency programs and a CHP program to capture energy efficiency and conservation opportunities available through four distinct types of market transactions. The first source of savings is to upgrade the efficiency of new gas-using appliances and equipment when those appliances and equipment require replacement. This market opportunity is called "natural replacement." The second opportunity to improve efficiency is before a building or renovation is designed and constructed, otherwise known as the new construction and gut renovation market. The third source of gas savings is to increase energy efficiency of existing buildings by retrofitting them with supplemental measures (like attic insulation) and with early replacement of inefficient equipment with high-efficiency models (like boilers and furnaces). The retrofit market also includes some larger opportunities to reduce overall net energy usage through fuel-switching measures, such as CHP plants. The final source of gas savings is to change customer behavior to use less energy without necessarily installing new equipment, a relatively new, but quickly growing sector of the efficiency market. UGI Gas's EE&C portfolio is explicitly designed and planned to achieve cost-effective savings through all four types of market transactions among residential and nonresidential customers by introducing programs to address each in the four-stage sequence.

Q. What are the programs proposed for inclusion in the Plan?

A. The following six natural gas energy efficiency programs are proposed for the five-year portfolio:

- Residential Prescriptive (RP)

- Nonresidential Prescriptive (NP)
- New Construction (NC)
- Residential Retrofit (RR)
- Nonresidential Retrofit (NR)
- Behavior and Education (BE)

The Plan also includes a CHP program that is proposed as a separate fuel-switching program, and a crosscutting budget for portfolio-wide administrative costs. These programs will be discussed in more detail later in my testimony.

Q. Has UGI Gas provided detailed plans for the proposed programs?

A. Yes, Section 2 of UGI Gas Exhibit TML-2 provides a detailed plan for each of the programs, including annual budgets, savings, and participation projections along with more information on program design, eligible rate classes, target markets, incentive approach, marketing, evaluation, measurement, and verification ("EM&V"), as well as implementation.

Q. Is UGI Gas's EE&C Plan modeled on successful efforts elsewhere?

A. Yes. UGI Gas's proposed portfolio incorporates many of the strategies proven effective around the country, by program administrators like National Grid in Massachusetts ("NGrid"), as well as by natural gas program administrators in Pennsylvania, such as PGW.

Q. What best practices in program and portfolio design are incorporated in the Plan?

A. Providing incentives to defray the efficiency cost premium for the purchase of new high-efficiency new equipment has been the cornerstone of gas energy efficiency efforts across the country for decades. Best practices included making sure that UGI Gas has the flexibility to address changing market conditions as new technologies enter the marketplace and as codes and standards are adopted that eliminate the least-efficient equipment. UGI Gas's minimum efficiency requirements will be updated to meet increasingly strict federal standards and to align with minimum requirements established in other leading efforts from utilities such as NGrid and PGW. These programs will also aggressively target market participants throughout the supply chain.

The most successful new construction programs take an integrated approach to building efficiency. These programs coordinate the multiple functions and stages associated with building construction with the array of efficiency opportunities across building energy sources and end uses. Financial incentives typically defray most or all of the incremental cost of high-efficiency design, equipment, and construction over and above standard market practice.

In the residential retrofit market, UGI Gas's program will target high-use customers while also allowing self-selected participation. Low cost audits will require blower-door tests in order to facilitate advanced air-sealing and insulation practices, as well as heating system retrofits. Nonresidential retrofits will be sold to customers as financial investments and technical assistance will be provided to ensure that all options are explored and that a given project goes as deep as cost-effectively possible.

UGI Gas will also launch a behavior program targeted at high usage residential heating customers, based on successful programs from Massachusetts. These types of behavior programs have proven effective at convincing large groups of customers to save small amounts of energy, which adds up to a large pool of savings that traditional programs have not captured. Similar programs have been adopted by Act 129 electric utilities and make up a significant portion of these utilities' annual savings.

Finally, UGI Gas will be providing opportunities for medium to large commercial and industrial customers to participate in a CHP program. Any potential CHP project will need to pass the TRC test, and resulting electric generation reductions should be directly applicable to statewide emission reduction goals tied to the CPP.

Q. How are low-income customers addressed by the Plan?

A. Low-income customers are allowed to participate in any of the programs open to residential customers. Although no program in the proposed EE&C portfolio specifically targets this market segment, UGI Gas already has a Low Income Usage Reduction Program ("LIURP") as discussed in the direct testimony of Robert R. Stoyko (UGI Gas Statement No. 7).

III. BENEFITS, COSTS, AND STAGING OF PROPOSED PLAN PORTFOLIO

Q. How did you assess the benefits and costs of UGI Gas's proposed portfolio?

A. Costs and benefits were compared from two perspectives: a total resource perspective and the gas system administrator perspective. The primary test for the UGI Gas EE&C Plan is the TRC test, which is most comparable to the test proposed by PGW for its Phase II plan and similar to the test used by the Commission for Act 129. This test compares the avoided cost of resources, including natural gas, electricity, and water, against the incremental cost of pursuing efficiency measures and any administration costs incurred under the programs.

The Gas Administrator Cost test only counts those costs and benefits within the sphere of costs paid by gas ratepayers. In this case, it means all the costs paid by UGI Gas for providing incentives and administering the proposed EE&C portfolio, ignoring any additional costs paid by participants. The benefits in the Gas Administrator Cost test are only the avoided costs of natural gas.

Q. What avoided cost values were used in the development of the UGI Gas EE&C Plan?

A. UGI Gas Exhibit TML-2 provides an overview of the avoided cost methodology in Section 1.8.2 and a table of projected values in Section 3.1.

Q. How does the assessment of the CHP Program differ from that of the energy efficiency programs?

A. The CHP Program will need to meet the same TRC cost-effectiveness criteria as the energy-efficiency programs, but will also need to demonstrate that the fuel-switching projects result in overall net primary energy reduction. These reductions will be tracked separately because the fuel-switching program will result in an increase in gas usage that should not be conflated with the savings from the energy efficiency programs.

Q. What are the lifetime costs and benefits you estimate from implementing UGI Gas's EE&C Plan?

A. The table below (Table 18 from UGI Gas Exhibit TML-2) shows the cost-effectiveness summary for UGI Gas's proposed portfolio of natural gas energy efficiency programs. The energy efficiency programs provide UGI Gas customers with present value of total resource benefits of $53.9 million at cost of $30.6 million, including the participant investments, for a net benefit to customers of $23.2 million with a BCR of 1.76. The CHP program provides $44.6 million in net total resource benefits with a BCR of 1.60. The entire EE&C Plan provides $67.9 million in net total resource benefits with a TRC BCR of 1.65.

Program	Total Resource PV Benefits	Total Resource PV Costs	Total Resource PV Net Benefits	Total Resource BCR
EE&C Total	**$172,528,340**	**$104,668,959**	**$67,859,381**	**1.65**
Residential Prescriptive (RP)	$31,130,604	$14,907,355	$16,223,249	2.09
Nonresidential Prescriptive (NP)	$8,708,345	$3,813,860	$4,894,485	2.28
Residential Retrofit (RR)	$4,816,226	$3,509,802	$1,306,423	1.37
Nonresidential Retrofit (NR)	$3,347,061	$1,739,899	$1,607,162	1.92
New Construction (NC)	$3,671,531	$1,919,760	$1,751,772	1.91
Behavior and Education (BE)	$2,178,476	$1,624,141	$554,335	1.34
Portfolio-wide Costs	$-	$3,108,352	$(3,108,352)	-
EE Programs	**$53,852,243**	**$30,623,169**	**$23,229,074**	**1.76**
CHP Program	$118,676,097	$74,045,790	$44,630,307	1.60

Q. Will these net benefits stimulate economic activity?

A. Yes. The present worth of TRC net benefits represents a long-term injection of wealth into the economy. For residential customers, the reduction in the total costs of gas service translates to after-tax disposable income, which can be saved or spent. Likewise, lower gas bills for business customers means some combination of increased profit margins and more competitive product and service pricing. Businesses will re-invest the resulting extra profits, or distribute them to owners, or some combination of the two. Either way, the TRC savings will stimulate additional business activity.

Moreover, the amount of additional economic activity stimulated by the efficiency investment will end up being several times the net benefits due to re-spending within the local, state, and regional economies. While there is doubtless some "leakage" as some spending takes place outside Pennsylvania, the majority of the economic benefits stay at the state and local levels.

This economic activity generated by the net economic benefits of efficiency investment is in addition to the economic activity generated directly by expenditures on the part of both UGI Gas and program participants to install the efficiency measures.

Q. How much natural gas will UGI Gas's customers save due to the energy efficiency programs?

A. The natural gas efficiency programs will save UGI Gas customers 7,385 BBtus over the lifetime of all measures installed. The table below (Table 4 from UGI Gas Exhibit TML-2) shows the first year and lifetime gas savings associated with each sector over the five years of the proposed portfolio of natural gas efficiency programs.

Sector	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 - '21
First Year Gas Savings	**14,769**	**54,316**	**151,025**	**208,869**	**218,428**	**647,407**
Residential (R/RT)	11,969	40,845	123,315	170,574	175,764	**522,468**
Nonresidential (N/NT)	2,800	13,471	27,709	38,295	42,664	**124,938**
Lifetime Gas Savings	**268,207**	**1,003,368**	**1,651,083**	**2,141,624**	**2,320,709**	**7,384,990**
Residential (R/RT)	222,047	781,454	1,199,174	1,524,193	1,646,485	**5,373,353**
Nonresidential (N/NT)	46,161	221,914	451,909	617,430	674,223	**2,011,636**

Q. What additional benefits do you project for UGI Gas customers from the energy efficiency portion of the EE&C Plan?

A. I estimate the proposed programs will save UGI Gas customers 92,460 MWh of electricity, 249 million gallons of water, and avoid the emission of 510,000 tons of CO_2 --

the equivalent of removing over 19,400 cars from the road for five years. Section 1.5 of UGI Gas Exhibit TML-2 contains a more detailed breakdown of additional savings due to the proposed portfolio.

Q. What benefits do you project for UGI Gas customers from the CHP program?

A. I estimate the CHP program will reduce net primary energy consumed by 25,591 BBtus over the lifetime of the installed plants.

Q. Will the CHP program help Pennsylvania meet its Clean Power Plan goals?

A. Yes. Any efficiency or conservation measures that reduce the output of CO_2 from fossil-fuel fired electric generating units ("EGUs"), that are installed after 2012, and that are operational during the years covered by the CPP could be incorporated into a state implementation plan ("SIP") to assist Pennsylvania achieve its CPP goals. I project that UGI Gas's CHP program will reduce net generation emissions by 101,000 tons of CO_2 per year by the end of the five-year plan, which is equivalent to taking 3,800 cars off the road for five years. These savings should persist through 2030, which should make them countable towards CPP goals. While Pennsylvania has yet to release its draft SIP, anticipated in spring of 2016, based on Pennsylvania's goal of prioritizing indigenous resources in its SIP and the clear benefits of CHP in reducing EGU CO_2 emissions, it is reasonable to assume that a Pennsylvania SIP will incorporate savings from CHP.

Q. How much additional employment do you estimate that the Plan will generate?

A. The Plan will generate between 222 and 369 additional new jobs over the lifetime of the efficiency measures installed. The majority of these jobs will stay close to where savings occurred due to most of the job creation being a product of the economic "multiplier" effect through the cycle of re-spending energy savings, and the shift away from spending in the less-labor intensive energy sector towards more job-intensive sectors such as food service and production, as discussed in Section 1.5.5 of UGI Gas Exhibit TML-2.

Q. How much will it cost to achieve these results?

A. For the natural gas energy efficiency programs, UGI Gas projects an investment of $24.8 million in real, 2015, dollar terms, or approximately $5.0 million per year.[3] For the CHP program, UGI Gas projects an investment of $2.8 million in real, 2015, dollar terms, or approximately $555,000 per year. For the combined portfolio, this would be an investment of $27.6 million over five years ($5.5 million per year) in real, 2015, dollars, or a nominal investment of $30.6 million ($6.1 million per year).

Q. How will these programs be staged to achieve the results you have identified?

A. Once final approval has been granted for the EE&C Plan, the Residential Prescriptive and Nonresidential Prescriptive programs will be the first programs fully developed and launched in fiscal year 2017. The New Construction, Residential Retrofit, and Nonresidential Retrofit programs will be developed throughout fiscal year 2017 and then launched in fiscal year 2018. The final program to launch will be the Behavior and Education program in coordination with planned updates to UGI Gas's customer

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[3] The real dollar figure adjusts future spending to account for inflation. An inflation rate of 2% was used for this analysis.

information system. All the programs will ramp up over the three to four years until the portfolio reaches its full level of annual investment in the final year of the five-year portfolio. The CHP program would be open to customers in fiscal year 2017. The table below shows the projected annual nominal dollar investment by program.

Program	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 17 - FY 21
EE&C Total	**$2,769,500**	**$4,556,650**	**$6,621,825**	**$7,945,412**	**$8,746,821**	**$30,640,208**
Residential Prescriptive (RP)	716,000	1,731,000	2,307,000	2,755,000	2,815,000	10,324,000
Nonresidential Prescriptive (NP)	250,000	331,000	587,000	663,000	713,000	2,544,000
Residential Retrofit (RR)	200,000	520,000	800,000	1,000,000	1,200,000	3,720,000
Nonresidential Retrofit (NR)	100,000	216,000	306,000	432,000	654,000	1,708,000
New Construction (NC)	135,000	273,000	479,000	638,000	782,000	2,307,000
Behavior and Education (BE)	-	320,000	510,000	735,000	735,000	2,300,000
Portfolio wide Costs	950,000	730,000	780,000	800,000	850,000	4,110,000
EE Total	**2,351,000**	**4,121,000**	**5,769,000**	**7,023,000**	**7,749,000**	**27,013,000**
CHP Program	418,500	435,650	852,825	922,412	997,821	3,627,208

The table below shows projected budgets, in real 2015 dollars, for the entire portfolio, including CHP, for fiscal year 2017, both by program category and broken out between residential (R/RT) and non-residential classes.

Program Category	R/RT	Non-Residential	Total
Customer Incentives	$ 471,396	$ 310,856	$ 782,252
Administration	$ 1,108,417	$ 339,349	$ 1,447,765
Marketing	$ 172,955	$ 209,851	$ 382,806
Inspections	$ 16,422	$ 9,262	$ 25,683
Evaluation	$ -	$ 20,000	$ 20,000
Total Expenses	$ 1,769,189	$ 889,317	$ 2,658,506

Please see Section 1.9.1 of UGI Gas Exhibit TML-2 for additional details regarding the proposed program staging, as well as Section 2 for individual program descriptions.

Q. Is UGI Gas proposing a set annual budget for these programs?

A. No. The proposal is for a real dollar investment in energy efficiency over five years of approximately $5.0 million dollars per year. The previously described staging and budget levels represent anticipated funding levels, but the utility should be allowed to move budget dollars between years and programs depending on market conditions and adoption rates, as long as program and portfolio cost-effectiveness and the overall five-year investment amount is met.

Q. Why is this flexibility important?

A. The ability to allocate funding effectively is crucial for a portfolio administrator, and especially so for a portfolio that is just starting up. The uncertainty inherent in launching and ramping up a new program or portfolio means that there can be faster or slower adoptions of efficiency measures. The ability to move budgets makes sure that unspent funds from one lower demand area can be used to address the higher demands in other areas, and helps provide continuity for customers, contractors, and suppliers. This flexibility must also extend to program design and implementation, such as increasing or decreasing incentives based on market conditions. As discussed in Section 1.9.5 of the EE&C Plan (UGI Gas Exhibit TML-2), UGI Gas would have flexibility within the existing proposed five-year budgets and programs, but would file a revised implementation plan if a program was added or removed, additional funds over and beyond the five year goal were required, or material changes were expected for portfolio-level cost-effectiveness projections.

Q. How will UGI Gas report results?

A. As described in Section 1.9.4 of UGI Gas Exhibit TML-2, UGI Gas will provide an annual report every January, three months after the close of the program year, that will provide verified savings and participation, costs committed to this activity, and the resulting cost-effectiveness. Results for the previous year and progress towards the five-year goal will be included. The annual report will also include highlights of program activity and any significant improvements made to program delivery and design.

Q. Please describe UGI Gas's evaluation, measurement, and verification plans for the portfolio?

A. UGI Gas Exhibit TML-2 provides an overview of the EM&V planned for the EE&C Plan (UGI Gas Exhibit TML-2, Section 1.10) as well as plans for each individual program. Measures will require proof of purchase and must be tied to a valid UGI Gas account. Third-party inspections will be performed on all complex projects and a subset of prescriptive rebates, to make sure the correct equipment is installed and solicit customer feedback. Savings are calculated using a technical reference manual ("TRM") that is based on PGW's FY 2016 TRM and calibrated to UGI Gas's territory. UGI Gas will develop a tracking system to store and analyze program activity, spending, and inspection data. Finally, each program will undergo regular impact and process evaluations approximately every two years.

IV. SUMMARY OF PROPOSED PROGRAMS

A. RESIDENTIAL PRESCRIPTIVE PROGRAM

Q. Please describe the Residential Prescriptive Program.

A. The Residential Prescriptive ("RP") Program offers cash incentives for high-efficiency, natural gas powered, residential-sized space and water heating equipment, which is the largest lost opportunity market in UGI Gas's territory. The program is expected to cost $10.3 million in nominal dollars over five years and save 4,094 BBtus of natural gas over the lifetime of measures installed. The program is projected to provide present value TRC net benefits of $16.2 million with a BCR of 2.09.

The RP program specifically targets high efficiency furnaces, boilers, combi-boilers, tankless water heaters and Wi-Fi-enabled thermostats. The rebates for this equipment were designed to be in line with other gas energy efficiency administrators in the region, such as PGW, and cover approximately two-thirds of the measures' incremental costs. A list of the proposed measures and corresponding incentives can be found in the RP Program Description Section on Financial Incentives in UGI Gas Exhibit TML-2.

Q. How were the efficiency levels for the program chosen?

A. In line with the general principles for the portfolio, the RP program targets the highest efficiency levels for the more traditional types of equipment, such as furnaces and boilers. It also seeks to promote market adoption of newer technology, such as tankless water heaters, and in doing so offers more efficiency level options.

Q. Please describe the roll of Wi-Fi thermostats in the program.

A. Wi-Fi thermostats provide the promise of customers more fully engaging with setting the comfort levels in their homes. Many models have additional capabilities that help customers fine tune temperature settings, or that adjust more intelligently to fit customer behavior. This next generation of thermostat technology is poised to potentially address the behavioral aspects of energy usage more effectively than traditional methods. The RP program will offer $100 incentives for these types of thermostats. In order to get an accurate picture of how this equipment affects space-heating usage, the program will include a rigorous evaluation schedule to proactively track results for this measure and inform long-term decision-making regarding the measure's place in the program. One possibility, if the measure proves to be effective at saving energy, is to move the rebate from a cash rebate to an upstream, point of sale incentive.

Q. Are there any key risk factors for the RP program?

A. A key aspect of future program uncertainty involves the potential shift in baseline efficiency levels for natural gas furnaces. Federal Standards are potentially moving towards requiring condensing units with annual fuel utilization efficiencies ("AFUEs") of 90 percent or more for the Northern region of the United States, which includes Pennsylvania. While the current efficient condition for natural gas furnace incentives of an ENERGY STAR ® rating would still exceed an anticipated baseline shift, savings and incentive levels would be adjusted downwards, and savings and/or spending goals may need to be adjusted accordingly.

B. NONRESIDENTIAL PRESCRIPTIVE PROGRAM

Q. Please describe the Nonresidential Prescriptive Program.

A. The Nonresidential Prescriptive ("NP") Program offers incentives for a variety of natural gas powered equipment used by UGI Gas's small business and commercial customers.

The program is expected to cost $2.5 million in nominal dollars over five years and save 1,358 BBtus of natural gas over the lifetime of measures installed. The program is projected to provide present value TRC net benefits of $4.9 million with a BCR of 2.28.

The program targets commercial sized boilers, unit heaters, steam traps, water heaters, and a few types of commercial kitchen equipment. Incentives for these measures have been designed to be in line with other jurisdictions and cover approximately two-thirds of the incremental cost of the measure. A custom incentive track is also offered for measures that are not currently covered by the prescriptive list, such as custom control and heat recovery systems. A list of the proposed measures and corresponding incentives can be found in the RP Program Description Section on Financial Incentives in UGI Gas Exhibit TML-2. Delivery of the program is nearly the same as the RP program and may have the same rebate processor to improve operation efficiency.

Q. How does implementation of the NP program differ from the RP program?

A. While the main processes used to implement the NP and RP programs are very similar, and will probably share much of the same infrastructure, the main difference comes in how the customers are funneled towards the respective measures. The RP will be driven more by the general portfolio awareness push due to the larger target audience and streamlined messaging of a smaller measure list. The NP, on the other hand, requires a more targeted outreach based approach, pulling participants into the program by working closely with contractors, suppliers, and community organizations. Most small businesses have trusted go-to contractors that service their equipment. When equipment is in need of repair or replacement, it should be easy for the contractor to understand the opportunity and easy for the business owner to participate. Reaching the contractor will be crucial, since the contractor will need to file paperwork and present the rebate to the business owner, who will therefore be placing trust in the contractor to take full advantage of the program. UGI Gas will also explore options to pay rebates directly to contractors to reduce the amount of the customer's invoice.

C. NEW CONSTRUCTION PROGRAM

Q. Please describe the New Construction Program.

A. The New Construction ("NC") program aims to address natural gas efficiency in new construction and gut rehabilitation projects. The program targets both the residential and nonresidential sectors by providing incentives for going beyond code. The program is performance based and will provide participants with a greater incentive for combining measures and going deeper than they would by upgrading just the space or water heating system through the RP or NP programs.

The program is expected to cost $2.3 million in nominal dollars over five years and save 519 BBtus of natural gas over the lifetime of measures installed. The program is projected to provide present value TRC net benefits of $1.8 million with a BCR of 1.91.

Q. How does the NC program address residential projects?

A. The program will provide a streamlined prescriptive rebate for customers who save at least 20% in gas usage compared to a baseline house just meeting code. The incentive will be designed to cover approximately 80% of the incremental costs.

Q. How does the NC program address nonresidential projects?

A. Since the NC projects tend to be more complicated, the program will focus first on providing technical assistance to potential projects in order to help include efficiency in the initial design process. Nonresidential projects will then be eligible for an incentive that gets larger as the savings increase. The program will have three tiers: at least 15% but less than 20%, at least 20% but less than 30%, and 30% or greater.

D. RESIDENTIAL RETROFIT PROGRAM

Q. Please describe the Residential Retrofit Program.

A. The Residential Retrofit ("RR") program is designed to overcome market barriers for existing residential customers to do comprehensive natural gas efficiency projects that save money and increase comfort. The program specifically addresses the space and water heating system, as well as improvements to the thermal envelope. The program is expected to cost $3.7 million in nominal dollars over five years and save 744 BBtus of natural gas over the lifetime of measures installed. The program is projected to provide present value TRC net benefits of $1.3 million with a BCR of 1.37.

Interested customers will receive an energy audit from a qualified contractor that includes a blower door test. The contractor will provide the customer with a list of recommended actions based on the audit. The customer will then receive an incentive of $60 per first year MMBtus savings based on the measures installed by a qualified contractor. The incentive is designed to offset most of the incremental cost of the higher efficiency equipment and to provide a significant contribution to the cost of qualifying thermal envelope improvements.

Q. How will customer participation in the program be encouraged?

A. The general awareness campaign for the entire portfolio will be the foundation for driving participation in the program. This will drive traffic to an online site that can help customers assess the energy savings potential in their homes and contact a qualified contractor for an in-home audit. Qualified contractors will also be able to generate leads through co-branding and direct marketing campaigns that help the contractor get more work and close larger projects.

Q. What does it mean to be a "qualified contractor"?

A. The cornerstone of the RR program will be the approved contractor network. In order to become part of the network, a contractor will be required to have certification from the Building Performance Institute ("BPI") and be trained in program protocols to ensure quality business practices. Approved contractors must also employ site technicians and site supervisors with BPI professional certifications appropriate to their duties. Once a contractor passes initial approval, the first three projects performed by that contractor will require confirmation of quality installation by an approved third party inspector before the contractor moves from probationary status to full certification. Subsequent contractor work will be sampled up to 10% of projects submitted. Protocols will also be put in place to remove a contractor from the program for poor performance.

UGI Gas already has a contractor portal for sharing leads for customers who are interested in switching to natural gas. UGI Gas will look for ways to use this platform to launch and manage a more comprehensive network of contractors focused on serving the RR program.

Q. Why would a contractor want to participate in the RR program?

A. Customers will only receive an incentive if they use an approved contractor. This gives qualified contractors an additional edge not just in selling a project, but also expanding the scope to include more measures. The quality assurance and inspections provided by UGI Gas give customers an added level of service, help ease customer uncertainty in an unfamiliar process, and help contractors close more jobs. Furthermore, UGI Gas will examine ways to get contractors to encourage deeper savings by potentially offering contractors a performance bonus for meeting heightened goals.

E. NONRESIDENTIAL RETROFIT PROGRAM

Q. Please describe the Nonresidential Retrofit Program?

A. The Nonresidential Retrofit ("NR") Program will provide incentives for overcoming market barriers for natural gas efficiency retrofits in existing commercial and multi-family buildings; it also will be open to agricultural and small industrial applications. Any measure that saves natural gas is eligible, with space heating, water heating, and process heating expected to be the largest opportunities. The program specifically addresses the space and water heating system, as well as improvements to the thermal envelope. The program is expected to cost $1.7 million in nominal dollars over five years and save 410 BBtus of natural gas over the lifetime of measures installed. The program is projected to provide present value TRC net benefits of $1.6 million with a BCR of 1.92.

Q. Why are multifamily projects included in this program?

A. Multi-family buildings technically are any housing other than single-family detached structures, including duplexes and townhouses, as well as apartments. They must have at least one surface defining a given housing unit that is shared by another unit within the building and space or water heating equipment that can service more than one unit. These considerations make multi-family structures difficult to administer within the RR program, which is geared for stand-alone residential units.

F. BEHAVIOR AND EDUCATION PROGRAM

Q. Please describe the Behavior and Education Program.

A. The Behavior and Education ("BE") program is designed to motivate a large group of residential customers to save small amounts of energy by changing behavior through education, outreach, and energy monitoring. The premise is that the delivery of timely, salient, and personalized information allows for informed decision-making. The program combines behavioral science with data analytics to provide clearly defined and actionable information that motivates customers to lower their energy use. The program is expected to cost $2.3 million in nominal dollars over five years and save 260 BBtus of natural gas over the lifetime of measures installed. The program is projected to provide present value TRC net benefits of $554,000 with a BCR of 1.34.

Q. How will savings be verified for this program?

A. A solid evaluation is crucial for the success of this program. UGI Gas will engage an evaluator to begin collecting data on the program as soon as it starts to be able to get as much real time feedback as possible regarding the size and persistence of savings and make sure that any early issues are caught quickly and addressed.

G. COMBINED HEAT AND POWER PROGRAM

Q. Please describe the CHP Program.

A. The CHP program provides incentives for CHP plants that have net-primary-energy savings and are cost-effective under the TRC test. The program also seeks to promote projects that would contribute CO_2 emission reductions that may be counted toward Pennsylvania's CPP goals. The program would offer an incentive of $750 per kW, with a cap of $250,000 per project. Over the five years of the portfolio, the CHP program is projected to cost $3.6 million, in nominal terms, and provide 25,591 BBtus in net-primary-energy savings as well as reduce net CO_2 emissions by 101,000 tons per year by the end of the five-year plan. The program is expected to have a present value of TRC net benefits of $44.6 million with a BCR of 1.60.

Q. What types of CHP projects will the program incentivize?

A. The program will target large commercial and industrial customers with high thermal and electric loads, such as hospitals, college campuses and multi-shift industrial customers. Due to the current state of avoided costs, UGI Gas anticipates that it will be difficult to find cost-effective projects that are much under 1,000 kW. However, UGI Gas will continue to monitor both the energy market and customer opportunities to address as wide a range of CHP technology types and sizes as possible.

H. PORTFOLIO-WIDE COSTS

Q. What do the portfolio-wide costs cover?

A. The portfolio-wide costs cover development, design, tracking, reporting, and administrative overhead that cuts across all the programs in the portfolio. The majority of development costs for the portfolio occur in the first year as programs are designed and reporting infrastructure is put in place. Costs then fall sharply in the second year before climbing as the portfolio grows. Over the five-year period, they represent 15% of the portfolio's expenditures.

V. CONCLUSIONS AND RECOMMENDATIONS

Q. What conclusions do you reach?

A. I conclude that UGI Gas's proposed portfolio of energy efficiency programs and CHP program will be cost-effective and economically beneficial to UGI Gas's ratepayers and the economy of the UGI Gas territory and Pennsylvania.

Q. On the basis of these conclusions, what are your recommendations to the Commission?

A. I strongly recommend that the Commission order implementation of UGI Gas's five-year EE&C Plan. Any delay in implementation represents delay of the benefits that will occur.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS EXHIBIT TML-1

THEODORE LOVE

147 S Oxford St, Apt 2C | Brooklyn, NY 11217
W: (718) 395 – 9458 | C: (919) 949 – 5906
tlove@greenenergyeconomics.com

Professional Experience

Green Energy Economics Group, Inc. – Cuttingsville, VT 2007 to Present
Senior Analyst and Data Scientist
Providing research and technical assistance relating to the design, analysis, and implementation of energy utility demand-side management (DSM) programs for electric and natural gas service providers around the world; including ten states, two Canadian provinces, and China. Currently focusing on building scalable tools to analyze everything from individual projects to programs to portfolios.

Alter & Rosen, LLP –New York, NY 2007 to 2010
Consultant
Managed the development of an online database management system for musical copyrights and brought on board paying beta users. Managed data entry, reporting, termination and reversion issues for transactions involving musical copyright catalogues valued at over $100 million.

AllianceBernstein LP – White Plains, NY 2006 to 2007
Client Reporting Analyst
Oversaw the monthly and quarterly report process for clients domiciled outside the United States. Increased by 150% the amount of accounts that met a fifth business day deadline. Transferred firm's quarterly reporting process to new system.

Compex Integrated Systems, Inc. LP – Framingham, MA 2005 to 2006
Database Systems Consultant
Designed and implemented custom modules for metal fabrication and finishing business management software. Recruited and trained a team of developers to aid in Compex Integrated System's growth.

Education

Clark University – Worcester, MA
B.A., Magna cum Laude, *Mathematics and Computer Science*, 2006.

Kansai Gaidai University: Hirakata City, Osaka Japan.
Spring Semester 2005

General Assembly: New York City, NY
Data Science Intensive Course, 2015

Recent Project Experience

Research on Leading Energy Efficiency Portfolios
Green Energy Economics Group *(November 2007 – Present)*

- Maintain research and proprietary analysis on actual and projected results from over a dozen electric and natural gas demand side management (DSM) portfolios throughout North America;
- Published paper for the 2012 ACEEE Summer Study on Energy Efficiency in Buildings.

Development of Energy Efficiency and Conservation Plan
UGI Utilities, Inc. – Gas Division ("UGI Gas") *(June 2015 – Present)*
Reading, Pennsylvania

Assist UGI Gas with the development of five year Energy Efficiency and Conservation (EE&C) Plan including:

- Developing an achievable efficiency scenario
- Designing six energy efficiency programs and one combined heat and power (CHP) program
- Preparing testimony before the Pennsylvania PUC

Strategic Planning and Implementation of Five-year DSM Portfolio
Philadelphia Gas Works ("PGW") *(August 2008 – Present)*
Philadelphia, Pennsylvania

- Member of lead consulting team that aided in the design and approval of PGW's five-year, $54 million portfolio of DSM programs;
- Providing ongoing technical assistance in the development of PGW's $35 million Phase II five year plan.
- Providing ongoing technical support in program design and implementation, including the roll-out of six programs that, combined since inception, have saved 120,000 MMBtus at a cost of approximately $17 million;
- Developed specifications for and currently collaborating with internal PGW staff on database system to track weatherization projects, rebate applications, and other information pertaining to PGW's DSM portfolio;
- Developed multiple Excel-based tools used by contractors to perform field audits, provide QA/QC, and track ongoing progress for contractors, programs, and the portfolio as a whole;
- Provided research and analysis support for multiple rounds of expert testimony before the Pennsylvania Public Utility Commission (Docket R-2009—2149884);
- Aided in the issuance of RFPs and selection of candidates for over $40 million in contracts;
- Major contributor to PGW's ongoing formal reporting and evaluation process, including the issuance of five implementation plans, three annual reports, and two impact evaluations.

Technical Assistance for Energy Efficiency Program Planning
Green Mountain Power *(August 2012 – Present)*
Vermont

- Developed multivariable regression model and framework to estimate the cost per kW to address a reliability gap in the St. Albans region with targeted energy efficiency.
- Reviewed and analyzed program proposals for the $20 million Community Energy & Efficiency Development Fund (CEED Fund), including the development of scoring and rebalancing mechanisms;
- Analyzed dataset of 5,000 custom business projects to establish models used for future planning exercises.
- Prepared report on uncounted benefits of renewable generation sources for Vermont.

Analysis of Energy Efficiency in British Columbia
BC Sustainable Energy Association & Sierra Club BC *(May 2011 – Present)*
British Columbia, Canada

- Provided comments and energy efficiency opportunities report for proceedings on FortisBC Gas and Electric's long-term DSM plans in December of 2013.
- Assisted on research for direct testimony on reasonableness of gas DSM Plan by Fortis Energy Utilities before the British Columbia Utilities Commission, BCUC Project No. 3698627;
- Technical support on assessment of FortisBC Electric's long-term DSM plan and corresponding expert testimony;
- Assistance with direct testimony and technical support on assessment of BC Hydro's long-term DSM plan, before the BCUC.

Technical Assistance for Energy Efficiency Programs
Focus on Energy *(June 2011 – Present)*
Wisconsin

- Developed and customized cost-effectiveness calculators for Wisconsin's Focus on Energy portfolio of energy efficiency programs;
- Trained staff and other consultants on usage of tools and general economic analysis of energy efficiency programs;
- Provided QA/QC on cost-effectiveness analysis of 14 programs spending over $160 million in two years.

Chicagoland Energy Efficiency Portfolio
People's Gas *(September 2008 – January 2013)*
Chicago, Illinois

- Providing ongoing regulatory support;
- Provided cost-benefit analysis of various program scenarios and aided in the analysis of contractor bids;
- Customized excel-based portfolio and project cost-effectiveness tools to client's specifications.

Energy Efficiency Potential in Oklahoma
Sierra Club *(April 2011 – November 2011, December 2013 – January 2014)*
Oklahoma

- Provided updated report for energy efficiency in Oklahoma and additional comments on PUC rulemaking for electric and gas utility programs.
- Preparation of report on energy efficiency potential for Oklahoma;
- Assistance with research and drafting comments on the US regional haze Federal Implementation Plan for the State of Oklahoma;
- Research and formulation of energy efficiency potential projections provided as part of expert testimony for Oklahoma Gas & Electric's rate case before the Corporation Commission of Oklahoma, Cause No. PUD 201100087.

Testimony Support for Expanding Gas Energy Efficiency in Pennsylvania
Citizens for Pennsylvania's Future, *Pennsylvania* *(July 2013 – September 2013)*

- Provided support on preparation of testimony regarding Peoples Gas of Pennsylvania's DSM plans, including preparation of benchmarking report and alternative scenario projections.

Energy Efficiency Potential in Texas
Sierra Club, *Texas* *(May 2012 – August 2012)*

- Research and development of alternative energy efficiency potential scenarios for the ten investor owned utilities (IOUs) in Texas;
- Development of comments for the Public Utility Commission of Texas;
- Development of presentation before the Energy Efficiency Incentive Program Committee.

Austin Energy's Energy Efficiency Potential
Austin City Council Consumer Advocate *(April 2012)*
Austin, Texas

- Research and development of alternative energy efficiency potential scenarios for Austin Energy.

Nevada Power's Energy Efficiency Potential
Sierra Club *(November 2011 – June 2012)*
Nevada

- Research on Nevada Power's Integrated Resource Plan (IRP) and development of alternative energy efficiency potential projections.

Comments on EmPower Maryland Programs
Sierra Club *(September 2011 – October 2011)*
Maryland

- Research for and development of comments on EmPower Maryland's energy efficiency programs, including the development of alternative energy efficiency potential projections.

Ontario Power Authority Field Audit Support Tool
Green Communities Canada *(January 2011 – May 2011)*
Ontario, Canada

- Collected and implemented specifications for updating the tool used by Ontario Power Authority's low-income program field agents to collect data and determine project net present values;
- Added custom features including customer input forms, saving and closing routines, and database file importing.

Energy Efficiency Potential in Arkansas
Sierra Club/Audubon Society *(September 2009 – March 2010)*
Arkansas

- Research and drafting assistance for expert testimony on energy efficiency' as an alternative to the White Bluff Steam Electric Station before the Public Service Commission of Arkansas, Docket No. 09-024-U.

Training for NGOs Working on Energy Efficiency Projects in China
ISC and NRDC *(August 2008 – September 2010)*
United States and China

- Developed training materials and provided remote and in-person training sessions on the economic and financial analysis of industrial retrofit projects for structuring and negotiating financial incentive offers to customers;
    - o Worked with the Institute for Sustainable Communities (ISC) to aid its efforts to promote energy efficiency in the Guangdong and Jiangsu Provinces (February 2009 – September 2010);
    - o Worked with the National Resource Defense Council (NRDC) to aid in its efforts in China, especially in conjunction with a $100 million revolving loan fund from the Asia Development Bank (August 2008- January 2009).

Incentive Calculations for the Project Cost-effectiveness Analysis Tool (CAT)
Efficiency Vermont *(November 2008 – June 2010)*
Burlington, Vermont

- Aided in the design of a new approach to calculating incentives for custom energy efficiency projects based on financing and reaching a desired rate of return;
- Modified CAT's cash-flow projection engine, an Excel VBA system, to accommodate the new approach to incentives.

Vermont's 20-year Forecast of Electricity Savings from Sustained Investment
Efficiency Vermont *(December 2008 – October 2009)*
Burlington, Vermont

- Provided components of final report relating to long-term trends for the environment (climate change, land-use, and water-use), population growth, and governmental regulation;
- Provided additional technical support on electric demand-side savings potential.

Connecticut's Long Term Acquisition Plan
Connecticut Office of the Consumer Council *(August – October 2008)*
Connecticut

- Provided research and support for expert testimony regarding long-range energy-efficiency procurement plan of the Energy Conservation Management Board, on behalf of the Connecticut Office of Consumer Counsel.

Energy Efficiency Plans of BC Hydro and Terasen Gas
BC Sustainable Energy Association and The Sierra Club *(October 2008 – March 2009)*
British Columbia, Canada

- Provided research and support for expert testimony and technical support on assessment of BC Hydro's long-term DSM plan, before the BCUC, on behalf of the BC Sustainable Energy Association and Sierra Club Canada (November 2008 – March 2009);
- Provided research and support for expert testimony on assessment of Terasen Gas conservation plans before the BCUC, on behalf of the BC Sustainable Energy Association and Sierra Club Canada (October 2008).

Publications

Plunkett, John, Theodore Love, Francis Wyatt. "An Empirical Model for Predicting Electric Energy Efficiency Acquisition Costs in North America: Analysis and Application". In *Proceedings of the ACEEE 2012 Summer Study on Energy Efficiency in Buildings*, #906, Washington, D.C.: American Council for an Energy Efficient Economy.

Gold, Elliott, Marie-Claire Munnelly, Theodore Love, John Plunkett, Francis Wyatt. "Comprehensive and Cost-Effective: A Natural Gas Utility's Approach to Deep Natural Gas Retrofits for Low Income Customers." In *Proceedings of the ACEEE 2012 Summer Study on Energy Efficiency in Buildings*, #442, Washington, D.C.: American Council for an Energy Efficient Economy.

UGI GAS EXHIBIT TML-2

UGI Utilities, Inc. – UGI Gas

Five Year Energy Efficiency and Conservation Plan

January 19, 2016

Table of Contents

1 Introduction and Background

1.1 Plan Overview

This plan provides a detailed description of the design and implementation of the energy efficiency and conservation portfolio (EE&C Portfolio or Portfolio) that UGI Utilities, Inc. – Gas Division (UGI Gas) is proposing to offer in its energy efficiency and conservation plan (EE&C Plan or Plan). The Plan will have a five-year duration, beginning in UGI Gas's fiscal year (FY) 2017 through FY 2021,[1] and will include both energy efficiency (EE) programs and a combined heat and power (CHP) program. Though UGI Gas is not mandated to enact an EE&C Plan under Act 129, UGI Gas's voluntary EE&C Plan was developed using the guiding principles of the Commission's 2015 Act 129 Phase III Implementation Order.[2] As discussed in more detail below, the Plan portfolio has been evaluated using a Total Resource Cost (TRC) test which is most comparable to the test proposed by PGW for its Phase II plan and similar to the test used by the Commission for Act 129. To estimate the resource savings from standard energy efficiency measures, UGI Gas developed a Technical Reference Manual (TRM) that builds upon the TRM used for PGW's FY 2016 TRM and calibrates it to UGI Gas's territory.

Over the five years of the EE&C Plan, UGI Gas plans to spend $24.8 million in real 2015 dollars on six energy efficiency (EE) programs. The energy efficiency programs are projected to save 647 BBtus of natural gas during the first five years of the Plan, and 7,385 BBtus of natural gas over the lifetime of the measures installed. From a total resource perspective, the present value of benefits is $53.9 million, with $30.6 million in present value of costs, leading to a present value of net benefits of $23.2 million and a TRC benefit-cost ratio of 1.76. Furthermore, the energy efficiency programs are expected to save 92,460 MWh of electricity, 248 million gallons of water, create between 222 and 369 jobs, and

[1] UGI Gas's fiscal year runs October 1st to September 30th.
[2] Implementation Order, Docket No. M-2014-2424864 (entered June 19, 2015)

avoid the emission of CO_2 equivalent to over 19,400 cars being removed from the road for 5 years.

UGI Gas is also proposing the investment of $2.8 million in real 2015 dollars over five years for a CHP program. This program would provide net energy savings to customers over the five years of the Plan of 1,706 BBtus, and 25,591 BBtus over the lifetime of the CHP projects installed. The CHP program will provide present value of net benefits of $44.6 million from a total resource perspective, with a TRC benefit-cost ratio of 1.60.

Altogether, the EE&C Portfolio is very cost-effective, providing $67.9 million in net resource benefits with a TRC benefit-cost ratio of 1.65, greatly increasing the economic wellbeing of UGI Gas's customers.

1.2 Natural Gas and Energy Efficiency

Natural gas is an abundant resource and an important component of the Pennsylvania economy. In 2014, Pennsylvania had the most shale gas proven reserves in the country, driven by the development of the Marcellus Shale,[3] and over 80 percent of the natural gas UGI Gas delivers to its customers comes from the Marcellus Shale. As a result of this reliable, local supply, UGI Gas customers have seen bills decrease substantially since 2008.

Natural gas also has many important advantages as an end-use fuel source. When compared to the use of electricity generated from natural gas or most other fuels, the direct end-use of natural gas is more efficient and environmentally preferable. Natural gas has a source-to-site efficiency of 92 percent, meaning the vast majority of the energy from natural gas is associated with on-site consumption. Electricity on the other hand, only has a source-to-site efficiency of 32 percent, meaning that less than one third of electric energy is used at the site.[4]

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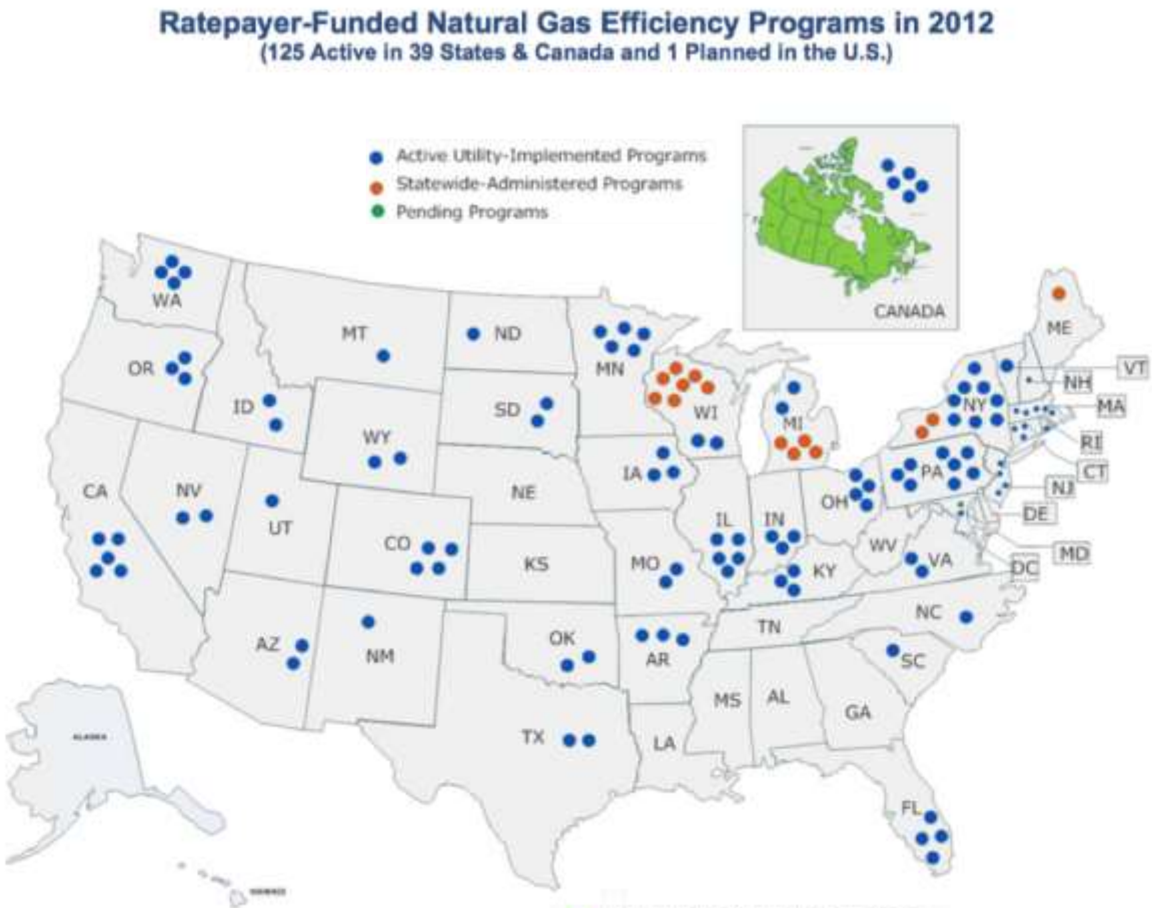
[3] http://marcelluscoalition.org/2015/11/pa-drives-increase-in-u-s-natural-gas-abundance/
[4] Meyer, Richard. Dispatching Direct Use: *Achieving Greenhouse Gas Reductions with Natural Gas in Homes and Businesses*. American Gas Association: Washington, DC. November 11, 2015, p. 5.

As natural gas has continued to grow in importance as a fuel source, natural gas energy-efficiency programs have also shown steady growth activity. The American Council for an Energy Efficient Economy (ACEEE) State Energy Scorecard shows that spending on natural gas energy-efficiency programs has grown both nationally and in the states surrounding Pennsylvania. Nationally, the spending on natural gas energy-efficiency programs has increased by more than five times to $1.4 billion in 2014 from 2006 levels.[5] For states close to Pennsylvania, the rise has been even greater, with New York more than tripling budgets to $175 million between 2009 and 2013 and Maryland going from a few hundred thousand dollars a year in 2009 to $15 million per year in 2013. Within Pennsylvania, a number of gas utilities have undertaken voluntary energy efficiency programs, including Columbia Gas and Philadelphia Gas Works (PGW), which is currently seeking approval for its second five-year gas efficiency portfolio. The trend towards gas efficiency has also spread throughout the United States, as shown in Figure 1.

[5] ACEEE (American Council for an Energy-Efficient Economy), *The 2015 State Energy Efficiency Scorecard*, Annie Gilleo, et al, October 2015, p. 23.

Figure 1. Spread of Natural Gas Energy Efficiency Programs[6]



As the energy market is becoming increasingly customer driven, utilities around the country are recognizing the opportunity to drive economic growth and an efficient economy by sponsoring energy efficiency and conservation programs. For natural gas utilities, the opportunity to invest in helping customers save money, increase comfort, and reduce the impact they have on the environment is now a crucial component of joining the next generation of energy utilities and benefiting the communities that they serve.

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[6] American Gas Association. “Natural Gas Efficiency Programs Brief: Investments and Savings – 2012 Program Year”. March 2014, p. 4.

1.3 Goals

UGI Gas has the following core goals:

- Help customers save energy cost-effectively through a holistic approach to energy efficiency and conservation;
- Avoid lost opportunities and provide deep levels of savings ;
- Provide a wide range of services for UGI Gas's diverse customer base; and
- Contribute to the economic welfare of its customers and Pennsylvania.

In order to reach these goals, UGI Gas will utilize energy efficiency programs and a CHP program. For its energy efficiency programs, UGI Gas plans to invest approximately $24.8 million in 2015 dollars ($27.0 million nominal) over five years with the goal of returning $23.2 million dollars in present value of total resource net benefits to customers. As a secondary goal for efficiency programs, UGI Gas expects to save customers 7,385 BBtus of natural gas and 510,000 tons of CO_2 emissions over the lifetime of installed measures during the five-year portfolio.

For the CHP program, UGI Gas also plans to invest approximately $2.8 million in 2015 dollars ($3.6 million nominal) over five years with the goal of returning $44.7 million dollars in present value of total resource net benefits to customers.

1.4 Plan Development

Figure 2. Plan Development Process

The UGI Gas EE&C Plan was developed in three stages, as shown Figure 2. The first stage involved the characterization of a wide range of natural gas efficiency measures and project energy savings and costs. Avoided costs for natural gas and electricity were calculated and combined with the measure and project characterizations for cost-effectiveness screening using the TRC test. The cost-effective measures and projects were then correlated with demographic, building stock, and equipment market characteristics for UGI Gas's territory to calculate achievable savings and participation levels.

Four types of market actions were then identified for inclusion in the portfolio. The first intervention is at the time of "natural replacement", which means helping customers replace broken equipment with equipment that has a higher efficiency than the market baseline. The second intervention is in the new construction and gut rehabilitation market, to make sure that new buildings go above code requirements to save energy. The third intervention is in the retrofit market of existing buildings to make existing buildings more energy efficient. The final intervention is in the behavioral side of energy consumption, through outreach and education. The natural replacement and retrofit markets were divided between residential and nonresidential programs in order to provide more effective program messaging, resulting in six separate energy efficiency programs. A stand-alone CHP program was established based on the program's unique market and reporting requirements. The seven resulting programs are set forth in the following table.

Table 1. Planned Programs

Abbreviation	Program Name	Market Intervention
RP	Residential Prescriptive	Natural Replacement
NP	Nonresidential Prescriptive	Natural Replacement
NC	New Construction	New Construction
RR	Residential Retrofit	Retrofit
NR	Nonresidential Retrofit	Retrofit
BE	Behavior and Education	Behavior
CHP	Combined Heat and Power	Retrofit

Incentive levels were established for each program. Next, non-incentive budgets were developed to address fixed and variable costs associated with each program and the portfolio as a whole. A target annual investment level was determined, and the programs were weighted to maximize net benefits and avoid lost opportunities. The programs were then staged to reach the target year given operational constraints, and program and portfolio level metrics were checked to make sure they lined up with similar programs and portfolios. Finally, details regarding the implementation of the EE&C Portfolio were developed based on best practices in program design from portfolio administrators in Pennsylvania, such as PGW, and the broader United States, such as National Grid.

1.5 Efficiency Program Benefits

1.5.1 Natural Gas Savings

The following tables provide projected natural gas savings by program and sector for the energy efficiency programs in the EE&C Portfolio.

Table 2. Projected First Year Gas Savings by Program (MMBtus)

Program	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 - '21
Portfolio Total	**14,769**	**54,316**	**151,025**	**208,869**	**218,428**	**647,407**
Residential Prescriptive (RP)	11,969	37,009	49,384	60,395	60,395	**219,152**
Nonresidential Prescriptive (NP)	2,800	10,017	19,819	24,548	24,548	**81,733**
Residential Retrofit (RR)	-	2,772	6,856	8,676	12,678	**30,982**
Nonresidential Retrofit (NR)	-	1,780	4,543	9,086	13,815	**29,223**
New Construction (NC)	-	2,737	5,475	8,742	9,570	**26,524**
Behavior and Education (BE)	-	-	64,948	97,422	97,422	**259,792**

Table 3. Projected Lifetime Gas Savings by Program (MMBtus)

Program	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 - '21
Portfolio Total	**268,207**	**1,003,368**	**1,651,083**	**2,141,624**	**2,320,709**	**7,384,990**
Residential Prescriptive (RP)	222,047	691,542	922,911	1,128,987	1,128,987	**4,094,474**
Nonresidential Prescriptive (NP)	46,161	166,851	329,005	408,224	408,224	**1,358,465**
Residential Retrofit (RR)	-	66,524	164,539	208,232	304,279	**743,574**
Nonresidential Retrofit (NR)	-	25,660	64,097	128,193	192,184	**410,134**
New Construction (NC)	-	52,791	105,582	170,564	189,612	**518,550**
Behavior and Education (BE)	-	-	64,948	97,422	97,422	**259,792**

Table 4. Projected Gas Savings by Sector (MMBtus)

Sector	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 - '21
First Year Gas Savings	**14,769**	**54,316**	**151,025**	**208,869**	**218,428**	**647,407**
Residential (R/RT)	11,969	40,845	123,315	170,574	175,764	**522,468**
Nonresidential (N/NT)	2,800	13,471	27,709	38,295	42,664	**124,938**
Lifetime Gas Savings	**268,207**	**1,003,368**	**1,651,083**	**2,141,624**	**2,320,709**	**7,384,990**
Residential (R/RT)	222,047	781,454	1,199,174	1,524,193	1,646,485	**5,373,353**
Nonresidential (N/NT)	46,161	221,914	451,909	617,430	674,223	**2,011,636**

1.5.2 Electric Savings

The following table shows electric savings for measures installed under the energy efficiency programs in the EE&C Portfolio. The electric savings are secondary savings from measures that primarily save natural gas, such as efficient natural gas furnaces with brushless fan motors and air-conditioning savings from higher insulation.

Table 5. Projected Electric Savings by Sector

Sector	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 - '21
First Year Energy (MWh)	**248.3**	**775.9**	**1,048.6**	**1,311.7**	**1,337.9**	**4,722.6**
Residential (R/RT)	248.3	775.9	1,048.5	1,311.5	1,337.7	**4,722.0**
Nonresidential (N/NT)	-	0.1	0.1	0.2	0.2	**0.6**
Lifetime Energy (MWh)	**4,819**	**15,131**	**20,502**	**25,706**	**26,302**	**92,460**
Residential (R/RT)	4,819	15,130	20,500	25,703	26,298	**92,449**
Nonresidential (N/NT)	-	1	2	4	4	**11**
Summer Peak (kW)	**55**	**172**	**234**	**292**	**300**	**1,052**
Residential (R/RT)	55	172	234	292	300	**1,052**
Nonresidential (N/NT)	-	-	-	-	-	**-**

1.5.3 Water Savings

This section contains projections for water savings due to the energy efficiency programs in the EE&C Portfolio.

Table 6. Projected Water Savings by Sector (Million Gallons)

Sector	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 - '21
First Year Water Savings	**0.6**	**2.8**	**5.8**	**8.0**	**9.0**	**26.2**
Residential (R/RT)	-	0.3	0.7	1.1	1.4	**3.4**
Nonresidential (N/NT)	0.6	2.5	5.1	6.9	7.5	**22.7**
Lifetime Water Savings	**3.4**	**24.6**	**51.8**	**76.4**	**92.2**	**248.5**
Residential (R/RT)	-	6.4	14.4	23.1	30.9	**74.8**
Nonresidential (N/NT)	3.4	18.1	37.4	53.4	61.3	**173.7**

1.5.4 Emission Reductions

This section contains projections for CO_2 emission reductions due to the energy efficiency programs in the EE&C Portfolio. The total savings of 510,000 tons of CO_2 is equivalent to removing 19,463 cars off the road for 5 years. The following table breaks out the emission reductions due to gas savings and electric savings.

Table 7. Projected CO_2 Emission Reductions by Energy Source (Short Tons)

Sector	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 - '21
First Year Reductions	**1,072**	**3,828**	**9,714**	**13,319**	**13,900**	**41,833**
From Gas Savings	864	3,177	8,835	12,219	12,778	**37,873**
From Electric Savings	208	651	879	1,100	1,122	**3,960**
Lifetime Reductions	**19,731**	**71,384**	**113,779**	**146,840**	**157,816**	**509,549**
From Gas Savings	15,690	58,697	96,588	125,285	135,761	**432,022**
From Electric Savings	4,041	12,687	17,191	21,555	22,054	**77,528**

1.5.5 Job Creation

Investing in cost-effective energy-efficiency creates jobs in two ways, one direct and the other indirect, as discussed in a 2012 white paper from the ACEEE.[7] Direct job creation results from hiring related to implementing the programs. Indirect job creation results from the substitution capital spent on natural gas with local capital spent in the local economy. Several times more jobs are created by the indirect or income effect from cost-effective energy-efficiency investment. Further, the net economic benefits from efficiency investment reduce household and business gas bills and raise household disposable incomes and business profitability. Customers will tend to spend most of this additional money and save the rest. This additional spending creates a "multiplier" effect through the cycle of re-spending of the initial cost savings, which stimulates aggregate demand for goods and services. Satisfying increased demand for goods and services requires more labor. While some of the jobs created leak into the broader U.S. and global economy, a good portion

[7] "Energy Efficiency Job Creation: Real World Experiences" Bell, Casey J. American Council for an Energy-Efficiency Economy. October 2012.

(possibly higher than 80%) of jobs created due to energy efficiency stay within the Commonwealth. The approach of looking at net job creation through both direct means and with economic multiplier effects is endorsed in the 2012 white paper from ACEEE.

The number of jobs created from investments in energy efficiency directly relates to the total resource value of the energy that these measures save. Studies of employment impacts of DSM use energy savings as a surrogate for total resource value. A recent meta-study of U.S. data found that estimates for the number of jobs created had a wide range, but that most studies estimate that between 30 and 60 net jobs are created by saving one TBtu.[8] In New York, New Jersey, and Pennsylvania, the ACEEE projected that 164,320 jobs, or 59 for every TBtu saved, could be attributed to EE in 1997 through 2010.[9]

As shown in the following table, UGI Gas estimates that its gas energy efficiency programs portfolio will generate between 222 and 369 net additional jobs over the lifetime of the efficiency measures installed over the next five-years. This range is based on assuming that each TBtu of gas savings creates between 30 and 50 full-time equivalent jobs in Pennsylvania.

[8] Laitner, Skip, and Vanessa McKinney. June 2008. *Positive Returns: State Energy Efficiency Analyses Can Inform U.S. Energy Policy Assessments*. Washington, D.C.: American Council for an Energy Efficiency Economy.

[9] Nadel, Steven, Skip Laitner, Marshall Goldberg, Neal Elliott, John DeCicco, Howard Geller, and Robert Mowris. 1997. *Energy Efficiency and Economic Development in New York, New Jersey, and Pennsylvania. Washington, D.C*.: American Council for an Energy Efficiency Economy.

Table 8. Estimated Job Creation due to Energy Efficiency Programs

	30 Jobs/TBtu	40 Jobs/TBtu	50 Jobs/TBtu
Residential Sector			
FY 2017	7	9	11
FY 2018	23	31	39
FY 2019	36	48	60
FY 2020	46	61	76
FY 2021	49	66	82
TOTAL	**161**	**215**	**269**
Nonresidential Sector			
FY 2017	1	2	2
FY 2018	7	9	11
FY 2019	14	18	23
FY 2020	19	25	31
FY 2021	20	27	34
TOTAL	**60**	**80**	**101**
Total Portfolio			
FY 2017	8	11	13
FY 2018	30	40	50
FY 2019	50	66	83
FY 2020	64	86	107
FY 2021	70	93	116
TOTAL	**222**	**295**	**369**

1.6 Efficiency Program Costs

The following table provides an overview of the spending by year and by sector on energy efficiency (EE) programs. The EE programs will cost approximately $5.0 million per year over the five years in 2015 dollars ($5.4 million in nominal dollars). The most spent in a single year is the final year, FY 2021, with a $6.9 million budget in 2015 dollars, which is approximately two percent (2%) of UGI Gas's 2015 revenues. This level is similar to the cap that Act 129 imposes on electric efficiency programs in Pennsylvania.[10]

[10] *See* 66 Pa. C.S. § 2806.1(g) (limiting the total cost of an EDC's EE&C Plan to 2% of the EDC's total annual revenue as of December 31, 2006).

Table 9. Projected Efficiency Portfolio by Budgets by Sector

Sector	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 - '21
Nominal	**$2,351,000**	**$4,121,000**	**$5,769,000**	**$7,023,000**	**$7,749,000**	**$27,013,000**
Residential (R/RT)	$1,831,507	$3,358,356	$4,517,817	$5,527,424	$5,969,491	**$21,204,594**
Nonresidential (N/NT)	$519,493	$762,644	$1,251,183	$1,495,576	$1,779,509	**$5,808,406**
2015$	**$2,271,006**	**$3,902,727**	**$5,356,313**	**$6,392,752**	**$6,915,295**	**$24,838,093**
Residential (R/RT)	$1,769,189	$3,180,477	$4,194,633	$5,031,390	$5,327,241	**$19,502,930**
Nonresidential (N/NT)	$501,817	$722,250	$1,161,680	$1,361,362	$1,588,054	**$5,335,163**

The following two tables present the projected efficiency budgets by program in nominal and real 2015 dollars.

Table 10. Projected Efficiency Portfolio Budgets by Program (Nominal)

Program	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 - '21
EE Total	**$2,351,000**	**$4,121,000**	**$5,769,000**	**$7,023,000**	**$7,749,000**	**$27,013,000**
Residential Prescriptive (RP)	716,000	1,731,000	2,307,000	2,755,000	2,815,000	10,324,000
Nonresidential Prescriptive (NP)	250,000	331,000	587,000	663,000	713,000	2,544,000
Residential Retrofit (RR)	200,000	520,000	800,000	1,000,000	1,200,000	3,720,000
Nonresidential Retrofit (NR)	100,000	216,000	306,000	432,000	654,000	1,708,000
New Construction (NC)	135,000	273,000	479,000	638,000	782,000	2,307,000
Behavior and Education (BE)	-	320,000	510,000	735,000	735,000	2,300,000
Portfolio-wide Costs	950,000	730,000	780,000	800,000	850,000	4,110,000

Table 11. Projected Efficiency Portfolio Budgets by Program (2015$)

Program	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 - '21
EE Total	**$2,271,006**	**$3,902,727**	**$5,356,313**	**$6,392,752**	**$6,915,295**	**$24,838,093**
Residential Prescriptive (RP)	691,638	1,639,316	2,141,968	2,507,765	2,512,138	9,492,824
Nonresidential Prescriptive (NP)	241,494	313,468	545,009	603,502	636,289	2,339,762
Residential Retrofit (RR)	193,195	492,458	742,772	910,259	1,070,893	3,409,577
Nonresidential Retrofit (NR)	96,597	204,559	284,110	393,232	583,637	1,562,136
New Construction (NC)	130,407	258,540	444,735	580,746	697,866	2,112,293
Behavior and Education (BE)	-	303,051	473,517	669,041	655,922	2,101,531
Portfolio-wide Costs	917,676	691,335	724,202	728,208	758,550	3,819,970

The portfolio-wide cost lines from the previous two tables are costs that apply to all programs in the EE portfolio. They are costs incurred at the portfolio level for program development, design, tracking, reporting, and administrative overhead. Development costs for the portfolio occur in the first year as programs are designed and reporting infrastructure is put in place. Costs then fall sharply in the second year before climbing as the portfolio grows. In the final year, the portfolio wide costs represent 11% of the portfolio total cost, however, over the five-year period they represent 15% of the portfolio's costs.

The following tables provide a portfolio-level look at costs by category in nominal and real 2015 dollars.

Table 12. Projected Efficiency Portfolio Budgets by Category (Nominal)

Program	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 - '21
EE Total	**$2,351,000**	**$4,121,000**	**$5,769,000**	**$7,023,000**	**$7,749,000**	**$27,013,000**
Customer Incentives	$551,000	$2,068,000	$3,670,000	$4,804,000	$5,198,000	$16,291,000
Administration	1,447,000	1,588,000	1,440,000	1,556,000	1,690,000	7,721,000
Marketing	329,000	338,000	322,000	367,000	396,000	1,752,000
Inspections	24,000	87,000	137,000	181,000	205,000	634,000
Evaluation	-	40,000	200,000	115,000	260,000	615,000

Table 13. Projected Efficiency Portfolio Budgets by Category (2015$)

Program	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 - '21
EE Total	**$2,271,006**	**$3,902,727**	**$5,356,313**	**$6,392,752**	**$6,915,295**	**$24,838,093**
Customer Incentives	$532,252	$1,958,466	$3,407,465	$4,372,886	$4,638,754	$14,909,824
Administration	1,397,765	1,503,890	1,336,989	1,416,364	1,508,175	7,163,183
Marketing	317,806	320,097	298,966	334,065	353,395	1,624,329
Inspections	23,183	82,392	127,200	164,757	182,944	580,476
Evaluation	-	37,881	185,693	104,680	232,027	560,281

1.7 CHP Program Benefits and Costs

The following tables show the net primary energy savings installed annually for the CHP program.

Table 14. Projected Net Primary Energy Savings from CHP (MMBtus)

Savings	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 - '21
First Year Savings	169,855	169,855	455,460	455,460	455,460	**1,706,090**
Lifetime Savings	2,547,828	2,547,828	6,831,898	6,831,898	6,831,898	**25,591,350**

The following table provides the net CO_2 emission reductions due to the CHP program.

Table 15. Net CO_2 Emission Reductions due to CHP (Short Tons)

Savings	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 - '21
Incremental Annual	17,155	17,155	22,271	22,271	22,271	**101,124**
Cumulative	17,155	34,310	56,582	78,853	101,124	**101,124**

The following table provides the annual projected budget for the CHP program in nominal and real 2015 dollars.

Table 16. Projected CHP Program Budgets

Spending	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 - '21
Nominal	$418,500	$435,650	$852,825	$922,412	$997,821	**$3,627,208**
2015$	$387,500	$373,500	$677,000	$678,000	$679,100	**$2,795,100**

The following table provides the combined EE Program and CHP budgets in real 2015 dollars by category for FY 2017, which is used as the reference year in UGI Gas's Base Rate Case filing.

Table 17. Reference Year (FY 2017) Budget by Category and Sector

Program Category	R/RT	Non-Residential	Total
Customer Incentives	$ 471,396	$ 310,856	$ 782,252
Administration	$ 1,108,417	$ 339,349	$ 1,447,765
Marketing	$ 172,955	$ 209,851	$ 382,806
Inspections	$ 16,422	$ 9,262	$ 25,683
Evaluation	$ -	$ 20,000	$ 20,000
Total Expenses	$ 1,769,189	$ 889,317	$ 2,658,506

1.8 Cost-Effectiveness Analysis

This section provides cost-effectiveness projections for EE&C using the TRC test, which is the primary metric by which UGI Gas judges the portfolio.

Table 18. Cost-effectiveness Summary of Energy Efficiency Programs for Five-Year Portfolio (2015$)

Program	Total Resource PV Benefits	Total Resource PV Costs	Total Resource PV Net Benefits	Total Resource BCR
EE&C Total	**$172,528,340**	**$104,668,959**	**$67,859,381**	**1.65**
Residential Prescriptive (RP)	$31,130,604	$14,907,355	$16,223,249	2.09
Nonresidential Prescriptive (NP)	$8,708,345	$3,813,860	$4,894,485	2.28
Residential Retrofit (RR)	$4,816,226	$3,509,802	$1,306,423	1.37
Nonresidential Retrofit (NR)	$3,347,061	$1,739,899	$1,607,162	1.92
New Construction (NC)	$3,671,531	$1,919,760	$1,751,772	1.91
Behavior and Education (BE)	$2,178,476	$1,624,141	$554,335	1.34
Portfolio-wide Costs	$-	$3,108,352	$(3,108,352)	-
EE Programs	**$53,852,243**	**$30,623,169**	**$23,229,074**	**1.76**
CHP Program	$118,676,097	$74,045,790	$44,630,307	1.60

1.8.1 Cost-Effectiveness Analysis Methodology

The cost-effectiveness results reported in the Plan followed standard industry practices for utilizing the TRC test for cost-effectiveness. The TRC test methodology used is similar to the test utilized by the electric utilities under Act 129 of 2008, and presents results from the standpoint of the entire service territory. To calculate benefits, projected natural gas, electricity, and water savings are multiplied by avoided costs and this stream of future values is discounted to the present.[11] For measures that have an increase in resource usage, such as CHP projects, the increase in usage may offset some, or all, of the positive benefit derived from resource savings. The cost side of the test consists of the present value of all incremental costs incurred by participants, including net operation and maintenance costs, and the non-incentive costs incurred by the portfolio administrator. If the benefits outweigh the costs (the benefit-cost ratio is above one), then the total cost of energy services for an average customer within the territory will fall and the portfolio is considered cost-effective. Results for the Program Administrator Cost (PAC) test are also included. The PAC only includes the costs for program administration and incentives, not additional customer costs. Since UGI Gas is a natural gas utility, the benefits for the PAC test are the natural gas savings.

The analysis used a real discount rate (RDR) of 5.88%. The RDR was calculated using an assumption of a nominal discount rate (NDR) of 8.00%, based on UGI Gas's weighted average cost of capital (WACC), and an inflation rate of 2.0%. UGI Gas employed an Excel spreadsheet-based tool to calculate the cost-effectiveness of the EE&C Portfolio.

1.8.2 Avoided costs

UGI Gas developed avoided costs following the approach used by the Pennsylvania PUC in the Act 129 proceedings. Gas costs were based on the Henry Hub forwards for 2016–2020, followed by a mix of forwards and Annual

[11] Savings are not currently adjusted for free-ridership or spillover, meaning there is a net-to-gross assumption of 1.0, which is in line with current assumptions by PGW and Act 129 utilities.

Energy Outlook values through 2025, and the Annual Energy Outlook projections thereafter. The costs of baseload, winter storage and peaking capacity were added (paralleling the inclusion of generation capacity in the electric avoided costs), along with avoidable local distribution costs, using the same method employed by the Statewide Evaluator and adopted by the PUC in the Act 129 TRC proceeding.[12]

Evaluation of some gas-efficiency programs and CHP also requires estimates of avoided electric costs, which were taken directly from the analysis by the Statewide Evaluator for PPL Electric Utilities Corporation and Metropolitan Edison Company, the two major EDCs whose service territories overlap with UGI Gas's service territory, restated to constant 2015 dollars.[13] Both the electric and gas avoided costs reflect the benefits of reduced supply prices and emissions. A table showing the annual values for gas and electric avoided costs is included in Appendix 3.1.

UGI Gas plans to use these avoided costs for the full five-year plan. However, future market volatility or a change in the regulatory environment may require that UGI Gas update some or all of the avoided costs. If so, UGI will file an updated avoided cost document which includes details on the changes to avoided costs, establishes an effective date for the application of new avoided costs, and provides updated cost-effectiveness projections.

1.9 Implementation

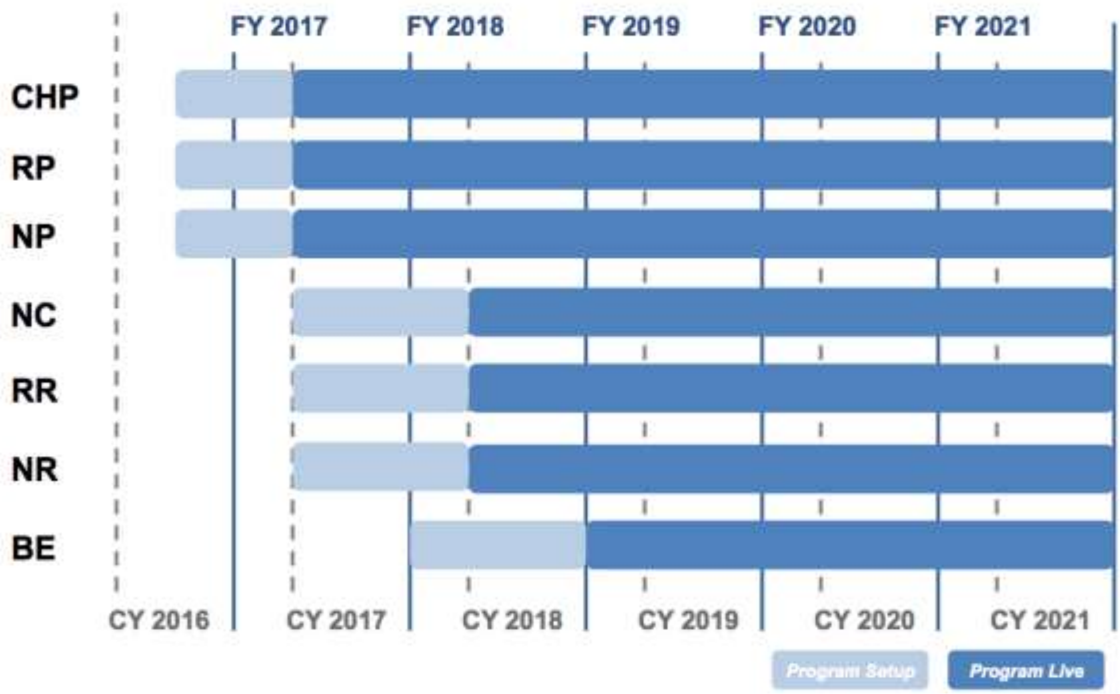
1.9.1 Program Staging

The staging of the EE&C Portfolio is dependent on the approval of the plan, which is anticipated to occur in mid-2016. Each program will require a setup period during which services are contracted through a competitive bidding process, protocols are put in place, reporting systems are established, and

[12] *See 2016 Total Resource Cost (TRC) Test*, Docket No. M-2015-2468992 (Final Order, entered June 22, 2015).
[13] Act 129 SWE Distributed Generation Potential Study, Docket No. M-2014-2424864 (February 13, 2015).

marketing initiatives are finalized before the program is officially launched and open for participation. Once launched, each program will ramp up for three or four years before reaching full participation levels. Figure 3 provides a high-level overview of the planning and launching of each program in the portfolio.

Figure 3. Overview of Program Staging



Once the Plan has been approved, the initial focus will be on rolling out the two prescriptive lost-opportunity energy efficiency programs, RP and NP, with anticipated launch dates in January of 2017. These programs are the cornerstone of the portfolio. The CHP program will also be launched at the same time in order to allow for the very long lead times required for CHP projects.

The NC, RR, and NR programs require a longer setup phase since the programs are more complex than the two prescriptive rebate programs. These three programs are anticipated to launch in January of 2018, and will benefit from the infrastructure developed from the launch of the first three programs.

Rounding out the portfolio is the BE program. It is anticipated to start in October of 2018, in coordination with planned upgrades to UGI Gas's customer information systems. After all programs are launched, they will continue to ramp up until the Plan reaches its maximum funding levels in FY 2021. Additional details on each program's staging can be found in the individual program description.

1.9.2 Marketing

The EE&C Plan has a two-pronged marketing approach consisting of raising general customer awareness through a campaign around a cohesive portfolio brand, combined with targeted outreach and strategic partnerships with community based organizations and trade allies. Marketing efforts will be coordinated at the program level in order to leverage opportunities for multiple programs at the same time, and focus on opportunities tailored to the customer, regardless of which program incentives will ultimately be offered.

General Awareness and Branding

UGI Gas will develop an overall brand for the EE&C Plan that will be used as an umbrella for all program activity. This will create a cohesive picture of UGI Gas's efficiency and conservation efforts that should translate into higher engagement levels and more customer participation. The general awareness campaign will be the top of the sales funnel, driving customers to more targeted opportunities (providing the "push"). The central component of the campaign will be a branded micro-website for the portfolio. To do this, the campaign will utilize many approaches including, but not limited to, TV, print, radio, billboards, online ads, social media, bill inserts, sponsorships, grass-roots outreach, residential canvassing efforts, and event sponsorship. Once a customer reaches the website, he or she will be funneled towards appropriate programs and incentives through activities and targeted links. While the website will be the center of the portfolio brand, it will be supplemented with physical handouts and applications. These efforts are anticipated to be particularly important for driving residential sector participation.

Targeted Outreach and Partnerships

The second prong of the marketing campaign is to engage customers through outreach efforts and strategic partnerships (providing a “pull”). These efforts are likely to be the best way to drive nonresidential participation. Successful activities involve all sectors within the community and may include such activities as:

- Partnering with local businesses and trade organizations (builders, contractors, electricians, plumbers, HVAC service providers, equipment suppliers, etc.) to familiarize them with program opportunities, energy efficiency practices and implementation requirements and to utilize them, where appropriate, as one of the program’s service delivery channels.
- Targeting equipment manufacturers, distributors, installation contractors and retailers/vendors to make sure they offer high-efficiency equipment and can make customers aware of available incentives.
- Connecting with local business organizations to provide opportunities to address their specific needs and translate them to their tenants, management, and facility operations personnel.
- Assisting school systems in developing comprehensive, standards-based curricula, resources, materials and professional development for educators, school facility audits, and special events.
- Partnering with community-based organizations to develop outreach and program delivery strategies.
- Leveraging any available federal tax credits, if applicable, as well as supplemental consumer incentives (e.g., equipment manufacturers) as a means to increase consumer adoption of high efficiency heating equipment.
- Working with Act 129 electric administrators to combine marketing and delivery options and address all aspects of efficiency at the same time.

1.9.3 Administration

UGI Gas will be the primary administrator of the Plan. UGI Gas will engage the services of various contractors to fulfill all the roles required to implement the Plan. Contractors will be selected through a competitive bidding process, and UGI Gas will streamline operations across programs as much as possible by hiring a single rebate processor for multiple programs. The table below describes the main roles in the management of the EE&C Plan.

Table 19. Overview of Administration Roles

Role	Description
Plan Administrator	Primarily responsible for program and portfolio planning, management and reporting. Supervises and manages all other roles.
Implementation and Design Consultants	Provides assistance in the design and implementation of many different aspects of the portfolio, including, but not limited to, program design, reporting, marketing, and training. UGI Gas will leverage internal resources wherever possible to provide these services.
Implementation Contractor	Directly responsible for main aspects of program delivery, including but not limited to, customer engagement and retention, technical assistance, measure installation, rebate processing, program tracking, and reporting.
Third-party Inspector	Responsible for measure and project inspections separately from the implementation contractor.
Evaluator	Performs independent program and portfolio evaluations that are used to verify savings and guide future plans.

1.9.4 Reporting

UGI Gas will submit an annual report on the EE&C Plan each January following the close of the fiscal year, approximately three months after the end of the program year. This report will provide information on activity for the previous year and progress towards five-year goals, including, but not limited to:

- First year and lifetime savings;
- Participation;
- Spending;
- Cost-effectiveness;
- Highlights of portfolio and program activity; and

- Updates to program delivery and design.

In order to tie savings and costs together as effectively as possible, results will be reported based on commitments made. Any measures that have been verified as installed within a program year along with any costs committed to these measures, including administration costs, will be counted for that Plan year.

1.9.5 Program Flexibility

In order to make sure that the EE&C Portfolio is able to address changing market conditions and improve service delivery as quickly as possible, UGI Gas requires flexibility in the allocation of budgets and implementation of program improvements. This plan document provides the principles and five-year goals that UGI Gas is seeking, but certain adjustments, such as providing incentives for new measures or moving budgets between years and programs, may be required in order to meet these goals. UGI will include any such adjustments in its annual report, but does not anticipate seeking initial approval for such updates. However, UGI Gas will file an updated EE&C Plan in anticipation of material changes that may have a serious effect on five-year goals, such as:

- The addition or removal of a program.
- A need for total funding levels above those approved for the five-year period.
- Significant changes to cost-effectiveness projections, such as an update to avoided costs or a large reduction in portfolio spending projections.

1.10 Evaluation, Measurement, and Verification

UGI Gas will monitor the ongoing progress of the EE&C Plan in order to provide the highest possible service to customers, while maintaining rigorous processes and controls to ensure that savings and costs are being properly accounted for. UGI Gas will closely track program data, perform independent inspections of completed projects, and perform periodic evaluations for all the programs.

1.10.1 Technical Reference Manual

As discussed above, in order to maintain consistency with existing gas efficiency programs in Pennsylvania, UGI Gas has developed a Technical Reference Manual (TRM) based on the one currently used by PGW's EnergySense portfolio. The UGI Gas TRM calibrates certain measure assumptions to UGI Gas's service territory (such as equivalent full load heating hours) and includes new entries for measures not covered in the PGW TRM. Any results from program evaluations that affect deemed savings calculations will also be added to the UGI Gas TRM.

1.10.2 Tracking System

UGI Gas will require that implementation contractors collect all relevant customer, application, measure, and contractor information and that this data is provided to UGI Gas in a timely fashion. UGI Gas will in turn maintain a program and portfolio-level aggregation of this information to be used for program management and assessment, as well as for annual reporting.

1.10.3 Third-party inspections

Each program will have a third-party inspector, separate from the contractor that performed the work, who will solicit customer feedback and will examine whether the work was done properly and whether the installed measures match the application data. Inspections for large, complex, and custom projects will be mandatory. Inspections rates for prescriptive programs will be designed to gather a statistically significant sample of program activity. See individual program plans for additional details.

1.10.4 Evaluations

With the exception of the BE (Behavior and Education) program, UGI Gas will evaluate each of its programs once adequate participation levels have been reached and a full 12 months of post-participation billing data has been collected. The program will be evaluated again after another two years have passed. Due to the unique nature of the BE program, evaluation activities will begin as soon as the program starts up and continue on an annual basis throughout the program’s existence.

As part of the initial program development, UGI Gas will work with the selected evaluator to establish the methodology and goals of the process evaluation. Initial objectives include:

- Verifying energy savings and associated costs;
- Assessing market attitudes towards the program, including contractors, customers, and efficient equipment suppliers; and
- Measuring the effectiveness of current program design, marketing, and service delivery.

The evaluation section of the individual program plans includes additional details on evaluation schedules and goals unique to that program.

2 Program Plans

2.1 Residential Prescriptive

Objective	The Residential Prescriptive (RP) program is designed to overcome market barriers to energy efficient space and water heating equipment in the residential sector through rebates and customer awareness. The objective of the program is to avoid lost opportunities by encouraging consumers to install the most efficient gas heating technologies available when replacing older, less efficient equipment. The program also aims to strengthen UGI Gas's relationship with HVAC contractors, suppliers, and other trade allies.
Eligible Rate Class	R/RT
Cost Effectiveness	***Five-Year Cost-Effectiveness Results (2015$)***

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC	$31,130,604	$14,907,355	$16,223,249	2.09
Gas Admin	$26,480,582	$7,479,279	$19,001,303	3.54

Savings Projections

Five-Year Savings Projections

	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Natural Gas (MMBtus)						
First Year	11,969	37,009	49,384	60,395	60,395	219,152
Lifetime	222,047	691,542	922,911	1,128,987	1,128,987	4,094,474
Electric Energy (kWh)						
First Year	248,350	753,969	1,002,319	1,231,218	1,231,218	4,467,074
Lifetime	4,819,127	14,635,782	19,454,909	23,899,518	23,899,518	86,708,853

	Peak (kW)	54.6	165.9	220.5	270.9	270.9	982.8
	Water (Gallons)						
	First Year	-	-	-	-	-	-
	Lifetime	-	-	-	-	-	-
Budget Projections	***Five-Year Budgets (Nominal)***						
	Category	**FY 2017**	**FY 2018**	**FY 2019**	**FY 2020**	**FY 2021**	**FY '17 – FY '21**
	Customer Incentives	$488,000	$1,528,000	$2,040,000	$2,500,000	$2,500,000	**$9,056,000**
	Administration	112,000	73,000	79,000	84,000	84,000	**432,000**
	Marketing	99,000	67,000	77,000	85,000	85,000	**413,000**
	Inspections	17,000	53,000	71,000	86,000	86,000	**313,000**
	Evaluation	-	10,000	40,000	-	60,000	**110,000**
	Total	**$716,000**	**$1,731,000**	**$2,307,000**	**$2,755,000**	**$2,815,000**	**$10,324,000**
	Five-Year Budgets (2015$)						
	Category	**FY 2017**	**FY 2018**	**FY 2019**	**FY 2020**	**FY 2021**	**FY '17 – FY '21**
	Customer Incentives	$471,396	$1,447,068	$1,894,068	$2,275,649	$2,231,028	**$8,319,208**
	Administration	108,189	69,133	73,349	76,462	74,963	**402,096**
	Marketing	95,631	63,451	71,492	77,372	75,855	**383,802**
	Inspections	16,422	50,193	65,921	78,282	76,747	**287,565**
	Evaluation	-	9,470	37,139	-	53,545	**100,154**
	Total	**$691,638**	**$1,639,316**	**$2,141,968**	**$2,507,765**	**$2,512,138**	**$9,492,824**

Participation Projections	***Five-Year Participation Projections***

	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Furnace - ENERGY STAR	520	1,580	2,100	2,580	2,580	**9,360**
Boiler - 94+ AFUE	40	140	180	230	230	**820**
Combi Boiler - 94+ CAE	-	10	20	20	20	**70**
Wi-Fi Thermostat	1,020	3,060	4,080	5,000	5,000	**18,160**
Tankless Water Heater - 82 EF	110	340	460	525	525	**1,960**
Tankless Water Heater - ENERGY STAR	110	340	460	560	560	**2,030**
Total	**1,800**	**5,470**	**7,300**	**8,915**	**8,915**	**32,400**

Program Rollout	*June 2016 – December 2017*	Finalize program process and implementation details, select vendors, and develop initial marketing push.
	January 2017	Launch Program.
	FY 2018 - FY 2019	Continue engagement activities with customers and trade allies.
	FY 2020	Reach full participation levels.

Program Design	The RP program offers mail-in rebates for qualifying residential-sized space and water heating equipment. Customers will be made aware of opportunities through traditional marketing efforts, such as bill inserts and media advertisements, as well as from installation contractors. For most measures, customers will have a contractor install the measure and receive a cash rebate to offset most of the incremental cost of the higher efficiency equipment. Smaller measures, such as Wi-Fi enabled thermostats, will only require a valid proof of purchase before a cash rebate is issued. UGI Gas will continue to examine other equipment for potential inclusion in the program, as well as

	the relative market adoption of equipment already receiving incentives. Any new equipment added to the program will have a TRC BCR above 1.0. If program funds begin to run low in a given year, incentive levels may be lowered or equipment removed from the program if additional budget adjustments cannot be made. UGI Gas will aim to provide as little interruption to customers as possible due to such adjustments.
Target Market and End Uses	The RP targets residential consumers who use natural gas to heat their homes and/or generate hot water. In general, the program aims to incentivize only the highest levels of efficient equipment on the market. On the space heating side, the program provides incentives for Wi-Fi enabled thermostats, ENERGY STAR® labeled furnaces, high efficiency boilers, and combination boilers. Wi-Fi enabled thermostats offer the potential for deeper savings than traditional programmable thermostats due to the wide range of features and feedback they offer. ENERGY STAR® requirements for furnaces drive customers toward the highest efficiency tier of condensing units (95+ AFUE) and also require efficient fans that save electricity. The program would require boilers to also go towards the highest efficiency tier with an AFUE of at least 94. Finally, offering incentives for combination space and water heating boilers addresses two types of end-use with one piece of equipment. These “combi boilers” also address issues with orphaned water heaters having existing atmospheric venting systems that are no longer adequate, when switching to condensing heating equipment. The program addresses water heating by offering incentives for tankless water heaters at two

	different efficiency levels due to the relatively low penetrations of this measure in UGI Gas's territory.
Financial Incentives	Incentives were designed to be in line with other offerings in the region and/or cover approximately two-thirds of the incremental cost of the measure. The table below lists the proposed incentive schedule. ***Proposed Residential Prescriptive Program Rebates (Nominal)*** (see table below) All equipment must be powered by natural gas.
Marketing Approach	The RP program will be a cornerstone of the two-pronged marketing approach for the portfolio. The program is expected to be a large portion of the general call-to-action on the residential side as well as a key part of trade ally outreach efforts. This will include placement on the UGI.com website as well as a general social media push. This program will also include more tailored messages for realtors, developers, owners, and managers of larger multi-family properties in order to make sure that high efficiency options are considered when bulk-purchasing decisions may be made.

Proposed Residential Prescriptive Program Rebates (Nominal)

Equipment	Minimum Efficiency	Proposed Incentive
Wi-Fi Thermostat	ENERGY STAR®	$100
Furnace	ENERGY STAR®	$500
Boiler	94+ AFUE	$1,500
Combi Boiler	94+ CAE	$1,800
Tankless Water Heater	82+ EF	$200
Tankless Water Heater	ENERGY STAR®	$400

Evaluation, Measurement, and Verification	<u>Quality Assurance</u> All applications will require proof of purchase and a valid UGI Gas account number. All equipment, except for Wi-Fi thermostats, will also require proof of installation, including information about the installing contractor. The rebate processor will verify that the equipment is eligible for the rebate based on the model number before issuing any rebate. The program's rebate processor will maintain a real-time database of rebate activity, which will be periodically reviewed by UGI Gas and stored separately for long-term purposes. A third-party inspector will perform on-site inspections on five percent (5%) of non-thermostat equipment rebates and three percent (3%) of Wi-Fi thermostat rebates in order to get a statistically significant sample of activity. The inspection will consist of verifying that the rebated equipment is installed and operational and conclude with a short informational interview with the participant. <u>Evaluations</u> The program is expected to have enough activity to allow for an impact evaluation to start at the end of FY 2018 with a second evaluation scheduled for FY 2021. The initial evaluation will have a particular focus on Wi-Fi thermostats in order to determine the best way to utilize them as a measure. The RP evaluations will also include feedback from installation contractors and supply houses about current market conditions, such as availability and adoption of high efficiency technology, and awareness of the program.

Program Administration	Rebate Processing UGI Gas will engage a contractor to be the main rebate processor. This may include accepting customer applications, tracking and verifying application information, notifying the customer of any issues, maintaining a call center, and reporting results to UGI Gas. The rebate processor may also be responsible for other rebate programs in order to streamline portfolio management. Marketing and Outreach The main marketing and outreach contractor in combination with the UGI Gas internal marketing team will handle marketing and outreach for the RP program. Inspector A separate contractor will perform on-site inspections and collect customer feedback. Evaluator A third-party evaluator will be retained to perform regular evaluations.
Special Notes	The program is currently designed so that a cash rebate will be offered for Wi-Fi thermostats. If initial evaluation, and participant and trade ally feedback are positive, UGI Gas will move towards offering upstream incentives for this technology. This could result in much higher levels of participation, but would have a lower impact on budgets due to the size of the incentive offered. A key risk factor for the program is a changing baseline for furnaces in the Northern United States.

	There is a possibility that new federal standards and/or a general market shift towards condensing furnaces may necessitate a higher baseline for high efficiency furnaces. While the current efficient condition for natural gas furnaces would still exceed an anticipated baseline shift, savings and incentive levels would be adjusted downwards and savings and/or spending goals may need to be adjusted accordingly.

2.2 Nonresidential Prescriptive

Objective	The Nonresidential Prescriptive (NP) Program is designed to overcome market barriers to energy efficient equipment in the small business and commercial sector through rebates and customer outreach. The objective of the program is to encourage business owners to install the most efficient gas heating and process technologies available to replace older, less efficient equipment. The program also aims to strengthen UGI Gas's relationship with HVAC contractors, suppliers, and other trade allies.
Eligible Rate Class	N/NT
Cost Effectiveness	***Five-Year Cost-Effectiveness Results (2015$)***

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC	$8,708,345	$3,813,860	$4,894,485	2.28
Gas Admin	$8,138,290	$1,845,275	$6,293,015	4.41

Savings Projections

Five-Year Savings Projections

	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Natural Gas (MMBtus)						
First Year	2,800	10,017	19,819	24,548	24,548	81,733
Lifetime	46,161	166,851	329,005	408,224	408,224	1,358,465
Electric Energy (kWh)						
First Year	-	-	-	-	-	-
Lifetime	-	-	-	-	-	-
Peak (kW)	-	-	-	-	-	-
Water (Gallons)						
First Year	573,340	2,231,055	4,362,355	5,509,035	5,509,035	18,184,820
Lifetime	3,440,040	13,386,330	26,174,130	33,054,210	33,054,210	109,108,920

Budget Projections	see tables below

Budget Projections

Five-Year Budgets (Nominal)

Category	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Customer Incentives	$63,000	$225,000	$450,000	$550,000	$550,000	$1,838,000
Administration	100,000	50,000	50,000	50,000	50,000	300,000
Marketing	80,000	31,000	32,000	33,000	33,000	209,000
Inspections	7,000	15,000	25,000	30,000	30,000	107,000
Evaluation	-	10,000	30,000	-	50,000	90,000
Total	**$250,000**	**$331,000**	**$587,000**	**$663,000**	**$713,000**	**$2,544,000**

Five-Year Budgets (2015$)

Category	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Customer Incentives	$60,856	$213,083	$417,809	$500,643	$490,826	$1,683,217
Administration	96,597	47,352	46,423	45,513	44,621	280,506
Marketing	77,278	29,358	29,711	30,039	29,450	195,835
Inspections	6,762	14,206	23,212	27,308	26,772	98,259
Evaluation	-	9,470	27,854	-	44,621	81,945
Total	**$241,494**	**$313,468**	**$545,009**	**$603,502**	**$636,289**	**$2,339,762**

Participation Projections

Five-Year Participation Projections

	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
C&I Custom Rebate	3	10	21	24	24	83
Commercial Boiler - 85+ Et	7	26	50	62	62	207
Commercial Boiler - 90+ Et	2	8	16	21	21	68
Unit Heater (Warm Air)	24	88	171	214	214	711
Steam Trap (<15 PSIG)	2	8	15	19	19	63
Steam Trap (15<= PSIG < 75)	2	8	15	19	19	63
Steam Trap (>= PSIG)	4	15	31	39	39	128
Commercial Water Heater	12	46	89	111	111	369
Commercial Gas Fryer	3	10	19	24	24	80
Commercial Gas Fryer (Large Vat)	1	3	6	8	8	26
Commercial Gas Steam Cooker	1	2	4	5	5	17
WaterSense Pre-Rinse Spray Valve	5	15	29	37	37	123
Total	**66**	**239**	**466**	**583**	**583**	**1,938**

Program Rollout	*June 2016 – December 2017* Finalize program process and implementations details, select vendors, and develop initial marketing push. *January 2017* Launch Program. *FY 2018 - FY 2019* Continue engagement activities with customers and trade allies. *FY 2020* Reach full program participation.
Program Design	The NP program offers rebates for qualifying commercial-sized space heating, water heating, commercial kitchen, and custom applications. Customers will be made aware of opportunities through traditional marketing efforts, such as bill inserts and media advertisements, installation contractors, and supply houses. Customers will have a contractor install the measure and receive a cash rebate to offset most of the incremental cost of the higher efficiency equipment. Given the anticipated enrollment numbers, a comprehensive (multi-measure) prescriptive rebate form is a good choice for documenting and reporting measures to UGI Gas managers. UGI Gas will continue to examine other equipment for potential inclusion in the program, as well as the relative market adoption of equipment already receiving incentives. Any new equipment added to the program will have a TRC BCR above 1.0. If program funds begin to run low in a given year, incentive levels may be lowered or equipment removed from the program if additional budget adjustments cannot be made. UGI Gas will aim to provide as little interruption to customers as possible due to such adjustments.
Target Market and End Uses	The NP program will serve the small business and commercial market such as office buildings,

	restaurants, and agricultural facilities, and targets three main end-uses. The first and largest end-use targeted is space heating, through commercial boilers, unit heaters, and steam traps. The second target end-use is commercial water heaters. The last end-use is for addressing both cooking and hot water heating through gas fryers, steam cookers, and pre-rinse spray valves. The program also offers a custom application track for single-measure projects that are not already covered by prescriptive rebates. The custom track is expected to cover technology like heat-recovery systems, infrared heaters, controls, range-hood ventilation make-up air systems, and other more site-specific applications. The custom track will be a source for potential technologies to include as prescriptive rebates.
Financial Incentives	Incentives were designed to be in line with other offerings in the region and/or cover approximately two-thirds of the incremental cost of the measure. The table below lists the proposed incentive schedule.

Proposed Nonresidential Prescriptive Program Rebates (Nominal)

Equipment	Minimum Efficiency	Proposed Incentive
Commercial Boiler (>= 300MBh)	85+ Et	$2 / MBh
Commercial Boiler (>= 300MBh)	90+ Et	$2 / MBh + $2,000
Unit Heater (Warm Air)	90+ Et/AFUE	$2 MBh
Steam Trap	<15 PSIG	$50
Steam Trap	15<= PSIG <75	$150
Steam Trap	>= 75 PSIG	$250

	Commercial Water Heater ENERGY STAR® $4 / MBh Commercial Fryer ENERGY STAR® $1,400 Commercial Fryer (Large) ENERGY STAR® $1,900 Commercial Steam Cooker ENERGY STAR® $600 Pre-Rinse Spray Valve WaterSense® $50 An application on the custom track will be analyzed for cost-effectiveness and a custom incentive will be offered based on the internal rate of return and simple payback of the project. The incentive will not be larger than the gas benefits or incremental cost of the project, and the maximum incentive allowed for a custom project will be $25,000. All equipment must be powered by natural gas.
Marketing Approach	The NP marketing approach focuses on targeted outreach to trade allies and supply houses. Outreach efforts will attempt to reach the decision maker at the time of, and in advance of, the need for equipment replacement. UGI Gas will provide regular outreach and training sessions on efficiency opportunities with HVAC contractors, heating suppliers, kitchen equipment suppliers, local business organizations, and other parties that deal with commercial equipment to provide education on opportunities for engagement with the program, hand out rebate applications, and encourage the stocking of high efficiency equipment. Good penetration rates will rely heavily on an educated contractor network to understand how to up-serve participants with more efficient

	products when a service call is requested or new equipment is needed. Contractor training will be provided to those already part of the existing contractor network and qualified for commercial work. UGI Gas will also promote the program through its UGI.com website and other online outreach activities.
Evaluation, Measurement, and Verification	<u>Quality Assurance</u> All applications will require proof of purchase and a valid UGI Gas account number. All rebates will require proof of equipment installation, including information about the installing contractor. The rebate processor will verify that the equipment is eligible for the rebate based on the model number before issuing any rebate. The program's rebate processor will maintain a real-time database of rebate activity, which will be periodically reviewed by UGI Gas and stored separately for long-term purposes. A third-party inspector will perform on-site inspections on all custom rebates and five percent (5%) of all prescriptive rebates in order to get a statistically significant sample of ongoing activity. The inspection will consist of verifying that the rebated equipment is installed and operational and conclude with a short informational interview with the participant. <u>Evaluations</u> The program is expected to have enough activity to allow for an impact evaluation to start at the end of FY 2018 with a second evaluation scheduled for FY 2021. The initial evaluation will have a particular focus on the accuracy of heating savings for varying customer types.

	The NP evaluations will also include feedback from installation contractors and supply houses about current market conditions, such as availability and adoption of high efficiency technology, and awareness of the program.
Program Administration	Rebate Processing UGI Gas will engage a contractor to be the main rebate processor. This may include accepting customer applications, tracking and verifying application information, notifying the customer of any issues, maintaining a call center, and reporting results to UGI Gas. The rebate processor may also be responsible for other rebate programs in order to streamline portfolio management. Marketing and Outreach The main marketing and outreach contractor in combination with the UGI Gas internal marketing team will handle marketing and outreach for the RP program. Inspector A separate contractor will perform on-site inspections and collect customer feedback. Evaluator A third-party evaluator will be retained to perform regular evaluations.
Special Notes	Due to the complex nature of the nonresidential equipment market, the exact mix of measures and adoption of different technologies is not easily predicted. While UGI Gas is confident that the

	projected budget levels are appropriate, the exact mix of measures may vary. In order to relieve busy business owners of the paperwork barrier and reduce pressure on the program’s rebate processor, UGI Gas will explore batching rebates and paying them directly to contractors, with the rebate amount clearly indicated on the participant’s invoice.

2.3 New Construction

Objective	The New Construction (NC) Program is designed to overcome market barriers to energy efficient space and water heating equipment, as well as high efficiency thermal envelopes, in both the residential and nonresidential new construction sector through rebates offered to builders and developers, and general potential buyer awareness. The objective of the program is to avoid lost opportunities by encouraging builders and developers to install the most efficient gas heating technologies available instead of less efficient baseline equipment, as well as promote thermal envelope best practices. The program also aims to strengthen UGI Gas's relationship with architects, builders, HVAC contractors, suppliers, and other trade allies.
Eligible Rate Class	R/RT, N/NT
Cost Effectiveness	***Five-Year Cost-Effectiveness Results (2015$)***

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC	$3,671,531	$1,919,760	$1,751,772	1.91
Gas Admin	$3,443,519	$1,643,772	$1,799,747	2.09

Savings Projections

Five-Year Savings Projections

	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Natural Gas (MMBtus)						
First Year	-	2,737	5,475	8,742	9,570	26,524
Lifetime	-	52,791	105,582	170,564	189,612	518,550
Electric Energy (kWh)						
First Year	-	12,007	24,014	45,011	59,058	140,089
Lifetime	-	275,822	551,645	1,034,239	1,357,319	3,219,026
Peak (kW)	-	2.0	4.0	7.6	10.0	23.7

	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Water (Gallons)						
First Year	-	118,382	236,763	355,145	355,145	1,065,435
Lifetime	-	2,130,870	4,261,741	6,392,611	6,392,611	19,177,832

Budget Projections

Five-Year Budgets (Nominal)

Category	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Customer Incentives	$-	$106,000	$212,000	$350,000	$400,000	$1,068,000
Administration	85,000	103,000	130,000	167,000	182,000	667,000
Marketing	50,000	55,000	70,000	94,000	109,000	378,000
Inspections	-	9,000	17,000	27,000	31,000	84,000
Evaluation	-	-	50,000	-	60,000	110,000
Total	**$135,000**	**$273,000**	**$479,000**	**$638,000**	**$782,000**	**$2,307,000**

Five-Year Budgets (2015$)

Category	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Customer Incentives	$-	$100,386	$196,835	$318,591	$356,964	$972,775
Administration	82,108	97,544	120,700	152,013	162,419	614,785
Marketing	48,299	52,087	64,993	85,564	97,273	348,215
Inspections	-	8,523	15,784	24,577	27,665	76,549
Evaluation	-	-	46,423	-	53,545	99,968
Total	**$130,407**	**$258,540**	**$444,735**	**$580,746**	**$697,866**	**$2,112,293**

Participation Projections

Five-Year Participation Projections

	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Residential Project	-	25	50	94	123	292
C&I Project	-	5	10	15	15	45
Total	**-**	**30**	**60**	**109**	**138**	**337**

Program Rollout

January 2017 – January 2018	Finalize program process and implementations details, select vendors, and develop initial marketing. Start initial engagement with builders and architects and solicit projects to begin technical assistance process.
January 2018	Launch program.

	FY 2018 - FY 2021 Continue engagement activities with customers reaching full program participation in FY 2021.
Program Design	Addressing efficiency when a building is first built is the cheapest and longest lasting way to change energy consumption patterns. The NC program offers incentives to builders and/or developers for going beyond building code to reduce natural gas consumption. The program targets both residential and nonresidential projects. UGI Gas will provide a technical assessment provider that will review customer applications, assess the project plans, verify that each project meets program eligibility requirements and help the customer to achieve the highest feasible and cost-effective savings. <u>Residential Projects</u> The program offers a streamlined prescriptive approach for residential new construction projects to go beyond the opportunities offered under the RP program. The NC residential track is designed to offer builders a higher incentive than they would otherwise receive from just combining RP measures. It encourages participants to go as deep as possible by addressing the space heating system, water heating system, and building envelope. <u>Nonresidential Projects</u> Each nonresidential project will require building simulation modeling showing the gas usage for a baseline building just meeting code and another model with the proposed modifications. UGI Gas will offer an incentive based on the percentage difference in gas usage between the baseline and

	proposed building. The technical assessment provider will provide guidance and propose revisions, which may last several iterations, in order to fully incorporate efficiency in to the design process.
Target Market and End Uses	The NC program targets all new construction projects (including “gut rehab”) contemplating use of natural gas to provide space and hot water heating. For the purposes of this program, gut rehabilitation is defined as a project where the interior space of the building exposes the studs or two or more of the mechanical systems are being replaced and are required to meet current energy code standards. In general, the program aims to incentivize only the highest levels of efficient equipment and construction practices on the market. The NC program takes a whole-building approach, acquiring savings from multiple measures compared to a baseline building just meeting code. For single family and small multi-family buildings, measures might include thermal envelope insulation, heating equipment, and water heating equipment and fixtures. Commercial or large apartment buildings might include HVAC equipment and controls, tighter and better-designed ducts, hot water heating equipment, and thermal envelope insulation.
Financial Incentives	Residential customers will receive a lump sum incentive for achieving 20% gas savings or greater, compared to a house only meeting code. The incentive amount will be designed to cover approximately 80% of the incremental cost. Nonresidential customers will receive an incentive calculated from a dollar per first-year MMBtu saved, depending on what percentage savings tier it falls in. The first tier will be greater than 15%

	but less than 20% savings, the second tier will be greater than or equal to 20% but less than 30%, and the third tier will be greater than or equal to 30% savings.
Marketing Approach	The NC program will focus on tailored messages for realtors, developers, and builders (including ENERGY STAR® builders) in order to ensure that high efficiency options are considered when engaging in major rehab projects as well as in new construction. UGI Gas will also explore ways in which to highlight the efficiency of homes to potential buyers, including through social media.
Evaluation, Measurement, and Verification	<u>Quality Assurance</u> All applications will require information confirming installation and proof of UGI Gas service for heating. Inspections will be performed on 25% of residential new construction projects and all nonresidential retrofit projects before a final rebate is issued. Inspections must verify that the measures proposed for the building were installed as planned and that savings targets have been met, and must conclude with a short informational interview with the owner and/or developer. The program's rebate processor will maintain a real-time database of rebate activity, which will be periodically reviewed by UGI Gas and stored separately for long-term purposes. <u>Evaluations</u> The program is expected to have enough activity to allow for an impact evaluation to start at the end of FY 2019 with a second evaluation scheduled for FY 2021. The NC evaluations will also include feedback from installation contractors and supply houses about current market conditions, such as availability and adoption of high efficiency technology and

	building practices, and awareness of the program and its efficiency tiers.
Program Administration	Technical Assistance and Rebate Processing UGI Gas will engage a contractor to be the main program implementation contractor. The contractor will be responsible for technical review of projects as well as assisting potential customers with including efficiency in their project design. This role will also include accepting program applications, tracking and verifying application information, notifying the applicant of any issues, maintaining a call center, and reporting results to UGI Gas. Marketing and Outreach The main marketing and outreach contractor, in combination with the UGI Gas internal marketing team, will handle marketing and outreach for the NC program. Inspector A separate contractor will perform on-site inspections and collect customer feedback. The same firm responsible for providing technical assistance may perform this role. Evaluator A third-party evaluator will be retained to perform regular evaluations.
Special Notes	The new construction market is highly cyclical and participation levels in the program will be highly influenced by broader economic trends beyond the control of UGI Gas.

2.4 Residential Retrofit

Objective	The Residential Retrofit (RR) Program is designed to overcome market barriers to energy efficiency in the existing residential sector through rebates offered either to customers undergoing a retrofit project or to their installation contractor(s). The program encourages improvements to the thermal envelope of the structure, particularly reductions in building air leakage and increases in insulation levels, as well as installation of the most efficient gas heating technologies. The program also aims to strengthen UGI Gas's relationship with HVAC contractors, suppliers, and other trade allies.
Eligible Rate Class	R/RT
Cost Effectiveness	***Five-Year Cost-Effectiveness Results (2015$)***

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC	$4,816,226	$3,509,802	$1,306,423	1.37
Gas Admin	$4,614,808	$2,661,253	$1,953,556	1.73

Savings Projections

Five-Year Savings Projections

	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Natural Gas (MMBtus)						
First Year	-	2,772	6,856	8,676	12,678	30,982
Lifetime	-	66,524	164,539	208,232	304,279	743,574
Electric Energy (kWh)						
First Year	-	5,010	12,390	15,681	22,914	55,994
Lifetime	-	120,229	297,372	376,339	549,924	1,343,864
Peak (kW)	-	3.6	8.9	11.3	16.4	40.2
Water (Gallons)						
First Year	-	130,508	322,795	408,513	596,939	1,458,755
Lifetime	-	3,132,192	7,747,080	9,804,318	14,326,537	35,010,128

Budget Projections	***Five-Year Budgets (Nominal)***

Category	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY ‘17 – FY ‘21
Customer Incentives	$-	$169,000	$418,000	$529,000	$773,000	$1,889,000
Administration	150,000	265,000	287,000	297,000	319,000	1,318,000
Marketing	50,000	81,000	82,000	83,000	85,000	381,000
Inspections	-	5,000	13,000	16,000	23,000	57,000
Evaluation	-	-	-	75,000	-	75,000
Total	**$200,000**	**$520,000**	**$800,000**	**$1,000,000**	**$1,200,000**	**$3,720,000**

Five-Year Budgets (2015$)

Category	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY ‘17 – FY ‘21
Customer Incentives	$-	$160,049	$388,098	$481,527	$689,834	$1,719,508
Administration	144,896	250,964	266,469	270,347	284,679	1,217,356
Marketing	48,299	76,710	76,134	75,552	75,855	352,549
Inspections	-	4,735	12,070	14,564	20,525	51,895
Evaluation	-	-	-	68,269	-	68,269
Total	**$193,195**	**$492,458**	**$742,772**	**$910,259**	**$1,070,893**	**$3,409,577**

Participation Projections

Five-Year Participation Projections

	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY ‘17 – FY ‘21
Residential Retrofit	-	100	247	313	457	1,118

Program Rollout

January 2017 – January 2018	Finalize program process and implementations details, select vendors, and develop initial marketing. Start initial engagement with contractors and provide initial training in protocols and program delivery.
January 2018	Launch program.
FY 2018 - FY 2021	Continue engagement activities with customers, reaching full participation in FY 2021.

Program Design

The RR program offers incentives to customers retrofitting or weatherizing their homes by installing qualifying residential-sized space and water heating equipment, programmable thermostats

	(including Wi-Fi enabled), and making thermal envelope improvements through use of approved contractors who may also receive an incentive to encourage comprehensiveness. Customers must have an in-home audit performed that includes a blower-door test. After the audit, the customer receives a list of recommended efficiency measures. The customer has a contractor perform the recommended measures, after which he or she receives an incentive. Audits and thermal envelope improvements must be made by a contractor previously selected by the program as meeting program standards for high quality and technical performance. The rebate will be given to the customer upon submission of suitable documentation. Thermal envelope improvement rebates will require submittal of pre-post blower door measurements to document leakage rate reductions, and pre-post R-values, along with affected square footage, to document insulation improvements. Program participation levels will dictate allocation of funds from year to year, as well as the incentive levels offered. Initially, both participating customers and contractors each will be given an incentive based on first-year MMBtu projected savings. UGI Gas will aim to provide as little interruption as possible to the general community due to any program adjustments made to accommodate market conditions.
Target Market and End Uses	The RR program targets all residential homes that can benefit from improved space and water heating efficiency by encouraging a whole house approach to consider the full implications of specific measures to the overall performance of the house. The program aims to incentivize only

	the highest levels of efficient equipment on the market and the overall reduction in gas usage, including the interactive effects of equipment efficiency and thermal envelope improvements. On the space and water heating side, the program effectively ties in closely with the RP program measures to provide incentives for installing such equipment as Wi-Fi enabled thermostats, ENERGY STAR® labeled furnaces, high efficiency boilers, and combination boilers as part of the home retrofit package. To qualify for even the lowest incentive tier, customers are guided toward the highest efficiency units (95+ AFUE) as well as envelope improvements. The highest incentive tier requires both the customer and the contractor to aggressively embrace the whole-house approach.
Financial Incentives	Incentives are designed to be in line with other offerings in the region and/or other companion programs in the UGI Gas portfolio such as the RP program. UGI Gas anticipates an incentive of approximately $60 per first year MMBtu savings for eligible projects. This incentive is designed to offset most of the incremental cost of the higher efficiency equipment and to provide a significant contribution to the cost of qualifying thermal envelope improvements.
Marketing Approach	Customers will be made aware of the RR program through the general media and bill inserts, as well as through equipment distributors, HVAC and plumbing contractors, and others in a position to affect equipment installation and thermal envelope improvement choices. The contractor network will play a large role in generating program leads. Approved program contractors will be encouraged to do their own marketing to enlist high quality leads to promote

	high lead conversion rates, and to up-serve comprehensive retrofit packages qualifying for the highest incentive tier(s). They will be supported in these efforts through training and the development of co-branding materials that the contractor can use to promote the program. UGI Gas also anticipates identifying qualified leads through an online audit tool. The tool will help homeowners identify opportunities for saving energy and put them in contact with a qualified contractor. Customers that have particularly large savings opportunities may be offered further rebates.
Evaluation, Measurement, and Verification	<u>Quality Assurance</u> A contractor previously approved by UGI Gas will supervise all audits and installation work. It is anticipated that an "approved contractor" will be required to possess Gold Star Contractor certification from the Building Performance Institute (BPI) to ensure quality business practices. Approved contractors must employ site technicians and site supervisors with BPI professional certifications appropriate to their duties. The approved contractor must also be trained in program protocols and the contractor's first three projects will require confirmation of quality installation by an approved third party before moving from probationary status to becoming fully approved. Subsequent contractor work will be sampled up to 10% of projects submitted. Program infraction penalties can range from a return to probationary status to being removed from the program. In the event of a significant customer complaint, which has been verified, or failure of an inspection, contractors must provide satisfactory resolution within 15 business days or face termination from

	program participation or reversion to probationary status, depending on the severity of the infraction or the continuation of relatively minor infractions. An initially approved contractor may be barred from program participation upon documentation that the contractor has not met program requirements even when given the opportunity to correct failings consistent with the probationary process. <u>Rebate Processing</u> The rebate processor must verify that the contractor is eligible to participate in the program and that any issues brought to the program's attention either by a customer or by the third party inspector has been resolved. The program's rebate processor will maintain a real-time database of program activity, including such metrics as leads and lead source, which will be periodically reviewed by UGI Gas and stored separately for long-term purposes. Inspections must verify that the project meets the requirements for incentive level offered by the contractor to the customer. <u>Evaluations</u> The program is expected to have enough activity to allow for an impact evaluation in FY 2020. The RR program evaluations will also include feedback from installation contractors, participating customers and supply houses about current market conditions, such as availability and adoption of high efficiency technology, barriers to participation and awareness of the program.

Program Administration	<u>Contractor Network</u> UGI Gas will put in place an approved contractor network that will perform energy audits, natural gas retrofit projects, and submit project and incentive application information to the program manager. <u>Program Manager</u> UGI Gas will engage a program manager to oversee the contractor network, accept program applications, track and verify application information, communicate with customers if necessary, and report results to UGI Gas. <u>Marketing and Outreach</u> The main marketing and outreach contractor, program administrator, and contractor network will be responsible for the marketing and outreach of the RR program. <u>Inspector</u> A separate contractor will perform on-site inspections and collect customer feedback. The inspector may also spend a portion of their time directed towards onsite mentoring for contractors. The program manager may perform the inspection role. <u>Evaluator</u> A third-party evaluator will be retained to perform regular evaluations.

Special Notes	UGI Gas will explore ways in which to encourage contractors to go after deeper savings. This may include setting aside a portion of incentives to go directly towards contractors in the form of a performance bonus. Through its parent company, UGI Gas has a network of over 400 contractors in Pennsylvania, many of which serve UGI Gas's territory. Contractors that express interest in participating, provide contact information, description of their business, and the territory that they serve. UGI Gas is able to provide leads to contractors regarding customers who have inquired about switching to natural gas. UGI Gas will examine ways to leverage this existing platform and contractor list to provide a launching off point for an enhanced contractor network able to deliver the services required under the RR program.

2.5 Nonresidential Retrofit

Objective	The Nonresidential Retrofit (NR) Program will provide incentives for overcoming market barriers for natural gas efficiency retrofits in existing commercial and multi-family buildings.
Eligible Rate Class	N/NT (R/RT as part of multi-family projects)
Cost Effectiveness	***Five-Year Cost-Effectiveness Results (2015$)***
Savings Projections	***Five-Year Savings Projections***

Five-Year Cost-Effectiveness Results (2015$)

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC	$3,347,061	$1,739,899	$1,607,162	1.92
Gas Admin	$2,954,830	$1,212,029	$1,742,801	2.44

Five-Year Savings Projections

	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY ‘17 – FY ‘21
Natural Gas (MMBtus)						
First Year	-	1,780	4,543	9,086	13,815	29,223
Lifetime	-	25,660	64,097	128,193	192,184	410,134
Electric Energy (kWh)						
First Year	-	4,950	9,901	19,801	24,751	59,404
Lifetime	-	99,006	198,012	396,024	495,029	1,188,071
Peak (kW)	-	0.4	0.9	1.8	2.2	5.3
Water (Gallons)						
First Year	-	364,872	867,507	1,735,014	2,513,176	5,480,569
Lifetime	-	5,903,958	13,598,841	27,197,681	38,474,414	85,174,894

Budget Projections	***Five-Year Budgets (Nominal)***

Category	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Customer Incentives	$-	$40,000	$100,000	$200,000	$300,000	$640,000
Administration	50,000	67,000	94,000	138,000	185,000	534,000
Marketing	50,000	104,000	61,000	72,000	84,000	371,000
Inspections	-	5,000	11,000	22,000	35,000	73,000
Evaluation	-	-	40,000	-	50,000	90,000
Total	**$100,000**	**$216,000**	**$306,000**	**$432,000**	**$654,000**	**$1,708,000**

Five-Year Budgets (2015$)

Category	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Customer Incentives	$-	$37,881	$92,846	$182,052	$267,723	$580,503
Administration	48,299	63,451	87,276	125,616	165,096	489,738
Marketing	48,299	98,492	56,636	65,539	74,963	343,928
Inspections	-	4,735	10,213	20,026	31,234	66,208
Evaluation	-	-	37,139	-	44,621	81,759
Total	**$96,597**	**$204,559**	**$284,110**	**$393,232**	**$583,637**	**$1,562,136**

Participation Projections

Five-Year Participation Projections

	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
C&I Retrofit Project	-	7	20	40	63	130
MF Retrofit Project	-	1	2	4	5	12
Total	**-**	**8**	**22**	**44**	**68**	**142**

Program Rollout

January 2017 – January 2018	Finalize program process and implementations details, select vendors, and develop initial marketing. Start initial engagement with contractors and provide initial training in protocols and program delivery.
January 2018	Launch program.
FY 2018 - FY 2021	Continue engagement activities with customers, reaching full participation in FY 2021.

Program Design	The NR program offers incentives to commercial buildings and multi-family projects that wish to upgrade some portion of the building's performance. A technical assistance provider will evaluate projects for both savings opportunities and cost-effectiveness. A custom package of measures will be determined that is cost-effective and an incentive offer will be extended to the customer based on the project's financial characteristics. The customer then has a set amount of time to perform the upgrades and receive a test-out audit after which the incentive will be paid.
Target Market and End Uses	The NR program primarily targets commercial buildings and multi-family housing projects, but is also open to agriculture and small industrial applications. Any measure that saves natural gas is eligible, with space heating, water heating, and process heating expected to be the largest opportunities.
Financial Incentives	Incentives for NR projects will all be based on the financial characteristics of the project. UGI Gas will negotiate with the customer to find an incentive that makes the project attractive enough for the customer to pursue without paying. The first approach for calculating an incentive will be to determine an acceptable internal rate of return (IRR) for the project that the customer will accept. A secondary approach will be to buy down the project's simple payback to between 5 and 10 years. The incentive for a single project will be capped at the lessor of the project's gas benefits, incremental cost, or $100,000.
Marketing Approach	Customers will be made aware of the NR program through the general media and bill inserts, as well as through equipment distributors, HVAC and plumbing contractors, housing program

	administrators, and others in a position to affect equipment installation and thermal envelope improvement choices.
Evaluation, Measurement, and Verification	<u>Quality Assurance</u> The technical assistance provider will monitor all projects from the outset. This includes monitoring the installation specifications and practices as well as the final project inspection to verify that all program requirements have been met for issuance of the requested incentive. <u>Evaluations</u> The program is expected to have enough activity to allow for an impact evaluation to start at the end of FY 2019 with a second evaluation scheduled for FY 2021. Since the number of projects anticipated to be completed under the program is so small, evaluations will be more focused on a “case study” approach that verifies performance once a project is complete and sufficient post data is collected.
Program Administration	<u>Technical Assistance Provider</u> The technical assistance provider will be responsible for the initial project analysis and design assistance, ongoing project monitoring, and the final inspection of all projects. <u>Evaluator</u> A third-party evaluator will be retained to perform regular evaluations.

Special Notes	

2.6 Behavior and Education

Objective

The objective of the BE program is to motivate a large group of residential customers to save energy by changing their behavior through education, outreach, and energy monitoring. The premise is that the delivery of timely, salient, and personalized information allows for informed decision-making. Small changes with noticeable results pave the way for wider program participation and increased future savings.

Eligible Rate Class

R/RT

Cost Effectiveness

Five-Year Cost-Effectiveness Results (2015$)

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC	$2,178,476	$1,624,141	$554,335	1.34
Gas Admin	$2,178,476	$1,624,141	$554,335	1.34

Savings Projections

Five-Year Savings Projections

	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Natural Gas (MMBtus)						
First Year	-	-	64,948	97,422	97,422	259,792
Lifetime	-	-	64,948	97,422	97,422	259,792
Electric Energy (kWh)						
First Year	-	-	-	-	-	-
Lifetime	-	-	-	-	-	-
Peak (kW)	-	-	-	-	-	-
Water (Gallons)						
First Year	-	-	-	-	-	-
Lifetime	-	-	-	-	-	-

Budget Projections	***Five-Year Budgets (Nominal)***

Category	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Customer Incentives	$-	$-	$450,000	$675,000	$675,000	$1,800,000
Administration	-	300,000	20,000	20,000	20,000	360,000
Marketing	-	-	-	-	-	-
Inspections	-	-	-	-	-	-
Evaluation	-	20,000	40,000	40,000	40,000	140,000
Total	**$-**	**$320,000**	**$510,000**	**$735,000**	**$735,000**	**$2,300,000**

Five-Year Budgets (2015$)

Category	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Customer Incentives	$-	$-	$417,809	$614,425	$602,378	$1,634,612
Administration	-	284,110	18,569	18,205	17,848	338,733
Marketing	-	-	-	-	-	-
Inspections	-	-	-	-	-	-
Evaluation	-	18,941	37,139	36,410	35,696	128,186
Total	**$-**	**$303,051**	**$473,517**	**$669,041**	**$655,922**	**$2,101,531**

Participation Projections

Five-Year Participation Projections

	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Participants	-	-	50,000	75,000	75,000	200,000

Program Rollout

October 2017 – October 2018	Finalize program process and implementations details, select vendors, and integrate energy reporting software with existing customer information system.
October 2018	Launch program.
FY 2019	Initial pilot year.[14]

[14] A single year pilot program will be performed in order to gauge the potential success of the program before it is rolled out to a wider customer base.

	FY 2020 – FY 2021 Run full program.
Program Design	The program pairs behavioral science with data analytics to provide clearly defined and actionable information that motivates customers to lower their energy use. An external vendor will be enlisted to deliver the service. The vendor will collect (from various sources) and analyze customer data including gas use, weather data, demographic and parcel information, and service interactions such as web visits and use of UGI Gas's call center data. Insights will be gathered and analyzed for each customer in order to develop personalized content and messaging to participants. The program will follow an "opt-out" model in which customers will be automatically enrolled to receive the service, but subsequently may choose to decline participation. Participants will receive an energy report detailing their gas usage and how their use compares with neighbors or others in a similar demographic. The report offers insights into how the household uses gas, provides tips on how to lower consumption, provides billing analysis, and promotes other UGI services. Customers are further engaged via access to a web portal that embeds the vendor's analytics into UGI's webpages, and stays connected with the service in real time by setting and tracking goals, receiving alerts indicating high use trends, weather or utility events, and receiving periodic home energy reports by email which may also contain UGI messaging.
Target Market and End Uses	The program will target residential heating customers who are identified as high users based on usage per customer analytics.
Financial Incentives	The service will be delivered at no cost to customers and is anticipated to cost approximately $9

	per customer per year.
Marketing Approach	UGI Gas will work with the selected vendor to produce a targeted rollout of the programs offerings. The program is expected to engage with a sub-section of UGI Gas's highest usage heating customers.
Evaluation, Measurement, and Verification	Since behavior programs are relatively new to the efficiency market, and particularly new to gas efficiency in Pennsylvania, extra care will be taken with verifying and measuring program savings. UGI Gas will retain an evaluator at the same time as a vendor is selected to be the service provider. All three parties will work closely to ensure that proper systems are set up so that data can be collected from the start to ensure that savings are being properly accounted for. Once the program launches, evaluation will be continuous. Some of the initial goals of the evaluation will be the following: • Selecting a proper control group; • Quantifying savings across different market segments; • Accounting for the effects of participation in other efficiency programs to measure the "channeling" effect of the BE program and avoid double counting savings; and • Examining the persistence of savings beyond a single year.
Program Administration	<u>Service Provider</u> UGI Gas will retain a service provider to provide the platform and analysis to deliver the energy

	reports and provide customer support. <u>Evaluator</u> A third-party evaluator will be retained to perform regular evaluations.
Special Notes	Evaluation results from similar programs have had a wide range of savings. The assumptions used for this program are conservative; however, market conditions in UGI Gas's territory may be very different from those experienced in other locations with successful programs.

2.7 Combined Heat and Power

Objective	The Combined Heat and Power (CHP) Program seeks to promote the installation of cost-effective and net-primary-energy-saving CHP projects and provide meaningful CO_2 emission reductions that may be counted toward Pennsylvania's Clean Power Plan goals. A CHP plant produces electricity at a commercial or industrial site while at the same time using the waste heat from the production of the electricity to serve a thermal load. Net efficiencies come from the recovered heat that is typically wasted in grid electricity production and avoided transmission and distribution losses from delivering the electricity from the generator to the customer site.
Eligible Rate Class	N, NT, DS, LFD
Cost Effectiveness	***Five-Year Cost-Effectiveness Results (2015$)***
Savings Projections	***Five-Year Savings Projections***

Five-Year Cost-Effectiveness Results (2015$)

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC	$118,676,097	$74,045,790	$44,630,307	1.60

Five-Year Savings Projections

	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Net Primary Energy Savings (MMBtus)						
First Year	169,855	169,855	455,460	455,460	455,460	1,706,090
Lifetime	2,547,828	2,547,828	6,831,898	6,831,898	6,831,898	25,591,350
Net Customer Gas Usage Increase (MMBtus)						
First Year	118,258	118,258	442,318	442,318	442,318	1,563,470
Lifetime	1,773,876	1,773,876	6,634,772	6,634,772	6,634,772	23,452,067

Budget Projections	***Five-Year Budgets (Nominal)***

Category	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Customer Incentives	$270,000	$291,600	$629,856	$680,244	$734,664	**$2,606,365**
Administration	54,000	59,486	65,505	72,106	79,491	**$330,588**
Marketing	70,200	58,320	125,971	136,049	146,933	**$537,473**
Inspections	2,700	2,916	6,299	6,802	7,347	**$26,064**
Evaluation	21,600	23,328	25,194	27,210	29,387	**$126,719**
Total	**$418,500**	**$435,650**	**$852,825**	**$922,412**	**$997,821**	**$3,627,208**

Five-Year Budgets (2015$)

Category	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
Customer Incentives	$250,000	$250,000	$500,000	$500,000	$500,000	**$2,000,000**
Administration	50,000	51,000	52,000	53,000	54,100	**$260,100**
Marketing	65,000	50,000	100,000	100,000	100,000	**$415,000**
Inspections	2,500	2,500	5,000	5,000	5,000	**$20,000**
Evaluation	20,000	20,000	20,000	20,000	20,000	**$100,000**
Total	**$387,500**	**$373,500**	**$677,000**	**$678,000**	**$679,100**	**$2,795,100**

Participation Projections

Five-Year Participation Projections

	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY '17 – FY '21
3326 kW CHP	1	1	1	1	1	**5**
7038 kW CHP	0	0	1	1	1	**3**
Total Projects	**1**	**1**	**2**	**2**	**2**	**8**

Program Rollout

June 2016 – December 2017	Finalize program process and implementations details, select vendors, and develop initial marketing.
January 2017	Launch Program.
FY 2018 - FY 2021	Continue engagement activities with customers.

Program Design

Customers that are considering CHP need to submit the project details including CHP installation costs, annual electricity production, and gas usage before and after the CHP project is completed.

	Based on the particular CHP project details, verified by UGI Gas or its contractor, UGI Gas will determine whether it is cost-effective from the TRC perspective and reduces net primary energy usage. If both of these criteria are met, then the CHP project is eligible for an incentive from UGI Gas. Though the customer has primary responsibility for developing the CHP costs, savings, and technical details, UGI Gas may provide some technical assistance, as well as business development for new projects.
Target Market and End Uses	The CHP Program targets large commercial and industrial customers with high thermal and electric loads. This program is most likely applicable to customers with year-round thermal requirements and high hours of use. Customer types that are likely candidates include hospitals, campuses and multi-shift industrial. Based on current avoided electric and gas avoided costs, only larger CHP projects (over 1,000 MW) are typically cost-effective from the TRC perspective. If avoided costs change or the costs for micro turbines decline, then some smaller projects may become cost-effective. UGI Gas will continue to closely monitor the CHP market and identify opportunities for all ranges of CHP technology and sizes.
Financial Incentives	$750/kW with a maximum of $250,000 per CHP project and no more than 50% of the CHP project cost.
Marketing	UGI Gas will market its CHP program through a combination of the portfolio’s mass-market

Approach	awareness campaign and by contacting specific customers that are likely candidates for CHP. UGI Gas will work with its internal gas planning and marketing team to make sure that potential users are aware of possible technical support and incentives for pursuing CHP projects.
Evaluation, Measurement, and Verification	Every CHP project will be inspected and its receipts reviewed to ensure that the expected technology is correctly installed and operational. A third party evaluator will be chosen to assess the actual versus projected electric and gas, generation and usage, respectively. Since the number of projects anticipated to be completed under the program is small, evaluations will be more focused on a "case study" approach that verifies performance once a project is complete and sufficient post data is collected.
Program Administration	The CHP program may be implemented either solely by UGI Gas or with assistance from an independent contractor chosen through an RFP.
Special Notes	The CHP Program's costs and savings will be reported separately from the other efficiency programs, due to this program's increase in gas usage, whereas the other efficiency programs decrease gas usage. This is similar to the separation made by PGW in its Phase II filing, as well as by other electric utilities that separate energy efficiency programs from load reduction programs. While UGI Gas is asking for general flexibility in annual program costs for the entire EE&C Portfolio, this flexibility is particularly important for the CHP program. CHP projects are complex and require long-term planning. Moreover, incentives represent a large percentage of the program budget. Because of these factors, it is difficult to predict the outcome for a single year. UGI Gas will

	limit its total spending to the five year projected total spending, and under-spending from one year may be carried over to the next year.

3 Appendices

3.1 Avoided Cost Tables

	Natural Gas			Other			
	Baseload	Space heating	Water heating	Energy	Peak Capacity	Capacity T&D	Water
Year	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/kWh*	*$/kW-Yr*	*$/kW-Yr*	*$/Gallon*
2016	$5.23	$10.34	$6.51	$0.0619	$42.682	$29.979	$0.0080
2017	$5.39	$10.53	$6.68	$0.0662	$42.207	$29.983	$0.0080
2018	$5.45	$10.56	$6.73	$0.0707	$42.208	$29.981	$0.0080
2019	$5.51	$10.61	$6.78	$0.0759	$42.204	$29.979	$0.0080
2020	$6.66	$11.83	$7.95	$0.0774	$42.204	$29.980	$0.0080
2021	$6.70	$11.85	$7.99	$0.0809	$42.207	$29.980	$0.0080
2022	$8.08	$13.22	$9.36	$0.1003	$42.206	$29.979	$0.0080
2023	$8.13	$13.26	$9.41	$0.0983	$42.207	$29.976	$0.0080
2024	$8.17	$13.30	$9.45	$0.0936	$42.211	$29.980	$0.0080
2025	$9.60	$14.84	$10.91	$0.0978	$42.209	$29.982	$0.0080
2026	$9.48	$14.71	$10.79	$0.0949	$42.209	$29.978	$0.0080
2027	$9.56	$14.78	$10.86	$0.0959	$42.210	$29.976	$0.0080
2028	$9.68	$14.89	$10.98	$0.0987	$42.206	$29.976	$0.0080
2029	$9.74	$14.93	$11.04	$0.1004	$42.210	$29.978	$0.0080
2030	$10.04	$15.24	$11.34	$0.1033	$42.208	$29.980	$0.0080
2031	$10.38	$15.58	$11.68	$0.1064	$42.206	$29.980	$0.0080
2032	$10.71	$15.91	$12.01	$0.1078	$42.205	$29.981	$0.0080
2033	$11.04	$16.25	$12.34	$0.1085	$42.204	$29.979	$0.0080
2034	$11.34	$16.55	$12.64	$0.1112	$42.210	$29.980	$0.0080
2035	$11.65	$16.86	$12.95	$0.1138	$42.208	$29.979	$0.0080
2036	$11.88	$17.09	$13.18	$0.1168	$42.206	$29.981	$0.0080
2037	$12.21	$17.42	$13.51	$0.1199	$42.210	$29.979	$0.0080
2038	$12.73	$17.96	$14.04	$0.1230	$42.206	$29.977	$0.0080
2039	$13.37	$18.62	$14.68	$0.1266	$42.206	$29.978	$0.0080
2040	$13.74	$19.00	$15.05	$0.1288	$42.206	$29.982	$0.0080
2041	$14.11	$19.38	$15.43	$0.1311	$42.209	$29.978	$0.0080
2042	$14.50	$19.78	$15.82	$0.1334	$42.205	$29.980	$0.0080
2043	$14.89	$20.18	$16.21	$0.1356	$42.210	$29.980	$0.0080
2044	$15.29	$20.58	$16.61	$0.1379	$42.206	$29.979	$0.0080
2045	$15.69	$21.00	$17.02	$0.1402	$42.206	$29.979	$0.0080
2046	$15.94	$21.26	$17.27	$0.1402	$42.206	$29.979	$0.0080
2047	$16.20	$21.54	$17.54	$0.1402	$42.206	$29.979	$0.0080
2048	$16.47	$21.82	$17.81	$0.1402	$42.206	$29.979	$0.0080
2049	$16.75	$22.11	$18.09	$0.1402	$42.206	$29.979	$0.0080
2050	$17.03	$22.41	$18.38	$0.1402	$42.206	$29.979	$0.0080
2051	$17.33	$22.72	$18.67	$0.1402	$42.206	$29.979	$0.0080
2052	$17.63	$23.03	$18.98	$0.1402	$42.206	$29.979	$0.0080

All values in 2015 dollars and include internalized market price of CO2, and DRIPE

Developed by Resource Insight, Inc.

3.2 Detailed Program and Portfolio Cost-effectiveness

	Total Resource					Gas Energy System				
	Present Value		PV of Net Benefits	Benefit-Cost Ratio	Levelized Cost $/MMBTU	Present Value		PV of Net Benefits	Benefit-Cost Ratio	Levelized Cost $/MCF
	Benefit [2]	Cost [3]	[4]	[5]		Benefit [10]	Cost [11]	[12]	[13]	
Portfolio Total	$53,852,243	$30,623,169	$23,229,074	1.76	8.62	$47,810,505	$19,574,100	$28,236,405	2.44	5.51
Non-Measure Costs		$7,990,223					$7,990,223			
Total Measure Costs	$53,852,243	$22,632,946	$31,219,297	2.38	6.37	$47,810,505	$11,583,877	$36,226,628	4.13	3.26
Program										
Residential Prescriptive (RP)										
Program Total	$31,130,604	$14,907,355	$16,223,249	2.09	7.67	$26,480,582	$7,479,279	$19,001,303	3.54	3.85
Non-Measure Costs		$943,425					$943,425			
Total Measure Costs	$31,130,604	$13,963,930	$17,166,674	2.23	7.19	$26,480,582	$6,535,854	$19,944,728	4.05	3.36
Nonresidential Prescriptive (NP)										
Program Total	$8,708,345	$3,813,860	$4,894,485	2.28	5.78	$8,138,290	$1,845,275	$6,293,015	4.41	2.80
Non-Measure Costs		$535,287					$535,287			
Total Measure Costs	$8,708,345	$3,278,573	$5,429,772	2.66	4.97	$8,138,290	$1,309,988	$6,828,302	6.21	1.99
Residential Retrofit (RR)										
Program Total	$4,816,226	$3,509,802	$1,306,423	1.37	11.37	$4,614,808	$2,661,253	$1,953,556	1.73	8.62
Non-Measure Costs		$1,346,932					$1,346,932			
Total Measure Costs	$4,816,226	$2,162,871	$2,653,355	2.23	7.00	$4,614,808	$1,314,321	$3,300,488	3.51	4.26
Nonresidential Retrofit (NR)										
Program Total	$3,347,061	$1,739,899	$1,607,162	1.92	8.23	$2,954,830	$1,212,029	$1,742,801	2.44	5.73
Non-Measure Costs		$772,997					$772,997			
Total Measure Costs	$3,347,061	$966,902	$2,380,159	3.46	4.57	$2,954,830	$439,032	$2,515,798	6.73	2.08
New Construction (NC)										
Program Total	$3,671,531	$1,919,760	$1,751,772	1.91	8.06	$3,443,519	$1,643,772	$1,799,747	2.09	6.90
Non-Measure Costs		$898,922					$898,922			
Total Measure Costs	$3,671,531	$1,020,837	$2,650,694	3.60	4.29	$3,443,519	$744,849	$2,698,670	4.62	3.13
Behavior and Education (BE)										
Program Total	$2,178,476	$1,624,141	$554,335	1.34	8.49	$2,178,476	$1,624,141	$554,335	1.34	8.49
Non-Measure Costs		$384,309					$384,309			
Total Measure Costs	$2,178,476	$1,239,832	$938,644	1.76	6.48	$2,178,476	$1,239,832	$938,644	1.76	6.48
Portfoliowide Costs										
Program Total	-	$3,108,352	$(3,108,352)	-	-	-	$3,108,352	$(3,108,352)	-	-
Non-Measure Costs		$3,108,352					$3,108,352			
Total Measure Costs	-	-	-	-	-	-	-	-	-	-