OCA Statement No. 1
6/2/16 [illegible]

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	**Docket No. R-2015-2518438**
v.	:	
	:	
UGI UTILITIES, INC. – GAS DIVISION	:	

DIRECT TESTIMONY OF

DAVID J. EFFRON

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

APRIL 12, 2016

DOCKET NO. R-2015-2518438
UGI UTILITIES, INC. - GAS DIVISION
DIRECT TESTIMONY OF DAVID J. EFFRON
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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is David J. Effron. My address is 12 Pond Path, North Hampton, New Hampshire.

Q. What is your present occupation?

A. I am a consultant specializing in utility regulation.

Q. Please summarize your professional experience.

A. My professional career includes over thirty years as a regulatory consultant, two years as a supervisor of capital investment analysis and controls at Gulf & Western Industries and two years at Touche Ross & Co. as a consultant and staff auditor. I am a Certified Public Accountant, and I have served as an instructor in the business program at Western Connecticut State College.

Q. What experience do you have in the area of utility rate setting proceedings?

A. I have analyzed numerous electric, gas, telephone, and water filings in different jurisdictions. Pursuant to those analyses, I have prepared testimony, assisted attorneys in case preparation, and provided assistance during settlement negotiations with various utility companies.

I have testified in over two hundred cases before regulatory commissions in Alabama, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Missouri, Nevada, New Jersey, New York, North

Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, Texas, Vermont, Virginia, and Washington.

Q. Please describe your other work experience.

A. As a supervisor of capital investment analysis at Gulf & Western Industries, I was responsible for reports and analyses concerning capital spending programs, including project analysis, formulation of capital budgets, establishment of accounting procedures, monitoring capital spending and administration of the leasing program. At Touche Ross & Co., I was an associate consultant in management services for one year and a staff auditor for one year.

Q. Have you earned any distinctions as a Certified Public Accountant?

A. Yes. I received the Gold Charles Waldo Haskins Memorial Award for the highest scores in the May 1974 certified public accounting examination in New York State.

Q. Please describe your educational background.

A. I have a Bachelor's degree in Economics (with distinction) from Dartmouth College and a Masters of Business Administration Degree from Columbia University.

II. PURPOSE OF TESTIMONY

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. What is the purpose of your testimony?

A. I have calculated the measures of value (or rate base) and pro forma operating income under present rates of UGI Utilities, Inc. – Gas Division ("UGI Gas" or "the Company") in this rate case, based on the adjustments to the Company's position that I am presenting in this testimony. I have also incorporated certain revenue adjustments addressed by OCA Witness Watkins, the depreciation adjustments proposed by OCA Witness Garren, and the overall rate of return recommended by OCA Witness Parcell into my calculation of the present revenue deficiency (or excess) of the Company.

III. REVENUE REQUIREMENT ISSUES

A. SUMMARY

Q. What revenue deficiency or excess have you calculated?

A. Based on the test year consisting of the 12 months ending September 30, 2017, I have calculated jurisdictional rate base (measures of value) of $863,747,000 and pro forma jurisdictional operating income under present rates of $77,494,000. Based on the overall rate of return of 7.17% recommended by Mr. Parcell, the Company presently has an operating income excess of $15,586,000. This translates into a revenue excess of $27,092,000 under present rates, as compared to the revenue deficiency of $58,564,000 presented by the Company in its filing. My calculation of the Company's revenue deficiency is summarized on my Schedule A. I have also prepared Table I and Table II, which summarize the effect of my adjustments in the format used by the Commission.

B. MEASURES OF VALUE

1. FPFTY RATE BASE

Q. What test year has the Company selected for the purpose of determining its revenue requirement?

A. The Company has selected the twelve months ending September 30, 2017, which is a fully projected future test year ("FPFTY"). The FPFTY selected by the Company consists entirely of forecasted, or projected, data, and it is intended to match the period during which the new rates being established will be in effect.

Q. How is the Company proposing to determine the test year rate base used in the calculation of its revenue requirement?

A. The Company is proposing to use FPFTY year end balances except for the working capital components and customer deposits. The plant-related components of rate base (plant in service, accumulated reserve for depreciation, and accumulated deferred income taxes) are all included in rate base by the Company at their projected end of test year balances as of September 30, 2017.

Q. In your experience is it typical to use an end of year rate base in conjunction with a fully forecasted future test year that matches the period when rates are going to be in effect?

A. No. I have not conducted research of practices in all other jurisdictions to the extent that I can say that a year-end rate base has never been used in conjunction with a fully projected future test year that coincides with the rate year. However, I can say that, in my own experience, it has been the consistent practice to use an average rate base when such a fully forecasted future test year has been used to determine a regulated utility company's revenue requirement.

For example, in Illinois, utility companies have the option of a using a future test year (the equivalent of the fully projected future test year in Pennsylvania) for the purpose of determining revenue requirements and rates. It is has been the routine practice there to use average test year balances in the calculation of rate base in the context of a future test year. On occasion, however, the utilities have sought to utilize a year-end rate base in conjunction with a future test year, but the Illinois Commerce Commission ("ICC") has consistently rejected such proposals, even when the future test year was earlier than the rate year. See, for example, the ICC Order in Docket Nos. 12-0511 and 12-0512 (North Shore Gas Company and The Peoples Gas Light and Coke Company), June 18, 2013, at 38.

Rhode Island does not use a future test year, as such. However utilities are allowed to adjust the plant-related elements of rate base, revenues, and expenses from the historic test year to the rate year. It is also the consistent practice in Rhode Island to state all of the plant-related components of rate base at their average balances for the rate year.

Q. Why is it appropriate to use an average rate base in conjunction with a fully forecasted future test year?

A. The average rate base measures the net investment in facilities to provide utility service over the course of the year, rather than as of a point in time at the end of the year. It is internally consistent with the measurement of expenses, billing determinants, and income over the course of the year. That is, using an average rate base properly matches the calculation of rate base with the other elements of the Company's revenue requirement and income in a given year.

The rate of return times the average rate base is the dollar cost to the Company of carrying its net capital investment for the year. The return on rate base is a component of the total revenue requirement, just as expenses such as salaries and wages, depreciation, and property taxes are such components. This component of the total revenue requirement, the return requirement, is calculated by multiplying the Company's cost rate of capital by its rate base. This converts the cost rate into a dollar cost, just as depreciation expense is calculated by multiplying the applicable depreciation rate by the relevant balances of depreciable plant.

When a unit of plant is put into service in December of a given year, the Company does not incur a capital cost on that plant for the whole year any more than it incurs depreciation expense on that plant for the whole year or any more than it incurs a year of payroll expense for an employee hired in December. The Company's annual revenue requirement does not include a full year of capital cost on plant that is put into service at the end of the year.

The use of the average rate base to calculate the return requirement included in the revenue requirement is similar to calculating the return requirement for the year by calculating the return requirement for each of the twelve months and then summing those monthly return requirements. The return on the average rate base represents the actual dollar cost of capital incurred by the Company over the course of the year, and that is what should be included in the Company's total revenue requirement.

Q. Why, then, is an end of test year rate base sometimes used in the determination of a utility company's revenue requirements?

A. The rate base is sometimes calculated as of the end of the test year (except for those elements of rate base that fluctuate or are seasonal in nature) when a historic test year is used to determine a utility company's revenue requirement. Generally speaking, a historic test year is a period consisting of twelve months of actual data, with that twelve-month period ending at a point in time before the record in the rate case being processed closes. The theory supporting the use of an end of test year rate base in these circumstances is that the rate base as of the end of the test year is more representative of the investment that the utility will have in its rate base at the time that the rates being set go into effect.

Q. Hasn't it been the practice in Pennsylvania to use a year-end rate base even in the context of a future test year?

Q. What has been characterized as a future test year in Pennsylvania is not a test year that matches the rate year. For example, in the present case, the "future test year" is the twelve months ending September 30, 2016, which approximates the expected start of the rate year. While this is characterized as a future test year, it obviously is not a test year that matches the rate year. The use of a year-end rate base in such a "future test year" in no way justifies the use of year-end rate base in a fully projected future test year that coincides with the rate year.

Q. In your opinion, is it appropriate to use an end-of-year rate base in the present case?

A. No. In effect, the use of a year-end rate base in the context of the Company's FPFTY would allow UGI to earn a return on its net plant investment in advance of when such investment is actually made. The rates in this case will go into effect in late 2016. Under the Company's proposal, the rates that go into effect at that time will reflect a rate base as of September 30, 2017, approximately one year later. Throughout the whole rate year, customers would be paying rates that include a return on a rate base larger than the actual investment in facilities being used to provide service. Clearly, such a mismatch would be inappropriate.

The Company has selected to use a fully projected future test year, not a historic test year, or the traditional Pennsylvania "future test year" (which ends approximately when the rate year starts), to develop its revenue requirement. Consistent with the use of a fully projected future test year, the rate base should reflect average balances, not end of year balances, for the major components.

Q. What is the effect of adjusting the Company's test year end balances to average test year balances?

A. The effect of using average balances to determine the FPFTY rate base is shown on my Schedule B-1. I have adjusted the plant in service, accumulated reserve for depreciation, and accumulated deferred income taxes to reflect average FPFTY balances. The effect of adjusting these components of rate base to the average test year balances is to reduce the test year rate base by $55,271,000.

2. GAS INVENTORY

Q. What balance of gas inventory does the Company include in its FPFTY rate base?

A. The Company includes $21,730,000 of gas inventory in its test year rate base. This balance is based on the average of the actual month-end balances for the year ended September 2015, as shown on UGI Gas Exhibit A (FPFTY), Schedule C-5.

Q. How does the balance of gas inventory as of September 2015 compare to the balance as of September 2014?

A. The balance of gas inventory as of September 2015 was $23,368,000. This was $16,643,000, or 42%, less than the balance of gas inventory of $40,011,000 as of September 2014.

Q. Has the Company explained why the balance of gas inventory was so much lower as of September 30, 2015?

A. Yes. In response to OCA Data Request I-11, the Company stated that "The decrease in gas inventory from September 2014 to September 2015 was driven by a decrease in the weighted average cost of gas. The average cost per Dth was $4.03 and $2.35 as of September 2014 and September 2015, respectively."

Q. Did the lower weighted cost of gas continue to affect the actual balance of gas inventory subsequent to September 2015?

A. Yes. In response to OCA Data Request I-12, the Company provided the actual balances of gas inventory for the months October 2015 through January 2016. As can be seen in that response, the actual balances of gas inventory for those months were significantly lower than were the corresponding balances twelve months earlier as shown on UGI Gas Exhibit A (FPFTY), Schedule C-5.

Q. Should the balance of gas inventory included in the Company's FPFTY rate base be adjusted?

A. Yes. The gas inventory include in the FPFTY rate base should be adjusted to reflect the lower balances in the most recent months. There is no evidence that the effect of lower prices on the balances of gas inventory is going to reverse any time soon.

I recommend that the gas inventory included in the FPFTY rate base be based on the actual average balance for the year ended January 2016, which includes the actual data in the response to OCA Data Request I-12. On my Schedule B-2, I have calculated that the average balance of gas inventory for the year ended January 2016 was $15,853,000. This is $5,877,000 less than the gas inventory included in the FPFTY rate base by the Company (my Schedule B). The Company's FPFTY should be reduced accordingly.

3. OPEB OVER-RECOVERY

Q. Is the Company proposing to return to customers amounts of postretirement benefits other than pensions ("OPEB") that it has over-recovered from customers in past years?

A. Yes. As explained by UGI Gas Witness Kelly, the Company has over-collected OPEB in the amount of $10,399,000 (corrected to $10,027,000 in response to OCA Data Request I-35) since its last rate case 22 years ago. UGI Gas is now proposing to return this over-collection to customers over 20 years, which represents a similar time period that the current recovery mechanism has been in place (UGI Gas Statement No. 2, Page 34).

Q. Is the Company proposing to deduct the over-recovered OPEB balance from rate base to the extent that it has not been returned to customers?

A. No. In response to OCA Data Request I-36, the Company stated that it "does not believe that it is appropriate to deduct the unamortized OPEB over-recovery from rate base during the 20-year refund period." The Company explained that it "adopted FAS 106 in 1993 and accrued $4.0 million from that time until the rate case in 1995. This amount was recovered in rates over a period of 17.25 years which did not include any return or interest on the unrecovered amount. Since we did not recover a return on the regulatory asset it would be inappropriate for the company to reduce rate base for the current over-recovery."

Q. Do you agree that because the Company did not recover a return on the regulatory asset related to earlier OPEB accruals, it would be inappropriate for the Company to reduce rate base for the current over-recovery?

A. No. As the Company noted in its response, the OPEB expense deferred from 1993 through 1995 and recovered in subsequent years was an *accrual*. In other words, that expense was an accrued liability, not an actual cash disbursement. Therefore, there were no actual investor-supplied funds on which it would have been appropriate to recover any return or interest. By contrast, the over-recovered OPEB expense represents real cash collected from ratepayers in excess of the actual OPEB cost recorded by the Company. The fact that it did not recover a return on the OPEB regulatory asset does not mean that it would be inappropriate for the Company to reduce rate base for the current over-recovery.

Q. Should the Company's rate base be reduced for the current OPEB over-recovery?

A. Yes. The Company has already enjoyed the benefit of this interest-free loan from customers for some twenty years. The Company will continue to have this source of customer supplied funds available until it is fully refunded to customers. The unamortized balance of the OPEB over-recovery should be deducted from rate base during the refund period to recognize the non-investor supplied funds available to the Company.

Q. What is the effect of deducting the balance of the OPEB over-recovery from the Company's rate base?

A. The over-recovered OPEB balance net of applicable income taxes is $5,866,000 (my Schedule B). Therefore, the Company's rate base should be reduced by $5,866,000 to reflect this source of non-investor supplied funds.

C. OPERATING INCOME

1. REVENUES

a. Customer Changes

Q. Did the Company annualize revenues to reflect the number of customers as of the end of the FPFTY?

A. Yes. As can be seen on UGI Gas Exhibit DEL-3(b), the Company has annualized revenues to reflect customer changes in the residential, commercial, and industrial customer classes.

Q. Are you proposing to eliminate the Company's annualization of revenues to reflect the number of customers as of the end of the FPFTY?

A. Yes. These adjustments to annualize sales to the end of year customers are consistent with the use of a year-end rate base. That is, if the rate base reflects the plant in service necessary to serve the end-of-year number of customers, the pro forma revenues under present rates and the billing determinants used to design rates should reflect the end of year number of customers. However, I am proposing to use a test year average rate base, so the adjustment to revenues and billing determinants to reflect the end of year number of customers is not necessary. Elimination of these adjustments reduces pro forma FPFTY revenues under present rates by $760,000, the FPFTY pro forma cost of gas by $430,000, and the pro forma FPFTY margin by $330,000 (my Schedule C-1).

Q. Are you also proposing to eliminate the Company's "Adjustment for Transport Changes" on UGI Gas Exhibit DEL-3(b)?

A. Yes. Mr. Lahoff describes this adjustment as having been "developed by UGI Gas marketing personnel following their review of individual large customer accounts and market segments" (UGI Gas Statement No. 6, Page 9). However, he has not established that these changes in transportation revenues and margins are actually taking place. Further, the reductions to volumes and margins appear to be inconsistent with the Company's projections of customers and volumes as addressed in the attachments to III-E-25 of the responses to Section 53.53. Therefore, I have eliminated the Company's "Adjustment for Transport Changes" on UGI Gas Exhibit DEL-3(b) on my Schedule C-1. Elimination of this adjustment increases the pro forma margin under present rates by $676,000.

b. Use per Customer

Q. In the determination of FPFTY base rate revenues, did the Company adjust the forecasted test year sales to annualize the effect of a supposed declining trend in usage per customer?

A. Yes. As explained by UGI Gas Witness Lahoff, the Company is proposing an "Adjustment for Annualized Use/Customer" that "annualizes usage per customer to projected end of year test levels based on a twenty-one year regression analysis" (UGI Gas Statement No. 6, Page 7).

Q. What is the effect of the Company's "Adjustment for Annualized Use/Customer"?

A. As can be seen on UGI Gas Exhibit DEL-3(c), the effect of this adjustment is to decrease FPFTY revenues by $34,878,000 and the FPFTY margin net of PGC revenues by $16,023,000 (including the effect of the adjustments to the transportation classes). The great majority of this adjustment takes place in the residential heat and commercial heat classes, which together account for $14,113,000 of the total margin adjustment of $16,023,000.

Q. Is the declining trend in use per customer used by the Company for the purpose of its "Adjustment for Annualized Use/Customer" appropriate for the purpose of forecasting the FPFTY billing determinants?

A. No. Referring to the graphs on UGI Gas Exhibits DEL-2(a) and DEL-(2)b, it is clear that all of the overall historic decrease in use per residential customer and use per commercial customer took place prior to 2011. In fact, the weather normalized residential heat use per customer (including transportation) *increased* by approximately 2.4% from the twelve months ended September 2010 to the twelve months ended September 2015; and the weather normalized commercial heat use per customer (including the NT and DS rate classes) *increased* by approximately 8.7% from the twelve months ended September 2010 to the twelve months ended September 2015. Therefore, whatever change there was in the normalized use per customer for these customer classes over the five years from 2010 to 2015 was more in the nature of increased usage rather than decreased usage.

Q. Did Mr. Lahoff explain why he used a twenty-one year regression analysis to develop the Company's proposed pro forma usage per customer, rather than relying on the trend for the most recent five years?

A. Yes. In response to a question regarding the models utilized in the 2009 PNG rate case and in the 2009 and 2011 CPG base rate cases (PNG and CPG are affiliates of UGI Gas), which used five years of data to project use per customer, Mr. Lahoff states that, "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." Coincidentally, both the five years used in the cited PNG and CPG cases and the twenty-one years used in the present case result in a trend of declining use per customer.

Q. What would have happened if UGI Gas had used five years of data to develop trends in use per customer in the present case?

A. Based on the usage patterns noted above, five years of data would imply increasing usage trends in the residential (including transportation) and commercial heat customer (including NT and DS) classes.

Q. Are the decreases in use per customer reflected by the Company in its "Adjustment for Annualized Use/Customer" plausible?

A. No. Referring to UGI Gas Exhibit DEL 3(c), the unadjusted residential heat use per customer in the FPFTY is 76.20 MCF. The adjusted residential heat use per customer in the FPFTY is 67.30 MCF, a decrease of 8.90 MCF. The adjusted use per customer is 12.7% below the unadjusted use per customer. The Company has explained that the difference between the adjusted and unadjusted use per customer represents the difference between the budgeted use per customer for the FPFTY and the usage per customer utilizing its multi-year (i.e., 21 years) regression analysis.

The problem with the model used by the Company to determine the adjusted use per customer is that it is contradicted by reality. For example, the actual weather normalized use per residential heat customer in the twelve months ended September 2015 (the historic test year) was 77.5 MCF (Attachment RS-27-D(b), Page 3, which includes RT customers). Based on its multi-year regression analysis, the Company projected annualized use per customer of 72.3 MCF per customer (UGI Gas Exhibit DEL-6(c) again including RT customers), for that year. Thus, the Company's model projected usage that was significantly below what *actually* happened in that year. Yet the Company has cited no abnormal or unusual factors that would have caused the weather normalized use per customer in the historic test year to have been so much greater than the usage projected in its multi-year regression analysis. In other words, when there is a discrepancy between actual experience and the Company's model, the Company opts to rely on its model.

Referring to UGI Gas Exhibit DEL 3(c), the unadjusted commercial heat use per customer (for Rate N customers) in the FPFTY is 337.80 MCF. The adjusted commercial heat use per customer in the FPFTY is 268.30 MCF, a decrease of 69.50 MCF. The adjusted use per customer is 20.5% below the unadjusted use per customer. The Company's model for commercial heat customers has also been shown to be inconsistent with actual experience. The actual weather normalized use per commercial heat customer in the twelve months ended September 2015 was 554.4 MCF (Attachment RS-27-D(d), Page 3, which also includes NT and DS customers). Based on its multi-year regression analysis, the Company projected annualized use per customer of 513.9 MCF per customer (UGI Gas Exhibit DEL-6(c), which also includes NT and DS customers) for that year. Again, while the Company has cited no abnormal or unusual factors that would have caused the weather normalized use per customer in the historic test year to have been so much greater than the usage projected in its multi-year regression analysis, it has opted to rely on its regression analysis rather than actual experience to determine the pro forma use per customer.

Q. What do you recommend?

A. Based on the data presented in UGI Gas Exhibits DEL-2(a) and DEL-(2)b, there is no evidence of declining trends in use per customer in recent years. The changes in use per customer on UGI Gas Exhibit DEL 3(c) should be eliminated, and the FPFTY unadjusted use per customer should be used both for the purpose of determining the Company's revenue deficiency (or excess) under present rates and for the purpose of designing rates to produce the Company's approved revenue requirement.

On my Schedule C-1, I have reflected an adjustment to reverse the Company's "Adjustment for Annualized Use/Customer" on UGI Gas Exhibit DEL 3(c). My adjustment increases pro forma FPFTY revenues under present rates by $34,878,000 (including PGC revenues), the FPFTY pro forma cost of gas by $18,855,000, and the pro forma FPFTY margin by $16,023,000.

c. Interruptible Revenues

Q. How did the Company determine pro forma test year interruptible revenues for the FPFTY?

A. As explained by Mr. Lahoff, the Company annualized interruptible revenues for the FPFTY revenue based on its proxy cost of service of $4.9 million (UGI Gas Statement 6, Page 11).

Q. Have you adjusted the Company's pro forma test year interruptible revenues for the purpose of calculating FPFTY adjusted operating income under present rates?

A. Yes. Based on the testimony of OCA Witness Watkins, I have reflected the budgeted FPFTY interruptible revenues, without adjustment, in total FPFTY operating revenues. This increases pro forma revenues under present rates by $15,722,000, pro forma purchased gas costs by $1,626,000, and pre-tax income by $14,096,000 (my Schedule C-1).

d. Transportation, Excess Take, Rate N Minimum Bills

Q. Has the Company reflected adjustments to pro forma test year transportation revenues to reflect the elimination of certain fees?

A. Yes. As explained by Mr. Lahoff, the Company's pro forma transportation revenues reflect the elimination of Pooling Fees, System Access Fees and Information Service Fees (UGI Gas Statement 6, Page 11).

Q. How have you treated these fees for the purpose of calculating pro forma FPFTY revenues and adjusted operating income under present rates?

A. I have added these fees back to pro forma operating revenues. The Company's present rates include these fees, and the determination of pro forma revenues being produced by the rates presently in effect should include the revenues from these fees. Whether the elimination of these fees is appropriate is more of a rate design issue. Mr. Watkins also addresses this issue. Inclusion of the revenues from these fees increases pro forma revenues under present rates by $5,075,000 (including PGC revenues), pro forma purchased gas costs by $2,731,000, and pre-tax income by $2,344,000 (my Schedule C-1).

Q. Have you also eliminated the Company's adjustments related to "Excess Take" revenues and "Rate N Minimum Bills"?

A. Yes. Again, the Company's rates, as they are presently structured, produce the revenues related to excess take provisions and Rate N minimum bills. Therefore, I have included these revenues in the determination of pro forma revenues and pro forma operating income under present rates. The inclusion of the excess take revenues increases the pro forma margin under present rates by $600,000 and the inclusion of the Rate N minimum bill revenues increases the pro forma margin under present rates by $1,279,000 (my Schedule C-1).

2. OPERATION AND MAINTENANCE EXPENSE

a. Labor Expense

Q. Did the Company propose to adjust the FPFTY payroll expense to annualize the effect of wage rate increases taking place during the twelve months ending September 30, 2017?

A. Yes. On UGI Gas Exhibit A (FPFTY), Schedule D-7, UGI Gas annualizes the effect of wage rate increases taking place over the course of 2017.

Q. **Are such adjustments appropriate when the test year matches the rate year?**

A. No. Such adjustments may be appropriate in the context of a historical test year or a future test year that is earlier than the rate year because the intent of such adjustments is to make the pro forma payroll expense more representative of the payroll expense that can reasonably be expected to be incurred in the rate year. However, such an adjustment is not appropriate when the test year matches the rate year, as the FPFTY in this case does. That is, the FPFTY already recognizes the payroll expense that the

Company is expected to incur in the rate year. By annualizing the impact of forecasted wage rate increases taking place in the FPFTY, the Company is, in effect, proposing to recognize payroll expense that will be incurred during periods after the FPFTY. Therefore, the adjustment to annualize the effect of the wage rate increases taking place in the FPFTY is not appropriate.

Q. What is the effect of eliminating the Company's adjustments to annualize the FPFTY wage rate increases?

A. The effect of eliminating the adjustment to annualize wage rate increases is to reduce the pro forma test year wage and salary expense by $378,000 (my Schedule C-2).

b. Environmental Remediation Expense

Q. Did the Company include an accrual for environmental remediation costs in its pro forma FPFTY operation and maintenance expenses?

A. Yes. UGI Gas Exhibit A (FPFTY), Schedule D-8 reflects a $3,000,000 expense for environmental expense. As explained by Company Witness Kelly, the adjustment is necessary because the UGI Gas budget did not include this expense (UGI Gas Statement No. 2). UGI Gas Witness Bell addresses the Company's environmental program and the estimates of environmental costs on which the expense shown on UGI Gas Exhibit A (FPFTY), Schedule D-8 is based.

Q. Has the Company established that the estimated FPFTY environmental expense is properly includable in its revenue requirements at this time?

A. No. The accrual does not represent an actual cost incurred by the Company – it is an accrual for estimated costs that the Company may incur in the future. In addition, it has not been demonstrated that these costs are properly recoverable from the Company's customers.

Q. What do you recommend?

A. The accrual for estimated environmental remediation costs should be eliminated from pro forma test year operation and maintenance expenses. The elimination of this accrual decreases gas pro forma expenses by $3,000,000 (my Schedule C-2).

c. Rate Case Expense

Q. Has the Company included rate case expense in pro forma FPFTY operating expenses?

A. Yes. The Company includes $628,000 of rate case expense in pro forma test year operation and maintenance expenses. This consists of the estimated cost of the present rate case normalized over two years (UGI Exhibit A (FPFTY), Schedule D-10).

Q. Are you proposing to modify the adjustment to the pro forma rate case expense included in the Company's revenue requirement?

A. Yes. Referring to the response to OCA Data Request I-33, it can be seen that the Company's last base rate case was filed in 1995, and the case prior to that was filed in 1982. Based on this experience, I believe that a normalization period of at least five years is more reasonable. Normalizing the estimated cost of the present case over five years, rather than three years, results in a reduction of $377,000 to the annual rate case expense included in the Company's revenue requirement (my Schedule C-2).

d. Uncollectible Accounts Expense

Q. Please describe your adjustment to uncollectible accounts expense.

A. Uncollectible accounts expense is treated as varying directly with revenue. Consistent with my adjustment to FPFTY revenues, I have also adjusted the FPFTY year uncollectible accounts expense. My adjustment of $957,000 is shown on Schedule C-2.

3. DEPRECIATION

Q. Have you reflected adjustments to test year depreciation and amortization expense in your calculation of pro forma operating income under present rates?

A. Yes. I have reflected the effect of Mr. Garren's proposed adjustments to the Company's depreciation rates on my Schedule C-3. In addition, the Company annualized the FPFTY depreciation and amortization expense based on the depreciable plant in service as of September 30, 2017, the end of the FPFTY. This method may be appropriate in the context of a historical test year or a future test year that is earlier than the rate year because the intent of annualizing such expenses is to make the pro forma expense more representative of the expenses that can reasonably be expected to be incurred in the rate year. However, this method is not appropriate when the test year matches the rate year, as the FPFTY in the present case does. The actual depreciation expense recorded in the FPFTY will reflect the average balance of depreciable plant over the course of the year. By annualizing the depreciation expense based on the end-of-year plant, the Company is, in effect, proposing to recognize depreciation expense that will be recorded beyond the end of the FPFTY. Therefore, the Company's calculation of depreciation expense based on the plant in service as of the end of the FPFTY is not appropriate.

Q. How are you proposing to adjust the depreciation expense included in the FPFTY revenue requirement?

A. The test year depreciation expense should be based on the average balances of FPFTY depreciable plant in service. With a composite depreciation rate of 1.88%, which is based on the recommendations of Mr. Garren, the FPFTY depreciation on the average balance of FPFTY depreciable plant is $1,480,000 less than the annualized depreciation expense on the end-of-year FPFTY depreciable plant (my Schedule C-3).

4. TAXES OTHER THAN INCOME TAXES

Q. Are you proposing to adjust the pro forma FPFTY taxes other than income taxes?

A. Yes. Consistent with my adjustments to FPFTY labor expense, I am proposing to adjust payroll taxes by $29,000. My adjustment to payroll taxes is shown on Schedule C-4.

5. INCOME TAXES

Q. Please explain the calculation of your pro forma adjustments to FPFTY income tax expenses.

A. The calculation of my adjustments to income tax expenses is shown on my Schedule C-5. This schedule shows the adjustments to taxable income from the other adjustments to operating income that I am proposing. I also calculate the adjustment to interest expense (the weighted cost of debt times rate base) resulting from my proposed adjustments to rate base. I apply the state income tax rate to the adjustments to taxable income to calculate the adjustment to state income tax expense, and I then apply the federal income tax rate to the adjustments to taxable income net of state income taxes to calculate the adjustment to federal income tax expense.

Q. Other than these derivative income tax adjustments, are you proposing any modifications to the Company's calculation of pro forma FPFTY state and federal income taxes?

A. Yes. I am proposing two modifications. First, I am proposing to flow through the Company's repairs tax deduction in the determination of the income tax expense included in the cost of service. Second, I am proposing to reflect a consolidated tax savings in the calculation of the Company's federal income tax expense.

Q. Please explain what the repairs tax deduction represents.

A. In September 2009, the Internal Revenue Service ("IRS") issued Revenue Procedure 2009-39, clarifying the procedures for taxpayers to obtain consent for changes in the method of accounting for which expenditures are currently deductible under Internal Revenue Code Section 162 and which expenditures must be capitalized under Internal Revenue Code 263. The current deductibility of such expenditures had been expanded by proposed regulations issued in March 2008, and Revenue Procedure 2009-39 clarified that consent to implement such changes in accounting would be automatic.

The combined effect of the proposed regulations and Revenue Procedure 2009-39 was to greatly enhance the current repair allowance deduction for certain expenditures (including "network assets") that are capitalized on the Company's books of account. As explained by Company Witness McKinney, UGI, including UGI Gas, adopted this method of accounting for income tax purposes in its tax return for the year ended September 30, 2009 (UGI Gas Statement No. 10, Page 10). The tax repairs deduction for the FPFTY is $22,541,000 (UGI Gas Exhibit A (FPFTY), Schedule D-34).

Q. How does the Company treat the repairs deduction in the determination of its FPFTY income tax expense?

A. The Company "has chosen to calculate its federal income tax expense claim, inclusive of the repairs tax deduction, consistent with normalization" (UGI Gas Statement No.10, Page 10). In other words, the Company records deferred income tax expense on the repairs tax deduction rather than flowing through the benefit of this tax deduction as an immediate reduction to the income tax expense included in the cost of service.

Q. Does the Internal Revenue Code require a normalization method of accounting to be applied to the tax repairs deduction in order for regulated utility taxpayers to utilize this tax deduction in the calculation of taxable income?

A. No. In fact, based on my experience it has been the practice of other utility companies in Pennsylvania, including PECO Energy, Duquesne Light Company, and Columbia Gas of Pennsylvania, to flow through the effect of the repairs deduction in the determination of the income tax expenses to be included in their revenue requirements.

Q. What do you recommend?

A. It is my understanding that it is the policy in Pennsylvania to flow though the effect of accelerated tax deductions except for deductions where a normalization method of accounting is required by the Internal Revenue Code. UGI Gas has presented no reason why it should be exempt from complying with this policy. Therefore, the tax repairs deduction should be treated as a flow-through item in the calculation of income tax expense.

Q. What is the effect of treating the FPFTY repairs tax deduction as a flow-through item?

A. The effect is to reduce the state deferred income tax expense by $791,000 and the federal deferred income tax expense by $7,889,000 (my Schedule C-5). I have also adjusted the average FPFTY balance of accumulated deferred income taxes deducted from plant in the determination of rate base on my Schedule B to reflect this adjustment to deferred income tax expense.

Q. Why are you proposing to include a consolidated income tax adjustment in the calculation of income tax expense?

A. The savings from participating in a consolidated income tax return reduce the actual taxes paid by the consolidated entity and the amounts that must be recovered from the entities with positive taxable income, such as UGI Gas, in order to pay the consolidated income tax liability. Therefore, I have reflected the consolidated tax savings adjustment of $181,000, as calculated by the Company, in my determination of federal income tax expense on my Schedule C-5.

Q. Does this conclude your direct testimony?

A. Yes.

OCA Statement No. 1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	**Docket No. R-2015-2518438**
v.	:	
	:	
UGI UTILITIES, INC. – GAS DIVISION	:	

APPENDIX ACCOMPANYING THE

DIRECT TESTIMONY OF

DAVID J. EFFRON

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

APRIL 12, 2016

Appendix 1

RESUME OF DAVID J. EFFRON

UTILITY REGULATION EXPERIENCE

Assistance to offices representing customer interests in Rhode Island, Maryland, Massachusetts, Illinois, and Texas regarding electric utility restructuring matters.

Presentation of testimony on various utility regulation matters involving electric, gas, telephone, and water utilities in the following jurisdictions: Alabama, Arizona, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Missouri, Nevada, New Jersey, New York, North Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, Texas, Vermont, Virginia, Washington, and FERC.

Assistance to attorneys in preparing discovery, cross-examination, post-hearing briefs, and analysis of orders; provision of technical assistance during settlement negotiations.

CABLE CONSULTING EXPERIENCE

Assistance to local franchising authorities in financial feasibility reviews, regulation of cable rates, franchise fee audits, and negotiation of franchise agreements.

OTHER BUSINESS EXPERIENCE

Supervision of capital project analysis, capital budgets, spending reports, leasing program, and special studies; feasibility studies, accounting systems, statistical surveys; audits of publicly held companies in various industries.

EMPLOYMENT HISTORY

Dates	Company
March 1982 - Present	Berkshire Consulting Services (Self-employed)
January 1977 - February 1982	Georgetown Consulting Group
April 1975 - January 1977	Gulf & Western Industries
February 1973 - March 1975	Touche Ross & Company

EDUCATION

Columbia University, MBA, 1973
Dartmouth College, BA Economics, 1968

HONORS AND AWARDS

Gold Charles Waldo Haskins Memorial Award for the highest scores in the May 1974 Certified Public Accounting Examination in New York State.

Graduated from Dartmouth College with distinction in the field of Economics

OCA Statement No. 1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	**Docket No. R-2015-2518438**
v.	:	
	:	
UGI UTILITIES, INC. – GAS DIVISION	:	

EXHIBITS ACCOMPANYING THE

DIRECT TESTIMONY OF

DAVID J. EFFRON

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

APRIL 12, 2016

TABLE I
INCOME SUMMARY
($000)

	Pro Forma Present Rates	Recommended Adjustments	Adjusted Present Rates	Revenue Adjustment	Total Allowable Revenue
Operating Revenue	$ 334,670	$ 57,326	$ 391,996	$ (27,092)	$ 364,904
Deductions					
O&M Expense	229,996	19,841	249,837	(452)	249,384
Depreciation	43,190	(9,278)	33,912		33,912
Taxes:					
State	1,740	4,008	5,748	(2,661)	3,087
Federal	12,222	7,064	19,286	(8,393)	10,893
Deferred and ITC	-		-		-
Other	5,748	(29)	5,719	-	5,719
Total Deductions	292,896	21,606	314,502	(11,506)	302,996
					-
Net Income Available for Return	$ 41,775	$ 35,720	$ 77,494	$ (15,586)	$ 61,908
Rate Base					$ 863,747
Return on Rate Base					7.17%

TABLE II
SUMMARY OF ADJUSTMENTS
($000)

Recommended Adjustment	Exhibit Reference		Rate Base Effect	Revenue Effect	Expense Effect	Depreciation Effect	Effect on Other Taxes	State Tax Effect	Federal Tax Effect
			$	$	$	$	$	$	$
Average FPFTY Rate Base	OCA St.1	Sch. B-1	(55,271)			(1,480)		148	466
Gas Stored Underground	OCA St.1	Sch. B	(5,877)						
OPEB Over-Recovery	OCA St.1	Sch. B	(5,866)						
Annualization of Res, Com Ind Cust	OCA St.1	Sch. C-1		(760)	(430)			(33)	(104)
Annualization of Transport Cust	OCA St.1	Sch. C-1		533	(143)			68	213
Use per Customer Adjustments	OCA St.1	Sch. C-1		34,878	18,855			1,601	5,048
Interruptible Revenues	OCA St.1	Sch. C-1		15,721	1,626			1,408	4,440
Transportation Service Revenues	OCA St.1	Sch. C-1		5,075	2,731			234	738
Excess Take Revenues	OCA St.1	Sch. C-1		600	-			60	189
Rate N Minimum Bills	OCA St.1	Sch. C-1		1,279	-			128	403
Salaries and Wages	OCA St.1	Sch. C-2			(378)		(29)	41	128
Environmental Remediation	OCA St.1	Sch. C-2			(3,000)			300	945
Rate Case Expense	OCA St.1	Sch. C-2			(377)			38	119
Uncollectible Accounts Expense	OCA St.1	Sch. C-2			957			(96)	(301)
Depreciation Rates	OCA St.1	Sch. C-3	2,714			(7,798)		779	2,457
Repairs Tax Deduction	OCA St.1	Sch. C-5	4,340					(791)	(7,889)
Consolidated Tax Savings	OCA St.1	Sch. C-5							(181)
Interest Synchronization	OCA St.1	Sch. C-5						125	393
Total Adjustment			(59,960)	57,326	19,841	(9,278)	(29)	4,008	7,064
Company Rate Base	UGI Exh. A, Sch. A-1		923,707						
Recommended Rate Base			863,747						

Schedule A

UGI UTILITIES, INC. - GAS DIVISION
REVENUE DEFICIENCY
($000)

	(1) Company Position	Adjustments		Proposed Position
Measures of Value (Rate Base)	$ 923,707	$ (59,960)	(2)	$ 863,747
Rate of Return	8.17%	-1.00%	(3)	7.17%
Operating Income Requirement	75,467	(13,559)		61,908
Adjusted Operating Income	41,775	35,720	(4)	77,494
Income Deficiency (Excess)	33,692	(49,278)		(15,586)
Gross Revenue Conversion Factor	1.7382	-		1.7382
Revenue Deficiency (Excess)	$ 58,564	$ (85,657)		$ (27,092)

Sources:
- (1) UGI Exhibit A, Schedule A-1
- (2) Schedule B
- (3) Schedule D
- (4) Schedule C

UGI UTILITIES, INC. - GAS DIVISION
MEASURES OF VALUE (RATE BASE)
($000)

	(1) Company	Adjustments		Proposed
Total Gas Plant	$1,649,567	$ (78,670)	(2)	$1,570,897
Reserve for Accumulated Depreciation	(448,737)	11,737	(3)	(437,000)
Net Utility Plant in Service	1,200,830	(66,933)		1,133,897
Working Capital	18,648			18,648
Materials and Supplies	4,212			4,212
Prepayments				-
Gas Stored Underground	21,730	(5,877)	(4)	15,853
Subtotal	44,590	(5,877)		38,713
Deduct				
Accumulated Deferred Income Taxes	307,196	(18,716)	(5)	288,480
Customer Deposits	14,517	-		14,517
OPEB Over-recovery	-	5,866	(6)	5,866
Subtotal	321,713	(12,850)		308,863
Net Measures of Value (Rate Base)	$ 923,707	$ (59,960)		$ 863,747

Sources:

(1)	UGI Exhibit A, Schedule C-1			
(2)	Schedule B-1			
(3)	Schedule B-1		7,098	
	Schedule C-3		4,639	Depreciation Adjustment/2
	Total Adjustment		11,737	
(4)	Schedule B-2			
(5)	Schedule B-1		(16,301)	
	Depreciation Adjustment		1,925	Tax Rate * Deprec. Adjstmt.
	ADIT - Repairs		(4,340)	C-5, Expense Adjustment/2
	Total		(18,716)	
(6)	OPEB Over-Recovery		10,027	Attachment OCA I-35
	Income Taxes	41.494%	4,161	
	Net of Tax Balance		5,866	

Schedule B-1

UGI UTILITIES, INC. - GAS DIVISION
YEAR END VS. AVERAGE RATE BASE
($000)

		(1) 9/30/2016	(2) 9/30/2017	Average	Difference
Plant in Service	(1)	1,492,227	1,649,567	1,570,897	(78,670)
Accumulated Depreciation	(2)	(434,541)	(448,737)	(441,639)	7,098
Deferred Income Taxes	(3)	(274,594)	(307,196)	(290,895)	16,301
Net Rate Base Balances		783,092	893,634	838,363	(55,271)

Sources:

(1) UGI Exhibit A (FTY), Schedule C-1
(2) UGI Exhibit A (FPFTY), Schedule C-1

UGI UTILITIES, INC. - GAS DIVISION
GAS INVENTORY
($000)

Jan-15	(1)	21,572
Feb-15	(1)	8,661
Mar-15	(1)	3,147
Apr-15	(1)	6,238
May-15	(1)	8,778
Jun-15	(1)	11,650
Jul-15	(1)	15,314
Aug-15	(1)	19,540
Sep-15	(1)	23,368
Oct-15	(2)	26,404
Nov-15	(2)	25,267
Dec-15	(2)	22,845
Jan-16	(2)	13,303
Average		15,853

Sources:
(1) UGI Exhibit A, Schedule C-5
(2) Attachment OCA-1-12

UGI UTILITIES, INC. - GAS DIVISION
OPERATING INCOME
($000)

	(1) Company Position	Adjustments		Proposed Position
Sales Revenue	$ 330,190	$ 57,326	(2)	$ 387,516
Other Operating Revenue	4,480	-		4,480
Operating Revenue	$ 334,670	$ 57,326		$ 391,996
Gas Supply Expense	114,125	22,639		136,764
Operation and Maintenance Expense	115,871	(2,798)	(3)	113,073
Depreciation and Amortization	43,190	(9,278)	(4)	33,912
Taxes other than Income Taxes	5,748	(29)	(5)	5,719
State Income Tax Expense	1,740	4,008	(6)	5,748
Federal Income Tax Expense	12,222	7,064	(6)	19,286
				-
Total Operating Expenses	292,896	21,606		314,502
Adjusted Operating Income	$ 41,775	$ 35,720		$ 77,494

Sources:
- (1) UGI Exhibit A, Schedule D-1
- (2) Schedule C-1
- (3) Schedule C-2
- (4) Schedule C-3
- (5) Schedule C-4
- (6) Schedule C-5

UGI UTILITIES, INC. - GAS DIVISION
OPERATING REVENUES
($000)

		Revenues	Cost of Gas	Margin
Annualization of Res, Com, Ind Customers	(1)	(760)	(430)	(330)
Annualization of Transport Customer Changes	(1)	533	(143)	676
Use per Customer Adjustments	(2)	34,878	18,855	16,023
Interruptible Revenues	(3)	15,721	1,626	14,095
Transportation Service Revenues	(4)	5,075	2,731	2,344
Excess Take Revenues	(5)	600	-	600
Rate N Minimum Bills	(6)	1,279	-	1,279
Totals		57,326	22,639	34,687

Sources:

(1) UGI Gas Exhibit DEL 3(b)
(2) UGI Gas Exhibit DEL 3(c)
(3) UGI Gas Exhibit DEL 3(h)
(4) UGI Gas Exhibit DEL 3(i)
(5) UGI Gas Exhibit DEL 3(j)
(6) UGI Gas Exhibit DEL 3(l)

UGI UTILITIES, INC. - GAS DIVISION
OPERATION AND MAINTENANCE EXPENSE
($000)

Salaries and Wages	(1)	(378)
Environmental Remediation	(2)	(3,000)
Rate Case Expense	(3)	(377)
Uncollectible Accounts Expense	(4)	957
Total Adjustment to Operation and Maintenance Expense		$ (2,798)

Sources:

(1) UGI Exhibit A, Schedule D-7

(2) UGI Exhibit A, Schedule D-8

(3) UGI Exhibit A, Schedule D-10

Total Rate Case Cost	1,256	
Normalization - Years	5	
Annual Expense	251	
Company Expense	628	
Adjustment	(377)	

(4)

Adjustment to Revenues	57,326	Schedule C-1
Uncollectible Accounts Rate	1.669%	UGI Exh A, Sch. D-11
Adjustment to Uncollectible Accounts	957	

Schedule C-3

UGI UTILITIES, INC. - GAS DIVISION
DEPRECIATION EXPENSE
($000)

Adjustment to Depreciation Rates		
OCA Depreciation Expense	(1)	31,033
Company Depreciation Expense	(2)	38,831
Adjustment		(7,798)
Adjustment to Plant in Service	(3)	(78,670)
Composite Depreciation Rate	(4)	1.88%
Adjustment to Reflect Average Plant for FPFTY		(1,480)
Total Adjustment to Depreciation Expense		(9,278)

Sources

(1) Testimony of Mr. Garren

(2) UGI Exhibit A, Schedule D-21

(3) Schedule B-1

(4) Testimony of Mr. Garren 31033/1649567

UGI UTILITIES, INC. - GAS DIVISION
TAXES OTHER THAN INCOME TAXES
($000)

Adjustment to FPFTY Payroll	(1)	(378)
Payroll Tax Rate		7.60%
Adjustment to Payroll Taxes		$ (29)

Sources
- (1) Schedule C-2
- (2) UGI Exhibit A, Schedule D-32

UGI UTILITIES, INC. - GAS DIVISION
INCOME TAXES
($000)

Adjustments to Taxable Income:

Revenue	(1)	$ 57,326
Cost of Gas	(1)	22,639
Operation and Maintenance Expense	(1)	(2,798)
Depreciation and Amortization	(1)	(9,278)
Taxes other than Income Taxes	(1)	(29)
Interest	(2)	(1,248)
Adjustment to Expenses		9,286
Net Adjustment to Taxable Income		48,040
Pennsylvania Income Tax Rate		9.99%
Adjustment to Current Pennsylvania Income Tax		4,799
Deferred State Income Taxes on Repairs Deduction	(3)	(791)
Adjustment to Pennsylvania Income Tax		$ 4,008
Adjustment to Federal Taxable Income		43,241
Federal Income Tax Rate		35%
Adjustment to Federal Income Tax		15,134
Deferred Taxes on Repairs Tax Deduction	(4)	(7,889)
Consolidated Tax Savings	(5)	(181)
Net Adjustment to Federal Income Tax		$ 7,064

Sources:

(1)	Schedule C		
(2)	Rate Base	863,747	Schedule B
	Weighted Debt Cost	2.18%	Schedule D
	Interest Deduction	18,796	
	Company Interest Deduction	20,044	UGI Exhibit A, Schedule D-33
	Adjustment	(1,248)	
(3)	UGI Exhibit A, Schedule D-33		
(4)	Repairs Tax Deduction	22,541	UGI Exhibit A, Schedule D-34
	Federal Income Tax Rate	35%	
	Deferred Federal Income Taxes	7,889	
(5)	SDR Attachment II-A-26		

Schedule D

UGI UTILITIES, INC. - GAS DIVISION
RATE OF RETURN
($000)

Company Position

	Percent of Total	Cost Rate	Weighted Cost
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 Capital	100.00%		8.17%

OCA Position

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	40.30%	5.07%	2.04%
Short Term Debt	5.15%	2.58%	0.13%
Common Equity	54.55%	9.15%	4.99%
Total Capital	100.00%		7.17%

Sources: UGI Exhibit A, Schedule B-7
Testimony of Mr. Parcell

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2015-2518438
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, David J. Effron, hereby state that the facts above set forth in my Direct Testimony, OCA St. No. 1, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: David J. Effron
David J. Effron

Consultant Address: Berkshire Consulting Services
12 Pond Path
Northampton, NH 03862

DATED: April 12, 2016

OCA St. No. 1-SR
6/2/16 Hbg TC

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2015-2518438**
	:	
UGI Utilities, Inc. – Gas Division	:	

SURREBUTTAL TESTIMONY

OF

DAVID J. EFFRON

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

MAY 25, 2016

PUBLIC VERSION

Q. Please state your name and business address.

A. My name is David J. Effron. My address is 12 Pond Path, North Hampton, New Hampshire.

Q. Have you previously submitted testimony in this docket?

A. Yes. I submitted Direct Testimony on April 12, 2016, marked as OCA Statement No. 1. My qualifications and experience are attached to my Direct Testimony.

Q. What is the purpose of this Surrebuttal Testimony?

A. In this Surrebuttal Testimony, I respond to the Rebuttal Testimony of UGI witnesses Szykman, Kelly, Lahoff, Bell, and McKinney. I am also presenting certain modifications to the adjustments that I proposed in my Direct Testimony and a revised calculation of the Company's revenue deficiency (or excess) to incorporate the effect of those modifications. I do not respond to all the Company's Rebuttal addressing the issues presented in my Direct Testimony. However, this should not be interpreted to mean that I agree with the Company's Rebuttal on those issues or that I no longer believe that the position expressed on those issues in my Direct Testimony is appropriate.

Q. With the modifications to the original adjustments proposed in your Direct Testimony, what is the Company's revenue deficiency (excess)?

A. Incorporating the modifications in the following Surrebuttal Testimony, I have calculated a revenue excess $10,570,000 (see my revised Schedule A, accompanying this testimony).

Year End Rate Base and Annualizing Adjustments

Q. What is the Company's position with regard to the use of a year-end rate base and annualization of expenses in association with a fully projected future test years ("FPFTY")?

A. Ms. Kelly addresses this issue and states that she does not "at all" agree with my Direct Testimony on this matter.

Q. Do any of the reasons cited for her disagreement cause you to reconsider your proposal to reflect an average rate base and eliminate annualizing adjustments in the determination of the FPFTY revenue requirement?

A. No. First, Ms. Kelly states that she does "not agree that using an average rate base more accurately reflects the entire time in which resulting rates are being collected" (UGI Statement 2-R, Page 29), because the rates established in this case will be in effect for more than one year. I did not claim that the average rate base for the FPFTY would be representative of the rate base after the rate year. However, this does not mean that the average rate base for the FPFTY is inappropriate for the purpose of determining the relationship among rate base, expenses, billing determinants, and other factors that go into the determination of the Company's rates, even if those rates are expected to be in effect for more than one year.

Q. What is the second reason cited by Ms. Kelly for opposing the average rate base methodology?

A. Ms. Kelly states that I "fail to acknowledge that under ratemaking treatment prior to passage of Act 11 of 2012, end of test year plant balances were routinely accepted." *Id.*

Q. Is this assertion accurate?

A. No. In fact, in my Direct Testimony at Page 7, Line 6, through Page 8, Line 3, I explicitly addressed the practice of using a year-end rate base in what has been characterized as a future test year in Pennsylvania and why that does not justify the use a year-end rate base in the context of the fully projected future test year being proposed by the Company in the present case.

Q. Does Ms. Kelly allege any "other flaws" in your adjustments to reflect an average FPFTY rate base?

A. Yes. She alleges two errors: 1) I "seriously understated, by about $2.3 million, the amount of end of test year operating revenue that should be removed from pro forma revenue in connection with [my] adjustment" (citing Mr. Lahoff's rebuttal testimony, UGI Gas Statement No. 6-R) and; 2) I "fail to acknowledge that [my] flow through recommendation, related to the Company's current year repairs tax deduction, should also be adjusted" (UGI Statement 2-R, Pages 30-31).

Q. Do you have a response?

A. Yes. First, the amount of end of test year operating revenue removed from pro forma revenue in connection with my adjustment is based on UGI Gas Exhibit DEL-3(b), as noted on my Schedule C-1. I simply reversed the Company's adjustments to annualize the sales to the end of year residential, commercial, and industrial customers. I do not know the source of $2.3 million cited in Ms. Kelly's and Mr. Lahoff's testimony.

Second, I did, in fact adjust rate base for the effect of flowing through the effect of the repairs deduction, as recommended in my Direct Testimony. My adjustment to the balance of accumulated deferred income taxes ("ADIT") for the flow-through of the repairs deduction is shown on my Schedule B, Footnote (5). There was no error or omission.

Q. Does Ms. Kelly express other concerns regarding the use of an average rate base?

A. Yes. She claims that the use of an average rate base "complicates the calculation of associated taxes" (UGI Statement 2-R, Page 31).

Q. Is this a valid concern?

A. No. I reflected the average balance of ADIT, based on the beginning balance and ending balance, as presented by the Company, in my calculation of the average FPFTY rate base. This is not terribly complicated, and Ms. Kelly does not allege that this method is erroneous or inappropriate.

Q. Does Ms. Kelly cite any additional concerns regarding the use of an average rate base?

A. Yes. She states that "The OCA's adjustment to use an average plant-in-service also complicates the Company's ability to effectively and efficiently use the DSIC mechanism to accelerate investment in its distribution infrastructure" (UGI Statement 2-R, Page 32).

It is not clear how the use of an average FPFTY in this rate case would add any significant complication to the implementation of the DSIC. As I understand the DSIC, it would allow the Company to recover the cost of plant additions over and above the plant included in rate base in the prior rate case. All that use of an average rate base in the present case means is that the DSIC would be based on the increase in plant over the average balance rather than increase in plant over the year-end balance. This does not strike me as a being particularly complicated.

Q. On Page 27 of her rebuttal testimony, Ms. Kelly states that Mr. Garren's depreciation expense adjustment duplicates your depreciation expense adjustment. Is there, in fact any such duplication?

A. No. Ms. Kelly is correct that my removal of $1.4 million of depreciation expense in my average plant addition adjustment is not accounted for in Mr. Garren's adjustments. However, I did use Mr. Garren's proposed depreciation accrual rates in my calculation of the adjustment to depreciation expense to reflect the average balance of depreciable plant in the FPFTY. Therefore, there was no duplication or overlap between Mr. Garren's adjustment and my adjustment.

Q. Has Ms. Kelly cited any sound reasons why the use of an average rate base in conjunction with an FPFTY is inappropriate?

A. She has not. I continue to believe that my average test year approach is reasonable.

Gas Inventory

Q. Does the Company agree with your quantification of the gas inventory to be included in the FPFTY rate base?

A. Yes. Therefore, this matter is no longer at issue.

OPEB Over-Recovery

Q. How does the Company respond to your proposal to deduct the over-recovered OPEB balance from rate base to the extent that it has not been returned to customers?

A. Ms. Kelly does not agree with this proposal. She states that the "OPEB trust amount was never included in base rates," and "because the Company did not recover a return on the regulatory asset, it would not be appropriate for the Company to reduce rate base for the current over-recovery" (UGI Statement 2-R, Page 26).

Q. Did you address this argument in your Direct Testimony?

A. Yes. As I explained, the regulatory asset did not represent actual investor-supplied funds on which it would have been appropriate to recover any return or interest, whereas the over-recovered OPEB expense represents real cash collected from ratepayers in excess of the actual OPEB cost recorded by the Company (OCA Statement No. 1, Page 12). Ms. Kelly did not dispute this testimony. Therefore, I continue to believe that the deduction from rate base for the over-recovered OPEB balance is appropriate.

Use per Customer

Q. Did the Company respond to your proposal to eliminate their adjustments to the FPFTY usage per customer?

A. Yes. Both Mr. Lahoff and Mr. Szykman address the issue of FPFTY usage per customer. Neither agrees with my recommendations on this matter.

Q. What is the primary reason Mr. Lahoff cites for disagreeing with your recommendations?

A. Mr. Lahoff primarily relies on supposed problems with my analysis of customer usage patterns over the last five years in his explanation of why my recommendations should be rejected.

Q. Do you have a response?

A. Yes. First, however, it is critical to note that while I did reference customer usage patterns in the last five years in my testimony on this issue, I did not attempt to project those usage patterns to the FPFTY, nor did I reflect any pattern of increasing usage in quantifying my adjustments to the Company's pro forma usage per customer. What I did rely on in quantifying my adjustment was the Company's forecasted usage per customer for the FPFTY before the pro forma adjustment based on the 21 year regression analysis. I did nothing more than eliminate the Company's pro forma adjustment to its own forecast.

Mr. Lahoff also takes me to task for not conducting certain studies that the Company seems to think I should have conducted, but as far as I can tell would serve no useful purpose. For example, Mr. Lahoff states that I did not conduct a study "to support the conclusion that residential and small commercial customers stopped undertaking conservation actions" (UGI Statement 6-R, Page 23). I did not conduct such a study because I did not conclude that residential and small commercial customers stopped undertaking conservation actions, nor did my testimony either imply or rest on such a conclusion, contrary to Mr. Lahoff's claim. However, looking at the Company's own data for the last five years, it is clear that to the extent that residential and small commercial customers have continued to undertake conservation actions, any effect on usage has been offset by other factors, as there has been no declining trend in usage in that timeframe.

He then notes that I have not "conducted a study of at what point expected errors from projections may be deemed reasonable, and when expected errors should be deemed 'abnormal or unusual' "(*Id.*). I did not conduct a study of this nature because I could see no purpose to doing so, nor does Mr. Lahoff describe what purpose such a study would serve.

Finally Mr. Lahoff states that I have "not researched alternative normalization methods that could otherwise have been applied to the regression data presented in SDR-RR-11 to determine use per customer" (UGI Statement 6-R, Page 24). I did not research alternative weather normalization methods because I accepted the Company's weather normalization method. It is not clear why Mr. Lahoff is criticizing me for accepting what the Company itself has presented or why he believes that the Company's normalization methods are so unreliable that other alternatives must be explored.

Q. Mr. Lahoff then presents customer usage data for the twelve months ended March 2016, which he asserts "refutes Mr. Effron's conclusion that average usage per customer has increased over the past five years, which is the principal basis for his rejection of the Company's analysis" ***Id.*** **Is this an accurate characterization of your testimony?**

A. No. My testimony on this issue did *not* in any way rest on a conclusion that there was an upward trend in customer usage in the last five years. Rather, my recommendation rested on the clearly stated conclusion that "there is no evidence of declining trends in use per customer in recent years" (OCA Statement 1, Page 18:21-22). Consequently, there is no reason to adjust the Company's own forecasts of FPFTY use per customer based on the 21 year regression analysis that appears to have been prepared solely for the purpose of quantifying the revenue deficiency in the present rate case.

Mr. Lahoff notes that the weather normalized residential heating use per customer decreased from the twelve months ended September 2015 to the twelve months ended March 2016. However, referring to UGI Exhibit DEL-16, Page 1, the change between September 2015 and March 2016 is not inconsistent with other periodic fluctuations in recent years. There is still no evidence of an ongoing downward trend in usage in recent years. Notably, Mr. Lahoff makes no reference to the weather normalized commercial heating use per customer in this section of his rebuttal testimony. This is understandable, as the weather normalized commercial heating use per customer for the twelve months ended March 2016, although less than the usage per customer for the twelve months ended September 2015, was still higher than it was in September 2010 (the starting point of the most recent five years in my direct testimony) or March 2011.

Q. Mr. Lahoff claims that its downward adjustment to use per customer is not inconsistent with evidence presented in its most recent 1307(f) filing because the most recent 1307(f) filing "is referencing the combined Peak Day requirements of UGI Gas's core market customers, not annual use per customer" (UGI Statement 6-R, Page 25, emphasis in original). Do you have a response?

A. Yes. While the testimony in the 1307(f) filing might address peak day requirements, the attachments to that testimony also show sales data. **BEGIN CONFIDENTIAL**

[redacted]

[redacted] END CONFIDENTIAL

Q. In his rebuttal testimony, Mr. Szykman offers an alternative recommendation based on a 15 year regression analysis (UGI Statement No. 1-R, Pages 36-37). Is this alternative reasonable?

A. No. This alternative would still reflect a declining trend in customer usage, albeit less severe than the decline based on the 21 year regression analysis. This alternative also reaches back to capture declines in usage that took place prior to 2010, but have not taken place since then. As there is no evidence of a declining trend in usage per customer in recent years, it would not be appropriate to adjust the Company's forecasted FPFTY sales volumes to reflect such a non-existent decline.

Annualized Revenues

Q. On Page 27 of his rebuttal testimony, Mr. Lahoff states that "Mr. Effron seriously understates the pro forma FPFTY margin associated with customer additions during the FPFTY." Do you understand the basis of this criticism?

A. I do not. As I noted previously, my adjustment related to pro forma FPFTY margin associated with customer additions during the FPFTY is based on UGI Gas Exhibit DEL-3(b), and I did nothing more than simply reverse the Company's adjustments to annualize the sales to the end of year residential, commercial, and industrial customers. Mr. Lahoff now states that "The Company's budget shows 4,340 Rate RH and 830 rate CH customers added during the FPFTY, producing about $3 million and $2.4 million in non-gas revenue. One-half of those amounts would be $1,471,260 and $1,141,392, respectively, which is $2,282,652 above Mr. Effron's figure of $330,000 of non-gas revenue." UGI Statement 6-R, Page 27.

These figures are inconsistent with the "adjustment for customer changes" on UGI Gas Exhibit DEL-3(b). For example, UGI Gas Exhibit DEL-3(b) shows a difference between average and year-end customers of 977 for the RH class and 172 for the CH class, implying additions of 1,954 RH customers and 344 CH customers over the course of the FPFTY. These are less than one-half of the additions cited by Mr. Lahoff in his rebuttal testimony. Based on Mr. Lahoff's rebuttal testimony, it appears that the problem is not that I have understated the pro forma FPFTY margin associated with customer additions during the FPFTY in my adjustment as Mr. Lahoff claims, but rather that the Company has understated the necessary adjustment to margin for customer changes on its UGI Gas Exhibit DEL-3(b).

Q. Mr. Lahoff claims that your elimination of the Company's proposed adjustment for Transportation Changes is "without merit" because the Transportation Change adjustment proposed by the Company is related to changes in the number of transportation customers that, due to timing reasons, are not reflected in the budget for Fiscal Year 2017" (UGI Statement No. 6-R, Page 27). Has the Company established that its adjustment for Transportation Changes is appropriate?

A. No. The Company has still not established that these changes in transportation revenues and margins are actually taking place. Therefore, I continue to believe that my adjustment is appropriate.

Transportation Charges

Q. At pages 30-33, Mr. Lahoff expresses his disagreement with your recommendation to include revenues from certain transportation charges that the Company is proposing to eliminate in the determination of pro forma revenues under present rates. Do you have a response?

A. Yes. Mr. Lahoff does not dispute the fact that as the Company's rates are presently structured, the Company will earn these revenues. That being said, this issue should be more a matter of presentation than one of substance from the perspective of residential customers, as the design of residential rates should not be affected by the elimination of the subject transportation charges. However, in calculating the Company's revenue deficiency under the rates presently in effect, I believe that it is appropriate to include the revenues being generated by the subject transportation charges, as there is no question that those charges are, in fact, presently in effect.

MGP Remediation

Q. Has the Company modified the requested accrual for manufactured gas plant ("MGP") remediation that it is proposing to include in its base rate revenue requirement?

A. Yes. The Company is now proposing to include an accrual of $2,500,000 for MGP remediation in the FPFTY revenue requirement. Citing the rebuttal testimony of Mr. Bell, Company Witness Kelly describes this amount as being "based on the actual minimum spending requirement in a recently executed Consent Order Agreement with the Pennsylvania Department of Environmental Protection" (UGI Statement 2-R, Page 3).

Q. Based on your review, does the referenced Consent Order Agreement ("COA") require minimum spending of $2,500,000 in the FPFTY?

A. **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL**

Q. What do you recommend?

A, **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** However, the Company has been incurring actual costs for MGP remediation in recent years. I&E Witness Gumby recommends that the pro forma MGP remediation expense be based on the actual average expense for the years 2011

– 2015 (I&E Statement No. 2, Page 29). I believe that this is a reasonable basis for the MGP remediation accrual to be included in the Company's revenue requirement in the present case. The five-year average is $409,000, which is $2,091,000 less than the MGP remediation accrual included by the Company in its revised revenue requirement. Accordingly I have reduced pro forma test year operation and maintenance by $2,091,000 to reflect this adjustment to the MGP remediation accrual (my Schedule C-2 accompanying this Surrebuttal Testimony).

Rate Case Expense

Q. What is the Company's position with regard to the proper period over which to normalize rate case expense?

A. Ms. Kelly believes that it would be improper to rely on the time since the last rate case to determine the appropriate number of years over which to normalize rate case expense. She believes that the normalization period should be based on the Company's stated expectation of filing a rate case in two to three years.

Q. Do you agree that normalization period should be based on the Company's expectation of when it will file its next rate case?

A. No. In my opinion, the timing of the Company's next rate case is speculative. Given that the Company is using a more forward looking test year now than it did in the last case and is also implementing a DSIC, I do not think that a five-year normalization period for rate case expense is at all unreasonable.

Repairs Deduction

Q. Did the Company address your recommendation on the treatment of the repairs deduction in its rebuttal testimony?

A. Yes. Ms. McKinney does not agree with my recommendation that the tax repairs deduction should be treated as a flow-through item in the calculation of income tax expense. She states that "The Company believes that the regulatory treatment of the federal repairs tax deduction should be normalized" (UGI Statement No. 10-R, Page 4).

Q. Do you have a response?

A. Yes. However, first it is necessary to clarify my Direct Testimony, at Page 28, Lines 4-11. In that testimony, I responded to a question as to whether the Internal Revenue Code requires a normalization method of accounting to be applied to the tax repairs deduction in order for regulated utility taxpayers to utilize this tax deduction in the calculation of taxable income. My answer to that question was "no," which is correct. However, my examples of other utility companies in Pennsylvania that flow through the effect if the repairs deduction were not all correct.

PECO Energy does flow through the effect of the repairs deduction. However, Duquesne Light Company does not. In preparing my Direct Testimony, I reviewed the income tax calculation by Duquesne on its Schedule D-18 in Docket No. R-2013-2372129. On that that schedule there was an income tax deduction for "Tax Basis Repairs Net of Losses." There was no deferred tax expense with a similar caption. However, in responding to data requests, on further investigation, I found that the deferred income tax expense on "Normalized Book/Tax Basis Adjustment" in fact included deferred taxes on the repairs deduction and that Duquesne has been normalizing the effect of the repairs deduction.

Columbia Gas of Pennsylvania did flow the effect of the Section 481(a) "catch-up" deduction through to customers (although not all in one year). However Columbia has normalized the ongoing annual repairs deduction. Thus, Columbia flowed through only part on the effect of the repairs deduction.

Q. How are you proposing to treat the repairs deduction in this Surrebuttal Testimony?

A. As I stated in my Direct Testimony, it was my understanding that it has been the general practice in Pennsylvania to flow though the effect of accelerated tax deductions except for deductions where a normalization method of accounting is required by the Internal Revenue Code, which would be consistent with the actual taxes paid doctrine. However, based on the above cases and the examples cited in the Company's rebuttal testimony, this practice has not been applied universally with regard to the repairs deduction. To my knowledge the Commission has not yet addressed the appropriate treatment of the repairs deduction in a contested rate case. That being said, it is clear that many of the utility companies in Pennsylvania have adopted normalization treatment for the repairs deduction either for ratemaking purposes pursuant to settlements or on their books of account on their own initiative. In these circumstances, the Company's belief that the repairs tax deduction should be normalized is not unreasonable. Therefore, I have not flowed through the effect of the repairs deduction in my calculation of the pro forma income tax expense in this Surrebuttal Testimony.

Consolidated Tax Savings

Q. Does the Company agree with your adjustment to income taxes to recognize a consolidated tax savings?

A. No. The Company essentially repeats the objections to the recognition of a consolidated tax savings adjustment expressed in its direct case. I have continued to reflect a consolidated tax savings in my calculation of pro forma income tax expense, as the Company has offered no new reasons why this adjustment should be eliminated.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes

OCA St. No. 1-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2015-2518438**
	:	
UGI Utilities, Inc. – Gas Division	:	

EXHIBITS ACCOMPANYING

THE

SURREBUTTAL TESTIMONY

OF

DAVID J. EFFRON

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

MAY 25, 2016

TABLE I
INCOME SUMMARY
($000)

	Pro Forma Present Rates	Recommended Adjustments	Adjusted Present Rates	Revenue Adjustment	Total Allowable Revenue
Operating Revenue	$ 334,463	$ 57,326	$ 391,789	$ (10,570)	$ 381,220
Deductions					
O&M Expense	229,830	20,750	250,580	(176)	250,404
Depreciation	43,190	(9,278)	33,912		33,912
Taxes:					
State	1,621	4,722	6,343	(1,038)	5,305
Federal	12,076	14,710	26,786	(3,274)	23,512
Deferred and ITC	-		-		-
Other	5,745	(29)	5,716	-	5,716
Total Deductions	292,462	30,876	323,337	(4,489)	318,848
					-
Net Income Available for Return	$ 42,002	$ 26,450	$ 68,452	$ (6,081)	$ 62,371
Rate Base					$ 870,208
Return on Rate Base					7.17%

TABLE II
SUMMARY OF ADJUSTMENTS
($000)

Recommended Adjustment	Exhibit Reference		Rate Base Effect	Revenue Effect	Expense Effect	Depreciation Effect	Effect on Other Taxes	State Tax Effect	Federal Tax Effect
			$	$	$	$	$	$	$
Average FPFTY Rate Base	OCA St.1	Sch. B-1	(63,121)			(1,480)		148	466
Gas Stored Underground	OCA St.1	Sch. B	(0)						
OPEB Over-Recovery	OCA St.1	Sch. B	(5,866)						
Annualization of Res, Com Ind Cust	OCA St.1	Sch. C-1		(760)	(430)			(33)	(104)
Annualization of Transport Cust	OCA St.1	Sch. C-1		533	(143)			68	213
Use per Customer Adjustments	OCA St.1	Sch. C-1		34,878	18,855			1,601	5,048
Interruptible Revenues	OCA St.1	Sch. C-1		15,721	1,626			1,408	4,440
Transportation Service Revenues	OCA St.1	Sch. C-1		5,075	2,731			234	738
Excess Take Revenues	OCA St.1	Sch. C-1		600	-			60	189
Rate N Minimum Bills	OCA St.1	Sch. C-1		1,279	-			128	403
Salaries and Wages	OCA St.1	Sch. C-2			(378)		(29)	41	128
MGP Remediation	OCA St.1	Sch. C-2			(2,091)			209	659
Rate Case Expense	OCA St.1	Sch. C-2			(377)			38	119
Uncollectible Accounts Expense	OCA St.1	Sch. C-2			957			(96)	(301)
Depreciation Rates	OCA St.1	Sch. C-3	2,714			(7,798)		779	2,457
Consolidated Tax Savings	OCA St.1	Sch. C-5							(181)
Interest Synchronization	OCA St.1	Sch. C-5						138	437
Total Adjustment			(66,273)	57,326	20,750	(9,278)	(29)	4,722	14,710
Company Rate Base	UGI Exh. A, Sch. A-1		936,481						
Recommended Rate Base			870,208						

Schedule A

UGI UTILITIES, INC. - GAS DIVISION
REVENUE DEFICIENCY
($000)

	(1) Company Position	Adjustments		Proposed Position
Measures of Value (Rate Base)	$ 936,481	$ (66,273)	(2)	$ 870,208
Rate of Return	8.17%	-1.00%	(3)	7.17%
Operating Income Requirement	76,510	(14,139)		62,371
Adjusted Operating Income	42,002	26,450	(4)	68,452
Income Deficiency (Excess)	34,509	(40,589)		(6,081)
Gross Revenue Conversion Factor	1.7382	-		1.7382
Revenue Deficiency (Excess)	$ 59,984	$ (70,553)		$ (10,570)

Sources:
- (1) UGI Exhibit A, Schedule A-1
- (2) Schedule B
- (3) Schedule D
- (4) Schedule C

Schedule B

UGI UTILITIES, INC. - GAS DIVISION
MEASURES OF VALUE (RATE BASE)
($000)

	(1) Company	Adjustments		Proposed
Total Gas Plant	$1,649,567	$ (78,670)	(2)	$1,570,897
Reserve for Accumulated Depreciation	(448,737)	11,737	(3)	(437,000)
Net Utility Plant in Service	1,200,830	(66,933)		1,133,897
Working Capital	21,600			21,600
Materials and Supplies	4,212			4,212
Prepayments				-
Gas Stored Underground	15,853	(0)	(4)	15,853
Subtotal	41,665	(0)		41,665
Deduct				
Accumulated Deferred Income Taxes	291,497	(6,527)	(5)	284,970
Customer Deposits	14,517	-		14,517
OPEB Over-recovery	-	5,866	(6)	5,866
Subtotal	306,014	(660)		305,354
Net Measures of Value (Rate Base)	$ 936,481	$ (66,273)		$ 870,208

Sources:

(1)	UGI Exhibit A, Schedule C-1 (REVISED)			
(2)	Schedule B-1			
(3)	Schedule B-1		7,098	
	Schedule C-3		4,639	Depreciation Adjustment/2
	Total Adjustment		11,737	
(4)	Schedule B-2			
(5)	Schedule B-1		(8,452)	
	Depreciation Adjustment		1,925	Tax Rate * Deprec. Adjstmt.
	Total		(6,527)	
(6)	OPEB Over-Recovery		10,027	Attachment OCA I-35
	Income Taxes	41.494%	4,161	
	Net of Tax Balance		5,866	

Schedule B-1

UGI UTILITIES, INC. - GAS DIVISION
YEAR END VS. AVERAGE RATE BASE
($000)

		(1) 9/30/2016	(2) 9/30/2017	Average	Difference
Plant in Service	(1)	1,492,227	1,649,567	1,570,897	(78,670)
Accumulated Depreciation	(2)	(434,541)	(448,737)	(441,639)	7,098
Deferred Income Taxes	(3)	(274,594)	(291,497)	(283,046)	8,452
Net Rate Base Balances		783,092	909,333	846,213	(63,121)

Sources:

(1) UGI Exhibit A (FTY), Schedule C-1

(2) UGI Exhibit A (FPFTY), Schedule C-1 (REVISED)

UGI UTILITIES, INC. - GAS DIVISION
GAS INVENTORY
($000)

Jan-15	(1)	21,572
Feb-15	(1)	8,661
Mar-15	(1)	3,147
Apr-15	(1)	6,238
May-15	(1)	8,778
Jun-15	(1)	11,650
Jul-15	(1)	15,314
Aug-15	(1)	19,540
Sep-15	(1)	23,368
Oct-15	(2)	26,404
Nov-15	(2)	25,267
Dec-15	(2)	22,845
Jan-16	(2)	13,303
Average		15,853

Sources:
(1) UGI Exhibit A, Schedule C-5
(2) Attachment OCA-1-12

Schedule C

UGI UTILITIES, INC. - GAS DIVISION
OPERATING INCOME
($000)

	(1) Company Position	Adjustments		Proposed Position
Sales Revenue	$ 330,190	$ 57,326	(2)	$ 387,516
Other Operating Revenue	4,273	-		4,273
Operating Revenue	$ 334,463	$ 57,326		$ 391,789
Gas Supply Expense	114,125	22,639		136,764
Operation and Maintenance Expense	115,705	(1,889)	(3)	113,816
Depreciation and Amortization	43,190	(9,278)	(4)	33,912
Taxes other than Income Taxes	5,745	(29)	(5)	5,716
State Income Tax Expense	1,621	4,722	(6)	6,343
Federal Income Tax Expense	12,076	14,710	(6)	26,786
				-
Total Operating Expenses	292,462	30,876		323,337
Adjusted Operating Income	$ 42,002	$ 26,450		$ 68,452

Sources:
- (1) UGI Exhibit A, Schedule D-1
- (2) Schedule C-1
- (3) Schedule C-2
- (4) Schedule C-3
- (5) Schedule C-4
- (6) Schedule C-5

Schedule C-1

UGI UTILITIES, INC. - GAS DIVISION
OPERATING REVENUES
($000)

		Revenues	Cost of Gas	Margin
Annualization of Res, Com, Ind Customers	(1)	(760)	(430)	(330)
Annualization of Transport Customer Changes	(1)	533	(143)	676
Use per Customer Adjustments	(2)	34,878	18,855	16,023
Interruptible Revenues	(3)	15,721	1,626	14,095
Transportation Service Revenues	(4)	5,075	2,731	2,344
Excess Take Revenues	(5)	600	-	600
Rate N Minimum Bills	(6)	1,279	-	1,279
Totals		57,326	22,639	34,687

Sources:

(1) UGI Gas Exhibit DEL 3(b)
(2) UGI Gas Exhibit DEL 3(c)
(3) UGI Gas Exhibit DEL 3(h)
(4) UGI Gas Exhibit DEL 3(i)
(5) UGI Gas Exhibit DEL 3(j)
(6) UGI Gas Exhibit DEL 3(l)

UGI UTILITIES, INC. - GAS DIVISION
OPERATION AND MAINTENANCE EXPENSE
($000)

Salaries and Wages	(1)	(378)
MGP Remediation	(2)	(2,091)
Rate Case Expense	(3)	(377)
Uncollectible Accounts Expense	(4)	957
Total Adjustment to Operation and Maintenance Expense		$ (1,889)

Sources:

(1)	UGI Exhibit A, Schedule D-7 (REVISED)			
(2)	Five Year Average MGP Remediation	I&E-RE-20-D		409
	UGI Exhibit A, Schedule D-8 (REVISED)			2,500
	Difference			(2,091)
(3)	UGI Exhibit A, Schedule D-10 (REVISED)			
	Total Rate Case Cost	1,256		
	Normalization - Years	5		
	Annual Expense	251		
	Company Expense	628		
	Adjustment	(377)		
(4)	Adjustment to Revenues	57,326	Schedule C-1	
	Uncollectible Accounts Rate	1.669%	UGI Exh A, Sch. D-11	
	Adjustment to Uncollectible Accounts	957		

Schedule C-3

UGI UTILITIES, INC. - GAS DIVISION
DEPRECIATION EXPENSE
($000)

Adjustment to Depreciation Rates		
OCA Depreciation Expense	(1)	31,033
Company Depreciation Expense	(2)	38,831
Adjustment		(7,798)
Adjustment to Plant in Service	(3)	(78,670)
Composite Depreciation Rate	(4)	1.88%
Adjustment to Reflect Average Plant for FPFTY		(1,480)
Total Adjustment to Depreciation Expense		(9,278)

Sources

(1) Testimony of Mr. Garren
(2) UGI Exhibit A, Schedule D-21 (REVISED)
(3) Schedule B-1
(4) Testimony of Mr. Garren 31033/1649567

UGI UTILITIES, INC. - GAS DIVISION
TAXES OTHER THAN INCOME TAXES
($000)

Adjustment to FPFTY Payroll	(1)	(378)
Payroll Tax Rate		7.60%
Adjustment to Payroll Taxes		$ (29)

Sources
(1) Schedule C-2
(2) UGI Exhibit A, Schedule D-32 (REVISED)

Schedule C-5

UGI UTILITIES, INC. - GAS DIVISION
INCOME TAXES
($000)

Adjustments to Taxable Income:

Revenue	(1)	$ 57,326
Cost of Gas	(1)	22,639
Operation and Maintenance Expense	(1)	(1,889)
Depreciation and Amortization	(1)	(9,278)
Taxes other than Income Taxes	(1)	(29)
Interest	(2)	(1,386)
Adjustment to Expenses		10,058
Net Adjustment to Taxable Income		47,268
Pennsylvania Income Tax Rate		9.99%
Adjustment to Pennsylvania Income Tax		$ 4,722
Adjustment to Federal Taxable Income		42,546
Federal Income Tax Rate		35%
Adjustment to Federal Income Tax		14,891
Consolidated Tax Savings	(3)	(181)
Net Adjustment to Federal Income Tax		$ 14,710

Sources:

(1)	Schedule C		
(2)	Rate Base	870,208	Schedule B
	Weighted Debt Cost	2.18%	Schedule D
	Interest Deduction	18,936	
	Company Interest Deduction	20,322	UGI Exh. A, Sch. D-33 (REV)
	Adjustment	(1,386)	
(3)	SDR Attachment II-A-26		

Schedule D

UGI UTILITIES, INC. - GAS DIVISION
RATE OF RETURN
($000)

Company Position

	Percent of Total	Cost Rate	Weighted Cost
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 Capital	100.00%		8.17%

OCA Position

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	40.30%	5.07%	2.04%
Short Term Debt	5.15%	2.58%	0.13%
Common Equity	54.55%	9.15%	4.99%
Total Capital	100.00%		7.17%

Sources: UGI Exhibit A, Schedule B-7
Testimony of Mr. Parcell

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2015-2518438
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, David J. Effron, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA St. No. 1-SR, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: David J. Effron
David J. Effron

Consultant Address: Berkshire Consulting Services
12 Pond Path
Northampton, NH 03862

DATED: May 25, 2016

OCA Statement No. 2

6/2/16 Hby TX

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	DOCKET NO. R-2015-2518438
	:	
UGI UTILITIES, INC. – GAS DIVISION	:	

DIRECT TESTIMONY OF

DAVID C. PARCELL

ON BEHALF OF OFFICE OF CONSUMER ADVOCATE

APRIL 12, 2016

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LIST OF SCHEDULES

I. INTRODUCTION

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

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 130, 1503 Santa Rosa Rd., Richmond, Virginia 23229.

Q. Please summarize your educational background and professional experience.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have provided cost of capital testimony in public utility ratemaking proceedings dating back to 1972. In this regard, I have previously filed testimony and/or testified in over 525 utility proceedings before about 50 regulatory agencies in the United States and Canada. Attachment 1 provides a more complete description of my education and relevant work experience.

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

A. The Office of Consumer Advocate ("OCA") retained me to evaluate the cost of capital aspects of UGI Utilities, Inc. – Gas Division's ("UGI Gas" or "Company") current filing. I have performed independent studies and am making recommendations of the current cost of capital ("COC") for UGI Gas. In addition, since UGI Gas is a division of UGI

Utilities, Inc. ("UGI Utilities") which is a subsidiary of UGI Corporation ("UGI" or "Parent"), I have also evaluated these entities in my analyses.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes, I have prepared one exhibit, labeled Exhibit DCP-1, identified as Schedule 1 through Schedule 14. This exhibit was prepared either by me or under my direction. The information contained in this exhibit is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. What is your recommendation in this proceeding?

A. My overall COC recommendation for UGI Gas is shown on Schedule 1 and is summarized as follows:

Item	Percent	Cost	Weighted Cost
Short-Term Debt	5.15%	2.58%	0.13%
Long-Term Debt	40.30%	5.07%	2.04%
Common Equity	54.55%	9.15%	4.99%
Total	100.0%		
			7.17%

UGI Gas' application requests a COC of 8.17 percent and a cost of equity ("ROE") of 11.00 percent.

Q. Please summarize your analyses and conclusions.

A. This proceeding is concerned with UGI Gas' regulated natural gas utility operations in Pennsylvania. My analyses concern the Company's COC. The first step in performing these analyses is to develop the appropriate capital structure. UGI Gas proposes use of the estimated September 30, 2017 capital structure of UGI Utilities. I also use this capital structure.

The second step in a COC calculation is to determine the embedded cost rates of debt. UGI Gas proposes to use a cost rate of 5.07 percent for long-term debt and 2.58 percent for short-term debt. I also use these cost rates.

The third step in the COC calculation is to estimate the ROE. I employ three recognized methodologies to estimate UGI Gas' ROE, each of which I apply to a proxy group of (natural gas distribution) utilities. These three methodologies and my findings are:

Methodology	Recommendation
Discounted Cash Flow ("DCF")	8.30%
Capital Asset Pricing Model ("CAPM")	6.9%
Comparable Earnings ("CE")	10.0%

Based upon these findings, I conclude that UGI Gas' ROE is within a range of 8.30 percent to 10.0 percent, which is based upon my DCF and CE models.[1]

Combining these three steps into the weighted COC results in an overall rate of return of 6.70 percent to 7.63 percent (which incorporates an 8.30 percent to 10.0 percent ROE). My specific COC recommendation is the mid-point of this range, or 7.17 percent (9.15 percent ROE).

[1] As I indicate in a later section, my ROE recommendation does not directly incorporate the CAPM results, which I believe to be somewhat low at this time, relative to the DCF and CE results.

III. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES

Q. What are the primary economic and legal principles that establish the standards for determining a fair rate of return for a regulated utility?

A. Public utility rates are normally established in a manner designed to allow the recovery of their costs, including capital costs. This is frequently referred to as "cost of service" ratemaking. Rates for regulated public utilities traditionally have been primarily established using the "rate base – rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets utilized (i.e., rate base) in providing service to their customers.

The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. Thus, the revenue impact of the COC is derived by multiplying the rate base by the rate of return, including income taxes.

The rate of return is developed from the COC, which is estimated by weighting the capital structure components (i.e., debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these values by their cost rates. This is also known as the weighted COC.

Technically, "fair rate of return" is a legal and accounting concept that refers to an <u>ex post</u> (after the fact) earned return on an asset base, while the COC is an economic and financial concept which refers to an <u>ex ante</u> (before the fact) expected, or required, return on a capital base. In regulatory proceedings, however, the two terms are often used interchangeably, and I have equated the two concepts in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

Although I am not a lawyer and I do not offer a legal opinion, my testimony is based on my understanding that two United States Supreme Court decisions provide the controlling standards for a fair rate of return. The first decision is *Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923). In this decision, the Court stated:

> The annual rate that will constitute just compensation depends upon many circumstances and must be determined by the exercise of fair and enlightened judgment, having regard to all relevant facts. 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; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. 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. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.

It is generally understood that the *Bluefield* decision established the following standards for a fair rate of return: CE, financial integrity, and capital attraction. It also noted that required returns change over time, and there is an underlying assumption that the utility be operated efficiently.

The second decision is *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1942). In that decision, the Court stated:

> The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and consumer interests. . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By this standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

The three economic and financial parameters in the *Bluefield* and *Hope* decisions – CE, financial integrity, and capital attraction – reflect the economic criteria encompassed in the "opportunity cost" principle of economics. The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise on which regulation rests, namely, that it is intended to act as a surrogate for competition.

Q. How can the *Bluefield* and *Hope* parameters be employed to estimate the COC for a utility?

A. Neither the courts nor economic/financial theory has developed exact and mechanical procedures for precisely determining the COC. This is the case because the COC is an opportunity cost and is prospective-looking, which dictates that it must be estimated.

However, there are several useful models that can be employed to assist in estimating the ROE, which is the capital structure item that is the most difficult to determine. These include the DCF, CAPM, CE and risk premium ("RP") methods. I have not directly employed a RP model in my analyses although, as discussed later, my CAPM analysis is a form of the RP methodology. Each of these methodologies will be described in more detail later in my testimony.

IV. GENERAL ECONOMIC CONDITIONS

Q. Are economic and financial conditions important in determining the costs of capital for a public utility?

A. Yes. The costs of capital, for both fixed-cost (debt and preferred stock) components and common equity, are determined in part by current and prospective economic and financial conditions. At any given time, each of the following factors has an influence on the costs of capital:

- The level of economic activity (i.e., growth rate of the economy);
- The stage of the business cycle (i.e., recession, expansion, or transition);
- The level of inflation;
- The level and trend of interest rates; and,
- Current and expected economic conditions.

My understanding is that this position is consistent with the *Bluefield* decision that noted "[a] rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally." *Bluefield*, 262 U.S. at 693.

Q. What indicators of economic and financial activity did you evaluate in your analyses?

A. I examined several sets of economic statistics from 1975 to the present. I chose this time period because it permits the evaluation of economic conditions over four full business cycles, allowing for an assessment of changes in long-term trends. Consideration of economic/financial conditions over a relatively long period of time allows me to assess how such conditions have had impacts on the level and trends of the costs of capital. This period also approximates the beginning and continuation of active rate case activities by public utilities, which generally began in the mid-1970s.

A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical (i.e., stage of business cycle) influences and, thus, permits a comparison of structural (or long-term) trends.

Q. Please describe the timeframes of the four prior business cycles and the current cycle.

A. The four prior complete cycles and current cycle cover the following periods:

Business Cycle	Expansion Cycle	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Mar. 1991-Mar. 2001	Apr. 2001-Nov. 2001
2001-2009	Nov. 2001-Nov. 2007	Dec. 2007-June 2009
Current	July 2009-	

Source: National Bureau of Economic Research, "Business Cycle Expansions and Contractions.[2]

Q. Do you have any general observations concerning the recent trends in economic conditions and their impact on capital costs over this broad period?

A. Yes, I do. From the early 1980s until the end of 2007, the United States economy had enjoyed general prosperity and stability. This period had been characterized by longer economic expansions, relatively tame contractions, low and declining inflation, and declining interest rates and other capital costs.

However, in 2008 and 2009, the economy declined significantly, initially as a result of the 2007 collapse of the "sub-prime" mortgage market and the related liquidity crisis in the financial sector of the economy. Subsequently, this financial crisis intensified with a more broad-based decline, initially based on a substantial increase in petroleum prices and a dramatic decline in the U.S. financial sector, culminating with the collapse and/or bailouts of a significant number of well-known institutions such as Bear Stearns, Lehman Brothers, Merrill Lynch, Freddie Mac, Fannie Mae, AIG and Wachovia. The recession also witnessed the demise of national companies such as Circuit City and the bankruptcies of automotive manufacturers such as Chrysler and General Motors.

[2] http://www.nber.org/cycles/cyclesmain.html.

This decline has been described as the worst financial crisis since the Great Depression and has been referred to as the "Great Recession." Beginning in 2008, the U.S. and other governments implemented unprecedented actions to attempt to correct or minimize the scope and effects of this recession.

The recession reached its low point in mid-2009, when the economy began to expand again, although at a slow and uneven rate. However, the length and severity of the recession, as well as a relatively slow and uneven recovery, indicate that the impacts of the recession have been and will be felt for an extended period of time.

Q. Please describe recent and current economic and financial conditions and their impact on the COC.

A. One impact of the Great Recession has been a reduction in actual and expected investment returns and a corresponding reduction in the costs of capital. This decline is evidenced by a decline in both short-term and long-term interest rates and the expectations of investors and is reflected in ROE model results (such as DCF, CAPM and CE). Regulatory agencies throughout the United States have recognized the decline in capital costs by authorizing lower ROEs for regulated utilities.

Schedule 2 shows several sets of relevant economic and financial statistics for the cited time periods. Pages 1 and 2 contain general macroeconomic statistics; pages 3 and 4 show interest rates; and pages 5 and 6 contain equity market statistics.

Pages 1 and 2 show that in 2007 the economy subsequently entered a significant decline, as indicated by the growth in real (i.e., adjusted for inflation) Gross Domestic Product ("GDP"), industrial production, and an increase in the unemployment rate. This recession lasted until mid-2009, making it a longer-than-normal recession, as well as a much deeper recession. Since then, economic growth has been somewhat erratic and the economy has grown slower than the prior expansions.

Pages 1 and 2 also show the rate of inflation. As reflected in the Consumer Price Index ("CPI"), for example, inflation rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation has declined substantially since 1981. Since 2008, the CPI has been 3 percent or lower, with 2013 being only 1.5 percent and both 2014 and 2015 being below 1 percent. It is thus apparent that the rate of inflation has generally been declining over the past several business cycles. Recent and current levels of inflation are at the lowest levels of the past 35 years, which is reflective of lower capital costs.[3]

Q. What have been the trends in interest rates over the four prior business cycles and at the current time?

A. Pages 3 and 4 show several series of interest rates. Both short-term and long-term rates rose sharply to record levels in 1975-1981 when the inflation rate was high. Interest rates declined substantially in conjunction with inflation since the early 1980's.

From 2008 to late 2015, the Federal Reserve System ("Federal Reserve") maintained the Federal Funds rate (i.e., short-term interest rate) at 0.25 percent, an all-time low. The Federal Reserve recently raised it slightly to 0.50 percent. The Federal

[3] The rate of inflation is one component of interest rate expectations of investors, who generally expect to receive a return in excess of the rate of inflation. Thus, a lower rate of inflation has a downward impact on interest rates and other capital costs.

Reserve also purchased U.S. Treasury securities to stimulate the economy.[4] As seen on page 4, in 2012, both U.S. and corporate bond yields declined to their lowest levels in the past four business cycles and in more than 35 years. Even with the "tapering" and eventual ending of the Federal Reserve's Quantitative Easing program, interest rates have remained low. Currently, both government and corporate lending rates remain at historically low levels, again reflective of lower capital costs.

Q. What does this exhibit show for trends of common share prices?

A. Pages 5 and 6 show several series of common stock prices and ratios. These indicate that stock prices were essentially stagnant during the high inflation/high interest rate environment of the late 1970s and early 1980s. The 1983-1991 business cycle and the more recent cycles witnessed a significant upward trend in stock prices. The beginning of the recent financial crisis saw stock prices decline precipitously, as stock prices in 2008 and early 2009 were down significantly from peak 2007 levels, reflecting the financial/economic crisis. Beginning in the second quarter of 2009, prices recovered substantially and ultimately reached and exceeded the levels achieved prior to the "crash." On the other hand, recent equity markets have been somewhat volatile.

Q. What conclusions do you draw from your discussion of economic and financial conditions?

---

[4] This is referred to as Quantitative Easing which was comprised of three "rounds." In "round" 3, known as QE3, the Federal Reserve initially purchased some $85 billion of U.S. Treasury Securities per month in order to stimulate the economy. The Federal Reserve eventually "tapered" its purchase of U.S. Treasury securities through October 2014, at which time Quantitative Easing ended.

A. Recent economic and financial circumstances have differed from any that have prevailed since at least the 1930s. The late 2008-early 2009 deterioration in stock prices, the decline in U.S. Treasury bond yields, and an increase in corporate bond yields were evidenced in the then-evident "flight to safety." Concurrently, there was a decline in capital costs and returns, which significantly reduced the value of most retirement accounts, investment portfolios and other assets. One significant aspect of this has been a decline in investor expectations of returns,[5] even with the return of stock prices to levels achieved prior to the "crash." This evident in several ways: 1) lower interest rates on bank deposits; 2) lower interest rates on U.S. Treasury and corporate bonds; 3), lower increases in social security cost of living benefits;[6] and 4), lower authorized ROEs by regulatory commissions. Finally, as noted above, utility bond interest rates are currently at levels below those prevailing prior to the financial crisis of late 2008 to early 2009 and are near the lowest levels in the past 35 years. It is also noteworthy that long-term interest rates have declined slightly in recent months, in spite of the Federal Reserve's raising of short-term rates in December of 2015.

Q. How do these economic/financial conditions impact the determination of a ROE for regulated utilities?

A. The costs of capital for regulated utilities have declined in recent years. For example, the current interest costs that utilities pay on new debt remain near the low point of the last several decades. In addition, the results of the traditional ROE models (i.e., DCF, CAPM

---

[5] *See*, for example, Kiplinger's Personal Finance, "Investors Brace for Smaller Gains, Focus on Long-Term," August 30, 2015.
[6] The 2015 increase in Social Security benefits was 1.70 percent – near an all-time low. There is no increase in 2016 Social Security benefits.

and CE) are lower than was the case prior to the Great Recession. In light of this, it is not surprising that the average ROEs authorized by state regulatory agencies have declined and continued to decline through 2015, as follows:

Year	Electric[7]	Natural Gas
2012	10.01%	9.94%
2013	9.94%	9.68%
2014	9.76%	9.78%
2015	9.58%	9.60%

V. UGI UTILITIES' OPERATIONS AND BUSINESS RISKS

Q. Please describe UGI Gas and its operations.

A. UGI Utilities is a natural gas distribution utility that serves nearly 617,000 customers in eastern and central Pennsylvania and about 500 customers in Maryland. UGI Utilities also has an electric utility segment, which also operates in Pennsylvania and a small portion of Maryland. UGI Utilities is a subsidiary of UGI. UGI Gas is a division of UGI Utilities and operates as the "Gas Utility" (Segment).

Q. Please describe UGI Gas' ownership structure.

A. As noted above, UGI Gas is a division of UGI Utilities, which is a subsidiary of UGI. UGI's other primary segments are:[8]

[7] Average ROE values for electric utilities exclude Virginia surcharge/rider generation cases that incorporate plan-specific ROE premiums. *See* Regulatory Research Associates, Regulatory Focus, January 14, 2016, page 1.

[8] UGI – 2015 Form 10-K.

AmeriGas Propane;
UGI International – UGI Finance
UGI International – Flaga & Other
Energy Services
Electric Generation; and,
Gas Utility.

UGI Gas' revenues represent about 14 percent of UGI's revenues.[9]

Q. What are the current security ratings of UGI Gas and UGI Utilities?

A. UGI Gas, as a division of UGI Utilities, does not issue its own securities directly to investors, but rather is a component of UGI Utilities. It follows that UGI Gas does not have rated securities. The current ratings of UGI Utilities are as follows:

Rating Agency	Senior Unsecured	Insurer Default
Moody's	A2	A2
S&P	NR	NR
Fitch	A	A-

(Source: Response to OCA-11-6)

Q. What have been the recent trends in UGI Utilities' debt ratings?

A. This is shown on Schedule 3. UGI Utilities' debt has been rated in the "Single A" category by both Fitch and Moody's since at least 2011.

Q. How do the bond ratings of UGI Utilities compare to other natural gas utilities?

A. As I indicated in a previous answer, UGI Utilities has single A bond ratings on its senior debt, which are investment grade (i.e., Triple-B or above). Of the 15 natural gas distribution and integrated utilities covered by AUS Utility Reports, the following numbers of bond ratings currently exist:

[9] Source: AUS Utility Reports.

Moody's Rating	Number of Companies
Aa2	1
Aa3	-
A1	2
A2*	6
A3	2
Baa1	1
Baa2	--
Baa3	--
Ba or less	--
NR	3

* UGI Utility's ratings.

This comparison indicates that UGI Utilities' ratings are in the most common rating category of most natural gas utilities.

Q. Have the rating agencies commented on UGI Utilities' risks?

A. Yes, they have. For example, Moody's made the following comments in a December 17, 2015 "Credit Opinion: UGI Utilities, Inc.":

> **Rating Drivers**
>
> - UGI Utilities' financial health remains strong, buoyed by attractive organic growth
> - Low risk regulated utility business model operating in credit supportive regulatory jurisdiction
> - Capex stays high to meet demand growth, system integrity standards and IT system upgrade
>
> **Corporate Profile**
>
> UGI Utilities, Inc. (Utilities) is a rate-regulated natural gas and electric utility serving about 600,000 gas customers throughout Pennsylvania (as well as several hundred customers in one county in Maryland) and over 60,000 electric customers in northeastern Pennsylvania. The company consists of four regulated entities: a gas utility division (UGI Gas), and electric utility division (UGI Electric) (together, the "legacy utilities") and two natural gas distribution company subsidiaries: UGI Penn Natural Gas (PNG) and UGI Central Penn Gas (CPG). The company is predominately

> a local gas distribution company (LDC) with the natural gas segment accounting for about 95% of its operating income and assets.
>
> Utilities is UGI Corporation's (UGI, not rated) largest subsidiary, representing an average of 30% of earnings. UGI is a holding company with significant investments in propane retailing and energy services that have a much higher business risk profile than Utilities. UGI's subsidiaries include its interest in propane distributor AmeriGas Partners, LP (Ba2 Corporate Family Rating, stable). AmeriGas accounts for about 23% of the company's earnings.
>
> **SUMMARY RATING RATIONALE**
>
> The rating for Utilities primarily reflects the company's low business risk profile, regulated revenues and stable operating cash flow generation. Virtually all of its operations fall under the jurisdiction of the Pennsylvania Public Utility commission (PUC), which we view as providing a credit supportive regulatory framework to utilities operating under its purview. The rating also considers its strong financial metrics that should continue over the intermediate-term thanks to organic growth opportunities in Utilities' service territory.

Q. Is UGI Gas using any regulatory mechanism in this proceeding which will impact its risk?

A. Yes. In this proceeding, UGI Gas is using a fully forecasted future test year. Using the fully forecasted future test year has the effect of reducing UGI Gas' risk by transferring a portion of the Company's risk of certain expense recoveries from its shareholders to its ratepayers.

Q. Why should use of the fully forecasted future test in this proceeding be considered in setting UGI Gas' ROE?

A. Implementation of a fully forecasted future test year permits a utility, such as UGI Gas, to include in rates an estimate of certain future costs. As such, the utility is able to avoid the "lag" of recovering increases in certain costs. As noted in a later answer, Moody's has specifically noted the positive aspects of a projected test period because it reduces regulatory lag and ensures that utilities can earn a return closer to the allowed ROE than utilities without forecasted test periods. As such, and as noted by Moody's, such a regulatory mechanism is risk-reducing to a utility such as UGI Gas.

Q. Are regulatory mechanisms a relatively new aspect of public utility regulation?

A. No, they are not. A brief history of regulatory mechanisms was provided in an October 2, 2015 report by Regulatory Research Associates, titled "Adjustment Clauses – a State-By-State Overview." This report stated (note that the term "Adjustment Clauses" was used in the report, which is a type of regulatory mechanism):

> The electric and natural gas utilities' use of adjustment clauses to recover variations in certain costs outside of the traditional rate case process had its origins in the 1973 Arab oil embargo, when fuel prices skyrocketed leaving the utilities with no way to recover the increased costs in a timely manner.
>
> . . .
>
> The result was the creation of the fuel adjustment clause (FAC), essentially a single-issue rate making process, whereby a utility is permitted to implement periodic adjustments (e.g., monthly, quarterly, semi-annually, annually) associated with changes in its cost of fuel.
>
> . . .
>
> Over the ensuing years, the use of adjustment clauses has expanded greatly. Adjustment clauses are generally reserved for expenses that are outside the control of the utility or are required by law or rule.
>
> . . .
>
> **A defining characteristic of an adjustment clause is that it effectively shifts the risk associated with the recovery of the expense in question from shareholders to customers**, because if the clause operates as designed, the company is able to change its rates to recover its costs on a current basis without any negative effect on the bottom line, without the expense and delay associated with seeking recovery through the general rate case process. **[Emphasis added]**

Q. Have the rating agencies commented on the risk-reducing nature of regulatory mechanisms?

A. Yes, they have. For example, a report by Moody's Investors Service, dated June 13, 2010 and titled "Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality," cited the risk-reducing nature of regulatory mechanisms. In this report, Moody's noted:

> Some regulators believe that mechanisms like automatic adjustment clauses materially reduce the business and operating risk of a utility, providing justification for a relatively low allowed return on equity. We believe this is one of several reasons why both allowed and requested ROEs have trended downward over the last two decades.
>
> Moody's views automatic adjustment clauses, the most common of which is for fuel and purchased power, the largest component of utility operating expenses, as supportive of utility credit quality and important in reducing a utility's cash flow volatility, liquidity requirements, and credit risk.

Moody's, in fact, upgraded the bulk of the entire U.S. investor-owned utility industry in early 2014, largely due to regulators' increasing use of regulatory mechanisms and the resulting improvement of utilities' finances. Moody's noted, in a February 3, 2014 Sector Comment titled "US Utility Sector Upgrades Driven by Stable and Transparent Regulatory Frameworks":

> We recently upgraded most US investor-owned utilities and many of their holding companies due to our view that the US regulatory environment has improved over the past several years. Most of the companies placed on review for upgrade in November 2013 were upgraded in late January 2014, and most by one notch.
>
> . . .
>
> US regulated utilities appear financially secure, thanks to their suite of transparent and timely cost and investment recovery mechanisms. When compared with other regulatory environments in developed countries, the overall regulatory environment for US utilities has steadily improved over the past few years and is expected to remain supportive and constructive for at least the next 3-5 years.
>
> Supportive regulatory frameworks

> Over the past few years, the US regulatory environment has been very supportive of utilities. We think this is partly a function of regulators acknowledging that their utility infrastructure needs a material amount of ongoing investment for maintenance, refurbishment and renovation purposes.
>
> . . .
>
> Stable and predictable financial profile
>
> A transparent suite of timely recovery mechanisms helps utilities generate stable and predictable revenues and cash flows, which can support a material amount of leverage.

Q. Has Moody's further commented on the impact of regulatory mechanisms and reduced risk/lower authorized ROEs for utilities?

A. Yes. In a March 10, 2015 Sector In-Depth report titled "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles", Moody's stated:

> The credit profiles of US regulated utilities will remain intact over the next few years despite our expectation that regulators will continue to trim the sector's profitability by lowering its authorized returns on equity (ROE). Persistently low interest rates and a comprehensive suite of cost recovery mechanisms ensure a lower business risk profile for utilities, prompting regulators to scrutinize their profitability, which is defined as the ratio of net income to book equity.

VI. CAPITAL STRUCTURE AND COSTS OF DEBT

Q. What is the importance of determining a proper capital structure in a regulatory framework?

A. A utility's capital structure is important because the concept of rate base – rate of return regulation requires the capital structure to be utilized in estimating the total COC. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to ascertain its capital costs. The rate base – rate of return concept recognizes the assets employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) used to finance the assets. In this process, the rate base is derived from the asset side of the balance sheet and the COC is derived from the liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the dollar values of the capital structure and the rate base are approximately equal and the former is utilized to finance the latter.

The common equity ratio (i.e. the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This is the case because common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and (3) causes the most controversy since its cost cannot be precisely determined.

Q. What are the historic capital structure ratios of UGI Utilities and UGI?

A. As a division of UGI Utilities, UGI Gas does not have its own distinct capital structure. I have therefore examined the historic (2011-2015) capital structure ratios of UGI Utilities and UGI. See Schedule 4. UGI Utility's common equity ratios have been:

	Including S-T Debt	Excluding S-T Debt
2011	52.3%	53.6%
2012	55.0%	55.8%
2013	54.6%	55.5%
2014	55.5%	56.5%
2015	56.9%	59.2%

Correspondingly, UGI's common equity ratios have been:

	Including S-T Debt	Excluding S-T Debt
2011	44.1%	45.5%
2012	31.9%	32.7%
2013	33.7%	34.8%
2014	36.0%	37.1%
2015	36.1%	37.0%

This indicates that UGI, on a consolidated basis, has maintained a capital structure with substantially less equity than UGI Utilities.

Q. How do these capital structures compare to those of investor-owned natural gas utilities?

A. Schedule 5 shows the common equity ratios (excluding short-term debt in capitalization) for the group of proxy natural gas companies developed in a later section of my testimony. These are:

Period	Average	Median
2011-2015	57.9%	54.3%
2018-2020	55.5%	53.7%

These equity ratios are similar than those requested by UGI Gas.

Q. What capital structure is UGI Gas requesting in this proceeding?

A. UGI Gas is proposing the following capital structure ratios, which reflects the estimated September 30, 2017 capital structure of UGI Utilities:

Short-Term Debt	5.15%
Long-Term Debt	40.30%
Common Equity	54.55%

Q. Do you use this is a proper capital structure to use for determining UGI Gas' COC?

A. Yes, I do.

Q. What are the cost rates of debt and preferred stock in the Company's application?

A. UGI Gas' filing requests a cost of long term debt of 5.07 percent and a cost of short-term debt of 2.58 percent. Each of these reflects the estimate September 30, 2017 cost rates for UGI Utilities. I also use these cost rates in my COC analyses.

Q. Can the ROE be determined with the same degree of precision as the cost of debt?

A. No. The cost rates of debt are largely determined by interest payments, issue prices, and related expenses. The ROE, on the other hand, cannot be precisely quantified, primarily because this cost is an opportunity cost. As mentioned previously, there are several models that can be employed to estimate the ROE. Three of the primary methods – DCF, CAPM, and CE – are developed in the following sections of my testimony.

VII. SELECTION OF PROXY GROUP

Q. How have you estimated the ROE for UGI Gas?

A. UGI Gas is a division of UGI Utilities and does not have its own distinct capital structure. UGI Utilities is not a publicly-traded company. Its parent company (UGI) is publicly-traded. Consequently, it is possible to directly apply ROE models to UGI. However, in COC analyses, it is customary to analyze groups of comparison, or "proxy," companies as a substitute for UGI Gas to determine its ROE.

I have accordingly selected such a group for comparison to UGI Gas. Schedule 6 shows certain operational risk characteristics of this group.

This is the same proxy group used by UGI Gas witness Paul R. Moul in his COC analyses.

VIII. DCF ANALYSIS

Q. What is the theory and methodological basis of the DCF model?

A. The DCF model is one of the oldest and most commonly-used models for estimating the ROE for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate (the "constant growth" or "Gordon DCF model"). In this framework, the ROE is derived from the following formula:

$$K = \frac{D}{P} + g$$

where: P = current price

D = current dividend rate

K = discount rate (cost of capital)

G = constant rate of expected growth

This formula essentially recognizes that the return expected or required by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. Please explain how you employ the DCF model.

A. I use the constant growth DCF model. In doing so, I combine the current dividend yield for each of the proxy utility stocks described in the previous section with several indicators of expected dividend growth.

Q. How did you derive the dividend yield component of the DCF equation?

A. Several methods can be used to calculate the dividend yield component. These methods generally differ in the manner in which the dividend rate is employed (i.e., current versus future dividends or annual versus quarterly compounding variant, which is expressed as follows:

$$Yield = \frac{D_0(1 + 0.5g)}{P_0}$$

This dividend yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average of the high and low stock price for each proxy company for the most recent three month period (January-March 2016). The D_0 is the current annualized dividend rate for each proxy company.

Q. How do you estimate the dividend growth component of the DCF equation?

A. The DCF model's dividend growth rate component is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the dividend growth component is to reflect the growth expected by investors that is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. This is evidenced by the fact that every investment decision resulting in the purchase of a particular stock is matched by another investment decision to sell that stock.

A wide array of indicators exists for estimating investors' growth expectations. As a result, it is evident that investors do not always use one single indicator of growth. It therefore is necessary to consider alternative dividend growth indicators in deriving the growth component of the DCF model. I have considered five indicators of growth in my DCF analyses. These are:

1. Years 2011-2015 (5-year average) earnings retention, or fundamental growth;
2. Five-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS);
3. Years 2016, 2017 and 2018-2020 projections of earnings retention growth (per Value Line);
4. Years 2012-2014 to 2018-2020 projections of EPS, DPS, and BVPS (per Value Line); and
5. Five-year projections of EPS growth (per First Call).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the groups of proxy companies. I also believe that these growth indicators reflect the types of information that investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which would be expected to have some impact on their decision-making process.

Q. Please describe your DCF calculations.

A. Schedule 7 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 show the growth rates for the groups of proxy companies. Page 4 shows the DCF calculations, which are presented on several bases: mean, median, low and high values. These results can be summarized as follows:

	Mean	Median	Mean Low[10]	Mean High[11]	Median Low[9]	Median High[10]
Proxy Group	8.0%	8.0%	7.6%	8.3%	7.4%	8.3%

I note that the individual DCF calculations shown on Schedule 7 should not be interpreted to reflect the expected COC for individual companies in the proxy groups; rather, the individual values shown should be interpreted as alternative information considered by investors.

[10] Using the lowest growth rate.
[11] Using only the highest growth rate.

Q. What do you conclude from your DCF analyses?

A. The DCF rates resulting from the analysis of the proxy groups fall into a wide range between 7.4 percent and 8.3 percent. The highest DCF rates are 8.3 percent.

I believe a range of 8.0 percent to 8.3 percent represents the current DCF-derived ROE for the proxy groups. This range includes most of the highest DCF rates and generally exceeds the low and mean/median DCF rates. I recommend a DCF ROE of 8.3 percent for UGI Gas, which focuses on the highest DCF rates and exceeds the low and mean/median DCF rates.

IX. CAPM ANALYSIS

Q. Please describe the theory and methodological basis of the CAPM.

A. CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory (MPT), which studies the relationships among risk, diversification, and expected returns. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return.

Q. How is the CAPM derived?

A. The general form of the CAPM is:

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

where:
- K = cost of equity
- R_f = risk free rate
- R_m = return on market
- β = beta
- R_m-R_f = market risk premium

The CAPM is a variant of the RP method. I believe the CAPM is generally superior to the simple RP method because the CAPM specifically recognizes the risk of a particular company or industry (i.e., beta), whereas the simple RP method assumes the same ROE for all companies exhibiting similar bond ratings or other characteristics.

Q. What do you use for the risk-free rate?

A. The first input of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any risk.

In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. Two general types of U.S. Treasury securities are often utilized as the R_f component, short-term U.S. Treasury bills and long-term U.S. Treasury bonds.

I have performed CAPM calculations using the three-month average yield (December 2015-February 2016) for 20-year U.S. Treasury bonds. I use the yields on long-term Treasury bonds since this matches the long-term perspective of ROE analyses. Over this three month period, these bonds had an average yield of 2.32 percent.

Q. What is beta and what betas do you employ in your CAPM?

A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to the overall market. Betas less than 1 are considered less risky than the market, whereas betas greater than 1 are more risky. Utility stocks traditionally have had betas below 1. I utilize the most recent Value Line betas for each company in my proxy group.

Q. How do you estimate the market risk premium component?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or long-term government bonds. For the purpose of estimating the market risk premium, I considered alternative measures of returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds (i.e., the same timeframe as employed in Morningstar sources used to develop risk premiums).

First, I compared the actual annual returns on equity of the S&P 500 with the actual annual yields of U.S. Treasury bonds. Schedule 8 shows the ROE for the S&P 500 group for the period 1978-2014 (all available years reported by S&P). This schedule also indicates the annual yields on 20-year U.S. Treasury bonds and the annual differentials (i.e., risk premiums) between the S&P 500 and U.S. Treasury 20-year bonds. Based upon these returns, I conclude that the risk premium from this analysis is 6.85 percent.

I next considered the total returns (i.e., dividends/interest plus capital gains/losses) for the S&P 500 group as well as for long-term government bonds, as tabulated by Morningstar (formerly Ibbotson Associates), using both arithmetic and geometric means. I considered the total returns for the entire 1926-2014 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	12.1%	6.1%	6.0%
Geometric	10.1%	5.7%	4.4%

I conclude from this analysis that the expected risk premium is about 5.75 percent (i.e., the average of all three risk premiums: 6.85 percent from Schedule 8; 6.0 percent arithmetic and 4.4 percent geometric from Morningstar). I believe that a combination of arithmetic and geometric means is appropriate since investors have access to both types of means[12] and presumably, both types are reflected in investment decisions and thus, stock prices and the ROE.

Q. What are your CAPM results?

A. Schedule 9 shows my CAPM calculations. The results are:

	Mean	Median
Proxy Group	6.7%	6.9%

Q. What is your conclusion concerning the CAPM ROE?

A. The CAPM results collectively indicate a ROE of 6.7 percent to 6.9 percent (6.8 percent mid-point) for the group of proxy utilities. I conclude that an appropriate CAPM ROE estimation for UGI Gas is 6.9 percent.

X. CE ANALYSIS

Q. Please describe the basis of the CE methodology.

A. The CE method is derived from the "corresponding risk" concept discussed in the *Bluefield* and *Hope* cases. This method is thus based upon the economic concept of opportunity cost. As previously noted, the ROE is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, it provides a direct measure of

[12] For example, Value Line uses compound (i.e., geometric) growth rates in its projection. In addition, mutual funds report growth rates on a compound basis.

the fair return, since it translates into practice the competitive principle upon which regulation rests.

The CE method normally examines the experienced and/or projected return on book common equity. The logic for examining returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's book common equity to determine the COC. This COC is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base – rate of return methodology used to set utility rates.

Q. How do you apply the CE methodology in your analysis of UGI Gas' ROE?

A. I apply the CE methodology by examining realized ROE for the group of proxy companies, as well as unregulated companies, and evaluating investor acceptance of these returns by reference to the resulting market-to-book ratios ("M/B"). In this manner it is possible to assess the degree to which a given level of return equates to the COC. It is generally recognized for utilities that an M/B of greater than one (i.e., 100 percent) reflect a situation where a company is able to attract new equity capital without dilution (i.e., above book value). As a result, one objective of a fair ROE is the maintenance of stock prices at or above book value. There is no regulatory obligation to set rates designed to maintain an M/B significantly above one.

I further note that my CE analysis is based upon market data (through the use of M/Bs) and is thus essentially a market test. As a result, my CE analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns do not represent the COC. In addition, my CE analysis also uses prospective returns and thus is not backward looking.

Q. What time periods do you examine in your CE analysis?

A. My CE analysis considers the experienced ROEs of the proxy group of utilities for the period 2002-2015 (i.e., the last fourteen years). The CE analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence from unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current ROE, I focused on two periods: 2009-2015 (the current business cycle) and 2002-2008 (the most recent business cycle). I have also considered projected ROEs for 2016 and 2018-2020.

Q. Please describe your CE analysis.

A. Schedule 10 and Schedule 11 contain summaries of experienced ROEs and M/Bs for two groups of companies, while Schedule 12 presents a risk comparison of utilities versus unregulated firms.

Schedule 10 shows the ROEs and M/Bs for the group of proxy utilities. These can be summarized as follows:

	Proxy Group
Historic ROE	
Mean	11.0-11.4%
Median	10.6-11.2%
Historic M/B	
Mean	179-181%
Median	170-173%
Prospective ROE	
Mean	9.4-11.2%
Median	10.5-10.8%

These results indicate that historic ROEs of 10.6 percent to 11.4 percent have been adequate to produce M/Bs of 170 percent to 181 percent for the group of utilities. Furthermore, projected ROEs for 2016, 2017 and 2018-2020 are within a range of 9.4 percent to 11.2 percent for the utility group. These relate to 2015 M/B of 186 percent or greater.

Q. Do you also review the earnings of unregulated firms?

A. Yes. As an alternative, I also examine the S&P's 500 Composite group. This is a well recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 11 presents the earned ROEs and M/Bs for the S&P 500 group over the past thirteen years (i.e., 2002-2014). As this schedule indicates, over the two business cycle periods, this group's average ROEs ranged from 12.4 percent to 13.6 percent, with average M/Bs ranging between 220 percent and 275 percent.

Q. How can the above information be used to estimate UGI Gas' ROE?

A. The recent ROE of the proxy utilities and S&P 500 groups can be viewed as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the ROE for the proxy utilities, however, it is necessary to compare the risk levels of the natural gas utilities and the competitive companies. I do this in Schedule 12, which compares several risk indicators for the S&P 500 group and the natural gas utility group. The information in this exhibit indicates that the S&P 500 group is more risky than the natural gas utility proxy group.

Q. **What ROE is indicated by your CE analysis?**

A. Based on recent and prospective ROEs and M/Bs, my CE analysis indicates that the ROE for the proxy utilities is no more than 9.0 percent to 10.0 percent (9.5 percent mid-point). Recent ROEs of 10.6 percent to 11.4 percent have resulted in M/Bs more than 170 percent. Prospective ROEs of 9.4 percent to 11.2 percent have been accompanied by M/Bs over 180 percent. As a result, it is apparent that authorized returns below this level would continue to result in M/Bs of well above 100 percent. As I indicated earlier, the fact that M/Bs substantially exceeds 100 percent indicates that historic and prospective ROEs of 9.5 percent reflect earning levels that are well above the actual ROE for those regulated companies. I also note that a company whose stock sells above book value can attract capital in a way that enhances the book value of existing stockholders, thus creating a favorable environment for financial integrity. My specific CE recommendation is the upper end of this range, or 10.0 percent.

XI. RETURN ON EQUITY RECOMMENDATION

Q. Please summarize the results of your three ROE analyses.

A. My three ROE analyses produced the following:

	Recommendation
DCF	8.3%
CAPM	6.9%
CE	10.0%

These results indicate an overall broad range of 6.998 percent to 10.0 percent, which focuses on the DCF results and the CE results. I recommend a ROE range of 8.3 percent to 10.0 percent for UGI Gas. This range includes my DCF result (8.3 percent), and my CE result (10.0 percent). Specifically, I recommend an ROE of 9.15% for UGI Gas.

Q. It appears that your CAPM results are less than your DCF and CE results. Do you directly consider the CAPM results in determining the ROE for UGI Gas?

A. Not at this time. I have conducted CAPM studies in my ROE analyses for many years. It is apparent that the CAPM results are currently significantly less than the DCF and CE results. There are two reasons for the lower CAPM results. First, risk premiums are lower currently than was the case in prior years. This is the result of lower equity returns that have been experienced beginning with the Great Recession and continuing over the past several years. This is also reflective of a decline in investor expectations of equity returns and risk premiums. Second, the level of interest rates on U.S. Treasury bonds (i.e., the risk free rate) has been lower in recent years. This is partially the result of the actions of the Federal Reserve System to stimulate the economy. This also impacts investor expectations of returns in a negative fashion.

I note that, initially, investors may have believed that the decline in Treasury yields was a temporary factor that would soon be replaced by a rise in interest rates. However, this has not been the case as interest rates have remained low and continued to decline for the past five-plus years. As a result, it cannot be maintained that low interest rates (and low CAPM results) are temporary and do not reflect investor expectations. Consequently, the CAPM results should be considered as one factor in determining the ROE for UGI Gas. Even though I do not factor the CAPM results directly into my ROE recommendation, I do believe these lower results are indicative of the recent and continuing decline in utility COC, including ROE.

XII. TOTAL COST OF CAPITAL

Q. What is the total COC for UGI Gas?

A. Schedule 1 reflects the COC for UGI Gas using the Company's proposed capital structure and embedded costs of debt, as well as my ROE recommendations. The resulting total COC is a range of 6.70 percent to 7.63 percent. I recommend a COC of 7.17 percent for UGI Gas, which incorporates a ROE of 9.15 percent.

XIII. COMMENTS ON COMPANY TESTIMONY

Q. What COC has UGI Gas requested in its application?

A. The Company's filing requests a total COC of 8.17 percent, which incorporates a ROE of 11.0 percent. The 11.0 percent requested ROE is developed in the testimony of UGI Gas witness Paul R. Moul.

Q. Please summarize your understanding of Mr. Moul's ROE analyses and recommendations.

A. Mr. Moul's ROE analyses focus on four sets of studies, whose results are summarized below:

	Cost of Equity Findings
Discounted Cash Flow	10.40%
Risk Premium	11.50%
Capital Asset Pricing Model	11.37%
Comparable Earnings	11.65%

Mr. Moul recommends a cost of common equity for UGI Gas of 11.00 percent. His 11.00 percent recommendation also reflects the "outstanding performance" of UGI Gas.

Q. Do you wish to comment on portions of Mr. Moul's testimony?

A. Yes. I will comment on each of the four methods Mr. Moul utilizes to determine the cost of common equity for UGI Gas. I also comment on his proposal to reflect the "outstanding performance."

Q. Please summarize your understanding of Mr. Moul's DCF analysis.

A. Mr. Moul performs DCF analyses for a group of eight natural gas utilities. His results are as follows:

	Gas Group
Yield	3.34%
Growth	6.25%
Leverage	0.81%
DCF	10.40%

Q. Which components of Mr. Moul's DCF analyses do you disagree with?

A. I disagree with two of the components of Mr. Moul's DCF analyses. These are his proposed 6.25 percent growth rate and his 0.81 percent leverage adjustment.

Q. What comments do you have concerning Mr. Moul's growth rate recommendation?

A. Mr. Moul recommends a 6.25 percent growth rate for his gas group. It is evident that this conclusion substantially exceeds investor expectations and is not even supported by Mr. Moul's analyses. As is indicated on Mr. Moul's Schedule 8, most of the historic and projected growth rates of EPS, DPS, BVPS and cash flow per share (CFPS) are well below his recommendations. Of the eight historic growth rates he examined, only one is as high as 6.25 percent. In addition, of the 10 projected growth rates he considered (Schedule 9) only one is as high as 6.25 percent. Mr. Moul's recommendation for 6.25 percent growth rate can thus only be derived by relying on two of eighteen growth indicators he examined.

Q. Do you have any comments concerning Mr. Moul's proposed leverage adjustment?

A. Yes. Mr. Moul is proposing a "leverage adjustment," which is essentially an adjustment to the DCF cost rate to offset Mr. Moul's concern that the divergence of stock prices from book values creates a conflict when the results of a market-derived ROE are applied to the common equity ratio measured at book value. Mr. Moul further claims that the existence of utility stock prices above book value creates greater financial risk for a book value capital structure versus a market value capital structure since the book value capital structure has a lower common equity ratio than the market value capital structure. As a result, Mr. Moul claims that because the rate setting process utilizes the book value capitalization, when computing the weighted average COC, it is necessary to adjust the market-determined ROE for the higher financial risk related to the book value of the capitalization. Mr. Moul employs a formula to quantify the differential between the book value and market value capital structure and concludes a 0.81 percent upward adjustment to the DCF cost ROE is warranted.

I strongly disagree with Mr. Moul's proposed adjustment. Investors are well aware that gas utilities have their rates established based upon the book value of their assets (rate base) and capitalization. As a result, investors are not expecting a regulatory award on any other basis, nor should they be compensated for any difference between the book value and market value of their common equity.

Mr. Moul cites, on page 27, several proceedings where he maintains this Commission chose to "adjust the ROE upward to make the return consistent with the book value capital structure." It is noteworthy that all of these cases occurred prior to 2007. In addition, Mr. Moul has not cited any cases after 2007 in which the Commission approved a leverage adjustment.

Q. Are you aware of any commission decisions after 2007 where the concept of a leverage adjustment was rejected?

A. Yes. In Docket No. R-00072711, the Commission rejected the 65 basis point leverage adjustment Mr. Moul proposed for Aqua Pennsylvania. In addition, in Docket No. R-2012-2290597 (which involved PPL Electric), the Commission rejected the proposed leverage adjustments proposed by Mr. Moul. In its December 5, 2012 Order, the Commission noted "Based upon our analysis of the evidence of record, we are persuaded by the arguments of the OCA and I&E that PPL's requested leverage adjustment is not reasonable and should be denied."

Q. Please summarize Mr. Moul's risk premium analysis.

A. Mr. Moul performs his risk premium analysis by combining the prospective yield on long-term A-rated public utility bonds (5.00 percent) with a 6.50 percent risk premium to derive a 11.50 percent ROE.

I primarily disagree with the risk premium component of Mr. Moul's risk premium method. His proposed risk premium is excessive and his conclusion thus over-states the ROE for UGI Gas.

Q. Please comment on Mr. Moul's 6.50 percent risk premium.

A. Mr. Moul's risk premium conclusion of 6.50 percent was developed by computing total returns (dividends/interest income plus capital gains/losses) for various classes of securities over various periods of time dating back to 1926 and ending in 2014.

I note that, over the entire period for which Ibbotson/MorningStar data is available (1926-2014), the following risk premiums are evident:

	Geometric	Arithmetic
Large Company Stocks	10.1%	12.1%
L-T Corporate Bonds	6.1%	6.4%
L-T Government Bonds	5.7%	6.1%
Risk Premium		
Stocks vs Corp. Bonds	4.0%	5.7%
Stocks vs Gov't Bonds	4.4%	6.0%

All of these are well below the 6.5 percent risk premium Mr. Moul proposes. It is only by picking selected portions of the period, as Mr. Moul has done, that a higher risk premium can be developed.

Q. Please summarize Mr. Moul's CAPM method.

A. Mr. Moul's CAPM method has the following results:

$$R_f + \beta(R_m - R_f) + size = K$$

$$3.75\% + 0.90 \times 7.24\% + 1.10\% = 11.37\%$$

Q. Do you agree with Mr. Moul's 3.75 percent risk-free rate?

A. No, I do not. Current yields on long-term U.S. Treasury bonds are well below 3.75 percent, and in fact are below 2.5 percent.

Q. Do you have any comments concerning Mr. Moul's "leveraged" beta?

A. Yes, I do. Mr. Moul claims that "Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas are applied to a capital structure measured with market values." He, therefore, employs a formula to adjust Value Line published betas to reflect tax rates and market value capital structures. The impact of this adjustment is to raise the average beta value for his gas group from 0.78 to 0.90.

I disagree with this adjustment. In essence, this is a similar adjustment to his "leverage adjustment" in his DCF analysis. The same reasons I stated in my response to this DCF adjustment apply to his CAPM leverage adjustment.

Q. Please comment on Mr. Moul's risk premium.

A. Mr. Moul's 7.24 percent risk premium (R_m-R_f) was developed from two types of analyses. First, he estimates the total market forecast return for the 1,700 stocks followed by Value Line (12.03 percent) and the S&P 500 index (8.24 percent) in comparison to his forecast of Treasury bonds (3.75 percent), the difference in these two numbers is 6.39 percent. He also computes the 1926-2014 risk premium based upon the Ibbotson Associates total return (8.08 percent).

If the expected return of the 1,700 Value Line stocks and S&P 500 is indeed 10.14 percent or greater, then it is improper to maintain that a less risky company (as shown earlier in my testimony), such as UGI Gas should have the same ROE. Yet, this is what Mr. Moul assumes.

Mr. Moul's second risk premium estimate, 8.08 percent from Ibbotson associates for the period 1926-2014, has the same problems I described earlier in connection with Mr. Moul's risk premium analysis.

Q. Do you agree with the proposition that UGI Gas should be entitled to a size or credit risk adjustment?

A. No, I do not. UGI Gas' ratepayers should not be charged natural gas rates which reflect an incremental return to reflect the size of the Company. Such an increment is not justified and not appropriate.

Q. Is it proper to compare the size of UGI Gas to the natural gas proxy companies and make risk comparisons based upon the size differentials between them?

A. No, it is not proper. Most of the proxy natural gas utilities have multiple subsidiaries that operate in different jurisdictions. Following Mr. Moul's reasoning, each of the subsidiaries of the proxy natural gas utilities should be considered as more risky than the proxy group since, by definition, they would have to be smaller. This reasoning is flawed, since these individual natural gas company subsidiaries do not raise their equity capital directly from investors, but rather do so as a consolidated entity.

Q. Are there other reasons why a size adjustment is improper?

A. Yes. There are other compelling reasons why a small size adjustment is not proper for regulated utilities. Mr. Moul's proposed size adjustment is based upon his reference to the Morningstar/Ibbotson studies. However, the small size adjustment in the Morningstar/Ibbotson studies is based on the analysis of all stocks, the majority of which are unregulated and include industries that are much more risky than utilities. While it may or may not be true that on an overall market basis, smaller publicly-traded firms exhibit more risk than larger firms, these smaller companies stocks tend to be engaged in riskier businesses as a whole than do larger businesses. Such is not the case for regulated utilities.

Indeed, an academic study conducted by Professor Annie Wong found that:

> "utility and industrial stocks do not share the same characteristics. First, given firm size, utility stocks are consistently less risky than industrial stocks. Second, industrial betas tend to decrease with firm size but utility betas do not. These findings may be attributed to the fact that all public utilities operate in an environment with regional monopolistic power than regulated financial structure. As a result, the business and financial risks are very similar among the utilities regardless of their sizes. Therefore, utility betas would not necessarily be expected to be related to firm size.
>
> . . .
>
> This implies that although the price phenomenon has been strongly documented for the industrials, the findings suggest that there is no need to adjust for the firm size in utility rate regulation."[13]

Q. Can you provide any evidence that "size" or "business risk" adjustments are not generally recognized as risk factors in regulatory proceedings such as this one?

A. Yes, I can. The following table reflects the average size (as measured by net plant) and currently authorized returns on equity of various types of regulated utilities:

[13] Wong, Annie, "Utility Stocks And The Size Effect: An Empirical Analysis," Journal of the Midwest Finance Association, 1993, pp. 95-101.

Industry	Average Net Plant (000)	Average Authorized ROE[14]
Electric	$18,285	10.42%
Combination		
Electric-Gas	$17,856	10.30%
Natural Gas	$3,519	10.28%
Water	$2,604	9.65%

Source: AUS Utility Reports, January 2016.

As shown here the smallest utilities (i.e., water utilities) have the lowest authorized ROEs.

Q. Is there any evidence that small natural gas companies are not perceived as more risky than larger water utilities?

A. Yes, there is. Schedule 13 indicates that this is the case. As this schedule indicates, there are no apparent risk-indicator differentials as one looks at the natural gas proxy group members sorted according to size.

Q. Can you provide any direct comparisons of electric utilities that demonstrate that smaller utilities are not more risky than larger ones?

A. Yes. Implicit in Mr. Moul's proposal is an assumption that any perceived small size risk adjustment for unregulated companies (i.e., source of information cited in Morningstar/Ibbotson source Mr. Moul relies on for small size adjustment) applies to regulated public utilities. Schedule 14 demonstrates objectively that this is not the case. As this exhibit shows, there is no significant difference, and even more to the point that

14 Note that "Authorized" ROEs do not necessarily indicate "recently authorized" ROEs, since some ROEs were established in prior periods. Moreover, AUS reports each utility's most recent explicitly-authorized ROE even where that result is aged and has been superseded by a more recent "black box" rate settlement.

there is no discernible pattern of increase, among the risk indicators of publicly-traded electric utilities of different sizes. The table below summarizes the information contained in this schedule:

Cap Size	Safety	Beta	Financial Strength	S&P Rank	S&P Rating	Moody's Rating
Under $2 B	2.0	.81	B++	B+	A-/BBB+	A3/Baa1
$2 - $5 B	2.2	.79	B++	B+/A-	BBB+	A3/Baa1
$5-$10 B	1.9	.76	B++	B+	BBB+	A3/Baa1
$10-$20 B	1.8	.69	A	B+/A-	BBB+	A3/Baa1
$20 B Plus	2.1	.68	A	B+	BBB+	A3/Baa1

The safety rank, beta values, financial strength and S&P stock ranking are about the same for all sizes of electric utilities. These risk indicators do not reflect any risk differential as the size of the electric utilities decrease from large to small. To the contrary, this data indicates that regulated monopoly utility providers have approximately the same risk regardless of size. As a result, the logic Mr. Moul uses to justify his proposed small size adjustment is not justified.

Q. Please summarize Mr. Moul's CE method.

A. Mr. Moul's CE analysis examines the historic and forecasted returns for non-utility companies which he perceives as being of similar risk to his gas group. For these companies he calculated a 5-year historic average and median returns on equity plus average values excluding returns above 20 percent.

I believe this analysis is an improper mechanism for estimating the cost of common equity for UGI Gas. The equivalence of timeliness, safety, financial strength, price stability, beta, and technical rank does not indicate that the expected earnings and cost of common equity for these non-utilities and utilities are the same. The 5-year historic and projected 3-5 year returns for the non-utilities is 11.2 percent and 12.1 percent respectively (excluding the values above 20 percent) in Mr. Moul's Schedule 14, whereas the 5-year historic and expected returns for Mr. Moul's proxy group of gas utility companies is only 10.6 percent to 11.4 percent (historical) and 9.4 percent to 11.2 percent (projected) (my Schedule 10). This difference in returns demonstrates that utilities are able to maintain similar Value Line rankings to non-utilities while earning lower returns. This result indicates that the expected earnings for the non-utilities are greater than for utilities such as UGI Gas.

Q. **Do you agree with Mr. Moul's proposal to recognize the "outstanding performance" of UGI Gas' management?**

A. No, I do not. Mr. Moul's return on equity recommendation for UGI Gas reflects the "outstanding performance" of the Company. Mr. Moul's only explanation for this is his statement on pages 5-6: "Mr. Szykman's testimony . . . demonstrates that the Company ranks high in customer service and management effectiveness." Nowhere else in Mr. Moul's testimony is any explanation given for the justification of this adjustment. Mr. Moul's testimony is also silent on how his 11.00 percent return on equity "reflects" the outstanding management service.

Q. **Are you aware that Mr. Moul routinely claims that virtually all Pennsylvania utilities have exemplary or outstanding managerial performance?**

A. Yes, I am. In response to OCA Set II, Question 17, Mr. Moul indicates that in his COC testimonies in Pennsylvania "to some degree, most recent cases have included some recognition of managerial performance, either through specific basis points recognition, or through a recommended return on equity that is above the midpoint of the range of the cost of equity".

Q. Does this conclude your direct testimony?

A. Yes, it does.

219357

OCA Statement No. 2

BEFORE THE PENNSYLVANIA PUBLIC
UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	DOCKET NO. R-2015-2518438
UGI UTILITIES, INC. – GAS DIVISION	:	

ATTACHMENT ACCOMPANYING THE

DIRECT TESTIMONY OF

DAVID C. PARCELL

ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

APRIL 12, 2016

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

2007-Present	President, Technical Associates, Inc.
1995-2007	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies. Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.
Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.
Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due

to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association, Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

OCA Statement No. 2

BEFORE THE PENNSYLVANIA PUBLIC
UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	DOCKET NO. R-2015-2518438
UGI UTILITIES, INC. – GAS DIVISION	:	

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY OF

DAVID C. PARCELL

ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

APRIL 12, 2016

Exhibit DCP-1
Schedule 1

UGI UTILITIES, INC.
TOTAL COST OF CAPITAL

Item	Percent 1/	Cost	Weighted Cost
Long-Term Debt	40.30%	5.07% 1/	2.04%
Short-Term Debt	5.15%	2.58% 1/	0.13%
Common Equity	54.55%	8.30% 9.15% 10.00%	4.53% 4.99% 5.46%
Total	100.00%		6.70% 7.17% 7.63%

1/ Percents of UGI Utilities estimated test year capital and costs of debt, as contained in Company filing.

ECONOMIC INDICATORS

Year	Real GDP* Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index
		1975 - 1982 Cycle		
1975	-1.1%	-8.9%	8.5%	7.0%
1976	5.4%	10.8%	7.7%	4.8%
1977	5.5%	5.9%	7.0%	6.8%
1978	5.0%	5.7%	6.0%	9.0%
1979	2.8%	4.4%	5.8%	13.3%
1980	-0.2%	-1.9%	7.0%	12.4%
1981	1.8%	1.9%	7.5%	8.9%
1982	-2.1%	-4.4%	9.5%	3.8%
		1983 - 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%
1984	6.8%	9.3%	7.5%	3.9%
1985	3.7%	1.7%	7.2%	3.8%
1986	3.1%	0.9%	7.0%	1.1%
1987	2.9%	4.9%	6.2%	4.4%
1988	3.8%	4.5%	5.5%	4.4%
1989	3.5%	1.8%	5.3%	4.6%
1990	1.8%	-0.2%	5.6%	6.1%
1991	-0.5%	-2.0%	6.8%	3.1%
		1992 - 2001 Cycle		
1992	3.0%	3.1%	7.5%	2.9%
1993	2.7%	3.4%	6.9%	2.7%
1994	4.0%	5.5%	6.1%	2.7%
1995	3.7%	4.8%	5.6%	2.5%
1996	4.5%	4.3%	5.4%	3.3%
1997	4.5%	7.3%	4.9%	1.7%
1998	4.2%	5.8%	4.5%	1.6%
1999	3.7%	4.5%	4.2%	2.7%
2000	4.1%	4.0%	4.0%	3.4%
2001	1.1%	-3.4%	4.7%	1.6%
		2002 - 2009 Cycle		
2002	1.8%	0.2%	5.8%	2.4%
2003	2.8%	1.2%	6.0%	1.9%
2004	3.8%	2.3%	5.5%	3.3%
2005	3.3%	3.2%	5.1%	3.4%
2006	2.7%	2.2%	4.6%	2.5%
2007	1.8%	2.5%	4.6%	4.1%
2008	-0.3%	-3.4%	5.8%	0.1%
2009	-2.8%	-11.3%	9.3%	2.7%
		Current Cycle		
2010	2.5%	5.6%	9.6%	1.5%
2011	1.6%	3.0%	8.9%	3.0%
2012	2.2%	2.8%	8.1%	1.7%
2013	1.5%	1.9%	7.4%	1.5%
2014	2.4%	3.7%	6.2%	0.8%
2015	2.4%	1.3%	5.3%	0.7%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

Year	Real GDP* Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index
2002				
1st Qtr.	2.7%	-3.8%	5.6%	2.8%
2nd Qtr.	2 2%	-1.2%	5.9%	0.9%
3rd Qtr.	2 4%	0.8%	5.8%	2.4%
4th Qtr.	0.2%	1.4%	5.9%	1.6%
2003				
1st Qtr.	1.2%	1.1%	5.8%	4.8%
2nd Qtr.	3.5%	-0.9%	6.2%	0.0%
3rd Qtr.	7.5%	-0.9%	6.1%	3.2%
4th Qtr.	2.7%	1.5%	5.9%	-0.3%
2004				
1st Qtr.	3.0%	2.8%	5.6%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%
3rd Qtr.	3.6%	4.6%	5.4%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%
2005				
1st Qtr.	4.1%	3.8%	5.3%	4.4%
2nd Qtr.	1.7%	3 0%	5.1%	1.6%
3rd Qtr.	3.1%	2.7%	5.0%	8.8%
4th Qtr.	2.1%	2.9%	4.9%	-2 0%
2006				
1st Qtr.	5.4%	3.4%	4.7%	4.8%
2nd Qtr.	1.4%	4.5%	4.6%	4.8%
3rd Qtr.	0.1%	5.2%	4.7%	0.4%
4th Qtr.	3.0%	3.5%	4.5%	0.0%
2007				
1st Qtr.	0.9%	2.5%	4.5%	4.8%
2nd Qtr.	3.2%	1.6%	4.5%	5 2%
3rd Qtr.	2.3%	1.8%	4.6%	1.2%
4th Qtr.	2.9%	1.7%	4.8%	6.4%
2008				
1st Qtr.	-1.8%	1.9%	4.9%	2.8%
2nd Qtr.	1.3%	0.2%	5.3%	7.6%
3rd Qtr.	-3.7%	-3.0%	6.0%	2.8%
4th Qtr.	-8.9%	6.0%	6.9%	-13.2%
2009				
1st Qtr.	-5.3%	-11.6%	8.1%	2.4%
2nd Qtr.	-0.3%	-12.9%	9.3%	3.2%
3rd Qtr.	1.4%	-9.3%	9.6%	2.0%
4th Qtr	4.0%	-4.5%	10.0%	2.5%
2010				
1st Qtr.	1.6%	2.7%	9.7%	0.9%
2nd Qtr.	3.9%	6.5%	9.7%	-1.2%
3rd Qtr.	2.8%	6.9%	9.6%	2.8%
4th Qtr.	2.8%	6.2%	9.6%	2.8%
2011				
1st Qtr.	-1.5%	5.4%	9.0%	4.8%
2nd Qtr.	2.9%	3.6%	9.0%	3.2%
3rd Qtr.	0.8%	3.3%	9.1%	2.4%
4th Qtr.	4.6%	4.0%	8.7%	0.4%
2012				
1st Qtr.	2.3%	4.5%	8.3%	3.2%
2nd Qtr.	1.6%	4.7%	8.2%	0.0%
3rd Qtr.	2.5%	3.4%	8.1%	4.0%
4th Qtr.	0.1%	2.8%	7.8%	0 0%
2013				
1st Qtr.	1.9%	2 5%	7.7%	2.0%
2nd Qtr.	1.1%	2.0%	7.6%	1.2%
3rd Qtr.	3.0%	2.6%	7.3%	1.6%
4th Qtr.	3.9%	3.3%	7.0%	1.2%
2014				
1st Qtr.	-0.9%	3.2%	6.6%	1.6%
2nd Qtr.	4.6%	4.2%	6.2%	3.6%
3rd Qtr.	4.3%	4.7%	6.1%	0.0%
4th Qtr.	2.1%	4.5%	5.7%	-2.8%
2015				
1st Qtr.	0.6%	3.5%	5.6%	-1.2%
2nd Qtr.	3.9%	1 4%	5.4%	3.2%
3rd Qtr.	2.0%	1.1%	5.2%	-0.1%
4th Qtr.	1.0%	-0.8%	5.0%	0.0%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issue:

INTEREST RATES

Year	Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.44%	5.02%	7.47%	7.59%	7.78%	8.02%
			2002 - 2009 Cycle				
2002	4.67%	1.62%	4.61%	[1]	7.19%	7.37%	8.02%
2003	4.12%	1.01%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%
2008	5.09%	1.48%	3.66%		6.18%	6.53%	7.25%
2009	3.25%	0.16%	3.26%		5.75%	6.04%	7.06%
			Current Cycle				
2010	3.25%	0.14%	3.22%		5.24%	5.46%	5.96%
2011	3.25%	0.06%	2.78%		4.78%	5.04%	5.57%
2012	3.25%	0.09%	1.80%		3.83%	4.13%	4.86%
2013	3.25%	0.06%	2.35%		4.24%	4.47%	4.98%
2014	3.25%	0.03%	2.54%		4.19%	4.28%	4.80%
2015	3.26%	0.60%	2.14%		4.00%	4.12%	5.03%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

	Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
2010						
Jan	3.25%	0.06%	3.73%	5.55%	5.77%	6.16%
Feb	3.25%	0.10%	3.69%	5.69%	5.87%	6.25%
Mar	3.25%	0.15%	3.73%	5.64%	5.84%	6.22%
Apr	3.25%	0.15%	3.85%	5.62%	5.81%	6.19%
May	3.25%	0.16%	3.42%	5.29%	5.50%	5.97%
June	3.25%	0.12%	3.20%	5.22%	5.46%	6.18%
July	3.25%	0.16%	3.01%	4.99%	5.26%	5.98%
Aug	3.25%	0.15%	2.70%	4.75%	5.01%	5.55%
Sept	3.25%	0.15%	2.65%	4.74%	5.01%	5.53%
Oct	3.25%	0.13%	2.54%	4.89%	5.10%	5.62%
Nov	3.25%	0.13%	2.76%	5.12%	5.37%	5.85%
Dec	3.25%	0.15%	3.29%	5.32%	5.56%	6.04%
2011						
Jan	3.25%	0.15%	3.39%	5.29%	5.57%	6.06%
Feb	3.25%	0.14%	3.58%	5.42%	5.68%	6.10%
Mar	3.25%	0.11%	3.41%	5.33%	5.56%	5.97%
Apr	3.25%	0.06%	3.46%	5.32%	5.55%	5.98%
May	3.25%	0.04%	3.17%	5.08%	5.32%	5.74%
June	3.25%	0.04%	3.00%	5.04%	5.26%	5.67%
July	3.25%	0.03%	3.00%	5.05%	5.27%	5.70%
Aug	3.25%	0.05%	2.30%	4.44%	4.69%	5.22%
Sept	3.25%	0.02%	1.98%	4.24%	4.48%	5.11%
Oct	3.25%	0.02%	2.15%	4.21%	4.52%	5.24%
Nov	3.25%	0.01%	2.01%	3.92%	4.25%	4.93%
Dec	3.25%	0.02%	1.98%	4.00%	4.33%	5.07%
2012						
Jan	3.25%	0.02%	1.97%	4.03%	4.34%	5.06%
Feb	3.25%	0.08%	1.97%	4.02%	4.36%	5.02%
Mar	3.25%	0.09%	2.17%	4.16%	4.48%	5.13%
Apr	3.25%	0.08%	2.05%	4.10%	4.40%	5.11%
May	3.25%	0.09%	1.80%	3.92%	4.20%	4.97%
June	3.25%	0.09%	1.62%	3.79%	4.08%	4.91%
July	3.25%	0.10%	1.53%	3.58%	3.93%	4.85%
Aug	3.25%	0.11%	1.68%	3.65%	4.00%	4.88%
Sept	3.25%	0.10%	1.72%	3.69%	4.02%	4.81%
Oct	3.25%	0.10%	1.75%	3.68%	3.91%	4.54%
Nov	3.25%	0.11%	1.65%	3.60%	3.84%	4.42%
Dec	3.25%	0.08%	1.72%	3.75%	4.00%	4.56%
2013						
Jan	3.25%	0.07%	1.91%	3.90%	4.15%	4.66%
Feb	3.25%	0.10%	1.98%	3.95%	4.18%	4.74%
Mar	3.25%	0.09%	1.96%	3.90%	4.15%	4.66%
Apr	3.25%	0.06%	1.76%	3.74%	4.00%	4.49%
May	3.25%	0.05%	1.93%	3.91%	4.17%	4.65%
June	3.25%	0.05%	2.30%	4.27%	4.53%	5.08%
July	3.25%	0.04%	2.58%	4.44%	4.68%	5.21%
Aug	3.25%	0.04%	2.74%	4.53%	4.73%	5.28%
Sept	3.25%	0.02%	2.81%	4.58%	4.80%	5.31%
Oct	3.25%	0.06%	2.62%	4.48%	4.70%	5.17%
Nov	3.25%	0.07%	2.72%	4.56%	4.77%	5.24%
Dec	3.25%	0.07%	2.90%	4.59%	4.81%	5.25%
2014						
Jan	3.25%	0.05%	2.86%	4.44%	4.63%	5.09%
Feb	3.25%	0.06%	2.71%	4.38%	4.53%	5.01%
Mar	3.25%	0.05%	2.72%	4.40%	4.51%	5.00%
Apr	3.25%	0.04%	2.71%	4.30%	4.41%	4.85%
May	3.25%	0.03%	2.56%	4.16%	4.26%	4.69%
June	3.25%	0.03%	2.60%	4.23%	4.29%	4.73%
July	3.25%	0.03%	2.54%	4.16%	4.23%	4.66%
Aug	3.25%	0.03%	2.42%	4.07%	4.13%	4.65%
Sept	3.25%	0.02%	2.53%	4.18%	4.24%	4.79%
Oct	3.25%	0.02%	2.30%	3.96%	4.06%	4.67%
Nov	3.25%	0.02%	2.33%	4.03%	4.09%	4.75%
Dec	3.25%	0.04%	2.21%	3.90%	3.95%	4.70%
2015						
Jan	3.25%	0.03%	1.88%	3.52%	3.58%	4.39%
Feb	3.25%	0.03%	1.98%	3.62%	3.67%	4.44%
Mar	3.25%	0.03%	2.04%	3.67%	3.74%	4.51%
Apr	3.25%	0.02%	1.94%	3.63%	3.75%	4.51%
May	3.25%	0.02%	2.20%	4.05%	4.17%	4.91%
June	3.25%	0.04%	2.36%	4.29%	4.39%	5.13%
July	3.25%	0.03%	2.32%	4.27%	4.40%	5.22%
Aug	3.25%	0.09%	2.17%	4.13%	4.25%	5.23%
Sep	3.25%	0.06%	2.17%	4.25%	4.39%	5.42%
Oct	3.25%	0.01%	2.07%	4.13%	4.29%	5.47%
Nov	3.25%	0.13%	2.26%	4.22%	4.40%	5.57%
Dec	3.50%	0.26%	2.24%	4.18%	4.35%	5.55%
2016						
Jan	3.50%	0.25%	2.09%	4.09%	4.27%	5.49%
Feb	3.50%	0.32%	1.78%	3.94%	4.11%	5.28%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin, various issues.

STOCK PRICE INDICATORS

	S&P Composite [1]	NASDAQ Composite [1]	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988	[1]	[1]	2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	$599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	2,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		2002 - 2009 Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2007	1,477.19	2,578.47	13,169.98	1.86%	5.29%
2008	1,220.04	2,161.65	11,252.62	2.37%	3.54%
2009	948.05	1,845.38	8,876.15	2.40%	1.86%
		Current Cycle			
2010	1,139.97	2,349.89	10,662.80	1.98%	6.04%
2011	1,268.89	2,677.44	11,966.36	2.05%	6.77%
2012	1,379.35	2,965.56	12,967.08	2.24%	6.20%
2013	1,462.51	3,537.69	14,999.67	2.14%	5.57%
2014	1,930.67	4,374.31	16,773.99	2.04%	5.25%
2015	2,061.20	4,943.49	17,590.81	2.10%	4.59%

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAC Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

	S&P Composite	NASDAQ Composite	DJIA	S&P D/P	S&P E/P
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
2008					
1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	4.55%
2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.05%
3rd Qtr.	1,251.94	2,290.87	11,322.40	2.29%	3.94%
4th Qtr.	909.80	1,599.64	8,795.61	2.98%	1.65%
2009					
1st Qtr.	809.31	1,485.14	7,774.06	3.00%	0.86%
2nd Qtr.	892.23	1,731.41	8,327.83	2.45%	0.82%
3rd Qtr.	996.68	1,985.25	9,229.93	2.16%	1.19%
4th Qtr.	1,088.70	2,162.33	10,172.78	1.99%	4.57%
2010					
1st Qtr.	1,121.60	2,274.88	10,454.42	1.94%	5.21%
2nd Qtr.	1,135.25	2,343.40	10,570.54	1.97%	6.51%
3rd Qtr.	1,096.39	2,237.97	10,390.24	2.09%	6.30%
4th Qtr.	1,204.00	2,534.62	11,236.02	1.95%	6.15%
2011					
1st Qtr.	1,302.74	2,741.01	12,024.62	1.85%	6.13%
2nd Qtr.	1,319.04	2,766.64	12,370.73	1.97%	6.35%
3rd Qtr.	1,237.12	2,613.11	11,671.47	2.15%	7.69%
4th Qtr.	1,225.65	2,600.91	11,798.65	2.25%	6.91%
2012					
1st Qtr.	1,347.44	2,902.90	12,839.80	2.12%	6.29%
2nd Qtr.	1,350.39	2,928.62	12,765.58	2.30%	6.45%
3rd Qtr.	1,402.21	3,029.86	13,118.72	2.27%	6.00%
4th Qtr.	1,418.21	3,001.69	13,142.91	2.28%	6.07%
2013					
1st Qtr.	1,514.41	3,177.10	14,000.30	2.21%	5.59%
2nd Qtr.	1,609.77	3,369.49	14,961.28	2.15%	5.66%
3rd Qtr.	1,675.31	3,643.63	15,255.25	2.14%	5.61%
4th Qtr.	1,770.45	3,960.54	15,751.96	2.06%	5.42%
2014					
1st Qtr.	1,834.30	4,210.06	16,170.26	2.04%	5.38%
2nd Qtr.	1,900.37	4,195.81	16,603.50	2.06%	5.26%
3rd Qtr.	1,975.95	4,483.51	16,953.85	2.02%	5.37%
4th Qtr.	2,012.04	4,607.88	17,368.36	2.03%	4.97%
2015					
1st Qtr.	2,063.46	4,821.99	17,806.47	2.02%	4.80%
2nd Qtr.	2,094.37	5,029.47	18,007.48	2.05%	4.60%
3rd Qtr.	2,026.14	4,921.81	17,065.52	2.16%	4.72%
4th Qtr.	2,053.17	5,000.70	18,482.97	2.16%	

Source: Council of Economic Advisors, Economic Indicators, various issues.

Exhibit DCP-1
Schedule 3

UGI UTILITIES, INC.
HISTORY OF CREDIT RATINGS

	Senior Unsecured Debt		LT Issuer Default Rating	
Year	Fitch	Moody's	Fitch	Moody's
2011	A	A3	A-	
2012	A	A3	A-	
2013	A	A3	A-	
2014	A	A2	A-	A2
2015	A	A2	A-	A2
2016	A	A2	A-	A2

Source: Response to OOCA-II-6.

UGI UTILITIES, INC.
CAPITAL STRUCTURE RATIOS
2011 - 2015
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT 1/	SHORT-TERM DEBT
2011	$740.7	$640.0	$21.5
	52.8%	45.6%	1.5%
	53.6%	46.4%	
2012	$758.3	$600.0	$19.5
	55.0%	43.5%	1.4%
	55.8%	44.2%	
2013	$800.3	$642.0	$24.1
	54.6%	43.8%	1.6%
	55.5%	44.5%	
2014	$848.0	$642.0	$36.8
	55.5%	42.0%	2.4%
	56.9%	43.1%	
2015	$904.3	$622.0	$63.8
	56.9%	39.1%	4.0%
	59.2%	40.8%	

Source: Attachment II-A-1.

UGI CORPORATION
CAPITAL STRUCTURE RATIOS
2011 - 2015
($millions)

YEAR	COMMON EQUITY	MINORITY INTERESTS	LONG-TERM DEBT	SHORT-TERM DEBT
2011	$1,977.7	$213.4	$2,157.1	$138.7
	44.1%	8.5%	48.1%	3.1%
	45.5%	8.5%	49.6%	
2012	$2,233.1	$1,085.7	$3,514.3	$165.1
	31.9%	22.8%	50.2%	2.4%
	32.7%	22.8%	51.4%	
2013	$2,492.5	$1,055.4	$3,609.4	$227.9
	33.7%	21.6%	48.9%	3.1%
	34.8%	21.6%	50.4%	
2014	$2,659.1	$1,004.1	$3,510.8	$210.8
	36.0%	21.2%	47.5%	2.9%
	37.1%	21.2%	48.9%	
2015	$2,692.0	$880.4	$3,699.8	$189.9
	36.1%	18.5%	49.6%	2.5%
	37.0%	18.5%	50.9%	

Note: Percentages may not total 100.0% due to rounding.

Source: Attachment II-A-1.

Exhibit DCP-1
Schedule 5

PROXY COMPANIES
COMMON EQUITY RATIOS

	2011	2012	2013	2014	2015	2011-2015 Average	2016	2018-2020
UGI Corp	48.4%	40.0%	41.3%	43.6%	44.0%	43.5%	45.5%	51.5%
Proxy Group								
Atmos Energy	50.6%	54.7%	51.2%	55.7%	56.5%	53.7%	55.0%	55.0%
Chesapeake Utilities	68.6%	71.6%	70.3%	65.5%	70.5%	69.3%	71.0%	70.0%
Laclede Group	61.1%	63.9%	53.4%	44.9%	47.0%	54.1%	45.5%	48.5%
New Jersey Resources	64.5%	60.8%	63.4%	61.8%	56.8%	61.5%	56.5%	59.0%
Northwest Natural Gas	52.7%	51.5%	52.4%	55.2%	57.6%	53.9%	55.5%	56.5%
South Jersey Resources	59.5%	55.0%	54.9%	52.0%	51.5%	54.6%	51.0%	52.4%
Southwest Gas	56.8%	50.8%	50.6%	47.6%	50.7%	51.3%	50.5%	51.5%
WGL Holdings	66.2%	67.3%	69.8%	63.8%	56.1%	64.6%	56.0%	51.0%
Average	60.0%	59.5%	58.3%	55.8%	55.8%	**57.9%**	**55.1%**	**55.5%**
Median	60.3%	57.9%	54.2%	55.5%	56.3%	**54.3%**	**55.3%**	**53.7%**

Note: Percentages exclude short-term debt.

Source: Value Line Investment Survey.

Exhibit DCP-1
Schedule 6

PROXY COMPANIES
BASIS FOR SELECTION

Company	Market Capitalization ($000)	Percent Reg Natural Gas Revenues	Common Equity Ratio	Value Line Safety	S&P Stock Ranking	S&P Bond Rating	Moody's Bond Rating
UGI Corp	$6,200,000	14%	44%	2	B+	NR	A2
Proxy Group							
Atmos Energy	$7,200,000	71%	57%	1	A-	A-	A2
Chesapeake Utilities	$975,000	54%	71%	2	A	NR	NR
Laclede Group	$2,800,000	97%	47%	2	B+	A+	A3
New Jersey Resources	$2,900,000	31%	57%	1	B+	A+	Aa2
Northwest Natural Gas	$1,400,000	97%	58%	1	B+	AA-	A1
South Jersey Resources	$1,800,000	57%	52%	2	A-	A	A2
Southwest Gas	$2,800,000	61%	51%	3	A-	A-	A3
WGL Holdings	$3,400,000	49%	56%	1	B+	A+	A1

Sources: AUS Utility Reports, Value Line.

PROXY COMPANIES
DIVIDEND YIELD

COMPANY	Qtr DPS	January - March, 2016 DPS	HIGH	LOW	AVERAGE	YIELD
Proxy Group						
Atmos Energy	$0.420	$1.68	$74.60	$60.00	$67.30	2.5%
Chesapeake Utilities	$0.288	$1.15	$67.36	$52.25	$59.81	1.9%
Laclede Group	$0.490	$1.96	$68.79	$57.10	$62.95	3.1%
New Jersey Resources	$0.240	$0.96	$36.85	$32.32	$34.59	2.8%
Northwest Natural Gas	$0.468	$1.87	$54.51	$49.30	$51.91	3.6%
South Jersey Resources	$0.264	$1.06	$29.14	$22.06	$25.60	4.1%
Southwest Gas	$0.405	$1.62	$67.29	$53.51	$60.40	2.7%
WGL Holdings	$0.463	$1.85	$74.10	$59.99	$67.05	2.8%
Average						**2.9%**

Source: Yahoo! Finance.

PROXY COMPANIES
RETENTION GROWTH RATES

COMPANY	2011	2012	2013	2014	2015	Average	2016	2017	2018-'20	Average
Proxy Group										
Atmos Energy	3.3%	2.8%	4.0%	4.7%	4.9%	3.9%	5.0%	5.0%	5.0%	5.0%
Chesapeake Utilities	6.6%	6.4%	7.1%	7.4%	6.5%	6.8%	7.0%	7.5%	8.0%	7.5%
Laclede Group	4.9%	4.3%	1.0%	1.5%	3.7%	3.1%	4.0%	4.0%	4.5%	4.2%
New Jersey Resources	6.2%	6.2%	5.2%	11.0%	6.8%	7.1%	5.0%	6.0%	5.0%	5.3%
Northwest Natural Gas	2.4%	1.6%	1.5%	1.1%	0.4%	1.4%	1.0%	1.5%	3.0%	1.8%
South Jersey Resources	6.7%	5.8%	4.8%	4.3%	3.5%	5.0%	3.5%	3.5%	4.0%	3.7%
Southwest Gas	5.3%	6.1%	6.1%	5.0%	3.9%	5.3%	4.0%	4.5%	6.5%	5.0%
WGL Holdings	3.4%	4.8%	2.6%	4.3%	5.4%	4.1%	5.0%	4.5%	4.5%	4.7%
Average						**4.6%**				**4.6%**

Source: Value Line Investment Survey.

PROXY COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '12-'14 to '18-'20 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Proxy Group								
Atmos Energy	7.0%	2.5%	5.0%	4.8%	6.0%	6.5%	3.5%	5.3%
Chesapeake Utilities	10.5%	4.5%	8.5%	7.8%	8.5%	6.0%	7.0%	7.2%
Laclede Group	-1.0%	3.0%	8.0%	3.3%	9.0%	3.5%	4.5%	5.7%
New Jersey Resources	4.5%	7.5%	5.5%	5.8%	1.5%	3.0%	6.5%	3.7%
Northwest Natural Gas	-4.0%	3.5%	3.0%	0.8%	5.0%	1.5%	3.5%	3.3%
South Jersey Resources	6.5%	10.0%	8.0%	8.2%	5.5%	6.5%	5.5%	5.8%
Southwest Gas	11.0%	8.0%	5.0%	8.0%	7.0%	7.5%	3.0%	5.8%
WGL Holdings	1.5%	3.0%	3.0%	2.5%	5.0%	2.5%	4.5%	4.0%
Average				**5.2%**				**5.1%**

Source: Value Line Investment Survey.

PROXY COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Proxy Group								
Atmos Energy	2.6%	3.9%	5.0%	4.8%	5.3%	6.4%	5.1%	7.7%
Chesapeake Utilities	2.0%	6.8%	7.5%	7.8%	7.2%	3.0%	6.5%	8.4%
Laclede Group	3.2%	3.1%	4.2%	3.3%	5.7%	4.7%	4.2%	7.4%
New Jersey Resources	2.9%	7.1%	5.3%	5.8%	3.7%	6.5%	5.7%	8.5%
Northwest Natural Gas	3.6%	1.4%	1.8%	0.8%	3.3%	4.0%	2.3%	5.9%
South Jersey Resources	4.2%	5.0%	3.7%	8.2%	5.8%	6.0%	5.7%	10.0%
Southwest Gas	2.8%	5.3%	5.0%	8.0%	5.8%	4.0%	5.6%	8.4%
WGL Holdings	2.8%	4.1%	4.7%	2.5%	4.0%	8.0%	4.7%	7.5%
Mean	3.0%	4.6%	4.6%	5.2%	5.1%	5.3%	5.0%	**8.0%**
Median	2.8%	4.6%	4.8%	5.3%	5.5%	5.4%	5.4%	**8.0%**
Composite - Mean		**7.6%**	7.7%	8.2%	8.1%	**8.3%**	8.0%	
Composite - Median		**7.4%**	7.7%	8.2%	**8.3%**	8.2%	8.2%	

Note: negative values not used in calculations.

Sources: Prior pages of this schedule.

Exhibit DCP-1
Schedule 8

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND YIELD	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$18.86	$149.74	12.22%	7.29%	4.93%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$216.51	16.58%	7.60%	8.98%
1996	$38.73	$237.08	17.08%	6.18%	10.90%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.70	$338.37	7.44%	5.53%	1.91%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
2006	$81.51	$504.39	17.03%	4.68%	12.35%
2007	$66.17	$529.59	12.80%	4.86%	7.94%
2008	$14.88	$451.37	3.03%	4.45%	-1.42%
2009	$50.97	$513.58	10.56%	3.47%	7.09%
2010	$77.35	$579.14	14.16%	4.25%	9.91%
2011	$86.95	$613.14	14.59%	3.81%	10.78%
2012	$86.51	$666.97	13.52%	2.40%	11.12%
2013	$100.20	$715.84	14.49%	2.86%	11.63%
2014	$102.31	$726.96	14.18%	3.33%	10.85%
Average					**6.85%**

Source: Standard & Poor's Analysts' Handbook, Ibbotson Associates Handbook.

Exhibit DCP-1
Schedule 9

PROXY COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Proxy Group				
Atmos Energy	2.35%	0.80	5.75%	6.9%
Chesapeake Utilities	2.35%	0.65	5.75%	6.1%
Laclede Group	2.35%	0.70	5.75%	6.4%
New Jersey Resources	2.35%	0.80	5.75%	6.9%
Northwest Natural Gas	2.35%	0.65	5.75%	6.1%
South Jersey Resources	2.35%	0.85	5.75%	7.2%
Southwest Gas	2.35%	0.80	5.75%	6.9%
WGL Holdings	2.35%	0.80	5.75%	6.9%
Mean				**6.7%**
Median				**6.9%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

20-year Treasury Bonds

Month	Rate
Jan. 2016	2.49%
Feb. 2016	2.20%
Mar. 2016	
Average	2.35%

PROXY COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2002-2008 Average	2009-2015 Average	2016	2017	2018-20
Proxy Group																			
Atmos Energy	10.3%	11.2%	9.1%	9.1%	10.0%	9.2%	9.0%	8.5%	9.1%	9.2%	8.2%	9.2%	10.0%	9.9%	9.7%	9.2%	10.5%	10.5%	11.0%
Chesapeake Utilities	8.5%	14.1%	12.3%	12.6%	11.1%	11.3%	11.7%	10.6%	11.8%	11.7%	11.5%	12.2%	12.4%	12.3%	11.7%	11.8%	12.0%	12.5%	13.0%
Laclede Group	7.8%	11.8%	11.2%	11.1%	13.1%	12.0%	12.6%	12.9%	10.3%	11.5%	10.7%	6.9%	7.0%	8.9%	11.4%	9.7%	9.0%	9.0%	9.5%
New Jersey Resources	16.0%	16.7%	15.8%	16.1%	14.5%	10.2%	16.5%	14 2%	14.4%	14.2%	14.2%	13.4%	18.8%	14.5%	15.1%	14.8%	12.0%	12.5%	11.5%
Northwest Natural Gas	8.7%	9.2%	9.3%	10.1%	10.9%	12.4%	11.1%	11.6%	10.7%	9.1%	8.2%	8.1%	7.7%	6.9%	10.2%	8.9%	7.5%	7.5%	9.0%
South Jersey Resources	13.9%	13.0%	13.4%	13.3%	17.2%	13.4%	13.6%	13.4%	14.5%	14.6%	13.8%	12.5%	11.9%	10.6%	14.0%	13.0%	10.5%	11.0%	11.5%
Southwest Gas	6.6%	6.2%	8.8%	6.5%	9.7%	8.8%	6.0%	8.1%	9.1%	9.3%	10.4%	10.6%	9.6%	8.9%	7.5%	9.4%	9.0%	1.0%	13.0%
WGL Holdings	7.1%	14.4%	11.9%	12.1%	10.8%	11.0%	12.0%	11.8%	10.2%	9.7%	11.1%	9.4%	11.0%	12.9%	11.3%	10.9%	12.0%	11.5%	11.0%
Average	9.9%	12.1%	11.5%	11.4%	12.2%	11.0%	11.6%	11.4%	11.3%	11.2%	11.0%	10.3%	11.1%	10.6%	**11.4%**	**11.0%**	**10.3%**	**9.4%**	**11.2%**
Median	8.6%	12.4%	11.6%	11.6%	11.0%	11.2%	11.9%	11.7%	10.5%	10.6%	10.9%	10.0%	10.5%	10.3%	**11.2%**	**10.6%**	**10.5%**	**10.8%**	**11.3%**

Source: Calculations made from data contained in Value Line Investment Survey.

PROXY COMPANIES
MARKET TO BOOK RATIOS

COMPANY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2002-2008 Average	2009-2015 Average
Proxy Group																
Atmos Energy	150%	152%	147%	145%	146%	136%	110%	109%	121%	130%	132%	151%	173%	186%	141%	143%
Chesapeake Utilities	236%	271%	272%	212%	205%	190%	159%	141%	152%	165%	171%	192%	226%	242%	221%	184%
Laclede Group	145%	169%	179%	179%	184%	168%	209%	171%	145%	153%	154%	147%	148%	155%	176%	153%
New Jersey Resources	221%	245%	252%	275%	246%	223%	201%	214%	226%	248%	232%	212%	244%	249%	238%	232%
Northwest Natural Gas	145%	144%	153%	172%	177%	208%	201%	173%	181%	168%	170%	157%	166%	167%	171%	169%
South Jersey Resources	185%	170%	195%	222%	209%	231%	196%	205%	245%	254%	236%	232%	215%	185%	201%	225%
Southwest Gas	123%	118%	127%	135%	161%	149%	117%	97%	127%	144%	155%	167%	178%	174%	133%	149%
WGL Holdings	152%	162%	175%	183%	168%	172%	146%	149%	159%	172%	168%	172%	189%	238%	165%	178%
Average	170%	179%	188%	190%	187%	185%	167%	157%	170%	179%	177%	179%	192%	200%	**181%**	**179%**
Median	151%	166%	177%	181%	181%	181%	178%	160%	156%	167%	169%	170%	184%	186%	**173%**	**170%**
#REF!																
#REF!			147%	145%	146%	136%	110%	109%	121%	130%	132%	151%	173%	186%	137%	143%
#REF!	236%	271%	272%	212%	205%	190%	159%	141%	152%	165%	171%	192%	226%	242%	221%	184%
#REF!	145%	169%	179%	179%	184%	168%	209%	171%	145%	153%	154%	147%	148%	155%	176%	153%
#REF!	138%	124%	155%	165%	161%	190%	145%	112%	118%	128%	134%	145%	162%	167%	154%	138%
#REF!	221%	245%	252%	275%	246%	223%	201%	214%	226%	248%	232%	212%	244%	249%	238%	232%
#REF!	137%	80%	90%	125%	142%	177%	127%	117%	148%	170%	192%	218%	239%	254%	125%	191%
#REF!	158%	180%	196%	242%	229%	256%	238%	186%	207%	235%	272%	313%	362%	352%	214%	275%
#REF!	145%	142%	132%	140%	134%	143%	101%	91%	116%	121%	137%	153%	170%	172%	134%	137%
#REF!	132%	133%	144%	148%	149%	150%	122%	100%	127%	128%	124%	131%	150%	144%	140%	129%
#REF!	163%	198%	218%	189%	181%	173%	113%	73%	87%	89%	97%	102%	116%	116%	176%	97%
#REF!	185%	170%	195%	222%	209%	231%	196%	205%	245%	254%	236%	232%	215%	185%	201%	225%
#REF!					160%	147%	109%	105%	122%	138%	146%	159%	174%	167%		144%
#REF!	245%	209%	185%	183%	178%	200%	167%	108%	120%	123%	152%	196%	196%	185%	195%	154%
#REF!	123%	118%	127%	135%	161%	149%	117%	97%	127%	144%	155%	167%	178%	174%	133%	149%
#REF!	95%	93%	124%	147%	134%	125%	72%	50%	68%	86%	100%	109%	130%	127%	113%	96%
#REF!					153%	140%	101%	83%	97%	109%	117%	131%	145%	149%		119%
#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
#REF!	152%	162%	175%	183%	168%	172%	146%	149%	159%	172%	168%	172%	189%	238%	165%	178%
#REF!	113%	113%	132%	139%	150%	154%	127%	121%	135%	143%	156%	157%	165%	171%	133%	150%
#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	**#REF!**	**#REF!**
#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	**#REF!**	**#REF!**

Source: Calculations made from data contained in Value Line Investment Survey.

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 2002 - 2014

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
2002	8.4%	295%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
2006	17.0%	277%
2007	12.8%	284%
2008	3.0%	224%
2009	10.6%	187%
2010	14.2%	208%
2011	14.6%	207%
2012	13.5%	214%
2013	14.5%	237%
2014	14.2%	268%
Averages:		
2002-2008	12.4%	275%
2009-2014	13.6%	220%

Source: Standard & Poor's Analyst's Handbook, 2015 edition.

RISK INDICATORS

COMPANY	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FINANCIAL STRENGTH		S& P STOCK RANKING	
Proxy Group						
Atmos Energy	1	0.80	A	4.00	A-	3.67
Chesapeake Utilities	2	0.65	B++	3.67	A	4.00
Laclede Group	2	0.70	B++	3.67	B+	3.33
New Jersey Resources	1	0.80	A+	4.33	B+	3.33
Northwest Natural Gas	1	0.65	A	4.00	B+	3.33
South Jersey Resources	2	0.85	A	4.00	A-	3.67
Southwest Gas	3	0.80	B++	3.67	A-	3.67
WGL Holdings	1	0.80	A	4.00	B+	3.33
	1.6	0.76	A	3.92	B+/A-	3.54

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B
Proxy Group	1.6	0.76	A	B+/A-

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the later representing the highest level.

Exhibit DCP-1
Schedule 13

PROXY COMPANIES
COMPARISON OF SIZE AND RISK INDICATORS

Company	Market Capitalization ($000)	Value Line Safety	S&P Stock Ranking	S&P Bond Rating	Moody's Bond Rating
Proxy Group					
Chesapeake Utilities	$975,000	2	A	NR	NR
Northwest Natural Gas	$1,400,000	1	B+	AA-	A1
South Jersey Resources	$1,800,000	2	A-	A	A2
Laclede Group	$2,800,000	2	B+	A+	A3
Southwest Gas	$2,800,000	3	A-	A-	A3
New Jersey Resources	$2,900,000	1	B+	A+	Aa2
WGL Holdings	$3,400,000	1	B+	A+	A1
Atmos Energy	$7,200,000	1	A-	A-	A2

Sources: AUS Utility Reports, Value Line.

COMPARISON OF SIZE AND RISK INDICATORS FOR PUBLICLY-TRADED ELECTRIC UTILITIES

COMPANY	CAP ($000) Value Line	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S&P STOCK RANKING S&P	S&P BOND RATING AUS	MOODY'S BOND RATING AUS
Empire District Electric Company	975,000	2	0.70	B++	B+	A-	Baa1
Otter Tail Corp	975,000	3	0.90	B+	B	BBB-	Baa2
MGE Energy Inc.	1,300,000	1	0.75	A	A-	AA-	Aa2
El Paso Electric Co.	1,400,000	2	0.75	B++	B	BBB+	Baa1
Black Hills Corp.	1,800,000	2	0.95	B++	B	BBB	A3/Baa1
Average		2.0	0.81	B++	B+	A-/BBB+	A3/Baa1
Avista Corp.	2,000,000	2	0.80	A	A-	A-	Baa1
PNM Resources	2,000,000	3	0.85	B	B	BBB	Baa2
ALLETE	2,400,000	2	0.80	A	A-	A-	A3
NorthWestern	2,400,000	3	0.75	B+	A+	NR	A3
Portland General	2,700,000	2	0.80	B++	NR	A-	A3
UIL Holdings	2,700,000	2	0.75	B++	B+	BBB	Baa1/Baa2
IDACORP	2,900,000	2	0.80	B++	A	A-	A3
Hawaiian Electric Industries, Inc.	3,200,000	2	0.80	A	B+	BBB-	Baa2
Cleco Corp.	3,300,000	1	0.75	A	B	BBB/BBB-	Baa1/Baa2
Vectren	3,300,000	2	0.80	A	B+	A/A-	A2
Great Plains Energy Inc.	3,800,000	3	0.85	B+	B	BBB	Baa2
Westar Energy, Inc.	4,500,000	2	0.75	B++	A-	A-	A3/Baa1
Average		2.2	0.79	B++	B+/A-	BBB+	Baa1
ITC Holdings Corp.	5,100,000	2	0.70	B++	A+		
TECO Energy, Inc.	5,200,000	2	0.80	B++	B	BBB+/BBB	A3
Integrys Energy Group	5,500,000	2	0.80	A	B	A-	A3
OGE Energy Corp.	5,800,000	1	0.90	A+	A-	BBB+	A3
Alliant Energy	6,500,000	2	0.80	A	B+	A-	A2/A3
Pinnacle West Capital Corp.	6,600,000	1	0.70	A+	B+	BBB	A3/Baa1
Pepco Holdings, Inc.	6,800,000	3	0.65	B+	B	A-/BBB+	Baa2
SCANA Corp.	8,000,000	2	0.75	B++	A	BBB+	Baa1/Baa2
CenterPoint Energy, Inc.	8,300,000	2	0.80	B++	B	A-/BBB+	A3/Baa1
CMS Energy Corp.	8,800,000	2	0.75	B++	B	BBB+/BBB	A3/Baa1
Ameren Corp.	9,200,000	2	0.75	A	B	BBB+/BBB	Baa1
Average		1.9	0.76	B++	B+	BBB+	A3/Baa1
Wisconsin Energy Corp.	10,000,000	1	0.70	A+	A	A-/BBB+	A1/A2
DTE Energy Company	13,000,000	2	0.75	B++	A-	A-/BBB+	A2/A3
Entergy Corp.	13,000,000	3	0.70	B++	A-	BBB+/BBB	Baa2/Baa3
FirstEnergy Corp.	14,000,000	3	0.65	B+	B	BBB	Baa2
Eversource Energy	16,000,000	1	0.75	A	A-	A-	A3/Baa1
Xcel Energy Inc.	17,000,000	1	0.65	A	A-	A-	A3
Consolidated Edison, Inc.	19,000,000	1	0.60	A+	B+	A-/BBB+	A3
Edison International	19,000,000	2	0.75	A	B	BBB+	A2/A3
Average		1.8	0.69	A	B+/A-	BBB+	A3/Baa1
Public Service Enterprise Group, Inc.	21,000,000	1	0.75	A++	B+	A-/BBB+	A2
PPL Corp	22,000,000	2	0.65	B++	B+	A-	Baa1/Baa2
PG&E Corp.	24,000,000	3	0.65	B+	B	BBB/BBB-	A3/Baa1
Sempra Energy	25,000,000	2	0.80	A	B+	A/A-	A2/A3
American Electric Power Company	26,000,000	2	0.70	A	A-	BBB/BBB-	Baa1
Exelon Corp.	28,000,000	3	0.65	B++	B	BBB+/BBB	Baa1
Southern Company	42,000,000	2	0.55	A	A-	A	A3/Baa1
Dominion Resources	43,000,000	2	0.70	B++	B	A-	A3/Baa1
NextEra Energy, Inc.	47,000,000	2	0.70	A	A	A -/BBB+	A2/A3
Duke Energy Corp.	52,000,000	2	0.60	A	B	BBB+	A3
Average		2.1	0.68	A	B+	BBB+	A3/Baa1

Sources:

Value Line Investment Survey
East -- August 21, 2015
Central -- June 19, 2015
West -- July 1, 2015

AUS Utility Reports, May, 2015

S&P Stock Guide, May, 2015

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2015-2518438
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, David C. Parcell, hereby state that the facts above set forth in my Direct Testimony, OCA St. No. 2, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: David C. Parcell
David C. Parcell

Consultant Address: Technical Associates, Inc.
1503 Santa Rosa Road, Suite 130
Richmond, Virginia 23229

DATED: April 12, 2016

OCA St. No. 2-SR
6/3/16 [illegible]

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2015-2518438**
	:	
UGI Utilities, Inc. – Gas Division	:	

SURREBUTTAL TESTIMONY OF

DAVID C. PARCELL

ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

MAY 25, 2016

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 130, 1503 Santa Rosa Road, Richmond, VA 23229.

Q. ARE YOU THE SAME DAVID C. PARCELL WHO FILED DIRECT TESTIMONY IN THIS PROCEEDING IDENTIFIED AS OCA STATEMENT 2?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR PRESENT TESTIMONY?

A. My present testimony is prepared to respond to the rebuttal testimony of UGI Utilities, Inc. Gas Division ("UGI Gas") witness Paul R. Moul.

Q. HOW IS YOUR SURREBUTTAL TESTIMONY ORGANIZED?

A. My surrebuttal testimony follows the same order of subjects contained in Mr. Moul's rebuttal testimony. My surrebuttal testimony therefore addresses the following general areas:

- General Comments
- "Rising" Interest Rates
- Capital Market "Turmoil"
- "Management Effectiveness" of UGI Gas'
- Discounted Cash Flow Issues
- Capital Asset Pricing Model Issues
- Comparable Earnings Issues

GENERAL COMMENTS

Q. MR. MOUL CLAIMS (PAGE 2, LINES 8-10) THAT "THE OPPOSING PARTY RECOMMENDATIONS FOR SUBSTANTIAL RATE DECREASES ARE PARTICULARLY TROUBLESOME AS THEY FAIL TO PROVIDE ADEQUATE SUPPORT FOR THE COMPANY'S FINANCIAL PROFILE AND WOULD MATERIALLY INCREASE ITS RISK AND COST OF CAPITAL." WHAT IS YOUR RESPONSE TO THIS ASSERTION?

A. I disagree with Mr. Moul's assertion. It appears that the major complaint that Mr. Moul has with mine and I&E's witness' respective testimonies is that our recommendations are less than what he is recommending in this proceeding. However, it is Mr. Moul who is outside the mainstream of cost of equity awards for regulated natural gas distribution utilities. As I indicated in my direct testimony, the average authorized returns on equity ("ROE") for natural gas utilities has declined over the past several years, from 9.94 percent in 2012 to 9.60 percent in 2015. It is noteworthy that Mr. Moul's proposed 11.0 percent ROE for UGI Gas is completely out of the mainstream of authorized ROEs for natural gas utilities.

Exhibit DCP-2, Schedule 1 indicates the authorized returns on equity (ROE) approved for natural gas distribution utilities over the period 2014 through 2015. As this indicates, there were 42 proceedings during this period in which a ROE was cited in the decision. Of these 42, all but one were below 10.5 percent and 29 (nearly 70 percent) were below 10.0 percent. Only one of these 42 decisions approved a ROE that was within even 60 basis points of Mr. Moul's 11.0 percent ROE recommendation for UGI Gas.

Schedule 1 also shows the approved common equity ratio for each decision. This indicates that only 5 of the 42 decisions (less than 12 percent) approved an equity ratio as high as the 54.55 percent requested by UGI Gas.

All of this information clearly indicates that Mr. Moul's proposed 11.0 percent ROE, as applied to a 54.55 common equity ratio, is well outside the mainstream of current ROE awards for natural gas distribution utilities.

Q. HAS MR. MOUL PREVIOUSLY CITED THIS SOURCE OF AUTHORIZED ROEs IN TESTIMONY BEFORE THIS COMMISSION?

A. Yes, he has. In his rebuttal testimony in Docket No. R-2015-2468981 (PECO Energy-Electric), Mr. Moul cited the same Regulatory Research Associates ("RRA") source. It is noteworthy that he does not acknowledge the sub-ten percent average return levels in recent years in his current rebuttal testimony.

Year	Avg ROE
2012	9.94%
2013	9.68%
2014	9.78%
2015	9.60%

These are well below the 11.0 percent Mr. Moul is recommending for UGI Gas. In fact, the 9.60 percent average ROE for 2015 is some 140 basis points below Mr. Moul's recommendation. It is also apparent that the RRA reports, as previously cited by Mr. Moul, demonstrate a continuing decline in ROEs, unlike the upward movement portrayed by Mr. Moul. In addition, it is evident that Mr. Moul's 11.0 percent ROE recommendation for UGI Gas is well above "returns investors can earn on other investments of comparable risk." Finally, no gas distribution utility has been awarded a ROE as high as 11.0 percent since 2010.

Q. ON PAGE 3, LINES 1-16, MR. MOUL CITES "AN INCREASING REGULATORY RETURN PREMIUM" IN RECENT YEARS. WHAT IS YOUR RESPONSE TO THIS ASSERTION?

A. Mr. Moul cites what he calls the "regulatory return premium," or the differential between the authorized ROEs for utilities and A-rated utility bonds. Yet, Mr. Moul cannot avoid the obvious fact that U.S. regulatory commissions have awarded lower ROEs over the past several years. None of these have been as high as his 11.0 percent recommendation for UGI Gas. In fact, not since 2010 has a single authorized ROE been as high as Mr. Moul's 11.0 percent ROE recommendation for UGI Gas. He also does not acknowledge or address why his proposed 11.0 percent ROE for UGI would result in this Company having the highest authorized ROE of any gas distribution utility in the United States.

Q. IS MR. MOUL CORRECT THAT YOUR ROE RECOMMENDATION WOULD NOT PROVIDE ADEQUATE SUPPORT FOR UGI GAS' FINANCIAL PROFILE AND WOULD MATERIALLY INCREASE ITS COST OF CAPITAL?

A. No, he is not correct. Mr. Moul's claim, as shown on page 2 of his rebuttal testimony, relates to a 10.0 percent ROE that applies to DSIC mechanism. This is not a proper standard to compare to mine and Ms. Maurer's respective recommendations. A DSIC mechanism, developed outside the scrutiny and quantifications of a general rate proceeding, does not provide a proper ROE standard for a subsequent rate proceeding.

As I have indicated above, the authorized ROE's for natural gas utilities throughout the United States have been declining over the past several years and are generally well below the 10.0 percent apparent standard Mr. Moul cites. In fact, my 9.15 percent ROE, applied to a 54.55 percent common equity ratio, would put UGI Gas in the "Mainstream" of equity returns for natural gas utilities. This can be demonstrated by comparing the weighted cost rates for common equity as follows:

	ROE	CE Ratio	Wgt. CE Return
UGI Gas	9.15%	54.55%	4.99%
Natural Gas (2015 cases)*	9.60%	49.93%	4.79%

* RRA, Regulatory Focus, January 14, 2016.

As this indicates, UGI Gas would have a larger weighted cost of equity than the average national gas utility with a 2015 rate proceeding. Thus, under my recommendations, UGI Gas would have a greater financial profile than most natural gas utilities.

"RISING" INTEREST RATES

Q. MR. MOUL MAINTAINS, ON PAGES 3-4, THAT THERE IS A "UNIVERSAL CONSENSUS THAT INTEREST RATES WILL INCREASE IN THE FUTURE." DO YOU HAVE ANY RESPONSE TO THIS?

A. Yes, I do. It is apparent that Mr. Moul has been predicting an increase in interest rates for several years now. Yet, rates have remained low and even declined in recent years. If Mr. Moul continues to predict an increase in interest rates, perhaps at some point in time he will be correct. However, to date, he has not been correct in predicting an increase in interest rates.

In fact, the yields on A-rated utility bonds have declined in recent months, notwithstanding the Federal Reserve's ("FED") increase in the Fed-Funds rate in December of 2015:

Month	A-Rated Yield
Nov, 2015	4.40%
Dec, 2015	4.35%
Jan, 2016	4.27%
Feb, 2016	4.11%
Mar, 2016	4.16%
Apr, 2016	4.00%

Q. DO YOU AGREE THAT THERE IS A "CONSENSUS" THAT INTEREST RATES WILL RISE SUBSTANTIALLY IN THE NEAR TO INTERMEDIATE FUTURE?

A. No. There have been several "predictions" in the financial press that do not agree with Mr. Moul's anticipation of increasing interest rates. I have attached the following examples in Attachment I to my surrebuttal testimony:

Kiplinger - "Long-Term Interest Rates To Stay Low Despite Fed Moves", November 6, 2015.

CNBC - "Fed May Hike More Slowly Than You Think", December 2, 2015

Kiplinger - "Why Bond Yields Aren't Going Up", November, 2015.

USA Today - "Fed Likely To Emphasize Gradual Rate Hikes", December 13, 2015.

Q. ARE THERE ANY INDICATIONS THAT ANY PERCEIVED INCREASE IN INTEREST RATES HAS DECLINED IN RECENT YEARS?

A. Yes. I have attached, as Attachment II, a table prepared and presented by Moody's Chief Capital Market Economist John Lunski in a recent Financial Forum of the Society of Utility and Regulatory Financial Analysts ("SURFA"). As this indicates, the "consensus" forecasts of 10-year U.S. Treasury bonds for the same 2016-2022 period by Blue Chip Forecasts (Mr. Moul's source) declined substantially between 2011 and 2016. This is further acceptance of a continuing low-interest rate environment and it directly contradicts Mr. Moul's assertions.

Q. TO THE EXTENT THAT INTEREST RATES ARE EXPECTED TO RISE, IS THIS ANY JUSTIFICATION FOR A HIGHER ROE FOR UGI GAS?

A. No. Any expected increase in interest rates should be acknowledged by investors and be reflected in stock prices. As a result, DCF and CAPM analyses (which utilize stock prices) already incorporate any such expectations. As a result, there is no justification for an interest rate "adder" to the ROE for UGI Gas.

CAPITAL MARKET "TURMOIL"

Q. MR. MOUL MAINTAINS, ON PAGES 4-5, THAT "TURMOIL" OR VOLATILITY IN THE STOCK MARKET SUPPORTS A HIGHER ROE FOR UGI GAS. DO YOU AGREE?

A. No, I do not. Utilities, including natural gas distribution companies in general and UGI Gas in particular, are less risky than the market in general. I demonstrated this on Schedule 12 of my direct testimony. One such indicator of lower risk of utilities is the lower betas (or lower volatility of stock prices, relative to the market), which indicates that volatility is not as pronounced for utilities as it is for the market as a whole. As a result, utilities are considered "safe havens" during periods of market volatility and "turmoil". Consequently, such conditions can actually make utilities more attractive. In any event, this is no justification for a higher ROE for UGI Gas.

"MANAGEMENT EFFECTIVENESS" OF UGI GAS

Q. MR. MOUL ALSO CITES UGI GAS' MANAGEMENT AS A SOURCE OF RETURN FOR THE COMPANY. DO YOU AGREE?

A. No, I do not. Mr. Moul cites UGI Gas' "exemplary performance" and "management effectiveness" in his testimony. He proposes a 0.25 percent "adder" to UGI Gas' ROE to reflect this.

Q. WHY DOES MR. MOUL PROPOSE SUCH AN ADJUSTMENT?

A. This is not clear. In his direct testimony, Mr. Moul cites UGI Gas' "outstanding performance." In his direct testimony, he does not indicate how the "outstanding performance" is incorporated in his 11.0 percent ROE recommendation. In addition, Mr. Moul admitted he "made no independent determination of the performance of the Company's management" (Response To OCA Set II, Q. 16).

Now, in his rebuttal testimony, Mr. Moul used the terms "management effectiveness" and "exemplary performance" to describe UGI Gas' management, with no explanation as to why he has changed the nomenclature. He also does not define either of these terms. In addition, in his rebuttal testimony for the first time he now claims a 0.25 percent "adder" be reflected in UGI Gas' ROE.

Q. DOES MR. MOUL ALWAYS INCORPORATE AN "EXEMPLARY PERFORMANCE" ADDER TO HIS ROE RECOMMENDATIONS FOR PENNSYLVANIA UTILITIES?

A. Apparently he does. In his response to OCA Set II, Q. 17, Mr. Moul stated:

> "to some degree, most recent cases have included some recognition of management performance."

It is thus apparent that Mr. Moul apparently believes that all Pennsylvania utilities, or at least all Pennsylvania utilities that are his clients, are "exemplary" and "outstanding."

DCF ISSUES

Q. ON PAGES 8-9 OF HIS REBUTTAL TESTIMONY, MR. MOUL REFERS TO YOUR "DCF RETURNS" AND CITES THE RESULTS OF INDIVIDUAL VALUES THAT HE SAYS ARE BELOW YOUR DCF RANGE. IS THIS AN ACCURATE PORTRAYAL OF YOUR DCF ANALYSIS?

A. No, it is not. Mr. Moul incorrectly implies his belief that some of my DCF results are too close to the cost of debt. I note that UGI Gas' embedded cost of debt is 5.07 percent and my DCF conclusion is 8.3 percent, which is more than 320 basis points above the company's debt cost.

Mr. Moul has made a significant mischaracterization and misinterpretation of my DCF analysis. Since I have shown the mathematical combination of dividend yields and various growth rates, he apparently has misinterpreted these combinations to be my "DCF results," which he attempts to imbue with some individual significance. That simply is not the case. In fact, I clearly state on page 27, lines 16-19:

> I note that the individual DCF calculations shown on Schedule 8 should not be interpreted to reflect the expected cost of capital for the proxy group; rather, the individual values shown should be interpreted as alternative information considered by investors.

Mr. Moul's statement in his rebuttal testimony ignores this portion of my testimony.

My testimony is clear that investors consider various alternative growth rates in making investment decisions. As such, investors evaluate these alternative growth rates to assist them in their investment decisions. However, it does not follow that each individual growth rate reflects an "investor decision," and thus, each growth rate creates a DCF estimated common equity cost rate. Rather, it is the cumulative impact of all these growth rates, or some combination of growth rates, which form the basis of investor decisions and thus, DCF estimated common equity cost rates.

The primary reason for Mr. Moul's misinterpretation of my DCF analysis is the difference in the manner in which he and I calculated and presented our respective DCF values. He looks at alternative growth rates and reaches a single growth rate conclusion to be combined with a single dividend yield to reach a DCF estimate of the cost of equity, whereas I combine the multiple growth rates directly with the dividend yields. We both reach conclusions based on our interpretations of the proper growth rates. The fact that I show individual combinations of yields and growth rates, which are then used as inputs into my ultimate and comprehensive estimate of the DCF costs of equity, has likely resulted in his misinterpretation of my analyses. Nevertheless, he has misinterpreted my analyses. As a result, his criticisms are unfounded.

This misinterpretation obscures the real difference in our respective DCF analyses, notably the weight to give analysts' forecasts of earnings per share (EPS) growth in a DCF analysis. As I have shown in my direct testimony, as well as in the following section, it is not proper to rely primarily on EPS forecasts.

Q. MR. MOUL, ON PAGES 10-12 OF HIS REBUTTAL TESTIMONY, CLAIMS THAT EPS PROJECTIONS SHOULD BE GIVEN GREATEST WEIGHT IN THE DCF MODEL. WHAT IS YOUR RESPONSE TO THIS ASSERTION?

A. This is Mr. Moul's attempt to give excessively heavy reliance to the EPS projections in his growth component. EPS projections are not the only measure of growth considered by investors and should not be looked at in a vacuum. I discussed this in greater detail in my direct testimony.

Q. ON PAGES 12-14 OF HIS REBUTTAL TESTIMONY, MR. MOUL CRITICIZES YOUR USE OF THE RETENTION GROWTH RATE. IS THIS CRITICISM JUSTIFIED?

A. No, it is not. The retention growth rate, which is one of several growth rates I utilize, has a long-standing history as an indicator of expected growth. In fact, Myron Gordon, the recognized originator of the DCF model as a method of estimating the cost of equity for utilities, identified retention growth as a primary source of growth in the DCF model. (Source: <u>The Cost of Capital for Public Utilities</u>). In addition, the Federal Energy Regulatory Commission has used retention growth as one of two growth rates it utilizes in setting rates for electric utilities at the interstate level.

Q. ON PAGES 15-16 OF HIS REBUTTAL TESTIMONY, MR. MOUL MAINTAINS, AS HE DID IN HIS DIRECT TESTIMONY, THAT THE DCF MODEL CANNOT BE USED AS AN ESTIMATE OF THE COST OF EQUITY FOR A UTILITY WHEN THE MARKET PRICE OF UTILITY STOCKS EXCEEDS THE BOOK VALUE. DO YOU AGREE WITH THIS POSITION?

A. No, I do not. Knowledgeable, informed investors are aware of the fact that most utilities have their rates set based on the book value of their assets (i.e., rate base and capital structure). This knowledge is reflected in the prices that investors are willing to pay for stocks and thus, is reflected in DCF cost rates. To make a modification of the DCF cost rates, as Mr. Moul proposes, amounts to an attempt to "reprice" stock values in order to develop a DCF cost rate more in line with what he thinks the results should be. This is clearly a violation of the principle of "efficient markets."[1] If one believes that markets are efficient, there is no reason to modify either stock prices or market models based on stock prices.

Q. MR. MOUL CONTINUES TO MAINTAIN, ON PAGES 17-19 OF HIS REBUTTAL TESTIMONY, THAT A "LEVERAGE ADJUSTMENT" IS NECESSARY. DO YOU AGREE?

A. No, I do not. As I indicate in my direct testimony, a leverage adjustment is not appropriate in a DCF contest.

Q. EVEN THOUGH MR. MOUL SEEMS TO ACKNOWLEDGE (PAGES 15-17) THAT THIS COMMISSION HAS NOT INCORPORATED HIS PROPOSED LEVERAGE ADJUSTMENT OVER THE PAST SEVERAL YEARS, HE NOW MAINTAINS THE COMMISSION HAS USED A "MANAGEMENT PERFORMANCE INCREMENT RATHER THAN THE LEVERAGE ADJUSTMENT." WHAT ARE YOUR RESPONSES TO THIS ASSERTION?

[1] The efficient market principle maintains that the capital markets are very efficient, and stock prices reflect the impact of all known and relevant information.

A. I note, first of all, that Mr. Moul is proposing *both* a leverage adjustment and management performance adjustment for UGI Gas. This is contrary to his claim of "rather than" as cited above.

Second, Mr. Moul has made no demonstration that UGI Gas management is "exemplary" or "outstanding". As I indicated previously, Mr. Moul has acknowledged that he has made no independent assessment of UGI Gas' management performance.

CAPM ISSUES

Q. MR. MOUL MAINTAINS, ON PAGE 20 OF HIS REBUTTAL TESITMONY, THAT YOU SHOULD HAVE USED 30-YEAR TREASURY BONDS AS THE RISK-FREE RATE IN YOUR CAPM ANALYSES, RATHER THAN 20-YEAR TREASURY BONDS. IS HE CORRECT?

A. No, he is not. I used a 20-year Treasury bond yield since the Morningstar/Ibbotson source used to develop my market risk premium used the 20-year Treasury bond as the source of "long-term government" bond returns. Thus, I am being consistent with my data sources. Use of any other term of Treasury bond yields, such as 30 years, would not be consistent.

Q. MR. MOUL, ON PAGES 21-23 OF HIS REBUTTAL TESTIMONY, CLAIMS THAT THE CAPM MODEL IS INCORRECT IF IT GIVES CONSIDERATION TO GEOMETRIC AS WELL AS ARITHMETIC RETURNS. WHAT IS YOUR RESPONSE TO THIS?

A. What is most important is what investors rely upon in making investment decisions. It is apparent that investors have access to both types of returns when they make investment decisions.

In fact, it is noteworthy that when mutual fund investors regularly receive reports on their own fund, as well as prospective funds they are considering investing in, these reports show only geometric returns. Based on this, I find it difficult to accept Mr. Moul's position that only arithmetic returns are appropriate.

Q. DOES MR. MOUL USE VALUE LINE INFORMATION IN HIS COST OF CAPITAL ANALYSES?

A. Yes, he does.

Q. DO THE VALUE LINE REPORTS SHOW HISTORIC AND PROJECTED GROWTH RATES FOR UTILITIES?

A. Yes, they do.

Q. DO THESE VALUE LINE REPORTS SHOW HISTORIC AND PROJECTED GROWTH RATES ON AN ARITHMETIC BASIS?

A. No, they do not.

Q. DO THE VALUE LINE REPORTS SHOW HISTORIC AND PROJECTED GROWTH RATES ON A GEOMETRIC OR COMPOUND GROWTH RATE BASIS?

A. Yes, they do.

Q. IS IT YOUR POSITION THAT ONLY GEOMETRIC GROWTH RATES BE USED?

A. No. Both arithmetic and geometric growth rates should be used. Investors have access to both, and it is reasonable to presume they use both. This is also consistent with the efficient market principle.

Q. IN HIS REBUTTAL TESTIMONY, MR. MOUL CONTINUED TO MAINTAIN HIS "SIZE ADJUSTMENT" IS PROPER. DO YOU AGREE?.

A. No, I do not. Mr. Moul maintains, on page 25, that water companies' authorized ROEs are downwardly-impacted by "revenue decoupling mechanisms." What he does not acknowledge is that natural gas distribution utilities also have revenue decoupling mechanisms. As a result, his conclusion is invalid.

COMPARABLE EARNINGS ISSUES

Q. ON PAGE 25 OF HIS REBUTTAL TESTIMONY, MR. MOUL MAINTAINS THAT THE UNDERLYING PREMISE OF THE COMPARABLE EARNINGS METHOD IS THAT REGULATION SHOULD EMULATE RESULTS OBTAINED BY FIRMS OPERATING IN COMPETITIVE MARKETS AND THAT A UTILITY MUST BE GIVEN AN OPPORTUNITY COST OF CAPITAL EQUAL TO THAT WHICH COULD BE EARNED IF ONE INVESTED IN FIRMS OF COMPARABLE RISK. DO YOU AGREE WITH THIS PREMISE?

A. I agree with this statement in principle, but I disagree with the interpretation made by Mr. Moul that regulated utilities should be entitled to returns commensurate with those earned by competitive firms. An implicit assumption in Mr. Moul's interpretation of the comparable earnings analysis is that the earnings of unregulated firms equates to the costs of capital for these firms. Yet, Mr. Moul has made no analyses or other attempts to indicate that the achieved and/or expected returns of unregulated firms do not exceed their cost of capital.

It is evident, however, from my analyses that the earnings of Mr. Moul's unregulated firms exceed the required cost of capital for regulated utilities such as UGI Gas. This is because unregulated firms are not comparable to regulated utilities. This is evidenced by the fact that the earnings in Mr. Moul's proxy group have been much less than those for his unregulated group, yet have been able to maintain the same levels of "risk indicators" while earning lower earnings levels. This is evidence that the required cost of equity is less for utilities than for unregulated firms. It is noteworthy that Mr. Moul does not address this in his rebuttal testimony.

Q. ON PAGE 29 OF HIS REBUTTAL TESTIMONY, MR. MOUL CLAIMS THAT "AN ANALYSIS OF M/B RATIOS IS NOT NECESSARY TO APPLY THE COMPARABLE EARNINGS METHOD." DO YOU AGREE?

A. No, I do not. I believe it is inconsistent for Mr. Moul to maintain that his DCF and CAPM results should be modified (i.e., leverage adjustment) for M/B (market-to-book ratio), but the comparable earnings analyses should not. It is appropriate for the comparable earnings analyses to be adjusted for M/B, since the comparable earnings method is based on book returns. The DCF and CAPM methodologies, in turn, are based on market returns, which already reflect any investor recognition of deviations of market prices from book values. As a result, it is improper for the DCF and CAPM to be adjusted for M/B, since any impact of M/B should already be reflected in the stock prices and thus, DCF and CAPM results.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2015-2518438**
	:	
UGI Utilities, Inc. – Gas Division	:	

EXHIBIT ACCOMPANYING

THE

SURREBUTTAL TESTIMONY OF

DAVID C. PARCELL

ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

MAY 25, 2016

Exhibit DCP2
Schedule 1

AUTHORIZED RETURNS ON EQUITY AND COMMON EQUITY RATIOS
NATURAL GAS UTILITIES

Date	Utility	State	ROE	Equity Ratio
01/21/14	Avista Corp.	OR	9.65%	48.00%
01/22/14	Connecticut Natural Gas	CT	9.18%	52.52%
02/20/14	Consolidated Edison of New York	NY	9.30%	48.00%
02/21/14	Questar Gas	UT	9.85%	52.07%
02/28/14	Bay State Gas	MA	9.55%	53.68%
03/16/14	Atmos Energy	CO	9.72%	52.57%
04/21/14	Northern Utilities	NJ	9.50%	51.76%
04/22/14	Atmos Energy	KY	9.80%	49.16%
05/08/14	CenterPoint Energy Resources	MN	9.59%	52.60%
05/08/14	National Fuel Gas Distribution	NY	9.10%	48.00%
06/06/14	Wisconsin Power and Light	WI	10.40%	50.46%
06/12/14	Southwest Gas (So. California)	CA	10.10%	55.00%
06/12/14	Southwest Gas (No. California)	CA	10.10%	55.00%
06/12/14	Southwest Gas (So. Lake Tahoe)	CA	10.10%	55.00%
07/07/14	SourceGas Arkansas	AR	9.30%	41.60%
07/25/14	Arkansas Oklahoma Gas	AR	9.30%	39.94%
07/31/14	Cheyenne Light, Fuel and Power	WY	9.90%	54.00%
09/04/14	Atmos Energy	KS	9.10%	53.00%
09/24/14	Minnesota Energy Resources	MN	9.35%	50.31%
09/30/14	South Jersey Gas	NJ	9.75%	51.90%
10/29/14	Summit Natural Gas of Missouri	MO	10.80%	57.00%
11/06/14	Wisconsin Public Service	WI	10.20%	50.28%
11/14/14	Wisconsin Electric Power	WI	10.20%	51.90%
11/14/14	Wisconsin Gas	WI	10.30%	48.91%
11/26/14	Madison Gas and Electric	WI	10.20%	58.96%
12/05/14	Liberty Utilities (Midstates NG)	MO	10.00%	45.89%
01/13/15	Consumer Energy	MI	10.30%	
01/21/15	North Shore Gas	IL	9.05%	50.48%
01/21/15	Peoples Gas Light & Coke	IL	9.05%	50.33%
04/09/05	Avista Corporation	OR	9.50%	51.00%
05/11/15	Atmos Energy	TN	9.80%	53.13%
06/17/15	Central Hudson Gas & Electric	NY	9.00%	48.00%
08/21/15	Columbia Gas of Virginia	VA	9.75%	42.01%
10/07/15	Bay State Gas	MA	9.55%	53.54%
10/13/15	Mountaneer Gas	WV	9.75%	45.50%
10/15/15	Orange and Rockland Utilities	NY	9.00%	48.00%
10/30/15	NSTAR Gas	MA	9.80%	52.10%
11/19/15	Wisconsin Public Service	WI	10.00%	50.47%
12/03/15	Northern States Power-Wisconsin	WI	10.00%	52.49%
12/09/15	Ameren Illinois	IL	9.60%	50.00%
12/11/15	Michigan Gas Utilities	MI	9.90%	52.00%
12/18/15	Avista Corp.	ID	9.50%	50.00%
Averages			9.71%	50.65%
Medians			9.75%	51.00%

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:		
	:		
v.	:	Docket No.	R-2015-2518438
	:		
UGI Utilities, Inc. – Gas Division	:		

ATTACHMENTS ACCOMPANYING

THE

SURREBUTTAL TESTIMONY OF

DAVID C. PARCELL

ON BEHALF OF
OFFICE OF CONSUMER ADVOCATE

MAY 25, 2016

ATTACHMENT I

FINANCIAL ARTICLES DISPUTING MR. MOUL'S PREDICTION OF "UNIVERSAL CONSENSUS THAT INTEREST RATES WILL INCREASE IN THE FUTURE"

Long-Term Interest Rates to Stay Low Despite Fed Moves

Kiplinger's latest forecast on interest rates..

By David Payne, November 6, 2015

Long-term interest rates should end the year around 2.3%, about where they are now. Rates bumped up when the October jobs report showed that the economy was still strong and the labor market was tightening, signs that the Federal Reserve will likely cite when it raises short-term rates next month for the first time in nine years. There is also less concern that China's growth will slow suddenly and roil the world economy in the near future.

The markets have almost fully priced in the expected Fed rate hike, so rates should stay roughly constant for a time. **Thirty-year fixed-rate mortgages will wind up at 4% at the end of this year,** versus 3.9% now. By the end of 2016, two more expected Fed rate increases should push the 10-year Treasury bond rate to 2.7% and the 30-year mortgage rate to 4.4%.

Long-term rates will stay relatively low because U.S. Treasuries will continue to be attractive, given that:

Consumer prices in the U.S. are unlikely to rev up much anytime soon. Although energy prices could bounce back a bit, the Fed tends to discount these. Prices excluding food and energy have been fairly stable, rising about 1.6% to 1.9% annually for several years now, and the rise in the dollar will keep prices for imported commodities lower.

China's growth is likely to continue slowing, keeping its central bank committed to easier monetary policy. It recently cut its main interest rate for the sixth time in less than a year.

- The European Central Bank will stay on an expansion path, despite improving growth in Europe. The ECB intends to keep buying 60 billion euros' worth of bonds a month until September 2016, a substantial share of the Eurobond market. Likewise, Japan's central bank will continue its easing policies.
- The Fed won't want to further boost the value of the dollar by making it even more attractive with higher rates, so it will be sparing with rate increases.

We expect the Federal Reserve to bump up short-term interest rates by a quarter-point at its December 16 meeting. But we don't see a second hike until several months later. Federal Reserve Chair Janet Yellen has signaled that the Fed won't increase rates at every meeting, as it did between 2004 and 2006 under former Chair Alan Greenspan. Yellen wants to be able to evaluate the impact of each hike before pulling the trigger on the next one.

Fed may hike more slowly than you think: Economist

CNBC

By Tom DiChristopher
Dec. 2, 2015 – Yahoo Finance

Current labor market conditions put the Federal Reserve on pace for a December interest rate hike, but other economic indicators suggest future increases may come more slowly than anticipated, Deutsche Bank Securities' chief economist said Wednesday.

"This is going to be very gradual increase, and certainly the data we've had more recently have suggested that, if anything, they'll be revising down a bit their expectations for rate increases for next year," Peter Hooper told CNBC's **"Squawk Box."**

Data from the Institute for Supply Management on Tuesday showed the U.S. manufacturing sector contracted in November, falling to its lowest levels since June 2009, when the economy was mired in the recession.

Hooper said a weak manufacturing sector, along with U.S. dollar strength and low oil prices, suggest the Fed can increase rates slowly next year. He told CNBC he is also looking for signs that businesses will ramp up capital spending, noting that low capital expenditures have been at the core of "dismal" productivity.

The Fed is now widely expected to raise interest rates for the first time in more than nine years at its December meeting. Central bankers have held U.S. benchmark fed funds rates at near zero percent since December 2008.

In the absence of productivity gains, employers may have to hire more workers, so the unemployment rate could fall faster than the Fed expects, Hooper said. That would introduce some pressure to hike rates despite a relatively sluggish economy, he said.

JPMorgan Chase Chief Economist Bruce Kasman said he believes the potential growth rate for the U.S. economy is 1.5 percent and that the economy cannot grow more than that 1.5 percent without a continued tightening of labor markets.

"Labor markets are starting to get tight and we're sitting here with zero-policy rates," he told "Squawk Box."

"I think the the surprise for the Fed next year is going to be the dynamics of the unemployment rate moving down to 4.5 percent, maybe lower."

David Zervos, chief market strategist at Jefferies, said the European Central Bank monetary policy meeting on Thursday will have implications for the Fed's rate hike pace next year.

Most in the market expect the central bank to increase its asset purchase program and lower its deposit rate, the rate at which banks park excess funds with it.

"They're going to much more negative rates, and I really don't think any of us are prepared for what it means to have a negative 40 or 50 ... basis-point deposit rate in a major currency," he told "Squawk Box."

The dollar is likely to strengthen as U.S. and European monetary policy diverge, alleviating pressure on the Federal Reserve to raise rates much, he said.

"I think the dollar does the heavy lifting, rates don't, and that's probably net a positive for the equity market, [and] also removes some uncertainty," Zervos said.

—Reuters contributed to this story. CNBC's Klaire Odumody contributed reporting.

Why Bond Yields Aren't Going Up

image: http://www.kiplinger.com/kipimages/staff/24.jpg

Inflation, the great enemy of bondholders, is almost nonexistent, and demand remains strong for Treasuries and other high-quality, income-paying assets.

By **Jeffrey R. Kosnett**, From *Kiplinger's Personal Finance,* November 2015

The Dow Jones industrial average is down 415 points when bond sage Sreeni Prabhu declares over the phone that "stock market volatility sure does help fixed income." Although he believes the Federal Reserve's plan to finally take short-term interest rates off rock bottom is correct, Prabhu doesn't worry that such a move will torpedo the bond market. In plain language, he's convinced that no matter what the Fed does with short-term rates, long-term rates aren't going to change much because investors are so concerned about turmoil in the stock market. (Prabhu's best idea, incidentally, is mortgage-backed securities, both government-backed and so-called non-agency securities. **DoubleLine Total Return Bond** (symbol DLTNX), a member of the Kiplinger 25, invests in both kinds.)

An hour later, with the Dow off 385 points, I ring up Kansas City bond strategist Dan Heckman. He seconds Prabhu's view that no matter what the Fed does, bond yields will remain flat or even dip a bit because "volatile stock markets create a floor that supports bond prices" (bond prices and interest rates move in opposite directions).

One reason the Fed's long-anticipated hike, the first since 2006, probably won't sink bond prices is that the Fed isn't really tightening credit; it's simply reclaiming some of the extreme stimulus measures it used to combat the Great Recession. Beyond that, inflation, the great enemy of bondholders, is almost nonexistent, and demand remains strong for Treasuries and other high-quality, dollar-denominated, income-paying assets.

And then there's China. Prabhu, chief investment officer for Angel Oak funds, and Heckman, who works for U.S. Bank, have crowned China as the best friend of U.S. bond investors. The downshift in growth and other economic stresses in the world's second-biggest economy buttress my contention that rates on high-quality medium- and long-term bonds in the U.S., Europe and the rest of the developed world will move little in the foreseeable future.

Worrywarts will always see disaster behind the headlines. The China horror movie goes like this: The country is a house of cards, full of zombie companies and insolvent banks. To rescue these walking-dead firms and buy social peace by paying wages to millions of people working at unnecessary jobs, the crony Communists in Beijing will cut purchases of Treasuries and draw down China's $4 trillion in hard-currency savings. The U.S. Treasury won't be able to find other big buyers to finance our debt, so T-bond prices will drop and yields will ascend. Main Street will join Wall Street in the soup as fear spreads that the days of affordable mortgages and cheap business credit are just about over.

Minimal impact. I don't buy the doomsday scenario. The Chinese stock market is a manipulated joke. Although its economy is a force, China accounts for only 1% of our exports. Moreover, compared with almost every other place in the world, the U.S. is cooking. Gross domestic product in the U.S. grew at an impressive annualized rate of 3.7% in the second quarter. Kiplinger expects growth of 2.5% for all of 2015 and 2.8% in 2016. And this is being accomplished with almost no inflation.

It's true that the U.S. bond market wobbled a bit over the summer, with the yield on the benchmark 10-year Treasury bond rising to 2.5%. For a while, all major bond categories briefly showed negative year-to-date returns. But as soon as China lit the stock market fire, the 10-year Treasury yield fell below 2% again. As of September 7, the 10-year yielded 2.1%. Look for the yield to stay in a narrow range the rest of the year. And if that happens, your bonds and bond funds will end 2015 in the plus column. Can't say that about your stocks.

Fed likely to emphasize gradual rate hikes

Paul Davidson, USA TODAY 5:30 p.m. EST December 13, 2015

Federal Reserve Chairman Janet Yellen testifies before a Joint Economic Committee hearing on Capitol Hill, December 3, 2015 in Washington, DC. Photo by Mark Wilson/Getty Images.(Photo: Getty Images)

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A historic interest rate hike at this week's Federal Reserve meeting seems a done deal.

Now, it's all about the pace.

The Fed faces a delicate balancing act as it attempts to further reassure financial markets that it will nudge up its benchmark rate gradually, without locking itself into a glacial pace that might well have to be adjusted if inflation picks up more than expected. Such a reversal could spook complacent investors.

The central bank, which will hold a two-day meeting that ends Wednesday, hasn't raised its key federal funds rate in nearly a decade and it has hovered near zero since the 2008 financial crisis.

Fed policymakers in recent months have emphasized that they will likely lift the rate gently, in part because of lingering headwinds to growth, such as weakness overseas and tight credit. Morgan Stanley argues the Fed will go further, both to reflect inflation that remains stubbornly below the Fed's annual 2% target and to avoid roiling markets conditioned to rock-bottom rates.

"We believe the Fed's message of gradualism needs to be, well, more gradual," the research firm wrote in a note to clients.

Morgan Stanley expects Fed policymakers to convey in a post-meeting statement that further rate increases will hinge on a pickup in inflation, not simply confidence in the prospect of inflation accelerating. The firm expects the Fed officials to slightly lower their inflation forecast for 2016 and 2017, and trim their estimate of the fed funds rate to 1.3% at the end of next year.

The dollar has strengthened even more recently, further tempering U.S. import prices and hobbling exports.

Policymakers also "want to avoid a repeat of the taper tantrum," the moniker for the spike in Treasury yields in 2013 after Fed officials signaled they were poised to wind down a bond-buying stimulus, says Barclays economist Michael Gapen, a former staffer in the Fed's monetary policy division. A message of gradual hikes also should mollify pro-growth Fed policymakers worried that acting this week poses risks to the recovery.

Economist Kathy Bostjancic of Oxford Economics agrees that Fed Chair Janet Yellen will stress the gradual pace of rate increases in her news conference but doesn't expect such language to be added to the statement. Financial markets are already expecting a far shallower path of increases than Fed forecasts.

"You don't want to reinforce expectations for very low rate hikes into the future," she says.

Paul Ashworth of Capital Economics believes the Fed will hoist rates more rapidly than it expects next year as the effects of the robust dollar and low oil prices fade more quickly than anticipated.

ATTACHMENT II

EXCERPTS OF PRESENTATION BY MOODY'S CHIEF MARKET ECONOMIST JOH LUNSKI AT SOCIETY OF UTILITY AND FINANCIAL ANALYSTS 2016 FINANCIAL FORUM

MOODY'S
ANALYTICS

Cost of Capital 2016: Credit Risk Outweighs Interest Rate Risk

John Lonski, MD-Chief Capital Mkt Economist, *Capital Markets Research Group*

April 2016

Blue Chip Consensus Forecasts for 2016 through 2022 Move to New Lows:

average annual projections for 2016-2022

Date of Forecast	Real GDP Growth	GDP Price Index Inflation	Nominal GDP Growth	Profits from Current Production Growth	10-year Treasury Yield
	1	*2*	*3*	*4*	*5*
March 2011	**2.6**	**2.1**	**4.7**	**5.3**	**5.4**
March 2016	**2.2**	**2.0**	**4.1**	**3.2**	**3.4**
percentage point difference from March 2011 to March 2016:					
	-0.4	***-0.1***	***-0.6***	***-2.1***	***-2.0***

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2015-2518438
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, David C. Parcell, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA St. No. 2-SR, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: David C. Parcell
David C. Parcell

Consultant Address: Technical Associates, Inc.
1503 Santa Rosa Road, Suite 130
Richmond, Virginia 23229

DATED: May 25, 2016

OCA Statement No. 3
6/2/16 Alg TR

BEFORE THE PENNSYLVANIA PUBLIC
UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	DOCKET NO. R-2015-2518438
	:	
UGI UTILITIES, INC. – GAS DIVISION	:	

DIRECT TESTIMONY
OF
GLENN A. WATKINS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

APRIL 12, 2016

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 1503 Santa Rosa Road, Suite 130, Richmond, Virginia

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am a Principal and Senior Economist with Technical Associates, Inc., which is an economics and financial consulting firm with offices in Richmond, Virginia. Except for a six month period during 1987 in which I was employed by Old Dominion Electric Cooperative, as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my career at Technical Associates, I have conducted marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving numerous electric, gas, water/wastewater, and telephone utilities, and have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. A more complete description of my education and experience as well as a list of my prior testimonies is provided in my Schedule GAW-1.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION ON THESE ISSUES IN THE PAST?

A. Yes, I have provided testimony before this Commission on issues concerning cost allocations, rate design, cost of capital, and revenue requirement in numerous natural gas distribution, electric distribution, and water utility general rate cases.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Technical Associates, Inc. has been retained by the OCA to evaluate UGI Utilities, Inc.'s – Gas Division ("UGI" or "Company") proposed ratemaking treatment of interruptible sales and transportation business, its class cost of service study, proposed distribution of revenues by customer class, residential rate design, its proposed Energy Efficiency & Conservation ("EE&C") rider/program and other proposed tariff changes. The purpose of my direct testimony is to provide comments regarding my analysis of the Company's proposals and to present my findings and recommendations based on the studies I have undertaken in this matter.

II. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR FINDINGS AND RECOMMENDATIONS.

A. I sponsor two revenue adjustments utilized by OCA witness Effron to reflect the Company's budgeted level of interruptible sales and reflect ancillary transportation fee revenues within current rates. I also comment on other OCA revenue adjustments to firm customers sponsored by Mr. Effron in which he provides further detail. With regard to class cost of service, I recommend several significant adjustments to the Company's (Paul Herbert) methods to assign Mains cost responsibility across classes. I also recommend a somewhat different class revenue allocation than that proposed by UGI. With respect to residential rate design, I agree with the Company's proposal to eliminate declining-block volumetric rates and recommend a maximum customer charge of $11.25 per month. Additionally, I recommend that UGI be required to revise its tariff provisions relating to Rate XD to include appropriate pricing parameters to ensure that all future contracts for negotiated rates are fair and reasonable.

I also address the Company's proposed Energy Efficiency & Conservation Program and recommend certain modifications to its proposal. Finally, I comment on several of the Company's proposed tariff changes including its proposed new Technology & Economic Development Rider.

III. REVENUE ADJUSTMENTS

Q. ARE YOU SPONSORING ANY REVENUE ADJUSTMENTS RECOMMENDED BY THE OCA?

A. Yes. In this case UGI is proposing numerous revenue adjustments to its Fully Forecasted Test Year. While witness David Effron incorporates all of the OCA's proposed revenue adjustments, I will address two specific sources of revenue in my testimony. These two revenue sources include UGI's proposed ratemaking treatment of its interruptible business as well as its proposed revenue adjustment to ancillary transportation fees.

A. Interruptible Sales and Transportation

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED RATEMAKING TREATMENT RELATING TO THE DISTRIBUTION SERVICES UGI PROVIDES TO ITS INTERRUPTIBLE CUSTOMERS.

A. Although UGI collects more than $20 million annually from interruptible customers, it proposes to essentially treat this type of distribution service as an unregulated business. More specifically, the Company's cost allocation witness, Paul Herbert, has allocated "costs" to the interruptible class and has determined that as a result of his cost allocations, the costs to serve these customers is only $4.9 million annually. As a result, the Company has made a downward adjustment to interruptible revenues to reflect interruptible revenue contributions of only $4.9 million such that the Company's remaining total revenue requirement must be absorbed by its firm customers. In simple terms, even though the Company collects in excess of $20 million annually from interruptible customers, its rate filing only reflects $4.9 million of interruptible revenue.

Q. TO THE EXTENT THAT UGI ACTUALLY COLLECTS MORE THAN $4.9 MILLION IN REVENUE FROM INTERRUPTIBLE CUSTOMERS, WHAT IMPACT WILL THIS HAVE ON UGI'S VARIOUS STAKEHOLDERS?

A. Because firm ratepayers would be assigned UGI's entire revenue requirement, but for $4.9 million, any revenue collected from interruptible customers in excess of $4.9 million would flow directly to UGI's shareholders as before-tax profits.

Q. WHAT IS THE DOLLAR MAGNITUDE OF UGI'S PROPOSED INTERRUPTIBLE REVENUE ADJUSTMENT?

A. UGI witness David Lahoff sponsors the Company's proposed interruptible revenue adjustment. As shown in his Exhibit DEL-3(h), UGI's budgeted interruptible revenues for the interruptible class for the Fully Forecasted Future Test Year is $20.621 million. Mr. Lahoff then reduces this budgeted amount by $14.096 million in margin revenues plus an additional $1.626 million in PGC revenues.

Q. WHAT JUSTIFICATION DOES THE COMPANY PROVIDE FOR SUCH A LARGE DOWNWARD ADJUSTMENT TO REVENUES?

A. UGI claims that it is at risk for its interruptible distribution revenues primarily because the Company claims that there is significant risk associated with the price differential between natural gas and competing alternative fuels. To better understand Mr. Lahoff's claim, he asserts that all interruptible customers must have alternative fuel capabilities such that if these alternative fuels become more attractive than natural gas, UGI may lose this business.

Q. BEFORE YOU CONTINUE, IS UGI AT RISK FOR ITS OTHER DISTRIBUTION SERVICES; I.E., THOSE PROVIDED TO FIRM CUSTOMERS?

A. Absolutely, UGI is at risk for all of its distribution margin business including those associated with residential, commercial, and industrial customers.

Q. IS THERE ANY REALISTIC POSSIBILITY THAT UGI'S INTERRUPTIBLE CUSTOMERS WILL ABANDON NATURAL GAS IN FAVOR OF ALTERNATIVE FUELS?

A. No. First it must remembered that the requirement for interruptible customers to have alternative fuel capability is to ensure that these customers indeed have the ability to curtail their natural gas usage for short periods of time. However, large commercial and industrial customers will not permanently replace all of their natural gas requirements with oil or propane simply due to the operational constraints and problems associated with oil and propane. To illustrate, if a large customer were to entertain the notion of fulfilling all of its energy needs with oil or propane, it must have tremendous storage capacity for these alternative fuels. Furthermore, with respect to oil usage, this requires more maintenance of boiler equipment and may limit an industrial customer's oil usage due to emissions constraints associated with the burning of oil. However, the most important point is that alternative fuels simply cannot compete with natural gas on a price basis. Even though oil and propane prices are much lower today than they were a couple of years ago, the price of natural gas is currently lower than we have seen in many years.

Q. HAS UGI ITSELF ACKNOWLEDGED THE PRICE ADVANTAGE THAT NATURAL GAS HAS OVER ALTERNATIVE FUELS?

A. Yes. In the Company's most recent 1307(f) filing in June 2015 (Docket No. R-2015-2480950), Company witness Shaun Hart testified as follows: "Given the significant price advantage natural gas has over competing energy products, more customers have been switching to natural gas, a trend UGI expects to continue while natural gas pricing remains the more economic fuel choice . . . ." (page 12).

Q. HAVE YOU EVALUATED THE LEVEL OF UGI'S INTERRUPTIBLE BUSINESS ON A HISTORICAL AND PROJECTED BASIS?

A. Yes. I have evaluated UGI's interruptible volumes and revenues both historically as well as what the Company projects for the next few years.

With respect to historical experience, the Company provided a ten-year history of interruptible volumes (MCF) and revenues for the last ten years in response to OCA-XIII-1. The following table shows these annual amounts for each of the last ten years:

TABLE 1
Interruptible Volumes and Revenues

	Volumes (MCF)	Revenue
2015	53,754,975	20,379,900
2014	50,522,402	22,408,953
2013	56,254,762	21,983,621
2012	61,928,488	22,297,743
2011	46,939,070	24,483,481
2010	38,897,370	25,185,071
2009	29,497,246	25,694,292
2008	34,279,651	26,616,984
2007	29,941,549	25,981,114
2006	26,115,100	21,285,353
2005	26,988,273	19,643,398

As can be seen above, UGI has collected in excess of $20 million every year since 2006.

Q. **THE ABOVE TABLE INDICATES THAT RECENT (2015) INTERRUPTIBLE VOLUMES ARE SOMEWHAT LOWER THAN THEY WERE IN 2012 AND 2013. CAN YOU EXPLAIN THIS REDUCTION IN INTERRUPTIBLE VOLUMES?**

A. Yes. This slight reduction is not a result of interruptible customers using alternative fuels or a result of reduced economic activity within UGI's service territory, but rather, largely the result of some UGI interruptible customers electing to reduce or abandon its their interruptible load and replace it with firm service load. Referring again to the direct testimony of Shaun Hart in Docket No. R-2015-2480950 (provided in this filing as Attachment III-E-25.2), Mr. Hart testified as follows:

> UGI is projecting, consistent with historical experience, firm demand growth due to customer additions resulting from new construction; conversions to natural gas from alternative energy sources such as heating oil, propane, and electricity; and customers upgrading the number of type of their appliances, such as, for example, a customer who previously only used gas for cooking upgrades to gas heat. **In addition, there are interruptible transportation customers who have switched from interruptible service to firm service**. (page 11) **[Emphasis added]**

Mr. Hart's testimony in the 1307(f) filing is consistent with the Company's response to OCA-IV-8 wherein UGI has increased the Rate XD firm daily entitlements by 37,038 Dth. In evaluating each of these XD customers' firm entitlements, it is apparent that some of these customer's increases are attributable to reducing interruptible volumes in favor of more firm service. In this regard, it should be remembered that firm service is generally priced higher than interruptible service, leading to even more revenue to UGI.

Q. HOW DO THE MOST RECENT INTERRUPTIBLE REVENUES COMPARE TO UGI'S BUDGETED INTERRUPTIBLE REVENUES FOR THE FULLY FORECASTED TEST YEAR?

A. As shown in the table above, interruptible revenue during 2015 was $20.380 million. This amount is very close to the budgeted Future Test Year revenue (before adjustments) of $20.621 million.

Q. WHAT ARE UGI'S NEAR-TERM INTERNAL PROJECTIONS FOR INTERRUPTIBLE USAGE VOLUMES?

A. In its most recent (2015) Integrated Resource Plan ("IRP"), the Company projects stable interruptible volumes each year during the 2016-2018 period. Attached as my Schedule GAW-2 is a copy of the Company's IRP forecasted usage volumes for each class during the period 2016-2018.[1] As a point of comparison, this document indicates that the then most recent actual experience was 2014 in which interruptible volumes were 51,061,000 MCF. This compares to the Company's projected interruptible volumes for planning purposes of 53,230,000 MCF (2016) and 53,282,000 MCF (2017 and 2018). Therefore, for planning purposes, UGI projects a slight increase in interruptible business.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE EXPECTED LEVEL OF INTERRUPTIBLE REVENUES DURING THE FULLY FORECASTED FUTURE TEST YEAR?

[1] Although the document in Schedule GAW-2 signifies that this is a confidential schedule, this document is provided in UGI's rate filing for this case as a public document and was downloaded from UGI's website.

A. Based on historical experience as well as UGI's own projections for planning purposes, it is implausible to believe that the Company's interruptible business will be substantially reduced anytime in the near future. Indeed, the Company's budgeted interruptible revenues for the Fully Forecasted Future Test Year of $20.621 million is reasonable and right on par with both historic and projected amounts.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING UGI'S PROPOSED DOWNWARD ADJUSTMENT TO INTERRUPTIBLE REVENUES?

A. I recommend that UGI's proposed adjustment of $14.096 million in interruptible margin revenues be rejected. My recommendation is incorporated in the analyses and recommendations set forth by OCA witness Effron.

Q. IF THE COMMISSION WERE TO ACCEPT UGI'S PROPOSED RATEMAKING TREATMENT FOR ITS INTERRUPTIBLE BUSINESS BY REDUCING THESE MARGIN REVENUES BY MORE THAN $14 MILLION, WHAT IMPACT WOULD THIS HAVE ON THE COMPANY'S REGULATED EARNINGS UNDER THIS COMMISSION'S JURISDICTION?

A. It is obvious that this would result in excess earnings substantially over and above the authorized rate of return ("ROR") granted in this case. This is because the Company proposes to collect all of its revenue requirement but for $4.9 million from firm customers and at the same time, it is reasonably certain that UGI would collect at least an additional $14 million of interruptible revenues over and above those reflected in the Company's total jurisdictional revenue requirement. As such, by mathematical definition, UGI would earn well above its authorized ROR on equity simply because these additional interruptible revenues would flow directly to the Company's bottom line (net of income tax).

B. Ancillary Transportation Fees

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED ADJUSTMENT RELATING TO ANCILLARY TRANSPORTATION FEES.

A. As a rate design matter, UGI proposes to eliminate fees that it currently collects associated with pooling, system access and information services. While there is no doubt that UGI currently collects these fees, the Company's filing eliminates this revenue source from current revenues. Therefore, it is inappropriate to reduce current revenues as these ancillary fees are actually imposed and collected by UGI. Whether these regulated fees should or should not be eliminated, is a rate design issue and should be reflected in the Company's proposed revenue levels. Mr. Effron also addresses this error in his testimony.

Q. WHAT IS THE REQUIRED ADJUSTMENT ASSOCIATED WITH ANCILLARY TRANSPORTATION FEE REVENUES AT CURRENT RATES?

A. UGI witness Lahoff reduces current transportation service margin revenues at current rates by $2.348 million as shown in his Exhibit DEL-3(i). This adjustment should be reversed such that UGI's current revenues should be increased by the same amount.

C. UGI Usage and Revenue Adjustments to Firm Rates

Q. DO YOU HAVE ANY COMMENTS PERTAINING TO UGI'S PROPOSED DOWNWARD ADJUSTMENTS TO ITS FIRM RATE CLASS REVENUES?

A. Yes. While OCA witness Effron discusses the Company's proposed significant downward adjustments to residential, commercial, and small industrial firm volumes and attendant margin revenues in detail, it is clear that these proposed adjustments do not reflect reality based upon its own internal projections for planning purposes (outside the context of this rate case), as well as the sworn testimony of its own company representative in the most recent 1307(f) filing wherein UGI was arguing for even higher levels of peak demand and usage volumes than those indicated by its forecasting models.

As shown in my Schedule GAW-2, the Company's IRP for planning purposes reflects considerable near-term growth to occur within the residential and commercial classes (sales and transportation combined). Indeed, the Company projects that residential usage will increase from 24.659 million MCF in 2015 to 26.605 million MCF in 2018. Similarly, the IRP indicates that commercial volumes will increase from 23.277 million MCF in 2015 to 24.595 million MCF in 2018. Furthermore, the Company projects modest growth in its firm industrial business from 23.518 million MCF in 2015 to 23.934 million MCF in 2018.

In Docket No. R-2015-280950, UGI employee Hart testified in June 2015 as follows:

> In general, the return of colder winter weather, increased economic activity, reduced gas prices resulting from prolific gas production, and record increases of customer additions, among other factors, has now been reflected in historical firm customer demand data that supports levels of firm peak day demand in excess of both UGI's prior predictions and the levels established in recent PGC settlements. (pp. 5 and 6)

Mr. Hart's testimony continues with the following statement:

> UGI is projecting, consistent with historical experience, firm demand growth due to customer additions resulting from new construction; conversions to natural gas from alternative energy sources such as heating oil, propane, and electricity; and customers upgrading the number of type of their appliances, such as, for example, a customer who previously only used gas for cooking upgrades to gas heat. In addition, there are interruptible transportation customers who have switched from interruptible service to firm service. It is also likely that customer additions from new construction will accelerate as the construction market rebounds from historic lows. In addition, UGI is in the first year of its five-year Growth Extension Tariff ("GET Gas") pilot program, for which each of the UGI NGDC's will be investing $5 million per year to extend its natural gas distribution system to unserved and under-served areas. GET Gas provides prospective customers with the opportunity to switch to natural gas and spread the line extension costs over a 10-year period. Given the significant price advantage natural gas has over competing energy products, more customers have been switching to natural gas, a trend UGI expects to continue while natural gas pricing remains the more economic fuel choice and UGI continues to implement GET Gas program. (pp. 11 and 12)

It is apparent that UGI's proposed downward adjustments in this rate case are in direct conflict with its own internal planning projections as well as its proposals and positions in its recent 1307(f) filing.

IV. CLASS COST OF SERVICE

A. Concepts and Methods

Q. PLEASE BRIEFLY EXPLAIN THE CONCEPT OF A CLASS COST OF SERVICE STUDY ("CCOSS") AND ITS PURPOSE IN A RATE PROCEEDING.

A. Generally there are two types of cost of service studies used in public utility ratemaking: marginal cost studies and embedded, or fully allocated, cost studies. Consistent with the practices of this Commission, UGI has utilized a traditional embedded cost of service study for purposes of establishing the overall revenue requirement in this case, as well as for class cost of service purposes.

Embedded class cost of service studies are also referred to as fully allocated cost studies because the majority of a public utility's plant investment and expense is incurred to serve all customers in a joint manner. Accordingly, most costs cannot be specifically attributed to a particular customer or group of customers. To the extent that certain costs can be specifically attributed to a particular customer or group of customers, these costs are directly assigned in the CCOSS. The costs jointly incurred to serve all or most customers; therefore, must be allocated across specific customers or customer rate classes.

It is generally accepted that to the extent possible, joint costs should be allocated to customer classes based on the concept of cost causation. That is, costs are allocated to customer classes based on analyses that measure the causes of the incurrence of costs to the utility. Although the cost analyst strives to abide by this concept to the greatest extent practical, some categories of costs, such as corporate overhead costs, cannot be attributed to specific exogenous measures or factors, and must be subjectively assigned or allocated to customer rate classes. With regard to those costs in which cost causation can be attributed, there is often disagreement among cost of service experts on what is an appropriate cost causation measure or factor; e.g., peak demand, energy or throughput usage, number of customers, etc.

Q. IN YOUR OPINION, HOW SHOULD THE RESULTS OF A CCOSS BE UTILIZED IN THE RATEMAKING PROCESS?

A. Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive individual costs. These disagreements can and do arise as a result of the quality of data and level of detail available from financial records. There are also fundamental differences in opinions regarding the cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned previously, cost causation factors cannot be realistically ascribed to some costs such that subjective decisions are required.

In these regards, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS only as a guide, with the results being used as one of many tools to assign class revenue responsibility.

Q. HAVE THE HIGHER COURTS OPINED ON THE USEFULNESS OF COST ALLOCATIONS FOR PURPOSES OF ESTABLISHING REVENUE RESPONSIBILITY AND RATES?

A. Yes. In an important regulatory case involving Colorado Interstate Gas Company and the Federal Power Commission (predecessor to FERC), the United States Supreme Court stated:

> "But where as here several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.[2]

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[2] 324 U.S. 581, 65 S. Ct. 829.

Q. DOES YOUR OPINION, AND THE FINDINGS OF THE U.S. SUPREME COURT, IMPLY THAT COST ALLOCATIONS SHOULD PLAY NO ROLE IN THE RATEMAKING PROCESS?

A. Not at all. It simply means that regulators should consider the fact that cost allocation results are not surgically precise and that alternative, yet equally defensible, approaches may produce significantly different results. In this regard, when all cost allocation approaches consistently show that certain classes are over or under contributing to costs and/or profits, there is a strong rationale for assigning smaller or greater percentage rate increases to these classes. On the other hand, if one set of cost allocation approaches show dramatically different results than another approach, caution should be exercised in assigning disproportionately larger or smaller percentage increases to the classes in question.

Q. PLEASE EXPLAIN THE BASIC CONCEPTS OF COST ALLOCATION FOR PUBLIC UTILITIES AND NATURAL GAS DISTRIBUTION COMPANIES ("NGDCs").

A. As I mentioned earlier, the majority of a NGDC's plant investment serves customers in a joint manner. In this regard, the NGDC's infrastructure is a system benefiting all customers. If all customers were the same size and had identical usage characteristics, cost allocation would be simple (even unnecessary). However, in reality, a utility's customer base is not so simple. Customers (or customer groups) tend to vary greatly in the amount of service required throughout the year such that there are small usage and large usage customers. Therefore, differences in usage should be considered. Because different groups of customers also utilize the system at varying degrees during the year, consideration should also be given to the demands placed on the system during peak usage periods.

Q. WITH REGARD TO NGDCs, IS THERE ANY ASPECT OF CLASS COST ALLOCATIONS THAT TENDS TO OVERSHADOW OTHER ISSUES OR IS OFTEN CONTROVERSIAL?

A. Yes. For virtually every NGDC, the largest single rate base item (account) is distribution Mains. Furthermore, several other rate base and operating income accounts are typically allocated to classes based on the previous assignment of distribution Mains. As such, the methods and approaches used to allocate distribution Mains to classes are usually by far the most important (in terms of class ROR results) and tend to be the most controversial.

Q. IS THERE A PREFERRED METHOD TO ALLOCATE NATURAL GAS DISTRIBUTION MAINS COSTS?

A. Yes. The Peak & Average ("P&A") approach is the most fair and equitable method to assign natural gas distribution Mains costs to the various customer classes. This method recognizes each class's utilization of the Company's facilities throughout the year yet also recognizes that some classes rely upon the Company's facilities (Mains) more than others during peak periods.

Q. HAS THIS COMMISSION PROVIDED GUIDANCE AS TO A PREFERRED APPROACH TO BE USED IN NATURAL GAS LOCAL DISTRIBUTION COMPANY CLASS COST OF SERVICE STUDY?

A. Yes. Based on my experience in other natural gas distribution company rate cases before this Commission, as well as review of Commission Orders in similar cases in which I did not participate, this Commission has a long history of providing guidance as to appropriate cost allocations for natural gas local distribution companies. First, the notion of allocating a portion of Mains investment based on the number of customers has been consistently rejected by this Commission, on the basis that there should not be a classification of Mains as partially demand-related and partially customer-related. Instead, the Commission has consistently found that distribution Mains should be classified as 100% demand-related; *i.e.* no portion of Mains allocated based on customers.

Second, with regard to the allocation of demand-related Mains, the Commission has consistently found that the allocation of Mains should consider both peak and average demands. For example, in a 2006 Philadelphia Gas Works case (Docket No. R-00061931), the Commission stated in its Order:

> "Reviewing the record, we find that the allocation of distribution Mains investment costs should be done using both annual and peak demands."[3]

Q. WHICH METHODS DID THE COMPANY USE TO ALLOCATE MAINS COSTS TO CUSTOMER CLASSES FOR THIS CASE?

A. Company witness Paul Herbert utilized a combination of three different approaches or methods to allocate UGI's investment in distribution mains to individual customer classes. These three approaches include: (1) a "direct assignment" of Mains to certain specific customers and classes; (2) a bifurcation of Mains diameters between small (2-inch and smaller) and large (greater than 2-inch); and, (3) a general allocation framework utilizing what is known as the Average & Excess ("A&E") method (not to be confused with the P&A method).

Q. DO YOU HAVE ANY DISAGREEMENTS WITH, OR RECOMMEND ALTERNATIVE APPROACHES TO, ALLOCATE MAINS THAN THOSE PROPOSED BY MR. HERBERT?

A. Yes. I disagree with all three approaches used by Mr. Herbert to assign Mains cost responsibility to specific rate classes and will explain and address each of my disagreements and recommended alternatives individually.

Q. BEFORE YOU DISCUSS YOUR SPECIFIC DISAGREEMENTS WITH THE WAY IN WHICH MR. HERBERT ALLOCATED MAINS INVESTMENT, IS THERE AN OVERARCHING CONSIDERATION THAT MUST BE GIVEN TO THE USEFULNESS AND ACCURACY OF ANY CCOSS CONDUCTED BY THE VARIOUS WITNESSES IN THIS CASE?

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[3] PA PUC v. Philadelphia Gas Works, Docket No. R-00061931, Order, at Page 80.

A. Yes. As I discussed in detail earlier in my testimony, the Company has made several substantial and unwarranted downward adjustments to margin revenues it collects from its customers. Mr. Herbert's CCOSS reflects these lower levels of margin revenues. Given the size and magnitude of the Company's proposed downward revenue adjustments, this has a significant impact on Mr. Herbert's calculated class RORs at current rates. To be clear, if the Commission rejects UGI's proposed downward adjustments to revenues (particularly for the residential, commercial, and interruptible classes), the corrected class RORs will be significantly higher. This is particularly true for the residential class because Mr. Herbert's CCOSS portrays the residential class ROR to be substantially deficient relative to other classes, but if the Company's unwarranted revenue adjustments were reflected in his CCOSS, Mr. Herbert's calculated residential ROR would be much higher. Therefore, and notwithstanding the inaccuracies inherent in any cost allocation study, the CCOSSs provided in this case (by any witness) should not be given but so much weight and certainly should not be considered precise or even reflect an accurate estimation of individual class' profitability.

Q. HAVE YOU MADE ANY REVENUE ADJUSTMENTS IN THE CCOSSs THAT YOU WILL BE SPONSORING AND RECOMMENDING IN THIS CASE?

A. Yes. While it is generally my preference and practice to utilize the same revenues, total expenses, and total rate base as Company witnesses in order to provide an apples-to-apples comparison, I have conducted my studies to reflect the two revenue adjustments I sponsor. These include adjustments to interruptible revenues and ancillary transportation fees. The reasons that I have only included these two revenue adjustments are due to: the Company's proposal to assign all of UGI's total revenue requirement to firm service customers but for $4.9 million that was calculated by Mr. Herbert as the "cost to serve" the interruptible class; and, the fact that ancillary transportation fees are certainly part of the Company's current revenues. The necessity of incorporating my interruptible revenue adjustment within my CCOSSs will become apparent later in my testimony.

Q. PLEASE PROVIDE A SUMMARY OF THE ADJUSTMENTS THAT YOU WILL BE RECOMMENDING TO MR. HERBERT'S CCOSS?

A. I recommend five areas of adjustments to Mr. Herbert's CCOSS.

(1) recognition of interruptible and ancillary transportation fee revenues in current rates;

(2) allocation of Mains to interruptible service;

(3) his proposed bifurcation of Mains between small and large diameter pipes;

(4) his proposed direct assignment of Mains to Rate XD and one interruptible customer; and,
(5) his use of the Average & Excess Method.

B. Allocation of Costs to the Interruptible Class

Q. EARLIER YOU STATED THAT THE COMPANY'S PROPOSAL TO ONLY REFLECT $4.9 MILLION OF MARGIN REVENUE ASSOCIATED WITH THE INTERRUPTIBLE CLASS IS A RESULT OF MR. HERBERT'S CCOSS WHEREIN HE CALCULATES THE "COST TO SERVE" THESE INTERRUPTIBLE CUSTOMERS. HOW DID MR. HERBERT DEVELOP HIS $4.9 MILLION COST OF PROVIDING SERVICE TO THE INTERRUPTIBLE CLASS?

A. Mr. Herbert's calculated $4.9 million interruptible cost of service is the result of averaging two separate cost analyses for this class. Under the first approach, Mr. Herbert assigned virtually no Mains cost responsibility to the interruptible class.[4] Mr. Herbert's second approach relates to his A&E method to allocate Mains to all classes. Under his second approach, Mr. Herbert assigned the average component of the A&E method to the interruptible class with no assignment of the excess component to this class. As shown in my Schedule GAW-3, Mr. Herbert's A&E approach assigns a weight of 23.5% to "average" demand (usage) and a weight of 76.5% to "peak" demand.[5] Stated differently,

[4] Mr. Herbert did directly-assign $506,656 Mains investment to one interruptible customer.

[5] Peak demand should not be confused with "excess" demand.

while Mr. Herbert's second approach supposedly relies upon the A&E method, he has only allocated a small portion of cost responsibility to the interruptible class in his second approach.

Q. BEFORE YOU CONTINUE, WHAT IS THE CONCEPTUAL BASIS FOR GIVING SPECIAL COST ALLOCATION CONSIDERATION TO INTERRUPTIBLE CUSTOMERS?

A. Because interruptible service can result in short-term curtailments of natural gas at the Company's discretion, this service is considered to be inferior in quality to firm service. As a result, cost allocation studies typically attempt to address the inferior quality of interruptible service is some manner. However, considering the fact that interruptions occur infrequently and are only for a short duration, these customers should not be afforded a free ride in cost responsibility; i.e., while interruptible service should not be treated in the same manner as firm service for cost allocation purposes, it should also receive some assignment of costs.

Q. IS MR. HERBERT'S PROPOSED AVERAGING OF THE TWO APPROACHES DISCUSSED ABOVE APPROPRIATE OR REASONABLE?

A. No. As will be explained below, Mr. Herbert has severely under-assigned cost responsibility to the interruptible class.

Q. IN ORDER TO PUT THE IMPORTANCE OF MR. HERBERT'S PROPOSED ASSIGNMENT OF COST RESPONSIBILITY TO THE INTERRUPTIBLE CLASS IN PERSPECTIVE, WHAT IS THE ABSOLUTE AND RELATIVE SIZE OF UGI'S INTERRUPTIBLE CLASS?

A. As shown in Mr. Herbert's Exhibit D, Schedule F (Factor 2), UGI's interruptible volume is 137,744 MCF/day or 50.277 million MCF/year. This is by far UGI's largest class and accounts for more throughput than the residential, commercial, and medium delivery service classes combined. In fact, UGI's interruptible class represents 41% of the Company's total system annual throughput. With this in mind, Mr. Herbert's method of averaging his two approaches only assigns 3.24% of the Company's total investment in Mains and Mains-related costs to the interruptible class.[6]

Q. DOES UGI ACTUALLY INTERRUPT, OR CURTAIL, ITS INTERRUPTIBLE CUSTOMERS?

A. UGI has interrupted a few customers to a limited degree during certain system peak demand periods. However, as I will explain below, these interruptions represent only a very small portion of interruptible customers' total load and usages during these periods of high system demand. In response to OCA-IV-9, the Company provided a list of specific interruptions during the last five years. While this list shows several interruptions over the last five years, it became apparent that the level of requested interruptions from interruptible customers was very small in relation to this class' total usage during peak periods. Standard Data Requests ("SDR") COS-10 indicates that the 2014-2015 heating season system peak day occurred on January 13, 2015. This schedule (SDR-COS-10) shows that the actual interruptible deliveries on January 13, 2015 was 197,600 Dth which is considerably larger than the interruptible average day usage over the entire year of 137,744 MCF (about 144,000 Dth). At the same time, UGI's response to OCA-IV-9 indicates that it only curtailed 5,266 MCF of interruptible deliveries on this date.[7] Therefore, it is apparent that only a very few interruptible customers were asked to curtail on the system peak day. Indeed, on the annual system peak day, UGI only called for interruptions of about 3% of total interruptible demand on that peak day such that 97% of interruptible demand continued to place load on the system during the peak day.[8]

Similarly, the Company's Filing Attachment IV-B-4-B (which is provided as my Schedule GAW-4 for ease of reference) provides the three consecutive day peak demands during the last several heating seasons. During the most recent year, these three consecutive day peaks occurred on January 5th, 6th, and 7th of 2015. As shown on this

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6 [($35,677,106 ÷ $558,074,997) + ($506,656 ÷ $558,074,997)] ÷ 2.

7 The requested interruptions for most customers were two days during this curtailment period. Therefore, the interrupted volume per day was calculated for each customer.

8 (5,266 MCF x 1.046)/[(5,266 MCF x 1.046) + 197,600 Dth].

Schedule, the interruptible loads on these three days were 199,200 Dth; 176,100 Dth; and 83,500 Dth, respectively.[9]

While it appears that UGI does interrupt a few customers on a very limited basis, the fact is, interruptible usage during system peak loads are exceptionally high, and in some cases, even higher than average annual day usage. This indicates that the quality of UGI's interruptible service is not that much inferior to firm service.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING MR. HERBERT'S PROPOSED ALLOCATION OF COSTS TO THE INTERRUPTIBLE CLASS?

A. It is apparent from the evidence provided that Mr. Herbert has grossly under allocated costs to UGI's interruptible class.

Q. BEFORE WE CONTINUE, IS THERE AN INCENTIVE FOR UGI TO UNDERSTATE THE COST ASSIGNMENT TO THE INTERRUPTIBLE CLASS.

A. Yes. Remember that UGI proposes to only assign the allocated "costs" to the interruptible class as a proxy for the revenue collected from these customers such that the remainder of the Company's entire revenue requirement must picked up, or be the responsibility of, its firm customers. I have established that there is no reasonable possibility that the Company will only collect $4.9 million in interruptible revenue such that the excess revenue that will be realistically collected from interruptible customers will simply flow to shareholders as excess profits. In more succinct terms, the lower the calculated "costs to serve" interruptible customers, the higher UGI's profits will be under its ratemaking proposal.

Q. ARE THERE MORE REASONABLE WAYS TO ALLOCATE COSTS TO INTERRUPTIBLE CUSTOMERS TO RECOGNIZE THAT THIS CLASS MAY RECEIVE SOMEWHAT INFERIOR SERVICE THAN THAT PROVIDED TO FIRM SERVICE?

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[9] Furthermore, SDR-COS-10 and Filing Attachment IV-B-4-B (Schedule GAW-4) clearly shows that interruptible usage during the 2015 annual system peak days (single day or three consecutive day peak) was not an anomaly in that these Schedules show a pattern of consistent (and considerable) interruptible usage during system peak days for each of the last five years.

A. Yes. Under typical circumstances in which a utility actually does curtail all, or most interruptible customers, an approach wherein this class is responsible for the "average" component but no "peak" component within the P&A method may be reasonable. However, this is not the case for UGI. As I have demonstrated, UGI only curtails a very small fraction of interruptible usage even during system peak days. As such, the above referenced approach is not fair and reasonable for assessing the quality of service attributable to UGI's interruptible customers. A much fairer and more reasonable approach is to recognize that UGI's interruptible customers do utilize and rely upon the Company's distribution system to a large degree even during system peak periods. However, some recognition should be given to the fact that these customers can be curtailed at the Company's discretion. Under this approach, the interruptible class would not be assigned the same level of relative costs as firm service customers, but would reflect the fact that these customers do utilize, and rely upon, UGI's system on peak days. I will explain and discuss my recommendation in this regard later in my testimony.

Q. HAVE YOU CALCULATED CLASS RORs AT CURRENT RATES REFLECTING THE INCLUSION OF BUDGETED INTERRUPTIBLE AND ANCILLARY TRANSPORTATION FEE REVENUES UTILIZING MR. HERBERT'S A&E APPROACH WHEREIN HE ALLOCATES ONLY THE AVERAGE PORTION OF THE A&E METHOD TO INTERRUPTIBLE CUSTOMERS?

A. Yes. Under this scenario, the following class RORs are achieved at current rates:[10]

[10] It should be remembered that these amounts do not reflect Mr. Effron's other revenue adjustments to the firm rate classes.

TABLE 2
OCA CCOSS Scenario 1

Class	ROR	Indexed ROR
Rate R	0.81%	14%
Rate N	6.04%	109%
Rate DS	20.63%	371%
Rate LFD	30.56%	549%
Rate XD Firm	50.85%	914%
Interruptible	29.10%	523%
Total Company	5.56%	100%

C. **Bifurcation of Mains**

Q. PLEASE EXPLAIN MR. HERBERT'S PROPOSED BIFURCATION OF MAINS BETWEEN SMALL AND LARGE DIAMETER PIPES.

A. Mr. Herbert proposes to allocate the Company's investment in Mains by assigning cost responsibility to classes based on different criteria for small (2-inch and smaller) and large (greater than 2-inch) diameter Mains. Specifically, Mr. Herbert assigns cost responsibility for large Mains to all customer classes (except XD Firm which is directly-assigned and will be discussed later) while the Company's investment in small diameter Mains must be borne only by Rates R, N, DS and a small portion of LFD and Interruptible.

Q. WHAT IS MR. HERBERT'S RATIONALE FOR BIFURCATING UGI'S MAINS INVESTMENT INTO SMALL AND LARGE DIAMETER MAINS?

A. Mr. Herbert's rationale, and theory, is that large industrial customers do not utilize, or rely upon, small Mains therefore, these customers should not have cost responsibility associated with small Mains.

Q. IS MR. HERBERT'S PROPOSED BIFURCATION OF MAINS THEORETICALLY SOUND OR REALISTICALLY ACCURATE?

A. No. First, it must be recognized that UGI's distribution system is just that – a system. This distribution system provides benefits to all ratepayers collectively such that all customers receive the benefits of economies of scale associated with the joint-use of UGI's Mains facilities. By assigning only a portion of the Company's joint-use Mains costs to large industrial customers, Mr. Herbert's approach cherry picks costs assigned to the large volume classes such that the end result is nothing more than an attempt to reduce the costs assigned to large industrial customers.

The second and interrelated bias in Mr. Herbert's proposed bifurcation of Mains approach concerns the fact that no recognition or consideration is given to those residential (Rate R) and small commercial (Rate N) customers that take service from large Mains and also do not rely upon small diameter Mains. While it would be unreasonable, an equally valid argument could be made by these residential and small commercial customers served by large diameter Mains that they too should not have cost responsibility associated with small diameter Mains placed upon them.

Third, Mr. Herbert has made no attempt to analyze or estimate whether the large volume classes (that are not assigned any small diameter Mains costs) utilize and rely upon the Company's large diameter Mains more than small volume customers in a relative sense.

Q. WAS UGI ABLE TO PROVIDE YOU WITH THE NUMBER OF SMALL VOLUME CUSTOMERS THAT TAKE SERVICE FROM LARGE DIAMETER MAINS?

A. No. In OCA data requests VIII-2, X-3, X-4, and X-5, I requested the Company to provide the number of interruptible, Rate R, Rate N, and Rate DS customers served by Mains over 2-inches in diameter. In each of these responses, the Company indicated that the data is not available.

Q. NOTWITHSTANDING THE INAPPROPRIATENESS OF BIFURCATING MAINS DISCUSSED ABOVE, DID YOU DISCOVER ANY UNREALISTIC ERRORS IN MR. HERBERT'S APPROACH TO BIFURCATE MAINS COST RESPONSIBILITY?

A. Yes. With regard to Rate LFD, Mr. Herbert was provided data by the Company that indicates 19.4% of LFD customers are served by Mains 2-inches or smaller. With this customer percentage, Mr. Herbert then applied this same ratio to the total LFD class' usage and peak day demand amounts proportionally. By doing so, Mr. Herbert's separation of the LFD class results in an unrealistic assumption that an LFD customer served by an 8-inch Main utilizes the same amount of natural gas and has the same peak day demand as an LFD customer served by a 2-inch Main.

With respect to the interruptible class (under his scenario in which interruptible customers are assigned the weighted average usage portion of his A&E method), Mr. Herbert assumed that all IL (large volume) customers are served by large Mains and all IS (smaller volume interruptible) customers are served by smaller diameter Mains. Again, this assumption is unrealistic.

Q. HAS THIS COMMISSION EXPRESSED ITS OPINION AND PROVIDED GUIDANCE REGARDING THE ISSUE OF BIFURCATING MAINS?

A. Yes. Based on my 20-plus years practicing before the Pennsylvania PUC I believe the issue of a proposed bifurcation of Mains was last litigated in the 1994 rate case involving National Fuel Gas Distribution Corporation ("NFG") in Docket No. R-00942991. In its Order, the Commission flatly rejected NFG's proposal to bifurcate Mains for cost allocation purposes. The Commission's findings in this NFG case were as follows:

> After a review of the record, we find that the arguments opined by OCA are most persuasive. We conclude that we should retain our historic practice of allocating total distribution main costs based on each class' contribution to peak and annual requirements. NFG's proposed small mains adjustment suffers from the same weaknesses that we have previously found required the rejection of other alternatives to a Peak and Average cost of service study.

> Specifically, we have previously rejected proposals for a zero-intercept or minimum system method of cost of service. In those cases we rejected these methods, agreeing with the OCA's position that such methods are not consistent with cost causation.
>
> There is little on this record to distinguish NFGD's proposed small main adjustment in the instant proceeding from the "minimum system" approach which we have previously rejected. Like the minimal system approach, the small mains adjustment would allocate the costs of smaller mains primarily to customers with smaller throughput. At the same time, NFGD did not propose an equally skewed allocation of larger distribution mains to customers with larger throughput based on any analysis of the use of such larger-size distribution mains by smaller customers. Instead, the focus of NFG's study was clearly to relieve large customers of the burden of paying for smaller distribution mains, without any consideration of whether small customers should be paying for larger distribution mains.
>
> NFGD's current system embodies numerous past and on-going augmentations to meet the continually changing requirements of its customers, and it is simply improper to look at the distribution system at a particular point in time and attempt to identify particular sizes of mains to particular customer classes. The Company's analysis focuses only upon the use of small mains by large customers and does not consider small customers' use of large mains. The size of mains directly connected to a customer is only a small factor in determining the cost of system augmentation necessary to serve a particular customer or customer class. Main line extensions are made based upon the particular economics of each extension in terms of the load generated and the number of customers served.
>
> For all the reasons discussed above, we find that NFGD's separate treatment of small and large mains for cost allocation purposes should be rejected. The Peak and Average method that allocates mains equally is a sound and reasonable method of cost allocation and should remain intact.[11]

Q. WHAT IS YOUR RECOMMENDATION CONCERNING MR. HERBERT'S PROPOSED BIFURCATION OF MAINS?

A. Mr. Herbert's proposal should be rejected such that all joint-use Mains costs should be aggregated and allocated to classes accordingly.

[11] Docket No. R-00942991, Final Order at pp. 101-102.

Q. CAN YOU PROVIDE A SUMMARY OF CLASS RORs AT CURRENT RATES WHEREIN THERE IS NO BIFURCATION OF MAINS-RELATED COSTS?

A. Yes. Building upon the scenario I presented earlier wherein I reflected my adjustments to interruptible and ancillary transportation service fee revenues, the following class RORs at current rates are produced under Mr. Herbert's A&E method:

TABLE 3
OCA CCOSS Scenario 2

Class	ROR	Indexed ROR
Rate R	0.93%	17%
Rate N	6.39%	115%
Rate DS	22.03%	396%
Rate LFD	20.30%	365%
Rate XD Firm	50.85%	914%
Interruptible	26.14%	470%
Total Company	5.56%	100%

D. Direct Assignment of Mains

Q. PLEASE EXPLAIN MR. HERBERT'S PROPOSED DIRECT ASSIGNMENT OF MAINS-RELATED COSTS TO CERTAIN RATE CLASSES.

A. Mr. Herbert proposes to "directly-assign" Mains investment and related costs to each of the 27 XD Firm customers and to one large interruptible customer. Specifically, UGI's engineering personnel developed an approach to assign a specific piping route of distribution Mains from a city gate to the customer's delivery point for each of the above-referenced customers. As will be discussed and shown below, this approach conducted by UGI personnel developed a path of natural gas flow wherein a specific distribution pipe is assumed to serve each customer. Then, UGI personnel somehow estimated the embedded cost of this assumed piping route based on the length and diameter of the Mains pipe associated with this path. These costs for each customer where then provided to Mr. Herbert.

Q. IS IT SOMETIMES REASONABLE AND APPROPRIATE TO DIRECTLY-ASSIGN MAINS COSTS TO SPECIFIC CUSTOMERS?

A. In some instances, yes. However, such is not the case for UGI. In instances in which there is a dedicated Main that serves no other customers (typically a spur from an interstate pipeline or a spur directly from a NGDC city gate) and which a customer relies upon no other upstream facilities of the NGDC, a direct assignment of Mains costs are commonly appropriate since these customers also typically have a legitimate threat of bypassing the NGDC, thereby relying only upon an interstate pipeline to obtain gas delivery.

Before I continue explaining why it is not appropriate to directly-assign costs to certain large industrial customers served by UGI, it is helpful to understand UGI's pricing and justification for offering an XD rate. Every XD customer is served under a contractual negotiated rate. UGI claims that these XD customers require negotiated rates because each has a legitimate threat of bypassing UGI's system entirely by having their gas delivered directly from an interstate pipeline.[12] As part of my investigation, I evaluated whether each of these XD customers truly have a legitimate threat of bypass. In response to I&E-RS-9-D, the Company provided its justification for offering a negotiated rate and confirmation that each customer has a legitimate alternative gas supply. I have included the Company's Attachment D(e) to this data request response as my Schedule GAW-5.

As can be seen in this Schedule, several XD Firm customers have no legitimate threat of bypassing UGI's distribution system simply due to the distance to an alternative gas supply (presumably an interstate pipeline). As an illustration, the very first customer on the list is located 20 miles from an alternative gas supply. It is inconceivable that a private firm with no powers of eminent domain could secure the rights of way over a 20-mile path in order to build its own natural gas pipeline in order to obtain natural gas from an alternative supplier. Notwithstanding the unrealistic legal hurdles that would have to be met in order to secure rights-of-way to build a stand-alone pipeline of this distance, the economic cost of building and maintaining such a stand-alone pipe over this distance is

[12] Per Company response to I&E-RS-9-D.

almost certainly prohibitive. As we move down the list of customers provided in this Schedule. There are a total of 12 customers that are at least 4 miles away to an alternative source of gas supply. As is the case for the first customer, it is frankly implausible that these individual customers could possibly secure rights-of-way or economically justify the cost of a stand-alone pipeline. The reason for my investigation of whether there are legitimate threats of bypass from these negotiated rate XD customers is that the vast majority of these negotiated rates are exceptionally low. As such, there is a clear incentive for UGI to assign as few costs as possible to this class of customer in order to lend legitimacy to these exceptionally low rates.

Q. PLEASE EXPLAIN WHY THE DIRECT ASSIGNMENT OF MAINS INVESTMENT TO XD CUSTOMERS IS NOT APPROPRIATE FOR UGI.

A. As explained above, the circumstances in which it may be appropriate to directly-assign Mains costs to individual customers, namely, that being when a large industrial customer is served by a single distribution Main that does not serve any other customers and which a customer does not rely upon any other facilities of the NGDC upstream from the dedicated spur, does not exist here.

In response to OCA-IV-3, the Company provided Highly Confidential schematics of each XD customer along with the path utilized by UGI's company personnel to "directly-assign" a Main's section to each customer. I have provided these schematics in my Highly Confidential Schedule GAW-6. While there are a few customers that are served by a dedicated Mains spur, such as the customer shown on page 1 of Attachment OCA-IV-3.2 (page 2 of my Schedule GAW-6), many (if not most) of these customers are simply located within the UGI system of jointly-used Mains wherein just like all other customers, they rely upon a host of Mains facilities. However, the Company's direct assignment approach assumes there is a specific direct Main from each customer's delivery point to a city gate. Using Customer "FOURTEEN" as an example, and shown on page 15 of my Highly Confidential Schedule GAW-6 (page 14 of Attachment OCA-IV-3.2), we can clearly see that this customer is simply part of the UGI distribution system and utilizes the Company's joint-use distribution Mains just like every other customer. As importantly it can be seen that the traced Mains for this customer also serves a multitude of other customers. Other examples include (but are not limited to) Customer Numbers "THREE," "FOUR," "FIVE," "SIX," "EIGHT," "TEN," "TWELVE," "THIRTEEN," "FIFTEEN," "SIXTEEN," "SEVENTEEN," "EIGHTEEN," "TWENTY-ONE," "TWENTY-TWO," "TWENTY-THREE," "TWENTY-FOUR," "TWENTY-FIVE," "TWENTY-SIX," and "TWENTY-SEVEN."

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE COMPANY'S SO-CALLED DIRECT ASSIGNMENT OF MAINS TO XD CUSTOMERS AND TO ONE LARGE INTERRUPTIBLE CUSTOMER?

A. The Company's proposal is an attempt to minimize the costs assigned to the XD class. I have clearly shown that these customers cannot be directly-assigned specific Mains investments as they are served and/or utilized by a multitude of joint-use Mains that serve all UGI customers.

Q. PLEASE PROVIDE A SUMMARY OF CLASS RORs AT CURRENT RATES WITHOUT THE DIRECT ASSIGNMENT OF MAINS TO THE XD CLASS AND ONE LARGE INTERRUPTIBLE CUSTOMER.

A. Building upon the scenarios provided earlier, the following class RORs at current rates are achieved with no direct assignment of Mains and utilizing Mr. Herbert's A&E methodology to allocate Mains:

TABLE 4
OCA CCOSS Scenario 3

Class	ROR	Indexed ROR
Rate R	1.49%	27%
Rate N	7.96%	143%
Rate DS	28.95%	520%
Rate LFD	35.78%	643%
Rate XD Firm	6.27%	113%
Interruptible	7.10%	128%
Total Company	5.56%	100%

E. The A&E Method Compared to the P&A Method

Q. YOU HAVE STATED EARLIER THAT MR. HERBERT HAS UTILIZED THE A&E METHOD TO ALLOCATE MAINS. DOES THIS COMMISSION HAVE A CONSISTENT POLICY REGARDING ITS PREFERRED METHOD TO ALLOCATE DISTRIBUTION MAINS FOR NGDCs?

A. Yes. As I discussed earlier in my testimony, this Commission has expressed a preference in NGDC cases that the allocation of distribution Mains should consider, or reflect, both peak demands and annual usage (average daily demands). This recognition of both annual usage and peak day demand is reflected in the P&A method and is only considered to a much lesser degree under the A&E method.

Q. PLEASE EXPLAIN, OR DEFINE, THE TERMS "AVERAGE DEMAND," "PEAK DEMAND," AND "EXCESS DEMAND."

A. Because class cost of service studies allocate costs based on relative (percentage) class contributions to a given allocator, the term average demand is identical to annual usage. That is, average (daily) demand is each class' annual MCF usage divided by 365. As such, the relative class percentages of average (day) demand and annual usage are identical. Peak demand can be expressed in terms of class contributions to system coincident peak demand (CP demand) or in terms of class non-coincident peak demand (NCP demand). NCP demands differ in concept from CP demands in that the former reflect a measurement of individual class peak usage, regardless of when the system as a whole experiences annual peak load whereas CP demands reflect class contributions to load at the time of the system peak.

"Excess demand" as used in the A&E method reflects the arithmetic difference between class NCP demand and average day demand. It is important to understand that class "Excess" demands are not the same in amount or concept as class peak demands. Class peak demands represent contributions to peak usage, whereas excess demands reflect relative differences in class load factors. This distinction is most important because the relative "excess demands" assigned to low load factor customer classes (such as the residential class) greatly exceed their relative contributions to peak demand.[13]

Q. PLEASE EXPLAIN HOW THE P&A METHOD IS DEVELOPED AND HOW IT REFLECTS AVERAGE AND PEAK DAY DEMANDS.

A. The P&A method uses a pre-determined weighting between annual usage and peak demand. In Pennsylvania, the Commission-accepted practice is an equal weighting between average demand and peak demand; i.e., 50% weighting to average and 50% weighting to peak demand. Under the P&A method, the calculations are straight forward and easily understood. That being, 50% weight is given to average demand and 50% weight is given to peak day demands such that an allocator is developed based on each class' relative contributions to both average day demand and peak demand.

Q. IS THERE A MATERIAL DIFFERENCE IN MR. HERBERT'S A&E METHOD COMPARED TO THE P&A METHOD AS IT RELATES TO THE WEIGHT GIVEN TO AVERAGE AND PEAK DEMANDS?

A. Yes. As referenced earlier in my testimony and as shown in my Schedule GAW-3, Mr. Herbert's A&E method uses a weighting of 23.5% toward average demand and 76.5% toward peak day demand.[14]

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13 This can easily be seen using two examples. Suppose there are two customer classes – an industrial class with a load factor of 100% and a residential class with a low load factor of 20%. Each class has the same level of peak day usage such that each class' relative contribution to system peak demand is 50%. Under the A&E method, the excess demand for the very high load factor industrial customer class will be zero since peak demand is the same as average demand such that this class would not be assigned any peak day responsibility. Similarly, the excess demand for the low load factor residential customer class would be significantly higher than its relative contribution to peak day demand because its peak day demand is five times as great as its average day demand (resulting in a 20% load factor). As such, the low load factor residential class would be allocated 100% of peak day demands embedded within the A&E method.

14 It should be noted that these weightings under Mr. Herbert's A&E method reflects his allocation factor for assigning large Mains. Because I have rejected Mr. Herbert's bifurcation of Mains proposal, this is the relevant weighting to compare to the P&A weighting of average and peak day demands. However, in the interest of full disclosure, Mr. Herbert's weighting for small Mains is 72.0% peak demand and 28.0% average demand.

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS CONCERNING THE USE OF MR. HERBERT'S PROPOSED USE OF THE A&E METHOD OVER THE LONG ACCEPTED P&A METHOD?

A. Considering that Mr. Herbert's A&E method weights peak demand at 76.5% and average demand at only 23.5% compared to this Commission's long accepted practice and policy of utilizing a 50%/50% weighting between peak demand and average demand, I recommend the use of the P&A method for purposes of this case.

Q. PLEASE PROVIDE A SUMMARY OF CLASS RORs AT CURRENT RATES UTILIZING THE P&A METHOD INSTEAD OF MR. HERBERT'S A&E METHOD TO ALLOCATE MAINS.

A. Building upon the scenarios provided earlier, the following class RORs at current rates are achieved under the P&A method:

TABLE 5
OCA CCOSS Scenario 4

Class	ROR	Indexed ROR
Rate R	1.83%	33%
Rate N	9.01%	162%
Rate DS	30.16%	542%
Rate LFD	23.87%	429%
Rate XD Firm	4.28%	77%
Interruptible	5.23%	94%
Total Company	5.56%	100%

F. Assignment of Some Peak Demand Responsibility to the Interruptible Class

Q. EARLIER IN YOUR TESTIMONY YOU EXPLAINED THAT UGI'S INTERRUPTIBLE CUSTOMERS UTILIZE AND RELY UPON THE COMPANY'S DISTRIBUTION SYSTEM EVEN DURING SYSTEM PEAK

PERIODS. PLEASE PROVIDE YOUR RECOMMENDATION TO REFLECT THIS FACT.

A. As discussed earlier in my testimony, UGI only interrupted about 3% of its interruptible load during the peak day on January 13, 2015 such that about 97% of the interruptible load continued to rely upon and place load on UGI's system. With this in mind, it must be remembered that Mr. Herbert assigned cost responsibility to the interruptible class based on the average of two methods: one in which virtually no Mains costs were assigned to interruptible customers; and, a second in which he assigned Mains costs to the interruptible class based only on the average component of his A&E allocation method, but no recognition of a peak demand measure. Furthermore, as discussed earlier, Mr. Herbert's A&E approach only places a weight of 23.5% towards average usage. In order to recognize that only a very small portion of interruptible load is curtailed during system peak periods, some weight and consideration should be given to this fact. In this regard, my Schedule GAW-4 indicates that on January 7, 2015 (which was not the system peak day), the interruptible load was 83,500 Dth. In addition, the Company's response to OCA-IV-9 indicates that 19,946 MCF was curtailed on that day (about 20,850 Dth). As such, on January 7, 2015, the Company curtailed about 20% of interruptible load.[15]

Based on the patterns of very limited interruptions and the fact that interruptible customers continually use and rely upon the Company's distribution system during periods of high system demand, a fair and reasonable proxy for interruptible load during peak day conditions is 80,000 MCF (approximately equal to the lowest interruptible load during the peak periods over the last few years).

Q. **PLEASE PROVIDE THE CCOSS RESULTS AT CURRENT RATES UTILIZING THE INCLUSION 80,000 MCF PEAK LOAD ATTRIBUTABLE TO INTERRUPTIBLE CUSTOMERS.**

A. Building upon my prior adjustments to Mr. Herbert's CCOSS, the following class RORs are achieved at current rates:

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[15] 20,850 Dth ÷ (20,850 Dth + 83,500 Dth).

TABLE 6
OCA Recommended CCOSS

Class	ROR	Indexed ROR
Rate R	1.99%	36%
Rate N	9.52%	171%
Rate DS	31.97%	575%
Rate LFD	24.85%	447%
Rate XD Firm	4.77%	86%
Interruptible	3.14%	56%
Total Company	5.56%	100%

Q. WHAT IS YOUR RECOMMENDED CCOSS FOR PURPOSES OF THIS CASE?

A. I recommend the Commission rely upon the CCOSS results I provided immediately above. The details of this CCOSS are provided in my Schedule GAW-7.

Q. WHAT CONCLUSIONS CAN BE DRAWN FROM YOUR RECOMMENDED CCOSS?

A. First it must be remembered that my recommended CCOSS (or any other conducted for this case) can only be relied upon in a limited fashion. This is primarily due to the significant downward revenue adjustments to the firm core classes reflected in Mr. Herbert's as well as my CCOSS. Indeed, if the Commission adopts the OCA's recommendations to reverse these various downward revenue adjustments, considerably different class RORs may result. Moreover, it is my understanding that OCA witness Effron is recommending a significant overall revenue requirement reduction such that his adjustments and recommendations likely have a material impact on allocated costs across classes.

With these limitations, there are a few conclusions that can reasonably be drawn from my CCOSS. First, unlike Mr. Herbert's CCOSS in which his allocation procedures develop a "cost to serve" the interruptible class of $4.9 million, my recommended CCOSS indicates an interruptible "cost to serve" of $29.3 million (utilizing UGI's proposed ROR). As such, even though UGI's ratemaking proposal regarding

Q. DO THE DOLLAR AND PERCENTAGE INCREASES SHOWN ABOVE AND REFLECTED IN MR. LAHOFF'S REVENUE PROOF AS WELL AS MR. HERBERT'S CCOSS ACCURATELY REFLECT THE COMPANY'S PROPOSED INCREASES?

A. No. As discussed at length earlier in my testimony, the Company's system-wide requested increase of $58.6 million reflects the exclusion of $14.1 million of current interruptible margin revenue as well as the exclusion of $2.3 million of current ancillary transportation fee margin revenues. When these two excluded revenue sources are reflected, the total Company proposed increase in margin revenues becomes 19.5% ($42.1 million).[16] However, most importantly, UGI is actually proposing an 8.0% reduction to Rate DS revenues. This is because while UGI claims that they are proposing a revenue increase of $981,480 to this class' revenues, they fail to consider that its rate design adjustment to eliminate current ancillary transportation fees reduces Rate DS revenues by $1,983,000.[17] Therefore, the true change in Rate DS revenue under UGI's proposal is a reduction of $1,001,520. UGI's claimed class revenue increases as well as the effective changes in class revenues is provided on page 1 of my Schedule GAW-8.

Q. NOTWITHSTANDING THE ABOVE, WHAT METHODOLOGICAL FRAMEWORK DID MR. LAHOFF USE FOR HIS PROPOSED CLASS REVENUE INCREASES?

A. Mr. Lahoff considered the CCOSS results developed by Mr. Herbert as well as rate gradualism. Specifically, on page 21 of his direct testimony, Mr. Lahoff indicates he utilized the following methodological framework: limit the increase to the residential class to 150% of the system average percentage increase; rate classes that are shown to have above average rates of return at present rates received increases less than the system average percentage increase (Rates N, DS, and LFD); and, Rates XD and Interruptible receive no increase since these rates are "negotiated and established under their current service agreements."

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[16] $58,563,925 minus $14,096,000 minus $2,348,000.

[17] Per Exhibit DEL-3(i).

Q. IS MR. LAHOFF'S CONCEPTUAL FRAMEWORK REASONABLE AND FAIR TO ALL RATEPAYERS?

A. Generally speaking, yes. However, as shown on page 1 of my Schedule GAW-8, Mr. Lahoff's proposed $43.3 million increase to the residential class (Rate R) results in an effective increase of 165% of the system average percentage increase. In addition and as discussed earlier, while Mr. Lahoff's analysis would lead one to believe that he is proposing a 9.3% increase to Rate DS, the reality is, his recommendations results in an 8.0% reduction in revenue responsibility to this class. While I have serious concerns regarding the revenue responsibility associated with the XD Firm and Interruptible class, and which will be discussed later in my testimony, I will accept the Company's proposed zero increases for these two classes due to the fact that these revenues are based on individual customer contract rates.

Q. GIVEN YOUR AGREEMENT WITH MR. LAHOFF'S GENERAL CONCEPTUAL FRAMEWORK, HAVE YOU PREPARED A CLASS REVENUE INCREASE ALLOCATION RECOMMENDATION THAT CORRECTS FOR THE INCLUSION OF INTERRUPTIBLE AND ANCILLARY TRANSPORTATION FEE REVENUE AT CURRENT RATES AS WELL AS RECOGNIZING THAT MR. LAHOFF EFFECTIVELY PROPOSES A RATE REDUCTION TO RATE DS?

A. Yes. When current interruptible and ancillary transportation fee revenues are added back into revenues at current rates, the Company's proposed increase becomes $42.120 million (which still generates the Company's proposed overall revenue requirement of $274.629 million). With these two corrections, the system-wide increase is 19.49%. I have accepted Mr. Lahoff's proposal to increase the residential class at 150% of the system average percentage increase of 19.49%, which results in a residential increase of $31.776 million (29.24%). Consistent with Mr. Lahoff's general conceptual framework, I then increased the Rate N, DS, and LFD revenues by a much smaller percentage increase than the system-wide average percentage increase. Specifically, I allocated the remaining $10.344 million increase to the Rate N, DS, and LFD classes in proportion to Mr. Lahoff's claimed proposed increases ($12.496 million to Rate N, $0.981 million to Rate DS, and $1.754 million to Rate LFD). My approach results in the following increases to each class:

TABLE 8
OCA Proposed Class Revenue Increases

Class	Increase $	Increase %
Rate R	$31,775,982	29.2%
Rate N	$8,486,075	15.4%
Rate DS	$666,538	5.3%
Rate LFD	$1,191,329	4.8%
Rate XD Firm	$0	0%
Interruptible	$0	0%
Total Company	$42,119,925	19.5%

The details supporting my recommended class revenue allocation are presented on page 2 of my Schedule GAW-8.

Q. DOES YOUR PROPOSED $0.667 MILLION INCREASE TO RATE DS INCLUDE THE EFFECTS OF ANY RATE DESIGN CHANGES ASSOCIATED WITH THE COMPANY'S PROPOSAL TO ELIMINATE ANCILLARY TRANSPORTATION FEES?

A. Yes. I take no position and offer no opinion as to whether these ancillary transportation fees should or should not be eliminated from the Company's current tariff. Whether these fees are or are not eliminated is immaterial as it regards my proposed $0.667 million increase to Rate DS. In other words, should the Commission decide to eliminate these current ancillary transportation fees, the Company will lose $1.983 million of tariff revenue currently received from Rate DS. Under this situation, this loss of $1.983 million must be made up somewhere within the DS class (presumably as an increase to volumetric charges). In short, my recommendation is that when all Rate DS rate design and tariff changes are said and done, the DS class should be responsible for an additional $0.667 million at the Company's requested overall revenue requirement.

Q. IN THE EVENT THE COMMISSION AUTHORIZES AN INCREASE LESS THAN THAT REQUESTED BY UGI, HOW SHOULD THE OVERALL INCREASE BE ALLOCATED TO INDIVIDUAL RATE CLASSES?

A. I recommend that class revenue increases by scaled-back proportional to my recommended class revenue allocation at the Company's requested overall revenue requirement; i.e., proportional to those provided on page 2 of my Schedule GAW-8.

Q. OCA WITNESS EFFRON IS RECOMMENDED A SIGNIFICANT REDUCTION TO UGI'S TOTAL REVENUES. HOW SHOULD ANY REVENUE REDUCTION BE ALLOCATED TO INDIVIDUAL RATE CLASSES?

A. Any overall decrease ordered by the Commission should be allocated to classes based on the reciprocal of my proposed relative class percentage increases. For example, if the Commission orders a $20.0 million revenue reduction, the residential class (Rate R) should receive 66.7% (1 ÷ 150%) of the system-wide percentage decrease, whereas, the remaining classes should receive reductions proportional to the reciprocal of my revenue allocations under a total revenue increase scenario. In this manner, all core classes would receive some rate reduction, however, those classes that exhibit a much higher rate of return than the system average (Rates N, DS, and LFD) would receive a larger percentage rate reduction than the residential class.

VI. NEGOTIATED RATES

Q. EARLIER IN YOUR TESTIMONY YOU INDICATED THAT ALL INTERRUPTIBLE AND XD FIRM RATES ARE ESTABLISHED ON A NEGOTIATED BASIS. PLEASE EXPAND ON THIS EXPLANATION.

A. Currently, there are more than 320 customers that receive interruptible service and about 27 large industrial customers that receive firm XD service. With regard to interruptible service, the Company claims that these rates are negotiated on a customer-by-customer basis based on unknown or undefined criteria. The Company has indicated that these negotiated rates are based on the price differential between natural gas and the customer's alternative fuel source. With regard to XD Firm service, UGI alleges that this service is offered to large industrial customers that have a legitimate threat of bypass.

As I have discussed earlier in my testimony, UGI rarely interrupts customers and when they do it is only for a very small fraction of the total interruptible load. With regard to XD customers, I have found numerous instances which there is no apparent threat of bypass and that many (if not most) of the XD Firm customers use the Company's distribution facilities in a joint manner just like any other customer that is served under Commission established rates.

Furthermore, I have observed that the distribution charges imposed on interruptible and XD Firm customers are in many cases exceptionally low -- so low in fact, that they cannot be justified as being fully compensatory. Indeed, these customers that represent more than 55% of UGI's total annual throughput are dispersed throughout its service area and utilize and rely upon the Company's distribution Mains and other facilities just like all other customers that must pay Commission-approved rates that are significantly higher. Because these rates are "negotiated," the Company's position is certainly that this Commission may not impose any increases to these customers simply because the rates are set by contract. In other words, UGI takes the position that its contractual agreements between it and individual customers circumvents the regulatory pricing authority and responsibility of this Commission.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THESE NEGOTIATED RATES?

A. I recommend that UGI be required to revise its tariff provisions relating to Rate XD to include appropriate pricing parameters to ensure that all future contracts for negotiated rates are fair and reasonable. I further recommend that UGI not be allowed to enter into any new contracts for negotiated rates for Rate XD until the Commission has approved UGI's revised Rate XD tariff. My recommendation will not affect any existing contracts, only future contracts.

VII. RESIDENTIAL RATE DESIGN

A. Residential Rate Structure

Q. PLEASE EXPLAIN THE CURRENT AND UGI PROPOSED RESIDENTIAL BASE NON-GAS RATE STRUCTURE.

A. Currently, UGI's residential base non-gas rates are structured with a fixed monthly customer charge and a declining-block distribution charge. UGI proposes to modify this current rate structure by eliminating the declining-block volumetric charge in favor of a flat volumetric rate for all gas consumed.

Q. DO YOU AGREE WITH THIS PROPOSED CHANGE?

A. Yes. I support the elimination of declining-block usage rates for NGDCs as they do not reasonably reflect the imposition of costs, nor do they send an appropriate price signal to promote energy conservation.

B. Residential Customer Charge

Q. WHAT ARE THE CURRENT AND UGI PROPOSED RESIDENTIAL FIXED MONTHLY CUSTOMER CHARGES?

A. Currently, the residential customer charge is $8.55 per month and UGI proposes to increase the customer charge by 105% to $17.50 per month.

Q. IS UGI'S PROPOSED 105% INCREASE TO THE RESIDENTIAL FIXED MONTHLY CHARGE FAIR AND REASONABLE?

A. No. While Mr. Lahoff clearly states that he recognized the important regulatory concept of gradualism within his class revenue allocation proposal, he totally abandoned this concept and constraint in proposing his $17.50 monthly customer charge. Indeed, an abrupt increase of this magnitude will cause rate shock to not only low volume customers that use small amounts of gas throughout the year but also virtually every residential customer during the non-heating months. That is, virtually all residential customers use relatively small amounts of natural gas during the non-heating seasons (late spring, summer and early fall), so for the majority of the year, all residential customers would incur massive percentage increases in their natural gas bills. In short, the Company's proposed residential customer charge increase of 105% to $17.50 is simply unfair, unreasonable, and does not comport with generally accepted ratemaking principles.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING RESIDENTIAL CUSTOMER CHARGES?

A. I recommend that the residential customer charge be increased to a level of no more than $11.25 per month. My recommended maximum residential customer charge reflects a 31.6% increase in this charge and is a higher percentage than that for the residential class as a whole. However, my recommendation of $11.25 per month is based on the Company's requested overall revenue requirement. Should the Commission authorize an overall revenue requirement less than that requested by UGI, my maximum customer charge of $11.25 should be reduced in proportion to the reduction in the overall revenue increase.

Q. IF THE COMMISSION ORDERS AN OVERALL REVENUE REQUIREMENT REDUCTION AS RECOMMENDED BY OCA, WHAT IS YOUR RECOMMENDED RESIDENTIAL MONTHLY CUSTOMER CHARGE?

A. To the extent that the overall and residential revenue requirement is reduced, I recommend that the current customer charge of $8.55 per month be maintained such that any residential revenue reduction be applied to the flat volumetric rate.

VIII. ENERGY EFFICIENCY AND CONSERVATION ("EE&C") PROGRAM/RIDER

Q. PLEASE BRIEFLY DESCRIBE UGI'S PROPOSED EE&C PLAN.

A. The Company proposes various five-year energy efficiency and conservation programs that will be applicable to residential and commercial customers generally. In this regard, the Company has structured its EE&C programs to differentiate between residential and commercial-specific programs. Because the amount of costs incurred by UGI to implement and administer these proposed EE&C programs will depend largely on the achieved participation levels, the Company proposes to be compensated for the expenses they incur using separate reconcilable riders applicable to residential and commercial customers. With respect to residential customers, UGI proposes a "Residential Prescriptive Plan" which provides incentives for several types of energy efficient appliances and equipment, a "New Construction Plan," a "Residential Retrofit Plan," and a "Behavior and Education Program."

Q. WITH REGARD TO THE RESIDENTIAL PRESCRIPTIVE PLAN, WHAT SPECIFIC INCENTIVES ARE PROPOSED BY UGI?

A. The Residential Prescriptive Program will include incentives (rebates) to residential customers that choose to install high efficiency furnaces, boilers, combination boilers, tankless water heaters and Wi-Fi enabled thermostats.

Q. PLEASE GENERALLY EXPLAIN UGI'S PROPOSED NEW CONSTRUCTION PLAN.

A. While the New Construction Plan will be available to both residential and non-residential sectors, UGI will track these expenses separately between the residential and commercial classes. While this program is not specifically defined, Company witness Theodore Love indicates that this program will be available to builders and developers that go beyond installing space and water heating equipment which simply meets code. This program will also provide incentives to builders and developers for other non-specifically defined criteria. According to Mr. Love's report on page 43, "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 envelop insulation, heating equipment, and water heating equipment and fixtures." In return for these additional upgrades, Mr. Love indicates that residential customers will receive a lump sum incentive for achieving 20% savings or greater compared to a house only meeting code. In reality, these incentives would be paid to a builder or developer as indicated on page 42 of Mr. Love's report.

Q. PLEASE GENERALLY EXPLAIN UGI'S PROPOSED RESIDENTIAL RETROFIT PLAN.

A. As its name implies, this proposed program will provide incentives to customers retrofitting or weatherizing their homes by installing energy efficient space and water heating equipment, programmable thermostats, and/or making thermal envelope improvements. While Mr. Love's description of the Residential Retrofit Plan is not entirely clear, the proposed "thermal envelope improvements" will be directed towards more efficient furnace blowers, increased insulation and decreased leakage from doors and windows. The Company's plan is to offer an incentive of approximately $60 per first year MMBtu savings for eligible projects.

Q. PLEASE GENERALLY EXPLAIN UGI'S PROPOSED BEHAVIOR AND EDUCATION PLAN.

A. Although this plan may be considered a customer education type program, UGI proposes to conduct specific analyses for individual residential customers. Moreover, and according to Mr. Love, the program will be targeted to residential heating customers who are identified as high users such that all of these identified customers will be automatically enrolled in this program unless they specifically opt-out. With this understanding, UGI proposes to provide each of these identified customers with specific data relating to their gas usage, weather data, demographic and parcel information, and service interactions. In addition, each identified customer that does not specifically opt-out of the program will receive an energy report detailing their gas usage and how their usage compares with neighbors or others with similar demographics. It is estimated that this program will cost approximately $9.00 per customer per year.

Q. DID UGI'S CONSULTANT, MR. LOVE, CONDUCT COST BENEFIT ANALYSES THAT SUPPORT THE EFFECTIVENESS OF EACH OF THE PROPOSED RESIDENTIAL PLANS?

A. Yes. Mr. Love conducted cost benefit analyses for each plan utilizing what is known as the Total Resource Cost test ("TRC"). In all instances, Mr. Love found that the present value of anticipated benefits exceeds the present value of the plan's costs; i.e., benefit-to-cost ratio is greater than 1.00.

Q. HAVE YOU REVIEWED THE COST BENEFIT ANALYSES CONDUCTED BY MR. LOVE, AND IF SO, WHAT ARE YOUR FINDINGS?

A. Yes. While Mr. Love's cost benefit models are inordinately complex, I was able to evaluate the sensitivities of the major assumptions used within his analyses. Furthermore, I was able to determine that Mr. Love's analyses generally follows the accepted TRC approach. When analyses of this type are conducted, the primary assumption drivers are participation levels, projections of future natural gas prices, inflation, and discount rates for present value purposes. In general, I found Mr. Love's assumptions to be reasonable. It should be noted that because Mr. Love's projection of future natural gas prices tend to be on what I would consider to be the high side, I conducted sensitivity analyses utilizing an extreme situation with no future increases in natural gas prices and all programs still pass the TRC. Similarly, I also conducted sensitivity analyses using alternative inflation and discount rates (upwards and downwards) and the proposed programs still pass the TRC standards. In summary, given the expected participation levels and proposed incentives, the residential programs proposed by UGI pass the TRC under any reasonable assumed inputs and forecasts.

Q. ARE THE SPECIFIC RESIDENTIAL EE&C PROGRAMS PROPOSED BY UGI REFLECTIVE OF OTHER NATURAL GAS CONSERVATION PROGRAMS YOU HAVE SEEN IMPLEMENTED BY OTHER NGDCs IN OTHER STATES?

A. In general, yes. This is particularly true for the Residential Prescriptive Plan. However, I am somewhat concerned about the ambiguity and non-specifically defined incentive programs that will be offered under the proposed Residential New Construction and Retrofit Plans which will be addressed later in my testimony.

Q. DO YOU RECOMMEND ANY SPECIFIC CLARIFICATIONS, MODIFICATIONS OR CHANGES TO UGI'S PROPOSED EE&C PLANS?

A. Yes. I will discuss my recommended clarifications, modifications, and changes to each of the proposed residential EE&C programs.

<u>Residential Prescriptive Program</u> – In general, the Company's proposed Residential Prescriptive Program is acceptable and is similar to those incentive programs offered by other NGDCs that have such programs around the Country. However, I do recommend a specific modification that all equipment and appliances (except for Wi-Fi thermostats) exceed U.S. Department of Energy ("U.S. DOE"), Energy Star minimum requirements. For example, under the Company's current proposal, customers would receive a $200 incentive for installing tankless water heaters with an energy factor of at least 82%. However, the U.S. DOE Energy Star program requires a minimum energy factor of 90%. Because all ratepayers will be required to fund programs that benefit a select few customers, the equipment qualifying for the ratepayer funded program should be limited to only the most energy efficient appliances and equipment.

The next clarification or modification that I recommend relating to the Residential Prescriptive Plan is that it should be clear that conversions from other fuel sources (such as electricity or oil) to natural gas will not qualify for incentives under this program. While it may legitimately be argued that conversions from alternative fuels will promote the conservation of society's resources and may even help reduce our carbon footprint, this ratepayer funded program should not be used as a marketing tool for UGI to expand its natural gas sales and business.

New Construction Plan – My major concern regarding the Company's proposed New Construction Plan is that it is vague and ambiguous as to what incentives will or will not be provided to builders and developers. Specifically, the Company claims that it will provide an incentive of "approximately 80% of the incremental cost" for achieving at least 20% gas savings over and above what would be required by building code. The ambiguous nature of the Company's plan as written is that it is unclear whether a builder/developer could (would) receive incentives for installing high efficiency furnaces, boilers, and/or tankless water heaters and then qualify again for savings because the culmination of these energy efficient appliances, coupled with say upgraded insulation, achieved at least 20% gas savings over what would occur under a minimum code standard. I would much prefer to see specific criteria developed for specific items such as predefined incentives for energy efficient windows and doors and specific criteria for insulation upgrades above building code requirements. Furthermore, there should be a specific limitation that the New Construction Plan is only available for developments that currently have gas or will have gas (as per a Main extension agreement). This will prevent developers from using the New Construction Plan incentives to offset Mains extension charges or charges imposed on new customers under the GET Gas Program.

Residential Retrofit Plan – My clarifications and modifications to the Company's proposed Residential Retrofit Plan mirror those provided under the New Construction Plan. That is, the proposed program incentives are ambiguous and extremely vague. Although Mr. Love explains that this program is aimed to encourage improvements to the thermal envelope of the existing structure with particular emphasis given to reductions in building air leakage and increased insulation levels, it also includes recognition of "the most efficient gas heating technologies." Again, there is ambiguity with regard to whether incentive payments will be made under both the Residential Prescriptive and Residential Retrofit Plans. As is the case under the New Construction Plan, specific criteria should be established for reducing air leakage (improving window and door efficiencies) as well as specific minimum standards for insulation upgrades. Finally, the Residential Retrofit Plan should also specifically exclude any conversions from alternative energy sources to natural gas.

Q. WHAT IS THE EXPECTED COST TO RATEPAYERS OF THE PROPOSED RESIDENTIAL EE&C PROGRAM?

A. While UGI cannot provide a specific cost of the program as it is largely dependent upon participation levels, the Company projects that it will spend $21.205 million (in nominal terms) over a five-year period. As part of its proposal, UGI proposes to not place a cap on annual spending as the Company expects the program to grow and mature over time. Notwithstanding the cost uncertainties inherent in this programs, UGI does not propose any overall spending cap for the EE&C program. However, its annual projections for the cost to residential ratepayers are as follows in nominal dollars:

TABLE 9
UGI Projected Residential
EE&C Annual Spending

Year 1	$1.831 million
Year 2	$3.358 million
Year 3	$4.518 million
Year 4	$5.527 million
Year 5	$5.969 million
Total	$21.205 million

Q. SHOULD SPENDING CAPS BE PLACED UPON THE RESIDENTIAL EE&C PROGRAM?

A. Yes. Since these programs will be funded by ratepayers there needs to be a spending cap on the program. In this way, ratepayers will have assurances as to their maximum overall exposure to these program costs and will also dissuade inefficient spending.

Q. PLEASE PROVIDE YOUR RECOMMENDATION AS TO OVERALL SPENDING OVER THE FIVE-YEAR PROGRAM PLAN AS WELL AS ANY CAPS PLACED ON ANNUAL RESIDENTIAL EE&C SPENDING.

A. As indicated above, the Company projects a total residential EE&C cost of $21.205 million over the course of five years. Rounding this amount to $21.0 million equates to an average spending amount of $4.2 million per year. I recommend that the program be capped at no more than $21.0 million over the course of five years with the following annual caps and allowances:

(1) If actual spending in any year is less than $4.2 million, UGI may carry-forward 75% of such underspending for a maximum of one year, up to a maximum for the next year's total spending allowance of $6.3 million (150% of $4.2 million);

(2) The cap on any year's annual spending is $6.3 million (150% of $4.2 million); and,

(3) If actual spending in any year is greater than $4.2 million (not including any limited carry-forward from the previous year), the cumulative overspending be reflected in future budgets and spending such that the total five-year cap of $21.0 million is not exceeded.

Q. DO YOU HAVE RECOMMENDED CHANGES TO UGI'S PROPOSED TARIFF FOR THE EE&C RIDER (RIDER G)?

A. Yes. Under the Company's proposal, the Company will update its Rider annually which will be filed with the Commission **on one day's notice** to be effective December 1 of each year. The Company also proposes to be able to "reserve the right" to make an interim reconciliation filing to adjust the EE&C Riders.

One day's notice is simply unacceptable in that it provides no opportunity for I&E, the OCA, or other stakeholders to review or comment on the Company's filing. The Company should provide at a minimum 30-day notice of a proposed rider change. Furthermore, the EE&C Rider should be limited to an update once annually with no interim adjustments.

IX. <u>TARIFF CHANGES</u>

Q. DOES UGI PROPOSE ANY CHANGES TO THE RETURNED CHECK FEE?

A. Yes. UGI proposes to increase the returned check fee from $20.00 to $35.00.

Q. HAS UGI PROVIDED ANY REASONABLE JUSTIFICATION FOR THIS INCREASE?

A. No. In OCA-X-10, I requested the Company to provide "all analyses, reports, source documents, etc. supporting the Company's proposed increase in the Returned Check Charge from $20 to $35." The Company responded as follows:

> UGI is proposing a $35 Return Check Service Charge in order to align it with the Commission approved Return Check Service Charges at CPG and PNG. Please see Attachment OCA-X-10 for the CPG and PNG tariff pages related to Return Check Service Charge.

As can be seen from the response above, the Company has not provided any justification for this increase in the returned check charge other than the fact that its sister companies have a $35 return check charge. As such, I recommend that the Company's proposed increase in the returned check charge be rejected as they have provided no support for this increase.

Q. DOES UGI PROPOSE ANY MODIFICATIONS TO THE RESIDENTIAL (RATES R AND RT) MINIMUM BILL PROVISIONS?

A. Yes. Currently, the minimum bill for residential customers is the monthly customer charge. The Company proposes to change this provision to read as follows:

> If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period. Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12 month intervening period.

Therefore, under this proposed change, if a customer voluntarily (at the request of the customer) elects to discontinue service for less than 12-months, that customer would then be subject to the monthly customer charges that would have accrued during the period when no service is provided. At the same time, Tariff Rule 9.4 (Reconnect Charge) states that if a customer is discontinued at the request of that customer, a reconnect charge of

$73.00 will be imposed if the customer resumes service within 12 months from the date of discontinued service. Therefore, customers that elect to discontinue service for less than 12 months will be subject to two charges: (1) the accrual of monthly customer charges; and, (2) a reconnect charge of $73.00. The Company's proposal appears to double-dip in that it would collect both reconnection fees as well as customer charges that accrue while the customer has received no service or benefit from the Company. I recommend that these customers be subject to only one of the other charges, but not both. And to be clear, it should not simply be the higher of these two possible charges.

Q. DOES THE COMPANY PROPOSE ANY CHANGES TO ITS TARIFF RULES CONCERNING EXTENSIONS (RULE 5)?

A. Yes. With regard to deposits and refunds, the current Rule 5.6 requires the Company to provide refunds to customers who paid a deposit under certain predefined conditions. The Company proposes to change this tariff language under its new Rule 5.5 to set forth the conditions of any refunds within the service agreement between the Company and the extension applicant. The concern I have is that smaller or less savvy customers may not have the negotiating skills or be aware of what refunds it should be entitled to. As such, the current language should be left as is and if it conflicts with any other aspects of the extension rules (such as the GET Gas Program), this Rule should be modified accordingly but not leave the discretion of refunds solely to what is contained in a service agreement.

UGI also proposes to add a new Rule 5.7 entitled "Special Utility Service." Under the Company's proposed additional rule, certain customers would be exempt from the Commission's rules for extensions. Specifically, the Company's proposed rule for Special Utility Service exempts the following requests for extensions:

> (1) A request for service from an Extension Applicant with installed alternate fuel capacity.
>
> (2) A request for service from an Extension Applicant located in an area where another natural gas utility also is authorized to serve.
>
> (3) A request for service from an Extension Applicant who, in the sole judgment of the Company, may not remain on the Company's

system for a sufficient period of time to justify the extension or expansion.

(4) Extension Applicants eligible for service under Rate Schedule XD.

(5) Extension Applicants receiving or capable of receiving gas from an interstate pipeline, local production fields, or production facilities.

If this rule is adopted, the Company would be permitted to extend its Mains and other facilities to commercial and industrial customers in which there is no economic justification. For example, the Company could extend its Mains by any length to serve a potential new customer that currently has alternative fuel capacity and negotiate a discounted rate for this customer that would not recover the cost of the Mains extension. Similar situations exist for the extension of facilities to serve potential new XD customers and/or those potential new customers capable of receiving gas from an interstate pipeline, production field, or production facility. Finally, this proposed rule would allow the Company to extend its Mains and other facilities to customers that are temporary in nature such that they may not be remain on the Company's system long enough to justify the investment in extending the Company's facilities.

While I do not question the expansion of natural gas to unserved and underserved areas, there must be predefined constraints to prevent abuses by the Company in simply extending its Mains that are not economically feasible and which must ultimately borne by all existing ratepayers. In this regard, this proposed new rule should be rejected.

X. TECHNOLOGY AND ECONOMIC DEVELOPMENT ("TED") RIDER

Q. DOES UGI PROPOSE A TARIFF RIDER THAT WOULD PROMOTE THE EXPANSION OF NATURAL GAS TO COMMERCIAL AND INDUSTRIAL CUSTOMERS IN UNSERVED AND UNDERSERVED AREAS?

A. Yes. Company witness Robert Stoyko proposes a new TED Rider that on its face, would appear to be intended to promote the availability of gas to unserved and underserved areas. Because of the unique nature of large commercial and industrial customers, UGI proposes to evaluate Mains extensions to serve these customers on a case-by-case basis with the ability to provide a surcharge to these customers to help fund or finance the Mains extension. However, upon a closer examination of Mr. Stoyko's testimony and the proposed tariff provision of the TED Rider, a much different picture is revealed. That is, the Company wants the ability to negotiate rates with DS and LFD customers as well as offer discounted rates to potential new customers in which Mains extensions are required in order to attract new business.

I am certainly not opposed to the concept of new and innovative methods to assist commercial and industrial customers in financing Mains extensions (within reasonable and explicit constraints), however, I strongly disagree with proposals to negotiate discounted rates to Rate DS and LFD customers or other potential new customers simply to attract new business for UGI. If the Company's TED Rider is approved, there will be situations in which Mains are extended to serve new commercial and industrial customers yet, they will be offered discounted distribution rates (with potentially no Mains extension funding requirements). Again, these subsidized rates, and/or uneconomic expansions must ultimately be borne by all existing ratepayers. If UGI desires to propose a true economic development rate, it is certainly free to do so and should be evaluated based on reasonable criteria with predefined constraints and requirements. However, under the Company's TED Rider, the Company may extend Mains or offer discounted rates at its sole discretion with no regulatory oversight or control. As a result, I recommend the TED Rider as proposed be rejected.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

219405

OCA Statement No. 3

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**DOCKET NO. R-2015-2518438**
	:	
UGI UTILITIES, INC. – GAS DIVISION	:	

SCHEDULES ACCOMPANYING THE
DIRECT TESTIMONY
OF
GLENN A. WATKINS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

APRIL 12, 2016

BACKGROUND & EXPERIENCE PROFILE

GLENN A. WATKINS

VICE PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Mar. 1993-Present	Vice President/Senior Economist, Technical Associates, Inc. (Mar. 1993-June 1995 Traded as C. W. Amos of Virginia)
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. Public Utility Regulation

A. Costing Studies -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. Rate Design Studies -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

GLENN A. WATKINS

C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI=s administrative assigned risk plan and pool expenses.

GLENN A. WATKINS

IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

CONFIDENTIAL
REVISED

FORM-IRP-GAS-1A: ANNUAL GAS REQUIREMENTS
REPORTING UTILITY: UGI UTILITIES, INC.
(volumes in MMcf)

	Historical Data		Current Year	Three Year Forecast		
Index Year	-2	-1	0	1	2	3
Actual Year	2013	2014	2015	2016	2017	2018
Firm Sales:						
Retail Residential	20,335	21,914	21,012	21,901	22,431	23,032
Retail Commercial	7,663	8,907	8,281	8,603	8,962	9,465
Retail Industrial	598	630	436	410	391	376
Electric Power Generation	0	0	0	0	0	0
Exchange with Other Utilities	0	0	0	0	0	0
Unaccounted For	481	(23)	601	598	602	606
Company Use	148	159	166	166	166	166
Other	0	0	0	0	0	0
Subtotal Firm Sales	29,225	31,587	30,496	31,678	32,552	33,645
Interruptible Sales:						
Retail	8	9	0	0	0	0
Electric Power Generation	0	0	0	0	0	0
Company's Own Plant	0	0	0	0	0	0
Subtotal Interruptible Sales	8	9	0	0	0	0
SUBTOTAL FIRM AND INTERRUPTIBLE SALES	29,233	31,597	30,496	31,678	32,552	33,645
Transportation:						
Firm Residential	2,901	3,663	3,647	3,641	3,606	3,573
Firm Commercial	13,500	15,436	14,996	15,217	15,229	15,130
Firm Industrial	18,783	20,420	23,082	23,120	23,634	23,558
Interruptible Residential	0	0	0	0	0	0
Interruptible Commercial	3,862	3,334	3,503	3,469	3,492	3,492
Interruptible Industrial	49,355	47,727	49,770	49,761	49,790	49,790
Electric Power Generation	0	0	0	0	0	0
Subtotal Transportation	88,402	90,580	94,998	95,207	95,751	95,542
TOTAL GAS REQUIREMENTS	117,635	122,176	125,494	126,885	128,302	129,187
Increase (Decrease)		4,541	3,318	1,391	1,417	885
Percent Change (%)		3.9%	2.7%	1.1%	1.1%	0.7%

UGI UTILITIES, INC. - GAS DIVISION
UGI AVERAGE & EXCESS
DETERMINATION OF AVERAGE & PEAK DEMAND WEIGHTING

		Class					
	Total	**Rate R**	**Rate N**	**Rate DS**	**Rate LFD**	**Rate XD Firm**	**Interruptible**

Large Mains Interupt @ Avg Only (Herbert Alloc Factor 4)

Average & Excess Proof

	Total	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
AVG	179,596	62,313	38,743	8,875	39,903	0	29,762
NCP	708,677	363772	224930	35791	54422	0	29762
Excess	529,081	301,459	186,187	26,916	14,519	0	0

Weighting Factor (W): 42.87%

A = (W*Class Avg/Total Avg)+((1-W)*Class Excess/Total Excess)
B = Class NCP/Total NCP
C=Class Avg/Total Avg

A=Bx+C(1-x) ---> A=Bx+C-CX ---> A-C=Bx-Cx ---> x=(A-C)/(B-C)

	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
A	47.427%	29.353%	5.025%	11.092%	0.000%	7.104%
B (NCP class Pct)	51.331%	31.739%	5.050%	7.679%	0.000%	4.200%
C (avg class pct)	34.696%	21.572%	4.942%	22.218%	0.000%	16.572%
Demand Weighting (x):	**76.528%**	**76.528%**	**76.528%**	**76.528%**		**76.528%**

Small Mains Interupt @ Avg Only (Herbert Alloc Factor 5)

Average & Excess Proof

	Total	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
AVG	134,797	62,313	38,743	8,875	7,582	0	17,284
NCP	652,117	363772	224930	35791	10340	0	17284
Excess	517,320	301,459	186,187	26,916	2,758	0	0

Weighting Factor (W): 42.87%

A = (W*Class Avg/Total Avg)+((1-W)*Class Excess/Total Excess)
B = Class NCP/Total NCP
C=Class Avg/Total Avg

A=Bx+C(1-x) ---> A=Bx+C-CX ---> A-C=Bx-Cx ---> x=(A-C)/(B-C)

	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
A	53.110%	32.883%	5.795%	2.716%	0.000%	5.496%
B (NCP class Pct)	55.783%	34.492%	5.488%	1.586%	0.000%	2.650%
C (avg class pct)	46.227%	28.742%	6.584%	5.625%	0.000%	12.822%
Demand Weighting (x):	**72.021%**	**72.021%**	**72.021%**	**72.021%**		**72.021%**

Schedule GAW-4

UGI Utilities, Inc. - Gas Division
Coincident 3-Day Peak Demand
Sendout By Rate Class

	2010-2011			2011-2012			2012-2013			2013-2014			2014-2015		
	JAN 22 (MDTH)	JAN 23 (MDTH)	JAN 24 (MDTH)	JAN 3 (MDTH)	JAN 4 (MDTH)	JAN 5 (MDTH)	FEB 19 (MDTH)	FEB 20 (MDTH)	FEB 21 (MDTH)	MAR 3 (MDTH)	MAR 4 (MDTH)	MAR 5 (MDTH)	JAN 5 (MDTH)	JAN 6 (MDTH)	JAN 7 (MDTH)
RG	3.5	3.6	3.4	3.5	3.3	2.9	3.0	4.0	3.6	4.9	4.0	2.1	2.7	3.0	3.8
RH	179.4	186.0	176.1	163.2	154.0	135.5	135.2	175.8	158.9	238.5	196.7	100.4	167.8	192.2	239.1
CG	2.5	2.6	2.5	2.4	2.3	2.0	2.0	2.6	2.3	4.1	3.4	1.7	2.2	2.5	3.1
CH	67.9	70.4	66.7	61.5	58.1	51.1	48.8	63.4	57.3	90.5	74.6	38.1	70.9	81.2	101.0
IG	0.4	0.4	0.3	0.8	0.7	0.6	0.2	0.2	0.2	0.3	0.3	0.1	0.2	0.2	0.3
IH	5.6	5.9	5.5	5.1	1.0	4.3	4.4	5.7	5.1	6.4	5.3	2.7	5.2	6.0	7.4
PGC FIRM	259.3	268.8	254.5	236.6	223.3	196.5	193.5	251.7	227.5	344.7	284.3	145.1	248.9	285.2	354.7
RT (CHOICE)	8.5	8.8	8.6	10.8	10.9	11.0	17.3	17.2	17.0	22.2	21.9	21.6	22.6	23.0	23.4
NT (CHOICE)	53.4	55.4	54.0	39.2	39.7	40.1	45.7	45.3	44.8	46.1	45.4	44.8	44.5	45.3	46.1
BD/BDL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DS	25.7	26.7	25.2	23.0	21.8	19.1	26.3	34.2	30.9	53.4	44.0	22.5	30.9	35.4	44.0
LFD	33.4	34.6	32.8	39.6	37.4	32.9	38.5	42.1	40.1	50.9	49.0	47.2	50.7	53.7	56.4
XD-F/CDS-F	37.0	38.4	36.4	40.9	38.6	33.9	34.6	35.7	36.1	38.8	37.9	37.8	50.0	49.7	51.1
FIRM TRANSPORTATION	158.1	163.9	157.0	153.5	148.3	137.0	162.4	174.6	168.9	211.4	198.2	173.9	198.7	207.0	221.0
INTERRUPTIBLE	72.0	87.0	93.2	220.9	225.9	222.0	199.9	207.6	202.6	119.8	157.2	305.4	199.2	176.1	83.5
TOTAL	489.3	519.7	504.7	611.0	597.4	555.4	555.8	633.9	599.0	675.9	639.7	624.4	646.9	668.3	659.2

Schedule GAW-5

Customer (may contain multiple accounts)	RATE	RATE_CLASS	RATE_CLASS_NAME	Date Bypass Verified	Miles/ Dist.
A	XDF	090	Industrial XD - Firm	Jun-15	20.00
B	XDF	092	Industrial XD - Firm	Jun-15	0.09
D	XDF	616	Commercial XD - FIRM	Nov-14	13.00
E	XDF	366	Industrial XD - Firm	Jun-15	3.03
F	XDF	990	Industrial XD - Firm	Jun-15	0.45
M	XDF	964	Industrial XD - Firm	Nov-14	1.33
O	XDI	392	Industrial XD - Interruptible	Jun-15	0.09
R	XDF	366	Industrial XD - Firm	Jul-15	5.66
T	XDF	366	Industrial XD - Firm	Jul-15	4.80
U	XDF	990	Industrial XD - Firm	Jul-15	0.78
V	XDF	366	Industrial XD - Firm	Jul-15	13.30
X	XDF	366	Industrial XD - Firm	Jul-15	2.94
Y	XDI	392	Industrial XD - Interruptible	Jul-15	8.33
Z	XDF	266	Commercial XD - Firm	Jul-15	10.23
AB	XDI	392	Industrial XD - Interruptible	Jul-15	0.68
AC	XDF	966	Industrial XD - Firm	Jul-12	14.65
AD	XDF	366	Industrial XD - Firm	Jul-15	7.39
AG	XDF	366	Industrial XD - Firm	Jul-15	3.75
AH	XDF	366	Industrial XD - Firm	Jul-15	0.09
AJ	XDF	366	Industrial XD - Firm	Jul-15	2.08
AL	XDF	744	Commercial XD - Firm	N/A	Utility Interconnect
AM	XDF	966	Industrial XD - Firm	Jul-15	7.39
AP	XDF	366	Industrial XD - Firm	Jul-15	2.93
AQ	XDF	090	Industrial XD - Firm	Jul-15	12.99
AR	XDF	266	Commercial XD - Firm	Jul-15	4.22

UGI UTILITIES, INC. – GAS DIVISION

HIGHLY CONFIDENTIAL
SCHEDULE GAW-6
(Schematics of XD Customers)

UGI UTILITIES, INC. - GAS DIVISION
OCA CLASS COST OF SERVICE STUDY
SUMMARY

	System Total	Class					
		Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
Under Current Rates:							
Rate Revenue	$232,509,024	$108,668,733	$55,100,277	$12,585,234	$25,013,284	$11,785,496	$19,356,000
Other Revenue	$4,480,000	$2,775,657	$1,272,631	$229,827	$46,187	$52,525	$103,173
Total Operating Revenue	$236,989,024	$111,444,390	$56,372,908	$12,815,061	$25,059,471	$11,838,021	$19,459,173
O&M Expenses	$115,870,001	$72,477,749	$20,532,836	$1,837,919	$4,971,430	$5,568,830	$10,481,238
Depreciation & Amort.	$43,188,948	$26,252,225	$8,522,703	$758,551	$1,639,192	$2,039,902	$3,976,376
Taxes Other Than Income	$5,750,000	$3,383,055	$1,139,417	$101,314	$258,190	$300,104	$567,919
Earnings Before Int. & Inc. Taxes	$72,180,075	$9,331,361	$26,177,952	$10,117,277	$18,190,659	$3,929,185	$4,433,640
Less: Interest Expense	$20,044,000	$10,824,398	$3,946,199	$424,414	$989,498	$1,313,567	$2,545,924
Taxable Income	$52,136,075	-$1,493,037	$22,231,753	$9,692,863	$17,201,161	$2,615,618	$1,887,717
Income Taxes	$20,785,273	-$595,234	$8,863,212	$3,864,288	$6,857,647	$1,042,778	$752,583
Net Operating Income	$51,394,802	$9,926,596	$17,314,741	$6,252,989	$11,333,012	$2,886,407	$3,681,058
Rate Base	$923,709,060	$498,832,302	$181,856,908	$19,558,703	$45,600,114	$60,534,516	$117,326,518
ROR on Rate Base	5.56%	1.99%	9.52%	31.97%	24.85%	4.77%	3.14%
Indexed ROR on Rate Base	100%	36%	171%	575%	447%	86%	56%
Factor for Interest		54.00%	19.69%	2.12%	4.94%	6.55%	12.70%
Factor for Income Taxes		-2.86%	42.64%	18.59%	32.99%	5.02%	3.62%
Cost of Service @ Equal RORs							
O&M Expenses	$ 116,847,001	$ 73,375,194	$ 20,594,172	$ 1,843,811	$ 4,979,175	$ 5,568,830	$ 10,485,819
Depreciation & Amortization	$ 43,188,948	$ 26,252,225	$ 8,522,703	$ 758,551	$ 1,639,192	$ 2,039,902	$ 3,976,376
Taxes Other than Income	$ 5,750,000	$ 3,383,055	$ 1,139,417	$ 101,314	$ 258,190	$ 300,104	$ 567,919
Required Return	$ 75,467,000	$ 40,749,428	$ 14,856,044	$ 1,598,494	$ 3,726,806	$ 4,947,365	$ 9,588,863
Income Taxes	$ 37,857,000	$ 20,441,399	$ 7,452,334	$ 801,863	$ 1,869,502	$ 2,481,779	$ 4,810,123
Total Revenue Requirement	$ 279,109,949	$ 164,201,301	$ 52,564,670	$ 5,104,032	$ 12,472,865	$ 15,337,981	$ 29,429,100
Less Other Income	$ 4,480,000	$ 2,775,657	$ 1,272,631	$ 229,827	$ 46,187	$ 52,525	$ 103,173
Revenue Requirment from Rate Revenue	$ 274,629,949	$ 161,425,644	$ 51,292,039	$ 4,874,206	$ 12,426,678	$ 15,285,455	$ 29,325,927

UGI UTILITIES, INC. - GAS DIVISION
OCA CLASS COST OF SERVICE STUDY
RATE BASE

Account		Herbert Factor Ref.	TAI Factor Ref.	Cost of Service	Class					
					Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
RATE BASE										
DISTRIBUTION PLANT										
374	Land	18	22	$2,273,343	$690,818	$427,874	$77,271	$207,018	$297,940	$572,421
374	Land Rights of Way	4	26							
375	Structures And Improvements	18	22	$739,180	$224,620	$139,124	$25,125	$67,312	$96,876	$186,123
376	Mains - Small	5	26	$215,322,849	$65,431,758	$40,526,669	$7,318,843	$19,608,045	$28,219,849	$54,217,684
	Mains - Large	4	26	$328,559,063	$99,841,690	$61,839,255	$11,167,752	$29,919,727	$43,060,396	$82,730,243
	Mains - Direct Assign	DA	26	$14,193,075	$4,312,955	$2,671,328	$482,424	$1,292,471	$1,860,120	$3,573,776
378	Measuring & Regulating Equipment - General	18	22	$28,975,073	$8,804,871	$5,453,500	$984,865	$2,638,571	$3,797,424	$7,295,841
379	Measuring & Regulating Equipment - SCADA	18	22	$656,319	$199,441	$123,528	$22,308	$59,767	$86,016	$165,259
379	Measuring & Regulating Equipment - City Gate	18	22	$1,700,598	$516,773	$320,076	$57,803	$154,862	$222,878	$428,206
380	Services	6C	10	$433,144,508	$372,393,473	$52,505,466	$3,406,032	$2,669,593	$317,339	$1,852,605
381	Meters	6	8	$36,121,391	$12,474,851	$22,817,139	$637,955	$0	$0	$191,446
382	Meter Installations	6	8	$42,041,136	$14,519,289	$26,556,520	$742,506	$0	$0	$222,821
383	House Regulators	6	8	$5,737,053	$1,981,344	$3,623,978	$101,324	$0	$0	$30,407
384	House Regulator Installations	6	8	$6,928,942	$2,392,973	$4,376,870	$122,375	$0	$0	$36,724
385	Industrial Measuring & Regulating Equipment	6B	9	$2,576,972	$0	$600,547	$0	$1,817,084	$155,181	$4,160
386	Other Property on Customer Premises	6	8	$206,382	$71,276	$130,367	$3,645	$0	$0	$1,094
386	Other Property on Customer Premises - Farm Taps	6	8	$362,939	$125,344	$229,261	$6,410	$0	$0	$1,924
386	Other Property on Customer Premises - Gas Lights	6	8	$1,113	$384	$703	$20	$0	$0	$6
386	Other Property on Customer Premises - CNG Refueling Station	6	8	-$1,036	-$358	-$654	-$18	$0	$0	-$5
387	Other Equipment	10	14	$1,330,441	$663,658	$350,226	$28,090	$76,568	$74,758	$137,141
387	Other Equipment - Graphic Data Base	10	14	$44,275	$22,085	$11,655	$935	$2,548	$2,488	$4,564
	Total Distribution Plant			$1,120,913,616	$584,667,247	$222,703,433	$25,185,666	$58,513,565	$78,191,266	$151,652,439
GENERAL PLANT										
389	Land and Land Rights	12	16	$1,492,767	$938,701	$260,092	$23,536	$63,851	$71,644	$134,943
390	Structures And Improvements	12	16	$16,370,674	$10,294,421	$2,852,341	$258,112	$700,230	$785,695	$1,479,875
391	Office Furniture And Equipment	12	16	$1,227,472	$771,875	$213,868	$19,353	$52,503	$58,911	$110,961
392	Transportation Equipment	12	16	$720,695	$453,197	$125,570	$11,363	$30,827	$34,589	$65,149
394	Tools, Shop And Garage Equipment	12	16	$6,627,397	$4,167,526	$1,154,723	$104,492	$283,477	$318,076	$599,103
396	Power Operated Equipment	12	16	$55,398	$34,836	$9,652	$873	$2,370	$2,659	$5,008
397	Communication Equipment	12	16	$90,438	$56,870	$15,757	$1,426	$3,868	$4,340	$8,175
398	Miscellaneous Equipment	12	16	$515,186	$323,966	$89,763	$8,123	$22,036	$24,726	$46,572
399	Other Tangible Property	12	16							
	Total General Plant			$27,100,027	$17,041,392	$4,721,768	$427,279	$1,159,162	$1,300,640	$2,449,787
	Total Plant			$1,148,013,643	$601,708,639	$227,425,201	$25,612,945	$59,672,727	$79,491,906	$154,102,225

UGI UTILITIES, INC. - GAS DIVISION
OCA CLASS COST OF SERVICE STUDY
RATE BASE

	Account	Herbert Factor Ref.	TAI Factor Ref.	Cost of Service	Class: Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
COMMON PLANT ALLOCATED @ 15.36%										
390.2	Structures and Improvements	12	16	$3,171	$1,994	$552	$50	$136	$152	$287
391	Office Furniture and Equipment	12	16	$110,464	$69,463	$19,247	$1,742	$4,725	$5,302	$9,986
392.1	Transportation Equipment	12	16	$1,520	$956	$265	$24	$65	$73	$137
	Total Common Plant			$115,155	$72,413	$20,064	$1,816	$4,926	$5,527	$10,410
INFORMATION SERVICES (IS) ALLOCATED @ 48.83%										
391	Office Furniture and Equipment	12	16	$9,425,306	$5,926,944	$1,642,216	$148,606	$403,153	$452,359	$852,028
391.1	Office Furniture and Equip. - New CIS Software	7	11	$43,006,009	$38,593,758	$4,256,488	$65,631	$51,441	$2,993	$35,698
	Total Information Services			$52,431,315	$44,520,701	$5,898,705	$214,237	$454,593	$455,352	$887,726
Less: Reading Service Center Allocated to Other Divisions										
390.1	Structures And Improvements @ 51.74%	12	16	-$476,229	-$299,469	-$82,976	-$7,509	-$20,370	-$22,856	-$43,050
INTANGIBLE PLANT										
301	Organization (Allocated at 15.36%)	14	18	$21,345	$11,525	$4,202	$452	$1,054	$1,399	$2,712
302	Franchises And Consents	14	18	$28,256	$15,257	$5,562	$599	$1,395	$1,852	$3,590
304	Land and Land Rights	14	18	$381,652	$206,078	$75,130	$8,084	$18,847	$25,020	$48,493
305	Manufactured Gas Plant Remediation	1	1	$316,923	$234,226	$82,697	$0	$0	$0	$0
	Total Nondepreciable Plant			$748,176	$467,087	$167,591	$9,135	$21,297	$28,272	$54,795
	Total Utility Plant in Service			$1,200,832,060	$646,469,373	$233,428,584	$25,830,624	$60,133,173	$79,958,200	$155,012,107
OTHER RATE BASE ELEMENTS										
	Gas Storage Inventory	1	1	$21,730,000	$16,059,861	$5,670,139	$0	$0	$0	$0
	Cash Working Capital	12	16	$10,687,000	$6,720,339	$1,862,047	$168,499	$457,120	$512,912	$966,083
	Cash Working Capital - Purchased Gas Related	1	1	$7,961,000	$5,883,689	$2,077,311	$0	$0	$0	$0
	Materials & Supplies	12	16	$4,212,000	$2,648,645	$733,877	$66,409	$180,162	$202,151	$380,756
	Deferred Taxes	14	18	-$307,196,000	-$165,874,636	-$60,473,019	-$6,506,830	-$15,170,340	-$20,138,748	-$39,032,428
	Customer Deposits	8	12	-$14,517,000	-$13,074,968	-$1,442,032	$0	$0	$0	$0
	Investment Tax Credit	14	18	$0	$0	$0	$0	$0	$0	$0
	Total Other Rate Base Elements			-$277,123,000	-$147,637,071	-$51,571,677	-$6,271,921	-$14,533,058	-$19,423,684	-$37,685,589
	Total Measure of Value			$923,709,060	$498,832,302	$181,856,908	$19,558,703	$45,600,114	$60,534,516	$117,326,518

UGI UTILITIES, INC. - GAS DIVISION
OCA CLASS COST OF SERVICE STUDY
EXPENSES

	Account	Herbert Factor Ref.	TAI Factor Ref.	Cost of Service	Class: Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
OPERATION AND MAINTENANCE EXPENSES										
NATURAL GAS PRODUCTION EXPENSES										
	Manufactured Gas Production Expenses									
710	Operation Supervision and Engineering	1	1	$0	$0	$0	$0	$0	$0	$0
717	Total Production Labor and Expenses	1		$0	$0	$0	$0	$0	$0	$0
725-736	Total Gas Fuels Expenses	1	1	$0	$0	$0	$0	$0	$0	$0
740-742	Total Gas Raw Materials Expenses	1	1	$68,000	$50,256	$17,744	$0	$0	$0	$0
	Total Operation			$68,000	$50,256	$17,744	$0	$0	$0	$0
	Production and Gathering									
750 - 760	Total Production & Gathering Operation Exps.	1	1	$0	$0	$0	$0	$0	$0	$0
761 - 769	Total Production & Gathering Maintenance Exps.	1	1	$0	$0	$0	$0	$0	$0	$0
770 - 783	Total Products Extraction Operation Expenses	1	1	$0	$0	$0	$0	$0	$0	$0
784 - 791	Total Products Extraction Maintenance Exps.	1	1	$0	$0	$0	$0	$0	$0	$0
	Total Production Expenses			$0	$0	$0	$0	$0	$0	$0
	Other Gas Supply Expenses									
800 - 803	Natural Gas Transmission Line Purchases	1	1	$0	$0	$0	$0	$0	$0	$0
804	Natural Gas City Gate Purchases	1	1	$0	$0	$0	$0	$0	$0	$0
813	Other Gas Supply Expenses	1	1	$0	$0	$0	$0	$0	$0	$0
	Total Other Gas Supply Expenses			$0	$0	$0	$0	$0	$0	$0
	Total Natural Gas Production Expenses			$68,000	$50,256	$17,744	$0	$0	$0	$0
OTHER STORAGE EXPENSE										
840	Operating Supervision and Engineering	4	26	$0	$0	$0	$0	$0	$0	$0
841	Operation Labor and Expenses	4	26	$0	$0	$0	$0	$0	$0	$0
842 - 842.3	Other Operations Expense	4	26	$0	$0	$0	$0	$0	$0	$0
	Total Natural Gas Storage Expense			$0	$0	$0	$0	$0	$0	$0
TRANSMISSION EXPENSE										
850 - 860	Total Transmission Operation Expenses	4	26	$0	$0	$0	$0	$0	$0	$0
861 - 867	Total Transmission Maintenance Expenses	4	26	$0	$0	$0	$0	$0	$0	$0

UGI UTILITIES, INC. - GAS DIVISION
OCA CLASS COST OF SERVICE STUDY
EXPENSES

	Account	Herbert Factor Ref.	TAI Factor Ref.	Cost of Service	Class Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
	Total Transmission Expense			$0	$0	$0	$0	$0	$0	$0
DISTRIBUTION EXPENSES										
	Operation									
870	Supervision And Engineering	10	14	$2,402,000	$1,198,179	$632,304	$50,715	$138,237	$134,970	$247,596
871	Distribution Load Dispatching	4a	6	$554,000	$207,341	$128,240	$20,858	$36,122	$63,880	$97,559
872	Compressor Station Labor and Expenses			$0	$0	$0	$0	$0	$0	$0
873	Compressor Station Fuel and Power	2	2	$1,000	$186	$116	$26	$119	$142	$411
874	Mains And Services Expenses				$0	$0	$0	$0	$0	$0
	Mains - Small	5	26	$2,077,287	$631,241	$390,973	$70,607	$189,165	$272,246	$523,055
	Mains - Large	17	26	$3,169,713	$963,204	$596,583	$107,739	$288,645	$415,417	$798,125
	Services	6C	10	$5,247,000	$4,511,078	$636,038	$41,260	$32,339	$3,844	$22,442
875	M & R Station Expenses -General	4a	6	$425,000	$159,061	$98,379	$16,001	$27,711	$49,005	$74,842
876	M & R Station Expenses - Industrial	6B	9	$417,000	$0	$97,179	$0	$294,037	$25,111	$673
877	M & R Station Expenses - City Gate Station	4a	6	$348,000	$130,243	$80,555	$13,102	$22,690	$40,127	$61,282
878	Meter and House Regulator Expenses	6	8	$1,959,000	$676,558	$1,237,460	$34,599	$0	$0	$10,383
879	Customer Installations Expenses	6	8	$1,281,000	$442,405	$809,181	$22,624	$0	$0	$6,789
880	Other Expenses	10	14	$2,527,000	$1,260,532	$665,210	$53,354	$145,431	$141,993	$260,481
881	Rents	10	14	$69,000	$34,419	$18,164	$1,457	$3,971	$3,877	$7,112
	Total Operation			$20,477,000	$10,214,447	$5,390,382	$432,342	$1,178,467	$1,150,612	$2,110,750
	Maintenance									
885	Supervision - Engineering and Labor	11	15	$786,000	$282,125	$157,521	$23,901	$68,595	$87,669	$166,189
886	Structures & Improvements	18	22	$3,000	$912	$565	$102	$273	$393	$755
887	Mains - Small	5	26	$5,287,245	$1,606,675	$995,131	$179,714	$481,475	$692,937	$1,331,313
	Mains - Large	17	26	$8,067,756	$2,451,609	$1,518,461	$274,224	$734,678	$1,057,346	$2,031,438
888	Maintenance of Compressor Station Equipment	4	26	$0	$0	$0	$0	$0	$0	$0
889	M & R Equip - General	4a	6	$167,000	$62,502	$38,657	$6,287	$10,889	$19,256	$29,408
890	M & R Equip - Industrial	6B	9	$242,000	$0	$56,397	$0	$170,640	$14,573	$391
891	M & R Equip - City Gate	4a	6	$436,000	$163,178	$100,926	$16,415	$28,428	$50,274	$76,779
892	Services	6C	10	$1,640,000	$1,409,980	$198,800	$12,896	$10,108	$1,202	$7,014
893	Meters & House Regulators	6	8	$617,000	$213,087	$389,746	$10,897	$0	$0	$3,270
894	Other Expenses	11	15	$102,000	$36,612	$20,442	$3,102	$8,902	$11,377	$21,567
895	Construction and Maintenance	11	15	-$176,000	-$63,173	-$35,272	-$5,352	-$15,360	-$19,631	-$37,213
	Total Maintenance			$17,172,001	$6,163,506	$3,441,372	$522,187	$1,498,628	$1,915,397	$3,630,913
	Total Distribution Expenses			$37,649,001	$16,377,953	$8,831,754	$954,528	$2,677,094	$3,066,009	$5,741,662

UGI UTILITIES, INC. - GAS DIVISION
OCA CLASS COST OF SERVICE STUDY
EXPENSES

	Account	Herbert Factor Ref.	TAI Factor Ref.	Cost of Service	Class: Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
CUSTOMER ACCOUNTING EXPENSES										
	Operation									
901	Supervision	7	11	$425,000	$381,397	$42,064	$649	$508	$30	$353
902	Meter Reading Expenses	7	11	$1,001,000	$898,301	$99,073	$1,528	$1,197	$70	$831
903	Customer Records & Coll Expenses	7	11	$13,681,000	$12,277,382	$1,354,067	$20,878	$16,364	$952	$11,356
904	Uncollectible Accounts @ Current Rates	19	23	$4,634,000	$4,256,665	$290,924	$27,947	$36,733	$0	$21,731
905	Miscellaneous Cust Accts Expenses	7	11	$358,000	$321,271	$35,433	$546	$428	$25	$297
	Total Customer Accounting Expenses			$20,099,000	$18,135,015	$1,821,561	$51,548	$55,231	$1,076	$34,568
CUSTOMER SERVICE AND INFORMATION EXPENSES										
	Operation									
907	Supervision	7	11	$164,000	$147,174	$16,232	$250	$196	$11	$136
908	Customer Assistance Expenses	9	13	$1,308,000	$1,308,000	$0	$0	$0	$0	$0
909	Informational and Instructional Advertising	7	11	$721,000	$647,028	$71,360	$1,100	$862	$50	$598
910	Miscellaneous Customer Service & Informational Exp.	7	11	$116,000	$104,099	$11,481	$177	$139	$8	$96
	Total Customer Service & Info Expenses			$2,309,000	$2,206,301	$99,073	$1,528	$1,197	$70	$831
SALES EXPENSES										
	Operation									
911	Supervision	8	12	$0	$0	$0	$0	$0	$0	$0
912	Demonstrating and Selling Expenses	8	12	$3,635,000	$3,273,921	$361,079	$0	$0	$0	$0
913	Advertising Expenses	8	12	$111,000	$99,974	$11,026	$0	$0	$0	$0
916	Miscellaneous	8	12	$104,000	$93,669	$10,331	$0	$0	$0	$0
	Total Sales Expenses			$3,850,000	$3,467,564	$382,436	$0	$0	$0	$0
ADMINISTRATIVE AND GENERAL EXPENSES										
	Operation									
920	Administrative & General Salaries	12	16	$9,958,000	$6,261,919	$1,735,030	$157,005	$425,938	$477,925	$900,183
921	Office Supplies and Expenses	12	16	$9,639,000	$6,061,322	$1,679,449	$151,975	$412,293	$462,615	$871,346
923	Outside Services Employed - Other	12	16	$9,243,000	$5,812,304	$1,610,452	$145,732	$395,355	$443,609	$835,548
924	Property Damage Insurance	12	16	$195,000	$122,622	$33,976	$3,075	$8,341	$9,359	$17,628
925	Injuries and Damages	12	16	$7,041,000	$4,427,613.38	$1,226,787	$111,014	$301,168	$337,926	$636,492
926	Employee Pensions and Benefits	13	17	$11,272,000	$6,721,756	$2,293,199	$188,213	$499,038	$547,521	$1,022,272
928	Regulatory Commission Expenses	16	20	$628,000	$368,726	$118,548	$11,511	$28,145	$34,632	$66,438
930	Miscellaneous General Expenses	12	16	$678,000	$426,349	$118,131	$10,690	$29,000	$32,540	$61,290
930	Miscellaneous Company Charges	12	16	$1,517,000	$953,940	$264,314	$23,918	$64,887	$72,807	$137,134
931	Other	12	16	$277,000	$174,187	$48,263	$4,367	$11,848	$13,294	$25,040

UGI UTILITIES, INC. - GAS DIVISION
OCA CLASS COST OF SERVICE STUDY
EXPENSES

	Account	Herbert Factor Ref.	TAI Factor Ref.	Cost of Service	Class: Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
	Total Operation			$50,448,000	$31,330,738	$9,128,150	$807,500	$2,176,014	$2,432,228	$4,573,370
	Maintenance									
932	Maintenance of General Plant	12	16	$1,435,000	$902,375	$250,027	$22,625	$61,380	$68,871	$129,721
935	Maintenance of General Plant	12	16	$12,000	$7,546	$2,091	$189	$513	$576	$1,085
	Total Maintenance			$1,447,000	$909,921	$252,118	$22,814	$61,893	$69,447	$130,806
	Total Administrative & General Expenses			$51,895,000	$32,240,659	$9,380,268	$830,314	$2,237,908	$2,501,675	$4,704,176
	Total Operation and Maintenance Expenses			$115,870,001	$72,477,749	$20,532,836	$1,837,919	$4,971,430	$5,568,830	$10,481,238
DEPRECIATION AND AMORTIZATION EXPENSE										
DISTRIBUTION PLANT										
305	Manufactured Gas Plant Site Remediation	1	1	$207,811	$153,586	$54,225	$0	$0	$0	$0
375	Structures And Improvements	18	22	$27,612	$8,391	$5,197	$939	$2,514	$3,619	$6,953
376	Mains - Small	5	26	$5,007,323	$1,521,613	$942,446	$170,199	$455,984	$656,251	$1,260,830
	Mains - Large	4	26	$7,640,626	$2,321,814	$1,438,069	$259,706	$695,782	$1,001,368	$1,923,888
	Mains - Direct Assign	DA	26	$310,359	$94,311	$58,414	$10,549	$28,262	$40,675	$78,148
378	Measuring & Regulating Equipment - General	18	22	$1,128,978	$343,071	$212,489	$38,374	$102,809	$147,962	$284,273
378	Measuring & Regulating Equipment - SCADA	18	22	$107,140	$32,557	$20,165	$3,642	$9,757	$14,042	$26,978
379	Measuring & Regulating Equipment - City Gate	18	22	$88,508	$26,896	$16,658	$3,008	$8,060	$11,600	$22,286
380	Services	6C	10	$18,440,532	$15,854,140	$2,235,348	$145,007	$113,654	$13,510	$78,872
381	Meters	6	8	$1,553,801	$536,619	$981,504	$27,442	$0	$0	$8,235
381.2	Electronic Meters	6	8	$445,841	$153,975	$281,629	$7,874	$0	$0	$2,363
382	Meter Installations	6	8	$1,578,782	$545,247	$997,284	$27,884	$0	$0	$8,368
383	House Regulators	6	8	$404,313	$139,633	$255,396	$7,141	$0	$0	$2,143
384	House Regulator Installations	6	8	$268,996	$92,900	$169,919	$4,751	$0	$0	$1,426
385	Industrial Measuring & Regulating Equipment	6B	9	$128,680	$0	$29,988	$0	$90,735	$7,749	$208
386	Other Property on Customer Premises	6	8	$23,414	$8,086	$14,790	$414	$0	$0	$124
387	Other Equipment	10	14	$105,852	$52,802	$27,865	$2,235	$6,092	$5,948	$10,911
387.1	Other Equipment	10	14	$4,539	$2,264	$1,195	$96	$261	$255	$468
	Total Distribution Plant			$37,473,107	$21,887,905	$7,742,581	$709,260	$1,513,911	$1,902,978	$3,716,472
GENERAL PLANT										
390	Structures And Improvements	12	16	$1,124,899	$707,374	$195,997	$17,736	$48,116	$53,988	$101,689
391	Office Furniture And Equipment	12	16	$109,370	$68,775	$19,056	$1,724	$4,678	$5,249	$9,887
392	Transportation Equipment	12	16	$80,541	$50,647	$14,033	$1,270	$3,445	$3,865	$7,281

UGI UTILITIES, INC. - GAS DIVISION
OCA CLASS COST OF SERVICE STUDY
EXPENSES

Account		Herbert Factor Ref.	TAI Factor Ref.	Cost of Service	Class					
					Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
394	Tools, Shop And Garage Equipment	12	16	$501,958	$315,648	$87,459	$7,914	$21,470	$24,091	$45,376
396	Power Operated Equipment	12	16	$8,536	$5,368	$1,487	$135	$365	$410	$772
397	Communication Equipment	12	16	$40,154	$25,250	$6,996	$633	$1,718	$1,927	$3,630
398	Miscellaneous Equipment	12	16	$85,585	$53,819	$14,912	$1,349	$3,661	$4,108	$7,737
399	Other Tangible Property	12	16		$0	$0	$0	$0	$0	$0
	Total General Plant			$1,951,043	$1,226,880	$339,940	$30,762	$83,453	$93,638	$176,370
COMMON PLANT ALLOCATED @ 15.36%										
390.2	Structures and Improvements	12	16	$2,114	$1,329	$368	$33	$90	$101	$191
391	Office Furniture and Equipment	12	16	$14,784	$9,297	$2,576	$233	$632	$710	$1,336
392.1	Transportation Equipment	12	16	$533	$335	$93	$8	$23	$26	$48
	Total Common Plant			$17,431	$10,961	$3,037	$275	$746	$837	$1,576
INFORMATION SERVICES (IS) ALLOCATED @ 48.83%										
391	Office Furniture and Equipment	12	16	$1,556,244	$978,618	$271,152	$24,537	$66,566	$74,690	$140,681
391.1	Office Furniture and Equip. - New CIS Software	7	11	$2,867,067	$2,572,917	$283,766	$4,375	$3,429	$200	$2,380
	Total Information Services			$4,423,311	$3,551,535	$554,918	$28,912	$69,995	$74,890	$143,061
Less:										
	Amount Charged to Clearing Accounts	12	16	-$637,000	-$400,567	-$110,988	-$10,043	-$27,247	-$30,572	-$57,583
390.1	Struct. & Imps- Reading Service Center @ 51.74%	12	16	-$38,944	-$24,489	-$6,785	-$614	-$1,666	-$1,869	-$3,520
	Total Depreciation & Amortization Expense			$43,188,948	$26,252,225	$8,522,703	$758,551	$1,639,192	$2,039,902	$3,976,376
TAXES OTHER THAN INCOME TAXES										
408.1	Capital Stock	15	19	$0						
408.1	County and Municipal Taxes	16	20	$177,000	$103,924	$33,412	$3,244	$7,933	$9,761	$18,725
408.1	Payroll Related Tax	13	17	$3,397,000	$2,025,710	$691,093	$56,721	$150,393	$165,004	$308,078
408.1	Public Utility Assessment	16	20	$1,663,000	$976,419	$313,926	$30,483	$74,531	$91,708	$175,934
408.1	Public Utility Realty Tax	15	19	$513,000	$277,001	$100,987	$10,866	$25,334	$33,631	$65,182
408.1	Miscellaneous Taxes	16	20	$0	$0	$0	$0	$0	$0	$0
	Total Taxes Other Than Income			$5,750,000	$3,383,055	$1,139,417	$101,314	$258,190	$300,104	$567,919
	Total Operating Expenses			$164,808,949	$102,113,029	$30,194,956	$2,697,784	$6,868,812	$7,908,836	$15,025,533
Additional Uncollectibles			23	$977,000	$897,445	$61,336	$5,892	$7,745	$0	$4,582

UGI UTILITIES, INC. - GAS DIVISION
OCA CLASS COST OF SERVICE STUDY
EXPENSES

Account	Herbert Factor Ref.	TAI Factor Ref.	Cost of Service	Class: Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
INCOME TAXES @ PROPOSED ROR & EQUAL CLASS RORs	15	19	$37,857,000	$20,441,399	$7,452,334	$801,863	$1,869,502	$2,481,779	$4,810,123
Required Return	15	19	$75,467,000	$40,749,428	$14,856,044	$1,598,494	$3,726,806	$4,947,365	$9,588,863
TOTAL COST OF SERVICE			$279,109,949	$164,201,301	$52,564,670	$5,104,032	$12,472,865	$15,337,981	$29,429,100
Less: Other Revenues									
Reconnection Charges	6C	10	$517,000	$444,488	$62,670	$4,065	$3,186	$379	$2,211
Rent From Gas Property	12	16	$165,000	$103,757	$28,749	$2,602	$7,058	$7,919	$14,916
Forfieted Discounts/Penalties	20	24	$2,996,000	$1,756,523	$1,029,818	$208,459	$0	$0	$1,200
Other Miscellaneous Revenues	16	20	$802,000	$470,889	$151,394	$14,701	$35,943	$44,227	$84,846
Subtotal			$4,480,000	$2,775,657	$1,272,631	$229,827	$46,187	$52,525	$103,173
TOTAL COST OF SERVICE RELATED TO TARIFF SALES AND TRANSPORTATION			$274,629,949	$161,425,644	$51,292,039	$4,874,206	$12,426,678	$15,285,455	$29,325,927

UGI UTILITIES, INC. - GAS DIVISION
OCA CLASS COST OF SERVICE STUDY
LABOR

	Account	Herbert Factor Ref.	TAI Factor Ref.	Cost of Service	Class Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
DIRECT LABOR EXPENSE										
750-760	Total Production & Gathering Operation Expenses	1	1		$0	$0	$0	$0	$0	$0
761 - 769	Total Gas Raw Materials Expenses	1	1	$68,000	$50,256	$17,744	$0	$0	$0	$0
850 - 860	Total Transmission Operation Expenses	4	26	$0	$0	$0	$0	$0	$0	$0
861 - 867	Total Transmission Maintenance Expenses	4	26	$0	$0	$0	$0	$0	$0	$0
870	Operation Supervision and Engineering	10	14	$2,093,000	$1,044,041	$550,963	$44,191	$120,454	$117,607	$215,744
871	Distribution Load Dispatching	4a	6	$436,000	$163,178	$100,926	$16,415	$28,428	$50,274	$76,779
874	Mains And Services Expenses									
	Mains - Small	5	26	$768,244	$233,452	$144,594	$26,113	$69,959	$100,685	$193,442
	Mains - Large	17	26	$1,172,256	$356,222	$220,634	$39,845	$106,750	$153,634	$295,171
	Services	6C	10	$1,940,500	$1,668,334	$235,226	$15,259	$11,960	$1,422	$8,300
875	M & R Station Expenses -General	4a	6	$233,000	$87,203	$53,935	$8,772	$15,192	$26,866	$41,031
876	Measuring and Regulating Station Expenses-Industrial	6B	9	$225,000	$0	$52,435	$0	$158,653	$13,549	$363
877	Measuring and Regulating Station Expenses-City Gate	4a	6	$168,000	$62,876	$38,889	$6,325	$10,954	$19,372	$29,585
878	Meter And House Regulator Expenses	6	8	$1,447,000	$499,735	$914,040	$25,556	$0	$0	$7,669
879	Customer Installation Expenses	6	8	$994,000	$343,287	$627,889	$17,555	$0	$0	$5,268
880	Other Expenses	10	14	$1,698,000	$847,005	$446,983	$35,851	$97,721	$95,411	$175,028
881	Rent	10	14	$0	$0	$0	$0	$0	$0	$0
885	Supervision - Engineering and Labor	11	15	$661,000	$237,258	$132,470	$20,100	$57,686	$73,727	$139,760
886	Structures & Improvements	18	22	$0	$0	$0	$0	$0	$0	$0
887	Mains - Small	5	26	$1,601,811	$486,754	$301,482	$54,446	$145,866	$209,931	$403,331
	Mains - Large	17	26	$2,444,189	$742,734	$460,029	$83,078	$222,576	$320,331	$615,440
889	M & R Equip - General	4a	6	$36,000	$13,473	$8,333	$1,355	$2,347	$4,151	$6,340
890	M & R Equip - Ind	6B	9	$60,000	$0	$13,983	$0	$42,307	$3,613	$97
891	M & R Equip - CG Check Station	4a	6	$180,000	$67,367	$41,666	$6,777	$11,736	$20,755	$31,698
892	Services	6C	10	$882,000	$758,294	$106,915	$6,936	$5,436	$646	$3,772
893	Meters & House Regulators	6	8	$371,000	$128,128	$234,353	$6,552	$0	$0	$1,966
895	Other Equipment	11	15	$47,000	$16,870	$9,419	$1,429	$4,102	$5,242	$9,938
894	Other Equipment	11	15	$0	$0	$0	$0	$0	$0	$0
901	Supervision	7	11	$362,000	$324,860	$35,829	$552	$433	$25	$300
902	Meter Reading Expenses	7	11	$626,000	$561,775	$61,958	$955	$749	$44	$520
903	Customer Records & Coll Expenses	7	11	$4,861,000	$4,362,280	$481,114	$7,418	$5,814	$338	$4,035
907	Supervision	7	11	$134,000	$120,252	$13,263	$204	$160	$9	$111
908	Customer Assistance Expenses	9	13	$868,000	$868,000	$0	$0	$0	$0	$0
910	Miscellaneous Customer Service & Info. Exp.	7	11	$28,000	$25,127	$2,771	$43	$33	$2	$23
911	Supervision	8	12	$0	$0	$0	$0	$0	$0	$0
912	Demonstrating And Selling Expenses	8	12	$546,000	$491,764	$54,236	$0	$0	$0	$0
920	Administrative & General Salaries	12	16	$8,808,000	$5,538,761	$1,534,660	$138,873	$376,748	$422,732	$796,225
921	Office Supplies And Expenses	12	16	$240,000	$150,920	$41,816	$3,784	$10,266	$11,519	$21,696
925	Injuries and Damages	12	16	$552,000	$347,116	$96,178	$8,703	$23,611	$26,493	$49,900
932	Maintenance of General Plant	12	16	$192,000	$120,735.94	$33,453	$3,027	$8,213	$9,215	$17,356
	Total Direct Labor Expense			$34,743,000	$20,718,060	$7,068,187	$580,117	$1,538,156	$1,687,592	$3,150,888
926	Employee Benefits and Pensions	13	17	$885,000	$527,746	$180,046	$14,777	$39,181	$42,988	$80,262
				$35,628,000	$21,245,806	$7,248,233	$594,894	$1,577,337	$1,730,580	$3,231,150

UGI UTILITIES, INC. - GAS DIVISION
OCA CLASS COST OF SERVICE STUDY
REVENUES

Account	Herbert Factor Ref.	TAI Factor Ref.	Cost of Service	Class: Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
Present Revenue									
Revenues from Tariff Sales (Per Herbert CCOSS)			$216,065,024	$108,668,733	$55,100,277	$10,602,234	$25,008,284	$11,785,496	$4,900,000
Adjustment for Interruptible			$14,096,000						$14,096,000
Adjustment for Current Transport Fees			$2,348,000			$1,983,000	$5,000		$360,000
Revenues from Tariff Sales			$232,509,024	$108,668,733	$55,100,277	$12,585,234	$25,013,284	$11,785,496	$19,356,000
Other Revenues:									
Reconnection Charges	6C	10	$517,000	$444,488	$62,670	$4,065	$3,186	$379	$2,211
Rent from Gas Property	12	16	$165,000	$103,757	$28,749	$2,602	$7,058	$7,919	$14,916
Forfeited Discounts	20	24	$2,996,000	$1,756,523	$1,029,818	$208,459	$0	$0	$1,200
Other Miscellaneous Revenue	16	20	$802,000	$470,889	$151,394	$14,701	$35,943	$44,227	$84,846
Total Other Revenue			$4,480,000	$2,775,657	$1,272,631	$229,827	$46,187	$52,525	$103,173
Total Operating Revenue			$236,989,024	$111,444,390	$56,372,908	$12,815,061	$25,059,471	$11,838,021	$19,459,173
UGI Proposed Revenue									
Revenues from Tariff Sales			$274,628,949	$152,001,162	$67,596,056	$11,583,714	$26,762,521	$11,785,496	$4,900,000
Other Revenues:									
Reconnection Charges	6C	10	$517,000	$444,488	$62,670	$4,065	$3,186	$379	$2,211
Rent from Gas Property	12	16	$165,000	$103,757	$28,749	$2,602	$7,058	$7,919	$14,916
Forfeited Discounts	20	24	$2,996,000	$1,756,523	$1,029,818	$208,459	$0	$0	$1,200
Other Miscellaneous Revenue	16	20	$802,000	$470,889	$151,394	$14,701	$35,943	$44,227	$84,846
Total Other Revenue			$4,480,000	$2,775,657	$1,272,631	$229,827	$46,187	$52,525	$103,173
Total Operating Revenue			$279,108,949	$154,776,819	$68,868,687	$11,813,541	$26,808,708	$11,838,021	$5,003,173

UGI UTILITIES, INC. - GAS DIVISION
OCA CLASS COST OF SERVICE STUDY
ALLOCATION AMOUNTS

Name	Herbert No.	TAI No.	Total	Class Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
PGC Sales	1	1	70,684	52,240	18,444	0	0	0	0
Average Daily Throughput	2	2	335,300	62,313	38,743	8,875	39,903	47,722	137,744
A&E - Excl. Interruptible	3	3	Not Used						
A&E - Small Mains	3B	4	Not Used						
A&E - Large Mains (Interrupt. Avg. only)	4	5	100.00%	47.43%	29.35%	5.02%	11.09%	0.00%	7.10%
Load Dispatching and M&R -- Some form of A&E	4A	6	100.00%	37.43%	23.15%	3.76%	6.52%	11.53%	17.61%
Small Distribution Mains -- Some form of A&E	5	7	100.00%	53.11%	32.88%	5.79%	2.72%	0.00%	5.50%
Account 381 - Meters	6	8	45,302,992	15,645,801	28,616,967	800,115	0	0	240,109
Account 385 - IM&R	6B	9	5,250,444	0	1,223,583	0	3,702,212	316,174	8,475
Services	6C	10	507,886,676	436,652,618	61,565,658	3,993,767	3,130,250	372,098	2,172,285
Customers	7	11	387,919	348,120	38,394	592	464	27	322
Sales Expenses	8	12	386,514	348,120	38,394	0	0	0	0
Customer Assistance/Direct Assignment	9	13	1	1					
Other Expenses and Rent	10	14	15,479,000	7,721,318	4,074,705	326,816	890,828	869,772	1,595,561
Distribution Maintenance Other	11	15	16,457,001	5,907,031	3,298,117	500,434	1,436,217	1,835,588	3,479,614
O&M Expenses Excl. A&G	12	16	63,907,001	40,186,833	11,134,824	1,007,604	2,733,523	3,067,155	5,777,061
Labor	13	17	34,743,000	20,718,060	7,068,187	580,117	1,538,156	1,687,592	3,150,888
Other Rate Base	14	18	1,230,156,884	664,239,850	242,162,336	26,056,398	60,749,157	80,644,992	156,304,150
Rate Base Less Certain Items	15	19	923,392,137	498,598,075	181,774,211	19,558,703	45,600,114	60,534,516	117,326,518
Expenses, Return and Income Taxes	16	20	275,664,949	161,854,786	52,037,448	5,052,902	12,354,512	15,201,880	29,163,421
Large and Directly-Assigned Mains Plant	17	21	342,752,138	104,154,645	64,510,583	11,650,176	31,212,198	44,920,517	86,304,019
M&R Station Equipment - Rate Base	18	22	558,074,987	169,586,403	105,037,253	18,969,019	50,820,243	73,140,366	140,521,703
Uncollectibles	19	23	7,105,868	6,527,255	446,108	42,855	56,327	0	33,323
Penalty Revenue	20	24	2,995,669	1,756,329	1,029,704	208,436	0	0	1,200
Average & Excess - No bifurcation and No Direct Assignment		25							
Peak & Average - No bifurcation and No Direct Assignment		26	100.0000%	30.39%	18.82%	3.40%	9.11%	13.11%	25.18%

UGI UTILITIES, INC. - GAS DIVISION
OCA CLASS COST OF SERVICE STUDY
ALLOCATION PERCENTAGES

Name	Herbert No.	TAI No.	Total	Class Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
PGC Sales	1	1	100.000000%	73.906400%	26.093600%	0.000000%	0.000000%	0.000000%	0.000000%
Average Daily Throughput	2	2	100.000000%	18.584253%	11.554727%	2.646883%	11.900686%	14.232627%	41.080823%
A&E - Excl. Interruptible	3	3	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!
A&E - Small Mains	3B	4	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!
A&E - Large Mains (Interrupt. Avg. only)	4	5	100.000000%	47.426518%	29.352954%	5.024870%	11.091996%	0.000000%	7.103662%
Load Dispatching and M&R -- Some form of A&E	4A	6	100.000000%	37.426208%	23.148052%	3.764965%	6.520250%	11.530662%	17.609863%
Small Distribution Mains -- Some form of A&E	5	7	100.000000%	53.109563%	32.883322%	5.794956%	2.715727%	0.000000%	5.496432%
Account 381 - Meters	6	8	100.000000%	34.535911%	63.167940%	1.766142%	0.000000%	0.000000%	0.530007%
Account 385 - IM&R	6B	9	100.000000%	0.000000%	23.304372%	0.000000%	70.512360%	6.021853%	0.161415%
Services	6C	10	100.000000%	85.974419%	12.121928%	0.786350%	0.616328%	0.073264%	0.427711%
Customers	7	11	100.000000%	89.740384%	9.897427%	0.152609%	0.119613%	0.006960%	0.083007%
Sales Expenses	8	12	100.000000%	90.066595%	9.933405%	0.000000%	0.000000%	0.000000%	0.000000%
Customer Assistance/Direct Assignment	9	13	100.000000%	100.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
Other Expenses and Rent	10	14	100.000000%	49.882537%	26.324081%	2.111353%	5.755075%	5.619048%	10.307906%
Distribution Maintenance Other	11	15	100.000000%	35.893725%	20.040813%	3.040856%	8.727091%	11.153844%	21.143671%
O&M Expenses Excl. A&G	12	16	100.000000%	62.883303%	17.423481%	1.576673%	4.277344%	4.799404%	9.039794%
Labor	13	17	100.000000%	59.632329%	20.344205%	1.669738%	4.427240%	4.857358%	9.069130%
Other Rate Base	14	18	100.000000%	53.996353%	19.685484%	2.118136%	4.938326%	6.555667%	12.706034%
Rate Base Less Certain Items	15	19	100.000000%	53.996353%	19.685484%	2.118136%	4.938326%	6.555667%	12.706034%
Expenses, Return and Income Taxes	16	20	100.000000%	58.714315%	18.877064%	1.832987%	4.481713%	5.514622%	10.579300%
Large and Directly-Assigned Mains Plant	17	21	100.000000%	30.387745%	18.821351%	3.399009%	9.106347%	13.105831%	25.179717%
M&R Station Equipment - Rate Base	18	22	100.000000%	30.387745%	18.821351%	3.399009%	9.106347%	13.105831%	25.179717%
Uncollectibles	19	23	100.000000%	91.857251%	6.278023%	0.603093%	0.792683%	0.000000%	0.468950%
Penalty Revenue	20	24	100.000000%	58.628941%	34.373090%	6.957912%	0.000000%	0.000000%	0.040058%
Average & Excess - No bifurcation and No Direct Assignment	0	25	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Peak & Average - No bifurcation and No Direct Assignment	0	26	100.000000%	30.387745%	18.821351%	3.399009%	9.106347%	13.105831%	25.179717%

UGI UTILITIES, INC. - GAS DIVISION
UGI PROPOSED REVENUE ALLOCATION

	UGI Case							
Rate Class	UGI Stated Current Non-Gas Rate Revenue	Plus Interruptible Revenue	Plus Transporation Fees	Total Current Non-Gas Rate Revenue	UGI Claimed Proposed Increase	UGI Effective Increase	Percent	Percent of System Average
Residential (Rate R)	$108,668;733		$0	$108,668,733	$43,332,429	$43,332,429	39.88%	165%
Commercial (Rate N)	$55,100,277		$0	$55,100,277	$12,495,779	$12,495,779	22.68%	94%
Delivery Service (Rate DS)	$10,602,234		$1,983,000	$12,585,234	$981,480	($1,001,520)	-7.96%	-33%
Large Firm Delivery (Rate LFD)	$25,008,284		$5,000	$25,013,284	$1,754,237	$1,749,237	6.99%	29%
Extra Large Delivery Firm (Rate XD Firm)	$11,785,496		$0	$11,785,496	$0	$0	0.00%	0%
Interruptible	$4,900,000	$14,096,000	$360,000	$19,356,000	$0	($360,000)	-1.86%	-8%
TOTAL	$216,065,024	$14,096,000	$2,348,000	$232,509,024	$58,563,925	$56,215,925	24.18%	100%
Less: Interruptible Margin and Transportation Fees @ Current Rates					($16,444,000)			
TOTAL INCREASE					$42,119,925			
PERCENT INCREASE					19.49%			

UGI UTILITIES, INC.
OCA PROPOSED REVENUE ALLOCATION

OCA Proposed Increase	Percent Increase	Percent of System Average
$31,775,982	29.24%	150%
$8,486,075	15.40%	79%
$666,538	5.30%	27%
$1,191,329	4.76%	24%
$0	0.00%	0%
$0	0.00%	0%
$42,119,925	19.49%	100%

Remaining $10,343,943
Dist Proportional to N, DS, LFD

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2015-2518438
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, Glenn A. Watkins, hereby state that the facts above set forth in my Direct Testimony, OCA St. No. 3, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: ______________________
Glenn A. Watkins

Consultant Address: Technical Associates, Inc.
1503 Santa Rosa Road, Suite 130
Richmond, Virginia 23229

DATED: April 12, 2016

OCA Statement No. 3R
6/2/16 Hlg vx

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
	)	
v.	)	Docket No. R-2015-2518438
	)	
	)	
UGI Utilities, Inc. – Gas Division	)	

REBUTTAL TESTIMONY
OF
GLENN A. WATKINS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MAY 10, 2016

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 1503 Santa Rosa Road, Suite 130, Richmond, Virginia

Q. HAVE YOU PREVIOUSLY PRE-FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I pre-filed direct testimony on April 12, 2016 which was designated as OCA Statement No. 3.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of this testimony is to comment on the direct testimony of OSBA witness Robert Knecht.

Q. OVERALL, DO YOU AND MR. KNECHT SHARE COMMON CONCERNS REGARDING UGI'S POSITIONS AND PROPOSALS IN THIS CASE?

A. In many respects, yes. While Mr. Knecht and I have philosophical differences of opinion as to how certain costs should be allocated to individual rate classes from a practical perspective, we agree in many respects as to how various contentious issues should be treated for cost allocation purposes in this case. Perhaps more importantly, Mr. Knecht, Company witness LaHoff and I all agree with a conceptual framework to assign revenue responsibility to the residential class.

Q. PLEASE COMMENT ON THE ALLOCATION METHODOLOGY UTILIZED BY MR. KNECHT IN THIS CASE.

A. As noted by Mr. Knecht and me (in my direct testimony), the method, or approach, used to allocate distribution mains tends to be the most contentious and important issue relating to natural gas distribution company ("NGDC") cost allocation studies. While Mr. Knecht is of the opinion that natural gas distribution mains should be allocated across customer classes based both on number of customers and peak demand, he has not incorporated a "customer" component in his class cost of service study ("CCOSS") in this case due to this Commission's prior practices and policies. Furthermore, on page 10 of his direct testimony, Mr. Knecht concludes that the peak demand method is most consistent with cost causation; i.e., no consideration should be given to average demand (annual throughput). However, Mr. Knecht claims there is Commission "precedent" for what is known as the Average and Excess ("A&E") methodology to allocate mains. As a result, and as stated on page 11 of his direct testimony, Mr. Knecht has accepted the A&E method (as modified by the Company) for this proceeding "for reasons of Commission precedent."

Q. BEFORE YOU DISCUSS WHETHER THE A&E METHOD IS THIS COMMISSION'S PREFERRED COST ALLOCATION METHODOLOGY FOR NGDCs IN PENNSYLVANIA AS A MATTER OF "PRECEDENT," PLEASE EXPLAIN WHY THIS ISSUE IS IMPORTANT NOT ONLY FOR THIS RATE CASE BUT FOR FUTURE NGDC RATE CASES.

A. For many years the Commission's accepted methodology to allocate mains for NGDCs has been the Peak and Average ("P&A") method in which mains are allocated based 50% on peak day demands and 50% on average day demands. Indeed, the Commission has ruled on numerous occasions that distribution mains are installed to meet not only peak day demands but also meet average day demands throughout the year. These findings came about as a result of some witnesses advocating the allocation of distribution mains based upon number of customers and peak demand; i.e., there is a customer component and a demand component associated with mains investment and average demand (throughput) should not be considered in the allocation of mains. This Commission has consistently rejected these proposals.

The A&E method is different than the P&A method both conceptually and mathematically. Whereas the P&A method is straight-forward in that equal weights are given to both class contributions to peak demand and average day demand, the A&E approach is not nearly as straight-forward in that class contributions to "excess" demands are calculated as the difference between each class' peak demand and average demand; i.e., the excess demands over average demands. Moreover, under the traditional A&E approach, the system-wide coincident load factor is utilized to weight the assignment of "average" and "excess" demands across classes. That is, class relative contributions to average demands are multiplied by the system coincident load factor and excess demands are weighted based on one minus the system coincident load factor. In this regard, it is most important to understand that when the A&E approach is utilized, class contributions to peak demand must be stated in terms of non-coincident peak demands as opposed to coincident peak demands. This is because if class contributions to coincident peak demands are utilized, along with the system coincident load factor, the class allocation factors will be reduced to, and exactly equal, class contributions to coincident peak day demands. In other words, there will be no recognition of average usage.

This mathematical reality is most important as it relates to NGDCs. This is because there tends to be very little difference between design day class coincident peak demands and design day class non-coincident demands. In simple terms, design day demands are, by definition, the maximum demands placed upon the system under the theoretically coldest day possible; i.e., these design day demands, by definition, are coincident with the system. As a result, and as noted by Mr. Knecht on page 11 of his direct testimony, NGDC A&E allocators are typically "more similar in magnitude to a peak demand allocator than a P&A allocator." In other words, when the A&E approach is utilized for NGDC CCOSS, the resulting allocators tend to be heavily weighted towards peak demand with little weight, or consideration, given to average day demands.

Because of the mathematical problems associated with using the traditional A&E method for NGDC CCOSS, cost allocation experts sometimes will select or utilize a weighting factor different than the system load factor as used under the traditional approach. In this way, the analyst will not be confronted with the class allocation factors being exactly (or closely) equal to simply peak day demands. As noted on page 11 of Mr. Knecht's direct testimony, the Company (Mr. Herbert) utilized a "modified" A&E approach wherein his weighting factors are not equal to the system load factor. As a result, Mr. Knecht observes that the Company's method "produces allocation results that fall about half-way between the traditional peak demand method and a traditional 50/50 P&A method."[1]

[1] Mr. Knecht and I both determined that Mr. Herbert's modified A&E approach weights peak demand at 77% and average demand at 23% for large mains and weights peak demand at 72% and average demand at 28% for small mains (see OCA Statement No. 3, Schedule GAW-3 and Knecht footnote number 9).

Q. PLEASE EXPLAIN MR. KNECHT'S ASSERTION THAT THE A&E METHOD IS NOW THIS COMMISSION'S APPROVED NGDC METHODOLOGY BY REASON OF PRECEDENT.

A. Mr. Knecht cites as precedent two fully litigated NGDC cases in which modified A&E methods were approved by the Commission. However, it is most important to understand the circumstances of these cases as well as the context under which the studies were approved.

The first case Mr. Knecht refers to is a 2006 rate case involving PPL Gas (Docket No. R-00061398). In that case, Mr. Herbert, Mr. Knecht and I all participated. Mr. Knecht and I both recommended various adjustments to Mr. Herbert's CCOSS study that utilized a modified A&E approach to allocate mains. With respect to my testimony in the 2006 PPL Gas case, I accepted Mr. Herbert's allocation of mains because his modified A&E approach was not materially different than the results that would be obtained under the P&A method. Therefore, in order to avoid arguing over two methods that produce very similar results, I focused my attention on other issues within Mr. Herbert's CCOSS.[2] At the same time, Mr. Knecht rejected Mr. Herbert's modified A&E approach and recommended that mains be allocated to classes based upon number of customers (28%) and peak day demands (72%). Furthermore, Mr. Knecht made adjustments to Mr. Herbert's class peak day demands. In its Opinion and Order, the Commission accepted the Administrative Law Judge's ("ALJ") recommendation and stated:

> The ALJ determined that the record does not demonstrate that the A&E allocator as calculated by PPL Gas is incorrect and that the OSBA failed to support its conclusion by explaining or demonstrating how the definition of the A&E methodology used by the Company is wrong. Finding that the A&E allocator is supported by the evidence, and that the OSBA modification to replace the A&E allocator with a peak demand allocator is not supported by the evidence, the ALJ recommended approval of the Company's A&E allocator. (Order, p. 114)

The only controversy surrounding the allocation of mains in the 2006 PPL Gas case concerned Mr. Knecht's proposal to allocate mains based on customers and peak day

[2] My adjustments in the 2006 PPL Gas case included different approaches to allocate storage, storage facilities, income taxes, low income (CAP) costs, miscellaneous revenue, uncollectibles, records and collections, and sharing of the revenue associated with discounted rates across all customer classes.

demand, which was rejected and the fact that I did not object to Mr. Herbert's modified A&E approach because it produced very similar results to those that would be obtained under the P&A method.

Q. PLEASE DISCUSS THE SECOND CASE THAT MR. KNECHT ASSERTS AS BEING PRECEDENTIAL AS IT RELATES TO THE ALLOCATION OF NGDC MAINS COSTS.

A. The second case Mr. Knecht refers to as precedential concerns the 2007 Philadelphia Gas Works ("PGW") general rate case (Docket No. R-00061931). As was the case in the PPL Gas case, the most controversial cost allocation issue concerned the allocation of mains investment. Company witness Howard Gorman conducted his CCOSS based upon an allocation approach in which mains were allocated 25% based on number of customers and 75% based on peak day demand. OCA witness Richard Galligan and OTS (now I&E) witness Joseph Kubas opposed the Company's allocation approach. OCA witness Galligan conducted an alternative CCOSS in which mains had no customer component and allocated mains with a weight of 20% on peak day demand and 80% on average day demands. OTS witness Kubas agreed conceptually with Mr. Galligan that there should be no customer component within the allocation of mains and stated on page 14 of his direct testimony as follows: "the A&E method reflects the fact that mains are built to deliver volumes of gas during both average and peak times. Therefore, an equal amount of weight should be given to both events." However, Mr. Kubas testified that he used a modified A&E approach to carry out his recommendation. In this case, the ALJ agreed with OCA and OTS concerning the two most relevant factors as it relates to the allocation of mains. First, the ALJ recommended that the Company's proposal to allocate mains based on number of customers and peak day demands be rejected. In its Opinion and Order, the Commission agreed with the ALJ's recommendation and found "PGW's proposal to allocate a percentage of the costs of the distribution mains as a customer cost not to be acceptable." The Commission found: "Reviewing the record, we find that the allocation of distribution mains investment costs should be done using both annual and peak demands."[3]

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[3] Order at page 80.

While I did not participate in the 2007 PGW rate case, I did participate in PGW's 2010 general rate case (Docket No. R-2009-2139884). In the 2010 case, Company witness Howard Gorman utilized a modified A&E approach that when evaluated against the traditional P&A method, produced no material differences.[4]

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING MR. KNECHT'S ASSERTION THAT THE A&E METHOD IS NOW THE COMMISSION PREFERRED APPROACH TO ALLOCATE MAINS INVESTMENT COSTS.

A. When the record of the two so-called "precedential" cases are carefully examined along with a clear understanding of the arithmetic involved within the traditional A&E approach, I can find no evidence of the Commission endorsing the traditional A&E method as its preferred, or allowable, allocation methodology. Indeed, in both of these cases, a "modified" A&E mathematical approach was utilized that gave significant weight to average and peak demands. These findings are entirely consistent with the Commission's long-standing practice of weighting mains allocation based 50% on peak demand and 50% on average demand. With this in mind, it is important to consider the weighting schemes utilized by Mr. Herbert and Mr. Knecht in the present case, whereas Mr. Herbert's A&E approach gives a 77% weight to peak demand and 23% weight to average demand, Mr. Knecht's A&E approach results in a 68% peak demand and 32% average demand weighting. In my opinion, Mr. Herbert's and Mr. Knecht's "modified" A&E approaches place too much weight on peak demand and not enough on average demand. Hence, I continue to support and recommend the use of the much more straight-forward 50%/50% P&A method that is easily understood and less prone to arbitrary manipulations than a "modified" A&E approach.

Q. DO YOU HAVE ANY COMMENTS CONCERNING MR. KNECHT'S ANALYSES OF THE UGI'S CLASS COST OF SERVICE STUDY?

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4 OCA Statement No. 4 (Watkins' direct testimony, page 12).

A. Yes. With the exception of Mr. Knecht's use of a "modified" A&E approach that he refers to as being precedential, I agree with most of the observations and conceptual framework set forth by Mr. Knecht as it relates to UGI's cost allocations.

Q. PLEASE COMMENT ON MR. KNECHT'S TREATMENT OF THE DIRECT ASSIGNMENT OF MAINS INVESTMENT TO THE XD CLASS.

A. Mr. Knecht sets forth the conceptual framework under which it may be appropriate to directly-assign mains (or other) investment to individual customers. Mr. Knecht then states, on page 12, that the Company's proposal to directly-assign mains to the XD customers is generally reasonable. However, on page 13 of his direct testimony, Mr. Knecht acknowledges that he did not conduct a detailed review of the Company's direct assignment of mains to the XD Firm class.

In my evaluation of the reasonableness of the Company's proposal to directly-assign mains, I evaluated UGI's Highly Confidential response to OCA-IV-3, which provided schematics of each individual XD customer location along with a diagram of UGI's distribution mains, as well as UGI's Informal Supplemental response to OCA-IV-2, which was provided to the OCA on CD and contained 29 separate Microsoft Excel files that were extremely detailed and shows the Company's allocation of specific mains to each individual XD customer. Based on my in-depth review of these materials, it is clear to me that the Company's proposed allocation of joint mains costs associated with these individual customers unreasonably minimizes cost responsibility to these individual customers. As such, and as discussed in my direct testimony, I concluded that the XD class should be allocated mains-related cost like all other customer classes.

Q. PLEASE COMMENT ON MR. KNECHT'S EVALUATION OF MR. HERBERT'S ALLOCATION OF COSTS TO THE INTERRUPTIBLE CLASS.

A. Mr. Knecht agrees with my assessment that Mr. Herbert's averaging of two approaches to allocate costs to Interruptible customers is unreasonable and understates any reasonable cost to serve these customers. Similar to my examination, Mr. Knecht observed that UGI rarely interrupts these customers and when it does, only a small percentage of Interruptible customers are curtailed. As such, on page 17 of his direct testimony, Mr. Knecht concludes that one of Mr. Herbert's approaches, in which he allocates mains costs to Interruptible customers considering average usage with no peak demand consideration, is "directionally reasonable." With this statement, I take the term "directionally reasonable" to mean that cost allocations are moving in the right direction as opposed to Mr. Herbert's other study that allocates virtually no mains to the Interruptible class. Towards this end, I do agree. However, the purpose and mechanics of a cost of service study is to quantify reasonable amounts for cost responsibility. This is most important because for any embedded cost allocation study, the sum of the parts must equal the whole such that individual class cost responsibilities are based on their relative, and quantifiable, contributions to a specific allocation factor.

However, the fact that a selected allocation factor may be moving in the right direction provides little to no guidance as to what a reasonable level should be. As explained in detail in my direct testimony, and as also acknowledged by Mr. Knecht, UGI's Interruptible customers continue to place significant load on the system during peak periods and rely upon the Company's distribution mains largely without interruption. Indeed, as set forth in my direct testimony, I have shown that only a very small percentage of Interruptible customers are curtailed during absolute peak periods such that the Interruptible load on the system during such periods represents the vast preponderance of these customer's total energy demands.

Q. PLEASE COMMENT ON MR. KNECHT'S ADJUSTMENTS TO CLASS DESIGN DAY DEMANDS.

A. First of all, Mr. Knecht's assessment is absolutely correct. That is, Mr. Knecht observes that UGI has made significant downward adjustments to budgeted usage levels for most every rate class. At the same time, Mr. Knecht also observed that the Company's design day demands as used by Mr. Herbert in his CCOSS are based on the loads and usages developed from the Company's most recent 1307(f) Filing that indicated much higher levels of demand and usage. As a result, Mr. Knecht observed that there is a mismatch in Mr. Herbert's CCOSS between his stated class revenues (based on much lower usages) and the design day peak demands. Furthermore, Mr. Knecht observed that UGI's approach to develop class design day demands for purposes of this rate case was largely nonsensical, at least for some classes. As such, Mr. Knecht developed his own estimates of class design day demands based on the lower usages proposed by UGI as well as estimating higher design day demands for the LFD class based on their contract demands. While Mr. Knecht's analyses may not be as robust as what would be preferred in a perfect world, he was limited in the data available.

Q. THE COMPANY'S PROPOSED DOWNWARD ADJUSTMENTS TO ITS BUDGETED USAGE AND REVENUE LEVELS ARE VERY CONTENTIOUS ISSUES IN THIS CASE AS IT RELATES TO THE COMPANY'S REQUIRED OVERALL REVENUE REQUIREMENT. IF THE COMMISSION AGREES WITH THE OCA OR I&E AS IT RELATES TO THESE ISSUES, HOW WILL THIS IMPACT MR. KNECHT'S CCOSS ANALYSIS?

A. As noted in my direct testimony, the CCOSS presented in this case by all parties reflects the Company's downward adjustments to residential and commercial revenues. If the Commission rejects UGI's proposed downward adjustments, Mr. Knecht's estimates of class design day demands are likely not very accurate. At the same time, Mr. Knecht's CCOSS reflects the class revenues associated with UGI's lower class revenues such that his (or any other) CCOSS should theoretically be adjusted to reflect these adjustments. This is precisely why I noted in my direct testimony that CCOSS analyses in this case should only be given limited weight or consideration. That is, there are so many unknowns and uncertainties that directly impact class cost allocations that it is not possible to reasonably evaluate class cost allocations without knowing how the Commission will rule on these many other separate issues.

Q. PLEASE COMMENT ON MR. KNECHT'S PROPOSED CLASS REVENUE ALLOCATIONS.

A. There appears to be a general conceptual consensus between the Company, Mr. Knecht and I as to how any overall revenue increase (if any) should be assigned to the residential class -- that being 150% of the system average percentage increase. However, Mr. Knecht is apparently uncertain as to the Company's proposed ratemaking treatment of interruptible business as well as its proposal to eliminate its current ancillary transportation charges.

With regard to UGI's proposed ratemaking treatment of interruptible business, Mr. Knecht states in footnote 22 (page 30) of his direct testimony that he is uncertain about the Company's reported levels for interruptible rate revenue at current rates. In this footnote, he sets forth his uncertainty in that he observed that the Company's budgeted interruptible revenues are significantly different than the $4.9 million in revenue the Company reports for the total interruptible class. As a result, it appears that Mr. Knecht does indeed have uncertainty as to UGI's proposed ratemaking treatment of its interruptible business. In my view, this is an important consideration in that Mr. Knecht's proposed class revenue allocations are based upon the Company's $58.56 million proposed increase which incorporates only $4.9 million of imputed revenue to the interruptible class.

With regard to ancillary transportation charges, even though the Company clearly collects these revenues at current rates, these revenues have been eliminated in the Company's filing at current rate revenues such that Mr. Knecht may be unaware of this error. This is important because Mr. Knecht acknowledges on page 31 of his Direct Testimony that "the Commission is reluctant to assign rate decreases to individual classes except in extraordinary circumstances, particularly when the utility is seeking a large overall rate increase as in the current proceeding." Under Mr. Knecht's proposed revenue allocation, he recommends a $1.43 million increase to Rate DS. However, Mr. Knecht's proposal does not recognize the impact of the elimination of tariffed ancillary transportation fees that this customer class currently pays. Under current rates, Rate Schedule DS pays $1.983 million in these ancillary transportation fees. As a result, under Mr. Knecht's class revenue allocation proposal, Rate DS would actually incur a rate reduction of $0.553 million under his recommendation which conflicts with his statement that no class should receive a rate reduction as noted above.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

220753

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2015-2518438
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, Glenn A. Watkins, hereby state that the facts above set forth in my Rebuttal Testimony, OCA St. No. 3R, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: ____________________
Glenn A. Watkins

Consultant Address: Technical Associates, Inc.
1503 Santa Rosa Road, Suite 130
Richmond, Virginia 23229

DATED: May 10, 2016

OCA St. No. 3-SR
6/2/16 [illegible]

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:		
	:		
v.	:	Docket No.	R-2015-2518438
	:		
UGI Utilities, Inc. – Gas Division	:		

SURREBUTTAL TESTIMONY
OF
GLENN A. WATKINS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MAY 25, 2016

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 1503 Santa Rosa Road, Suite 130, Richmond, Virginia

Q. HAVE YOU PREVIOUSLY PRE-FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I pre-filed direct testimony on April 12, 2016, which was designated as OCA Statement No. 3, as well as rebuttal testimony on May 10, 2016, which was designated as OCA Statement No. 3R.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. I have reviewed the rebuttal testimony filed by the other parties participating in this proceeding. The purpose of my surrebuttal testimony is to respond to the rebuttal testimonies of UGI witnesses Szykman, Herbert, Lahoff, Stoyko, Love and Borelli, as well as Industrial Intervenor witnesses Schreiber and Davey. To the extent that I do not respond to a particular issue or argument contained within another party's rebuttal testimony, I defer to my Direct Testimony on those issues.

Q. PLEASE RESPOND TO THE COMPANY'S VARIOUS REBUTTAL TESTIMONIES CONCERNING YOUR ADJUSTMENT TO INCLUDE ALL INTERRUPTIBLE REVENUE WITHIN UGI'S REVENUE REQUIREMENT.

A. First, it is important to separate two issues concerning UGI's interruptible business. The first issue concerns whether all interruptible sales should be reflected in the Company's revenue requirement. The second issue relates to the allocation of costs to various customer classes; i.e., class cost of service. In this regard, Company witness Szykman tends to mix and combine these two separate issues in an attempt to support the Company's proposal to exclude approximately $15 million of interruptible revenue from its revenue requirement.

The issue concerning the level of interruptible revenues that should be reflected in the Company's overall revenue requirement is very simple: whereas, the Company has consistently collected more than $20 million annually in interruptible revenue and also forecasts that this level of revenue will continue into the foreseeable future, UGI's proposal is to only impute $4.9 million of revenue associated with interruptible business for purposes of establishing the Company's revenue requirement. Because UGI's total cost of service (i.e., revenue requirement) reflects its total cost of providing service (O&M expenses, depreciation, taxes, and return), the Company's proposal simply calculates its proposed revenue requirement minus $4.9 million of its imputed interruptible revenues to determine the revenues that must be collected from firm ratepayers. As a result, any revenues collected over and above the $4.9 million will flow directly to shareholders as before income tax profits. In short, the Company's proposal would certainly result in excess monopoly profits in that it is been clearly demonstrated that UGI will collect about $20 million annually in interruptible revenues.

Q. DOES MR. SZYKMAN CLAIM THERE IS A RISK THAT UGI WILL LOSE ITS INTERRUPTIBLE BUSINESS AND SOURCE OF REVENUE?

A. Yes. On pages 21 and 22 of his rebuttal testimony, Mr. Szykman states that the Company receives substantial revenue from interruptible customers and if these revenues were lost, the Company would need to replace that source of cash through higher rates for remaining firm customers. While Mr. Szykman's statement is mathematically correct, the same is true for the loss of any group of customers. Indeed, Mr. Szykman's statement goes to the crux of my disagreement and rejection of the Company's proposal to only include about 25% of the revenues actually collected from interruptible customers. That is, while the Company will actually collect about $20 million from interruptible customers, it only imputes $4.9 million of revenue responsibility to this business. Therefore, UGI is asking all other customers' to reflect this $15 million imputed shortfall in revenue (even though UGI will continue to collect this $15 million).

Perhaps more importantly is Mr. Szykman's statements on pages 29 and 30 of his rebuttal testimony that natural gas currently does not have a price advantage over alternative fuels. Remembering that UGI's negotiated interruptible rates are based on the price spread between natural gas and alternative fuels, Mr. Szykman claims that #2 fuel oil is 20% cheaper than natural gas.[1] Mr. Szykman's statement is simply incorrect. That is, Mr. Szykman claims that the current spot price for #2 fuel oil is $8.38 per Dth equivalent.[2] At the same time, Mr. Szykman states that during February 2015, natural gas prices in the UGI gas market area averaged $10.84 per Dth. While Mr. Szykman's estimate of current #2 fuel oil prices are reasonable, his claim that natural gas prices are $10.84/Dth are tremendously overstated. According to the U.S. Department of Energy, Energy Information Administration ("EIA"), the average wholesale price of #2 fuel oil in Pennsylvania during February 2016 was $1.198 per gallon, which translates into a price of $8.65 per Dth. At the same time, EIA reports that the average price of natural gas delivered to city gates in Pennsylvania was $3.19 per MCF, or about $3.07 per Dth. As such, we can see that the current price advantage of natural gas is more than $5.50 per Dth, which is substantially higher than the rates that interruptible customers are paying for distribution service from UGI. Indeed, and as discussed in my direct testimony, while alternative fuels reflect legitimate back-up energy sources for short-term curtailments, natural gas has a significant price advantage over alternative fuels and it is not feasible for most customers to use alternative fuels as their primary energy source.

Q. AS PART OF ITS REBUTTAL FILING, DOES UGI OFFER AN ALTERNATIVE RATEMAKING TREATMENT FOR ITS INTERRUPTIBLE BUSINESS?

A. Yes. On Pages 30 through 32 of his rebuttal testimony Mr. Szykman offers an alternative ratemaking treatment for Interruptible business.

Q. PLEASE EXPLAIN MR. SZYKMAN'S ALTERNATIVE RATEMAKING APPROACH.

A. As an alternative to UGI's proposal to only reflect $4.9 million of interruptible revenue within its total revenue requirement (thereby requiring firm customers to be responsible for the remainder to the Company's revenue requirement), Mr. Szykman

[1] The vast majority of UGI's interruptible customers use #2 fuel as back-up for natural gas. In response to OCA-XIII-4, the Company indicated that 238 out of 319 interruptible customers use #2 fuel oil as their alternative or back-up fuel source.

[2] A dekatherm (Dth) is equal to 1,000,000 BTUs. #2 fuel oil has a heating value of approximately 138,500 BTUs per gallon.

offers an alternative in which the Company's total revenue requirement will be established by the Commission and all costs will be assigned to firm ratepayers, i.e., firm rates will be design as if there are no interruptible revenues. Then, the Company would share interruptible revenue with firm customers (50%/50%) as a bill credit. In other words, this alternative treatment would allow shareholders to retain half of the revenue collected as before tax profits since firm rates would be developed under an assumption that interruptible business does not exist. Furthermore, the firm ratepayer sharing credit (ratepayers 50% share) would be allocated to classes each year based on non-gas revenue and be reflected as a credit to the customer charge.

Q. SHOULD MR. SZYKMAN'S ALTERNATIVE INTERRUPTIBLE RATEMAKING PROPOSAL BE CONSIDERED?

A. No. As has clearly been established, UGI has historically collected, and is expected to continue to collect, about $20 million annually in interruptible business. Under this alternative plan, ratepayers would bear all risk associated with interruptible revenues such that the revenue collected from this business would be a windfall to UGI's shareholders. Indeed, based on historical experience, UGI's own forecasts, and Mr. Szykman's example provided in his rebuttal Exhibit PJS-2, the Company would over collect about $10 million annually ($20 million actual interruptible revenue less 50% sharing).

Q. PLEASE RESPOND TO MR. HERBERT'S CRITICISMS OF YOUR ANALYSES CONCERNING CLASS COST ALLOCATIONS.

A. On page 9 of his rebuttal testimony, Mr. Herbert claims that my approach to not directly-assign mains cost to the XD class and to allocate more mains cost to interruptible customers produces anomalous results. Mr. Herbert indicates that the XD and interruptible customers represent only 0.09% of UGI's total number of customers, yet, I allocate 38.3% of UGI's total investment in mains to these two classes. There is nothing anomalous about this result, simply because, on a combined basis, these two classes represent more than 55% of the usage on UGI's system. Indeed, Mr. Herbert infers that a residential customer in a small apartment should carry the same weight (cost responsibility) as a huge factory.

On page 10, lines 2 and 3 of his rebuttal testimony, Mr. Herbert claims that there is a "customer" component associated with mains investments. As is well known, this Commission has rejected the consideration of number of customers within the allocation of mains for decades; i.e., there is no customer component of mains. Yet, Mr. Herbert clearly attempts to hide this fact within his allocation approach. Indeed, Mr. Herbert states on page 10, lines 9 through 11 as follows: "Therefore, the solution is to directly assign the mains used to serve the large customers, and then allocate the remaining mains to the remaining classes using accepted methods."

On pages 12 and 13 of his rebuttal testimony, Mr. Herbert claims that there is an inherent flaw in the Peak & Average ("P&A") method. That is, Mr. Herbert claims that within the P&A method, the average component is counted twice. Mr. Herbert's reasoning is that because average use is less than peak day use, it is a subcomponent of the use during the peak day. This argument is nothing more than a red herring. The concept of the P&A method and that expressed and approved by the Commission numerous times is that mains should be allocated considering both peak day usage and annual throughput. In a relative sense, average day use is exactly equal to annual throughput simply because every class' annual usage is divided by a constant (365 days). Therefore, the P&A method appropriately recognizes these two concepts; i.e., peak use and utilization throughout the year.

On page 13 of his rebuttal testimony, Mr. Herbert claims that the P&A method is not identified as a standard cost allocation method set forth in the AGA's Gas Rate Fundamentals. This is simply incorrect. On page 145 of the 1987 Edition (most recent), this book refers to the P&A method as the "seaboard" method. More importantly, the P&A method is used extensively around the Country for cost allocation purposes and has been used and accepted for many years by this Commission.

Q. MR. HERBERT AND MS. BORELLI CLAIM THAT YOUR ASSIGNMENT OF SOME CAPACITY COSTS TO INTERRUPTIBLE CUSTOMERS IS INCORRECT IN THAT UGI DOES NOT DESIGN ITS SYSTEM TO SERVE INTERRUPTIBLE LOADS UNDER DESIGN DAY CONDITIONS. PLEASE RESPOND.

A. The most important thing to consider in cost allocation studies is the reasonableness of how costs are ultimately assigned to customer classes. In this regard, UGI has claimed that it has connected tens of thousands new customers over the last several years, yet, this customer growth certainly has not required UGI to totally replace and redesign its distribution system. In other words, and is the case for virtually every NGDC, UGI has a considerable amount of capacity over and above its current needs to meet customer's demands. In fact, the term design day demand is utilized to ensure that there is enough natural gas supply on the coldest day that can realistically be expected. In other words, design day demands are used primarily for gas supply and do not relate to the actual physical capacity within the distribution system.

In my direct testimony, I showed that UGI only interrupts a very small percentage of interruptible load during peak day periods. Both Mr. Herbert and Ms. Borelli focus on a single day (January 13, 2015), which was the system peak day during the 2014/2015 heating season. In my direct testimony, I showed and explained that UGI's practice of curtailing only a very small percentage of interruptible load on January 13, 2015 was not an aberration or unusual event in that UGI consistently only interrupts a small portion of these customers during peak day periods. To further exemplify this fact, the coldest day in UGI's service area during the 2014/2015 heating season was February 19, 2015, as discussed in the testimony of Shaun Hart in Docket No. R-2015-2480950 (most recent 1307(f) Filing), with the average temperature at 7 degrees Fahrenheit in the primary area and 3 degrees Fahrenheit in the secondary area. UGI's design day temperature is -3.6 degrees Fahrenheit in the primary area and -8 degrees Fahrenheit in the secondary area. While the temperatures on this date were not quite as cold as design day temperatures, they were close. With this information, I then examined the level of interruptions that occurred on February 19, 2015. The Company's response to OCA-IV-9 shows every interruption over a several year period. On February 19, 2015, the Company curtailed

12,595 Dth of interruptible load. Considering that the total interruptible load on a somewhat warmer day (January 13, 2015) was 197,600 Dth, we can see that UGI only curtails about 6% of total interruptible load even on the coldest of days. In this regard, it must be remembered that I have not treated interruptible load as if it were firm service in that I have only assigned a peak day load to interruptible customers of 80,000 Dth when in fact, these customer's usage on peak days is very close to 200,000 Dth. In this way, I have not assigned a full level cost responsibility to interruptible customers.

Q. PLEASE RESPOND TO MR. LAHOFF'S DISAGREEMENT WITH YOUR ADJUSTMENT TO REFLECT POOLING FEES, SYSTEM ACCESS FEES, AND INFORMATION SERVICE FEES (ANCILLARY TRANSPORTATION FEES) WITHIN CURRENT RATE REVENUES.

A. As discussed in my direct testimony, the revenues derived from these fees are currently rate revenues contained in the Company's current tariff. UGI proposes to eliminate these fees. Whether these fees are or are not eliminated has no bearing on current revenues as the Company clearly is still earning these revenues. Mr. Lahoff's rationale is that on a proforma basis, current rates would no longer contain these charges in the FPFTY. Mr. Lahoff's argument is, quite frankly, in error and is at odds with every rate case I have been involved in. As an analogy, utilities in Pennsylvania collect STAS revenues through a rider in between rate cases and when a rate case establishes new rates, these STAS revenues are eliminated. However, current rate revenues in utility filings always properly include the revenues currently collected through STAS.

Q. PLEASE RESPOND TO MR. STOYKO'S REBUTTAL TESTIMONY CONCERNING UGI'S PROPOSED TED RIDER.

A. Mr. Stoyko responds to my recommendation to disallow the TED Rider as written because this will permit UGI the unilateral ability to negotiate discounted rates to large commercial and small industrial customers. Mr. Stoyko claims that the TED Rider will only apply to those instances in which a project is deemed "economically" feasible. However, the Company's proposed tariff as written provides great latitude to offer discounted rates to new customers. Furthermore, it will be unmanageable for the

Commission or other parties to have any effective regulatory oversight over these special projects as there will be no review or approval process before the Commission prior to the rates going into effect.

Q. PLEASE RESPOND TO MR. STOYKO'S REBUTTAL TESTIMONY CONCERNING THE RESIDENTIAL CUSTOMER CHARGE.

A. My position regarding the residential customer charge has not changed, and I stand by my direct on this issue.

Q. PLEASE RESPOND TO MR. LOVE'S DISAGREEMENTS WITH YOUR RECOMMENDATIONS CONCERNING THE EE&C PLAN IF IT IS APPROVED BY THE COMMISSION.

A. I do not think Mr. Love is correct. First, Mr. Love objects to my recommendation that if the EE&C plan is approved, all qualifying residential appliances must exceed the U.S. Department of Energy "EnergyStar" ratings. Mr. Love simply responds that the Act 129 EDCs will offer incentives for EnergyStar rated measures under their Phase III EE&C plans. Furthermore, Mr. Love responds to my observation that the Company proposes to offer incentives for tankless water heaters that do not meet EnergyStar minimum standards by claiming there are significant benefits to be obtained by customers switching from water storage to tankless water heaters. While Mr. Love's statements may indeed be correct, the reality is, the Company is voluntarily seeking to implement a program that will be totally funded by ratepayers to pay for the energy efficiency programs that will only benefit a few customers. Since ratepayers will indeed be paying for this program (if approved), they should be assured that they are paying for a program that encourages consumers to only purchase the most energy efficient appliances and not simply paying so that other consumers can receive a discount on the appliances that they would likely have purchased even without incentives (i.e., free-ridership).

Next, Mr. Love disagrees with my recommendation that the EE&C plan and incentives should not apply, or be available, to customers switching to natural gas from alternative energy sources. Again, ratepayers will be funding 100% of the cost of these incentives and rebates, while the Company will bear zero cost associated with the EE&C

plan, and as such should not be used as part of a marketing plan to increase its customer base.

The third disagreement Mr. Love has relates to my concerns regarding the ambiguity and lack of specificity within certain proposed "performance" oriented programs. Once again, ratepayers will be paying for these programs and the Commission should have a specific understanding of what costs ratepayers are expected to pay. Under the Company's plan it will be impossible to evaluate whether these "performance" based plans are money well spent.

Finally, Mr. Love opposes my recommendation to place a specific spending cap on the EE&C plan if approved. The Commission and ratepayers have a right to know how much exposure they have for this EE&C plan. Furthermore, spending limits will help prevent unnecessary and wasteful spending.

Q. PLEASE RESPOND TO INDUSTRIAL WITNESSES SCHREIBER AND DAVEY CONCERNING NEGOTIATED RATES AND THREATS OF BYPASS.

A. Both Mr. Schreiber and Davey take my direct testimony out of context. Mr. Schreiber states that my position in Direct Testimony is that only distance to alternative supplies is a proxy for establishing bypass risk. Mr. Davey states that I conducted an "independent" study and determined that distance to substitute gas supply is not enough to warrant negotiated contracts with negotiated rates to incentivize industrial customers to remain with UGI's system. Mr. Davey continues by stating that I only considered distance to alternative sources of supply when I determined there is a lack of bypass opportunities for customers connected to UGI's system. All of these statements are incorrect. First, I did not conduct an independent study of the threats of bypass, but rather relied on the Company's response to I&E-RS-9-D which asked for the following:

> Provide a proof of revenue in Microsoft Excel format, with all source data and formulae intact, for each flex rate customer provide the following, by month, in the historic test year and to date in the future test year:
>
> A. Name of customer, class and historic volumes;
>
> B. Breakdown of revenue under flex rates;
>
> C. Breakdown of revenue under present tariff rates;

D. Reason for not paying fully tariff rates;

E. Confirmation of the last time an alternative gas supply was verified for each flex rate customer.

With regard to item D., the Company simply provided a one page document which is provided in my direct testimony as Schedule GAW-5. The only indication or support provided by the Company for offering negotiated rates to XD customers is the distance to an alternative natural gas supply. While I will be the first to agree that there are many factors influencing whether an industrial customer has a legitimate threat of bypass, I can only rely upon the justification provided by the Company for offering these negotiated rates. So that it is clear, it is not my testimony or position that there are absolutely no threats of bypass by some customers on the UGI system, and indeed, I imagine there probably are customers with legitimate abilities to economically bypass the UGI system absent a discounted rate. As was clearly stated in my direct testimony, I simply observed that there are some customers that have no realistic possibility of bypassing the system simply due to the very long distance to an alternative natural gas supply which would require that these customers build their own pipeline and secure title or rights-of-way traversing a very long distance.

Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

221307

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2015-2518438
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, Glenn A. Watkins, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA St. No. 3-SR, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: ______________________
Glenn A. Watkins

Consultant Address: Technical Associates, Inc.
1503 Santa Rosa Road, Suite 130
Richmond, Virginia 23229

DATED: May 25, 2016

OCA Statement No. 4
6/2/16 Hlg JR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	**Docket No. R-2015-2518438**
v.	:	
	:	
UGI UTILITIES, INC. – GAS DIVISION	:	

DIRECT TESTIMONY OF

ROGER D. COLTON

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

April 12, 2016

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Roger Colton. My business address is 34 Warwick Road, Belmont, MA 02478.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a principal in the firm of Fisher Sheehan & Colton, Public Finance and General Economics of Belmont, Massachusetts. In that capacity, I provide technical assistance to a variety of federal and state agencies, consumer organizations and public utilities on rate and customer service issues involving telephone, water/sewer, natural gas and electric utilities.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Office of Consumer Advocate.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I work primarily on low-income utility issues. This involves regulatory work on rate and customer service issues, as well as research into low-income usage, payment patterns, and affordability programs. At present, I am working on various projects in the states of New York, Pennsylvania, Michigan, Illinois, Iowa and California, as well as in the provinces of Ontario, Manitoba and British Columbia. My clients include state agencies (e.g., Pennsylvania Office of Consumer Advocate, Maryland Office of People's Counsel, Iowa Company of Human Rights), federal agencies (e.g., the U.S. Company of Health and Human Services), community-based organizations (e.g., Energy Outreach Colorado, Natural Resources Defense Council, Action Centre Tenants Ontario), and private utilities (e.g., Unitil Corporation d/b/a Fitchburg Gas and Electric Company, Entergy Services, Xcel Energy d/b/a Public Service of Colorado). In addition to state- and utility-specific work, I engage in national work throughout the United States. For example, in 2011, I worked with the U.S. Department of Health and Human Services (the federal LIHEAP office) to advance the review and utilization of the Home Energy Insecurity Scale as an outcomes measurement tool for LIHEAP. In 2007, I was part of a team that performed a multi-sponsor public/private national study of low-income energy assistance programs. At present, I have been retained by the National Coalition on Legislation for Affordable Water (NCLAWater) has retained me to write a comprehensive "water bill of rights" to be introduced in Congress. A brief description of my professional background is provided in Appendix A.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. After receiving my undergraduate degree in 1975 (Iowa State University), I obtained further training in both law and economics. I received my law degree in 1981 (University of Florida). I received my Master's Degree (regulatory economics) from the MacGregor School in 1993.

Q. HAVE YOU EVER PUBLISHED ON PUBLIC UTILITY REGULATORY ISSUES?

A. Yes. I have published three books and more than 80 articles in scholarly and trade journals, primarily on low-income utility and housing issues. I have published an equal number of technical reports for various clients on energy, water, telecommunications and other associated low-income utility issues. A list of my publications is included in Appendix A.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS OR OTHER UTILITY COMMISSIONS?

A. Yes. I have testified before the Pennsylvania Public Utility Commission ("PUC" or "Commission") on numerous occasions regarding utility issues affecting low-income customers and customer service. I have also testified in regulatory proceedings in more than 30 states and various Canadian provinces on a wide range of utility issues. A list of the proceedings in which I have testified is listed in Appendix A.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR DIRECT TESTIMONY.

A. The purpose of my Direct Testimony is as follows.

- First, I examine the proposed cost recovery for UGI's (sometimes referred to as the "Company") Customer Assistance Program ("CAP"). I will examine certain cost offsets that should be adopted for the Universal Service Surcharge related to CAP;
- Second, I examine the impact of the Company's proposed increase in its fixed monthly customer charge; and
- Third, I examine a series of customer service issues; and
- Finally, I examine certain issues presented by the Company's proposed Energy Efficiency and Conservation ("EE&C") Plan.

Part 1. Customer Assistance Program ("CAP") Cost Recovery.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I examine the adjustments I make to ensure that the Company accurately portrays and characterizes the revenue reduction that should be attributed to bill discounts provided through the CAP program. In addition, I discuss a source of "offsets" that should be, but has not been, adequately taken into account in assessing the costs of CAP to be collected through rates.

A. Embedded Lost Revenues.

Q. PLEASE EXPLAIN THE ADJUSTMENTS YOU PROPOSE TO UGI'S CAP COST RECOVERY.

A. UGI proposes to recover its universal service costs through a reconcilable revenue rider in this proceeding. One of the costs to be recovered through that Rider is the cost of providing CAP Credits. The level of CAP Credits which UGI claims, however, represents 100% of the difference between the revenues which UGI would have billed at standard residential rates and the revenues that UGI bills at CAP rates. To recognize 100% of that discount as a new cost is inappropriate.

Whenever a public utility, whether it be UGI or another utility, adopts a low-income bill affordability program such as CAP, there will, by definition, be some amount of discount offered to program participants tied to bills that would have been rendered at standard residential rates. The difference between the bill at standard residential rates and the discounted bill, however, does not constitute lost revenue to the utility. The loss to the utility is not the difference between *billings* and the discounted rate, but rather is the difference between *revenue* collected and the discounted rate. If, in other words, the utility is not fully collecting the bills that it is rendering in the first place, the fact that some portion of that bill is set aside as a discount does not represent lost revenue that should be separately recovered as a "cost" of the program.

Q. WHAT IS THE IMPACT OF FAILING TO RECOGNIZE THE DOLLARS THAT ARE BILLED TO LOW-INCOME CUSTOMERS BUT THAT ARE NOT ACTUALLY COLLECTED AS REVENUE?

A. The impact of failing to recognize these dollars that are billed to low-income customers, but that are not collected from those customers even in the absence of their participation in CAP, is that the Company claims an already existing cost as a "new" CAP program cost. The Company is claiming that the CAP causes the Company to lose revenue that would have been lost even in the absence of the program. That lost revenue is already included in rates.

Q. TO WHAT EXTENT DOES UGI NOT COLLECT ALL OF THE REVENUE THAT IT BILLS?

A. UGI fails to collect the revenue that it bills to the extent that there are dollars that the Company ultimately writes off as uncollectible. According to UGI's most recent data reported to the Commission's Bureau of Consumer Services ("BCS"), its annual uncollectible rate for confirmed low-income customers in 2014 was 12.80%. Its three-year average (2012 – 2014) confirmed low-income write-off rate was 12.57%. The lost revenue attributed to the CAP Credits subject to recovery through the Universal Service Rider should be reduced by this percentage.

Q. DOES UGI's CAP COST RECOVERY CONSIDER THE COLLECTION RATE FOR LOW-INCOME BILLS IN THE ABSENCE OF A BILL AFFORDABILITY PROGRAM?

A. No. What the Company does in its CAP cost analysis is to assume that 100% of the bills to CAP participants will be collected in the absence of the CAP discount. We know this to be wrong. The Company then assigns the difference between the discounted CAP bill and 100% of the billed revenue at standard residential rates as a cost of the program. We know, too, this to be incorrect. To allow UGI to collect 100% of the difference through the Universal Service Rider would thus allow UGI to recover the portion of the bills that would go unpaid even without CAP twice: first by UGI's inclusion of this unpaid revenue in the Company's write-offs and again in UGI's inclusion of this unpaid revenue as part of the CAP Credits recovered through the Universal Service Rider.

Q. IS THERE A SIMILAR ADJUSTMENT THAT SHOULD BE MADE TO THE COSTS OF ARREARAGE FORGIVENESS?

A. Yes. The lost revenue already included in rates is higher for arrearage forgiveness than it is for bills for current service. It is generally recognized in the utility industry that bills are less and less subject to collection the older they become. Accordingly, to provide credits against those pre-existing arrears is not to create new costs, but rather to recognize lost revenue that is already included in UGI's rates.

Q. HAS THE PENNSYLVANIA PUC PREVIOUSLY RECOGNIZED THE NEED TO ELIMINATE THIS DOUBLE-RECOVERY OF LOST REVENUE ALREADY INCLUDED IN RATES?

A. Yes. In reviewing the ALJ opinion in a Philadelphia Gas Works proceeding,[1] the Pennsylvania PUC noted: "The ALJs believe that the OCA made a convincing argument that double recovery is a possibility and can be alleviated by implementing a mechanism for reconciliation and that PGW did not provide a persuasive argument that the current practice guards against double recovery."[2] The Commission held: "Double recovery of uncollectible accounts expense is a possibility and can be alleviated by implementing a mechanism for reconciliation."[3]

In sum, to the extent that billings are already recognized as being not subject to collection, the dollars of discount that represent those uncollected billings should not be claimed as a new cost. To include those lost revenues already included in rates as part of the cost of CAP would allow the Company to double-recover the same dollars. As I discussed above, this lost revenue already included in rates is 12.8% (the existing low-income write-off rate) of the CAP credits applied toward bills for current service. The

[1] Pennsylvania PUC v. Philadelphia Gas Works, R-0006193, slip opinion, at 39, citing CAP Policy Statement (Order entered September 28, 2007).
[2] Id.
[3] Id., at 42.

CAP Credits provided to CAP participants should be reduced by this percentage in the costs recovered through the Company's Universal Service Rider.

B. Increased Revenue and Reduced Expenses.

(1) Increased Revenue due to Decreased Bad Debt.

Q. PLEASE IDENTIFY THE PART OF THE CAP COST RECOVERY TO WHICH YOUR NEXT RECOMMENDED ADJUSTMENT APPLIES.

A. A bill for *current* service rendered to a CAP participant is comprised of two parts:

- that portion of the bill that is at or below an affordable percentage of income ("CAP Bill"), which is charged to the CAP participant; and
- that portion of the bill that is above an affordable percentage of income ("CAP Credit"), which is collected from CAP non-participants.

The issue that I discuss below involves how the second part of the bill ("CAP Credit") is treated.

Q. IF THE AMOUNT OF CAP CREDITS INCREASES OR DECREASES AS CAP PARTICIPATION INCREASES OR DECREASES, WHAT HAPPENS TO BASE RATES?

A. Base rates remain the same. It is important to remember that UGI has already set its proposed base rates as though the unpaid bills from non-CAP customers will be a part of uncollectibles. Through its proposed base rates, the Company continues to collect that uncollectible expense as though CAP participation rates are exactly on target.

Q. WHY IS THAT SIGNIFICANT?

A. Revenues must be one place or another. Customers (and their associated revenue) *must* be in *either* the group of CAP non-participants *or* in the group of CAP participants. They cannot be in both. A customer is either a CAP participant or is *not* a CAP participant; the customer cannot be both places at once. There is no dispute, in other words, that in any given month, the group of residential customers who receive a CAP bill and the group of customers who do not receive a CAP bill are mutually exclusive groups. No group of customers receives both a CAP bill and a non-CAP bill in the same month. Increased participation by low-income customers in CAP, in other words, simply *moves* the unpaid bills out of the group of customers known as "residential" customers and into the group of customers known as "CAP participants."

Q. IS THE COMPARISON YOU ARE MAKING BETWEEN LOW-INCOME CUSTOMERS AND NON-LOW-INCOME CUSTOMERS?

A. No. The BCS comparison is *not* between confirmed low-income customers and *non*-low-income customers. It is between confirmed low-income customers and *all* residential customers (a population that includes the confirmed low-income group as one of its component parts). For example, a comparison of the last three years of write-off data, as reported by BCS, is set forth immediately below:

	2012	2013	2014
Confirmed low-income	13.30%	11.60%	12.80%
All residential	2.30%	2.20%	3.00%

The 2014 "residential" write-off rate in the table above is the blended rate of customers that are "confirmed low-income" customers and those that are not.

Q. HOW DOES THE TREATMENT OF THE BILL CHANGE WHEN THE CUSTOMER ENROLLS IN CAP?

A. When a customer enrolls in CAP, the program participant is provided an affordable bill ("CAP Bill"), which the participant is expected to pay. The remainder of the bill ("CAP Credit") is charged to CAP *non*-participants through the CAP Rider. Accordingly, when a low-income customer enrolls in CAP, the portion of the bill that the customer previously could not afford now becomes the CAP credit and is recovered on a dollar-for-dollar basis through the CAP Rider.

Q. PLEASE SUMMARIZE THE SIGNIFICANCE OF THIS DISCUSSION AS TO HOW IT REFLECTS AN IMPACT ON HOW MUCH REVENUE THE COMPANY COLLECTS?

A. When billings are rendered to low-income customers, the level of revenue collection reflects the non-payment level of low-income customers. In contrast, when billings are rendered to residential customers in general, the level of revenue collection reflects the different, and lower, non-payment level of residential customers as a whole. Through CAP, the level of CAP credits will no longer represent billings to low-income customers, but are instead billings to residential customers as a whole. Accordingly, since the level of non-collection is lower, the rate at which these billing dollars are converted into actual revenue to the Company is higher. That increased collection of revenue should be reflected as an offset to the costs of the CAP program.

Q. DOES THIS ADJUSTMENT DEPEND ON, OR ASSUME IN ANY WAY, THAT THE OFFER OF AN AFFORDABLE BILL WILL IMPROVE THE PAYMENT PATTERNS OF PROGRAM PARTICIPANTS?

A. No. Whether or not CAP participants improve their payment patterns is completely irrelevant to this adjustment. This adjustment is based on two simple observations. First, residential customers as a whole impose fewer bad debts on the Company than low-income customers. Second, the revenues reflected in the CAP credits represent dollars that had historically been billed to low-income customers but, under the CAP program, will instead be billed to residential customers in general in the future. As a result of these two observations, it becomes clear that on the dollars of CAP credits billed to non-CAP participants, future bad debt will be incurred at the rate for residential customers generally rather than at the low-income rate. Revenue will be higher to the extent of the difference between the low-income write-off rate and the residential write-off rate.

Q. DOES THIS SAME OFFSET APPLY BOTH TO CREDITS AGAINST CURRENT SERVICE AND TO CREDITS AGAINST PRE-EXISTING ARREARS SUBJECT TO FORGIVENESS?

A. Yes.

Q. HAS THE PENNSYLVANIA PUC EVER PREVIOUSLY RECOGNIZED THE NEED TO PREVENT THE OVER-RECOVERY OF ARREARAGE FORGIVENESS COSTS?

A. Yes. In its CAP cost recovery order, the Pennsylvania PUC specifically addressed the issue, stating:

> There is some merit in reasoning that arrearage forgiveness amounts should not be recovered separately because these are amounts that, but for the existence of the CAP program, would be included within the utility's claim for uncollectible expenses. The law requires "full recovery" of CAP costs, but not "double recovery." At the same time, utilities should have the opportunity to demonstrate when they seek to establish a surcharge that arrearage forgiveness costs are not completely covered by uncollectible expenses. *The utilities should bear the burden of proving that allowing recovery of their claim for arrearage forgiveness costs will not give them double-recovery of these costs.*[4]

(emphasis added). The PUC's experience with percentage of income programs over more than 30 years, and the reasoning it engages in based on that experience, is compelling.

Q. HAS UGI DEMONSTRATED THAT IT IS NOT DOUBLE-RECOVERING COSTS?

A. No.

Q. FOR UGI, WHAT OFFSETS SHOULD APPLY TO THE CURRENT BILL CREDITS AND TO THE ARREARAGE FORGIVENESS CREDITS?

A. The appropriate offset for UGI current bill credits and arrearage forgiveness credits is 9.8%. This offset is the difference between the bad debt rate for residential customers as a whole (3.0%) and the bad debt rate for low-income residential customers (12.8%).

[4] Final Investigatory Order, at 38 – 39.

A Gross Low-Income Write-off[5]	B Gross Residential Write-off[6]	Added Revenue from Moving Revenue from Low-Income to Residential (A – B)
0.128	0.030	0.098

Q. IS IT MORE APPROPRIATE TO USE NET UNCOLLECTIBLES OR GROSS UNCOLLECTIBLES IN APPLYING THIS OFFSET?

A. It is most appropriate to use gross uncollectibles in applying the offset I describe above. The Company argues that it is more appropriate to use a net bad debt rate for purposes of calculating the bad debt offset.[7] This argument should be rejected. The purpose of the adjustment I propose is to prevent the over-recovery of universal service costs for active CAP customers. I am not proposing to recalculate the Company's uncollectible expense or uncollectible reserve.

The use of a net write-off figure would reduce the universal service cost adjustment by an amount of revenue recovered from customers that have ceased to be active UGI customers. By definition, revenue recoveries netted against write-offs are from inactive customers; the only circumstances in which a customer's account would have been written-off as uncollectible is if the customer has left the system and become inactive.

In contrast, my adjustment relates to the changes in revenue between *active* confirmed low-income (and non-low-income) customers and *active* CAP participants. To reach into the inactive customer base to reduce that over-recovery of universal service costs from

[5] OCA-III-1(b).
[6] OCA-III-1(a).
[7] The Company does not refer to "net" write-offs. It instead refers to "gross write-off percentage adjusted for write-off recovery." Lahoff, at 20. When directly asked whether its reference to gross write-offs adjusted for recoveries was, in fact, simply a different way of saying "net write-offs," they agreed that was the case. (OCA-III-2).

active CAP participants would be inappropriate. The adjustment that I propose based on gross write-offs should be approved.

(2) Decreased Expenses Due to Decreased Working Capital.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I explain why there should be a working capital offset that reflects the difference in nonpayment between low-income customers and residential customers generally in those circumstances when the nonpayment does not result in a write-off of the unpaid balance as bad debt.

The working capital offset reflects the fact that rather than the billed revenue recovered as CAP credits being charged to confirmed low-income customers, that billed revenue will instead be collected through the Universal Service Rider charged to CAP non-participants who are primarily non-low-income customers. Since these CAP non-participants have a more favorable payment profile regarding timely and complete payments, there will be less working capital associated with the billings. This reduction in working capital should be reflected in the CAP cost recovery.

Q. IS RECOGNIZING THE WORKING CAPITAL COST-OFFSETS CONSISTENT WITH THE COMMISSION'S CAP POLICY STATEMENT?

A. Yes. The Commission has stated:

> In evaluating utility CAPs for ratemaking purposes, the Commission will consider both revenue and expense impacts. Revenue impact considerations

> include a comparison between the amount of revenue collected from CAP participants prior to and during their enrollment in the CAP. CAP expense impacts include both the expenses associated with operating the CAPs as well as the potential decrease of customary utility operating expenses. ***Operating expenses include the return requirement on cash working capital for carrying arrearages. . .***When making CAP-related expense adjustments and projections, utilities should indicate whether a customer's participation in a CAP produced an immediate reduction in customary utility expenses and a reduction in future customary expenses pertaining to that account.

Pennsylvania PUC, CAP Policy Statement, Section 69.266, 52 Pa. Code § 69.266 (Supp. 389, April 2007) (emphasis added).

Q. PLEASE EXPLAIN THE CONCEPTUAL BASIS FOR THE WORKING CAPITAL OFFSET.

A. Without the CAP, the portion of low-income bills that exceeds the affordable percentage of income payments (i.e., that portion that will be the "CAP Credit") would be charged to low-income customers. Under the CAP, that portion of low-income bills that exceeds the affordable percentage of income payments will instead be charged to residential customers as a whole. Since, as I documented above, residential customers as a whole have a better payment profile –they pay more of their bills and they pay their bills in a more timely fashion—moving these dollars from low-income bills to the bills of residential customers as a whole will be collected in a more complete and timely fashion, and will thus generate a working capital savings. The Company is entitled to recovery of its universal service costs. But the Commission has made clear that it is entitled only to its costs net of any offsetting expense reductions.[8]

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[8] As quoted above in its CAP Policy Statement, the PUC stated: "In evaluating utility CAPs for ratemaking purposes, the Commission will consider both revenue and expense impacts . . . CAP expense impacts include both

Q. PLEASE EXPLAIN THE BASIS FOR CONCLUDING THAT LOW-INCOME CUSTOMERS HAVE A POORER PAYMENT PROFILE THAN RESIDENTIAL CUSTOMERS AS A WHOLE.

A. The PUC's Bureau of Consumer Services publishes an annual report on Universal Service Programs and Collections Performance. That annual BCS report differentiates collections performance based on "confirmed low-income customers" and on all residential customers. According to the most recent BCS report, UGI's confirmed low-income customers exhibit greater payment difficulties. Confirmed low-income customers, among other things: (1) have a proportionately greater number of customers in arrears; (2) have a proportionately greater number of dollars in arrears; and (3) have a higher dollar level of arrears.

There can be no question that confirmed low-income customers for UGI impose disproportionate payment difficulties on the utility. The confirmed low-income population is not only disproportionately in arrears, but it is further in arrears. The data demonstrates that while confirmed low-income customers represent 12.6% of all residential customers for UGI (41,639 confirmed low-income / 331,583 residential), they represent 49.8% of all of UGI's residential customers in arrears (16,302 confirmed low-income in arrears / 32,724 residential in arrears). The data demonstrates that while bills to confirmed low-income customers represent 15.5% of all residential revenues ($35,997,461 / $231,993,035), they represent 66.0% of all residential revenues in arrears

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the expenses associated with operating the CAPs as well as the potential decrease of customer utility operating expenses."

($6,656,967 / $10,093,006). Finally, the BCS data demonstrates that while low-income customers, on average, owe $384, residential customers, on average, owe only $308.

Q. WHY IS THIS SIGNIFICANT FOR PURPOSES OF THE UNIVERSAL SERVICE COST RECOVERY THROUGH THE UNIVERSAL SERVICE RIDER?

A. Through the Company's CAP program, the Company removes part of the billings to confirmed low-income customers and moves that billing to the general residential population. This occurs through the CAP Credit. The CAP Credit is the portion of the bill that is no longer charged to CAP participants (who are all confirmed low-income customers) and instead is recovered through the Universal Service Rider charged to residential non-participants. As a result of moving this revenue from a more-payment-troubled population to a less-payment-troubled population, to the extent that the CAP participation exceeds the base number of CAP participants in the test year, there will be an over-collection of working capital expenses.

This impact can be clearly seen by applying an adjustment to the lead-lag study as described by UGI witness Ann Kelly (page 17, et seq.) and presented at Schedule C-4 (page 3 of 9). (OCA-III-25 and OCA-III-26). When one adjusts the Accounts Receivable (Lines 15 and 17) to reflect the higher proportion reasonably expected to be contributed by confirmed low-income customers, and adjusts the Total Sales (Lines 18) to reflect the proportion reasonably expected to be contributed by confirmed low-income customers (at a much lower rate than the low-income contribution to accounts receivable), the Total

Revenue Lag Days (Line 23) substantially increases, thus reflecting a higher working capital requirement.

Q. IS THERE A SPECIFIC WORKING CAPITAL DOLLAR OFFSET THAT YOU PROPOSE FOR THE RATES IN THIS PROCEEDING?

A. No. As I explain with respect to the bad debt offsets, the impact of exceeding the base number of CAP participants for purposes of the cost recovery of CAP credits requires no single dollar offset. The amount of the offset depends on the number of actual CAP participants exceeding the base number of CAP participants and the level of the CAP credits sought to be recovered. What is needed, therefore, is to prevent the over-recovery of working capital costs by adopting a percentage offset for incremental CAP Credit costs collected through the Universal Service Rider.

Q. HOW DID YOU CALCULATE THE WORKING CAPITAL OFFSET FOR CAP CREDITS?

A. I begin with the difference between the percentage of confirmed low-income dollars in arrears and the percentage of total residential dollars in arrears as described above. I then distribute those arrears over "aging buckets" for residential customers. As arrears get older, they impose a greater working capital expense. I thus calculate a working capital offset for each aging bucket.[9] The appropriate working capital offset is the sum of the offset for each "aging bucket." The appropriate working capital offset for incremental CAP credits is 8.6%. The calculation is set forth in Schedule RDC-1 (page 1 of 2).

[9] I use the following buckets: 31-60 days in arrears; 61-90 days in arrears; 91-120 days in arrears; and 121 or more days in arrears.

(3) Adjusting CAP Cost Recovery for a Working Capital Offset for Arrearage Forgiveness Credits.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I explain that the arrearage forgiveness credits to be collected through the Universal Service Rider should be subject to a working capital offset. A working capital offset should be imposed for incremental arrearage forgiveness credits for the same reasons that such an offset should be imposed for incremental CAP Credits.

Q. IS THE WORKING CAPITAL OFFSET FOR INCREMENTAL ARREARAGE FORGIVENESS CREDITS CALCULATED IN THE SAME MANNER AS THE WORKING CAPITAL OFFSET FOR CAP CREDITS?

A. Yes. The calculation methodology is the same. The percentage of billing in arrears is determined for the credits at issue using the confirmed low-income percentage and the residential percentage as the input data. Those billings in arrears are then distributed into "aging buckets." The reduction in working capital is then used as the offset percentage. The only difference between the calculation of the CAP Credit working capital offset and the Arrearage Forgiveness Credit working capital offset is the proportion of confirmed low-income billings in arrears. For Arrearage Forgiveness Credits, by definition, 100% of the confirmed low-income billings are in arrears without the CAP program.[10] As a

[10] This occurs "by definition" since Arrearage Forgiveness Credits are limited to dollars of pre-existing arrears. If a bill is not in arrears at the time the customer enrolls in CAP, that bill is not subject to the arrearage forgiveness program.

result, the working capital offset for incremental arrearage forgiveness credits will be somewhat higher than the corresponding offset for incremental CAP Credits. The appropriate working capital offset for incremental Arrearage Forgiveness Credits is 45.3%. The calculation is set forth in Schedule RDC-1 (page 2 of 2).

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS SECTION OF YOUR TESTIMONY.

A. I recommend that the UGI be required to implement the following actions regarding its Universal Service Rider.

- The UGI Universal Service Rider should include a revenue offset of 12.8% to reflect those dollars of revenue that are billed to low-income customers but will not be collected even in the absence of the customers' participation in CAP.
- The UGI Universal Service Rider should incorporate a bad debt offset for CAP Credits of 9.8%.
- The UGI Universal Service Rider should incorporate a working capital offset for CAP Credits of 8.6%.
- The UGI Universal Service Rider should incorporate a bad debt offset for Arrearage Forgiveness Credits of 9.8%.
- The UGI Universal Service Rider should incorporate a working capital offset for Arrearage Forgiveness Credits of 45.3%.

The offsets recommended above are only additive within the separate components of credits being collected through the Universal Service Rider. The bad debt and working capital offsets for CAP Credits are additive; the bad debt and working capital offsets for the Arrearage Forgiveness Credits are additive.

(4) The Base Participation Rate to Use.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I explain the base participation rate over which the bad debt and working capital offsets I recommend above should be applied. The Company urges the base participation rate should be set at 10,000 customers. (Lahoff, at 20). This participation rate, however, comes nowhere close to reflecting what the participation rate historically has been or what it is likely to be in the future. The Company provided CAP participation by month since January 2012. As of the last Monday of January 2016, UGI had only 7,843 CAP participants. (OCA-III-4(a)).[11] The increased CAP participation rate from January 2015 to January 2016 was only 228 customers (from 7,615 to 7,843). While the 2015 participation (7,615) was substantially in excess of January 2014, that only occurred because the Company experienced a significant decline in participation in January 2013 (from 6,610 in 2012 down to 4,858 in January 2013 down even further to 4,706 in January 2014), from which it has since been recovering. According to the annual BCS report on Universal Service programs, since 2006, the UGI-Gas participation rate has not approached 10,000 customers nor evidenced any trend that would indicate the Company's participation rate is moving toward 10,000.

[11] UGI reports that it captures enrollment numbers every Monday. The data provided in response to discovery was thus for the last Monday of every month.

Q. IS THERE REASON TO USE THESE HISTORIC CAP PARTICIPATION RATES RATHER THAN THE COMPANY'S PROJECTED PARTICIPATION OF 10,000?

A. Yes. The question does not ask what future CAP participation rate the Company expects to achieve. The question is what CAP participation rate was experienced at the time that residential write-off and confirmed low-income write-off amounts were being experienced as reflected in this rate case. Excluding the non-representative year of 2013, the appropriate base participation rate to use would be 8,700 (the rounded participation from 2015).

Q. IS THERE ANY OTHER FLAW IN THE COMPANY'S PROPOSED BASE OF 10,000 CAP PARTICIPANTS?

A. Yes. The Company acknowledges that it does not simply project a year-end participation rate of 10,000 low-income customers in its CAP, it projects a *monthly* average of 10,000 CAP participants. (OCA-III-7(a) and 7(e)). It assumes that 100% of those 10,000 customers will receive both a CAP credit and an arrearage forgiveness credit in each month of the test year. (OCA-III-7(g) and 7(h)). This is an unreasonable assumption. The UGI data demonstrates that participation in the Company's CAP reflects the typical CAP participation in that it significantly varies throughout the year. In 2015, for example, while the monthly average participation rate was 8,678 participants, the range of participation varied from a low of 7,615 (January)[12] to a high of 9,328 (June). If the Company were to achieve a monthly average participation of 10,000, in other words, it would need to expect a participation rate of nearly 11,000 low-income customers at some

[12] The lowest participation rate in a year occurred in January in only two of the four years examined.

point in the year in order for the monthly average to reach 10,000. This far exceeds any participation rate the Company has ever come close to achieving.[13] As even the Company acknowledges, the use of its base participation of 10,000 would result in the application of no cost offsets as described above. (OCA-III-12).

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My recommendations as to offsets for universal service costs are as follows:

- The UGI Universal Service Rider should reduce the <u>*total*</u> CAP Credits to be collected through the Rider (irrespective of CAP participation) by 12.8% to reflect the offset based on lost revenue already included in rates.
- The UGI Universal Service Rider should reduce CAP Credits recovered through the Rider by 9.8% on program participants exceeding an average annual participation rate of 8,700 to reflect a bad debt offset for CAP Credits.
- The UGI Universal Service Rider should reduce CAP credits recovered through the Rider by 8.6% on program participants exceeding an average annual participation rate of 8,700 to reflect a working capital offset for CAP Credits.
- The UGI Universal Service Rider reduce should reduce Arrearage Forgiveness Credits recovered through the Rider by 9.8% on program participants exceeding an average annual participation rate of 8,700 to reflect a bad debt offset for Arrearage Forgiveness Credits.

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[13] One should remember, too, that even the Company's own most recent independent third party Universal Service evaluation noted "lower than expected program participation." APPRISE, Inc. (2012). "UGI Utilities, Inc. – Gas Division and UGI Penn Natural Gas, Inc., Universal Service Program, Final Evaluation Report," at iii and 7.

- The UGI Universal Service Rider should reduce Arrearage Forgiveness Credits recovered through the Rider by 45.3% on program participants exceeding an average annual participation rate of 8,700 to reflect a working capital offset for Arrearage Forgiveness Credits.

Part 2. The Company's Fixed Monthly Customer Charge.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I assess the impacts of the Company's proposal to increase its fixed customer charge to $17.50 per month. The current charge is $8.55. I conclude that the Company's proposal will have substantial adverse impacts on low-income and low-use customers. The Company's proposal will harm low-income customers in at least the following ways:

- The increased monthly customer charge will increase CAP bills to customers who use the average monthly bill aspects of CAP;
- The Company's proposal will completely offset the level of benefits achieved for the UGI service territory through the Low-Income Home Energy Assistance Program ("LIHEAP");
- The increased monthly customer charge will disproportionately increase monthly bills to confirmed low-income customers who do not participate in CAP; and
- The increased monthly customer charge will make it less likely that low-income customers will be able to reduce their bills through implementation of energy efficiency investments.

I will discuss each of these harms in more detail below.

Q. PLEASE EXPLAIN YOUR CONCLUSION THAT THE INCREASED MONTHLY CUSTOMER CHARGE WILL HARM LOW-INCOME CUSTOMERS WHO RECEIVE CAP BILLS AS AN AVERAGE MONTHLY BILL.

A. Not all low-income customers have bills that exceed the affordable percentage of income burden prescribed by the Commission. If application of the Commission's burden would yield a CAP bill of $75, while the customer's actual bill at standard residential rates would be only $60, the customer is better off by taking service priced at the standard residential rate. Such customers, however, whose bills at standard rates are *less* than a bill at the affordable percentage of income burdens prescribed by the Commission might still benefit from participation in CAP to access benefits such as arrearage forgiveness of pre-existing arrears. These customers would receive a CAP bill, under the UGI program, that is set equal to their average monthly bills.

According to the Company, 45% of the Company's CAP customers receive such average monthly CAP bills. (CAUSE-PA-I-1(a)). The Company acknowledges that "upon recertification, these average monthly bill CAP payments could be impacted. . ." up to where the payment equals the customer's percentage of income limit on affordability. (Id.) The fact that "no CAP customer would pay more than their applicable percentage of income" (CAUSE-PA-I-1(a)) does not detract from the conclusion that their bills will increase.

Q. PLEASE EXPLAIN YOUR CONCLUSION THAT THE INCREASED MONTHLY CUSTOMER CHARGE WILL HARM LOW-INCOME CUSTOMERS BY OFFSETTING LIHEAP BENEFITS.

A. Low-income customers who receive LIHEAP benefits will be harmed to the extent that their increased bills at standard rates will make it more likely that the customer will not receive the full benefit of the LIHEAP payment. According to the Company, 10,259 low-income UGI customers received a LIHEAP grant but were not enrolled in the Company's CAP program. (CAUSE-PA-I-9(3)). In 2014, the average LIHEAP grant to UGI customers was roughly $185. (CAUSE-PA-1-14(1)).[14] UGI reports that its confirmed low-income customers (CAP and non-CAP combined) received an aggregate of $2,452,331 of LIHEAP benefits in 2014.

In contrast, Schedule RDC-2 (page 1 of 2) presents the revenue loss to the confirmed low-income community resulting from the total rate increase proposed in this proceeding. This revenue loss is calculated by subtracting the average bill at current rates (by usage tier) from the average bill at the Company's proposed rates and multiplying that difference times the number of customers in each usage tier. As Schedule RDC-2 shows, the increased rates in this proceeding will pull $4,783,009 out of the confirmed low-income community. This loss is roughly twice the total amount of LIHEAP received by UGI low-income customers in 2014.[15]

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[14] LIHEAP benefits of $2,452,331 divided by 13,245 LIHEAP recipients.

[15] The loss is from the entire confirmed low-income community, not merely from those low-income customers receiving LIHEAP.

More than 95% of these dollars pulled out of the low-income community come from the Company's proposed increase in its customer charge. Schedule RDC-2 presents the aggregate increase in rates attributable exclusively to the increase of the customer charge from $8.55 per month to $17.50 per month. As can be seen, the increase simply in the customer charge adds an aggregate of $4,527,125 to the rates of low-income customers. That additional customer charge of $4,527,125 is to be compared to the total rate increase of $4,783,009 ($4,527,125 / $4,783,009 = 94.65%).

Q. PLEASE EXPLAIN YOUR CONCLUSION THAT THE INCREASED MONTHLY CUSTOMER CHARGE WILL DISPROPORTIONATELY INCREASE BILLS TO LOW USE, LOW-INCOME CUSTOMERS WHO DO NOT PARTICIPATE IN CAP.

A. Not surprisingly, the Company's proposed increase in distribution rates – 94.65% of which increase comes simply from the increase in customer charge as demonstrated above – harms the lowest usage customers the most. As Schedule RDC-3 demonstrates, confirmed low-income customers not participating in CAP, with annual usage below 500 CCF, will experience a rate increase of more than 30% from this proceeding.[16] Even confirmed low-income non-CAP customers with annual usage of between 500 and 1,000 CCF will experience a rate increase of more than 16%. As usage increases, the percentage rate increase correspondingly decreases. These high rate increases are not insubstantial from the perspective of the number of customers affected. Nearly three

[16] The Company presented annual bills by usage tiers at existing and proposed rates. (OCA-III-14). The Company presented a distribution of customers by usage tiers for three groups of customers: (1) all residential; (2) CAP participants; and (3) confirmed low-income (including CAP). (OCA-III-13). Accordingly, it was possible to calculate data for confirmed low-income customers without CAP (Confirmed Low-income with CAP – CAP = Confirmed Low-income without CAP).

quarters of UGI's confirmed low-income customers have annual usage below 1,000 CCF (29.4% below 500 CCF; 43.5% between 500 and 1,000 CCF). Low-use low-income customers disproportionately tend not to participate in CAP. As a result, the entire increase in bills to these customers will be borne by the customers themselves.

These observations regarding low-use customers, however, do not appertain exclusively to low-income customers. Nearly 80% of residential customers in general (including low-income and non-low-income) have annual usage below 1,000 CCF (37% below 500 CCF and 43% between 500 and 1,000 CCF). Residential customers as a whole with usage below 500 CCF will experience a rate increase of 35.7%, while residential customers with usage between 500 and 1,000 CCF will experience a rate increase of 19.0%.

Q. PLEASE EXPLAIN YOUR CONCLUSION THAT THE INCREASED MONTHLY CUSTOMER CHARGE WILL IMPEDE THE ABILITY OF LOW-INCOME CUSTOMERS TO REDUCE THEIR BILLS THROUGH ENERGY EFFICIENCY INVESTMENTS.

A. Because the Company's increased customer charge creates substantial impediments to the ability of low-income households to control their bill, and thus their bill unaffordability, through usage reduction, the proposed customer charge increase will result in substantial harm to UGI's inability-to-pay low-income customers.

Given the importance of usage reduction not only in promoting affordability, but in controlling the universal service program costs to non-participating residential ratepayers, increasing the impediments to low-income usage reduction generates adverse impacts to both low-income customers (decreased affordability) and non-low-income customers (increased universal service costs).

Q. WILL THE INCREASED CUSTOMER CHARGE IMPEDE THE PURSUIT OF ENERGY EFFICIENCY INVESTMENTS BY LOW-INCOME CUSTOMERS?

A. Yes. The substantial increase that the Company proposes for its customer charge will impede the ability of low-income households to reduce their bills by reducing their consumption. This occurs because the Company proposes to move a higher proportion of cost recovery to a fixed bill component that cannot be reduced as a result of reduced usage. The data is set forth in Schedule RDC-4. As can be seen, under the monthly customer charge proposed by the Company in this proceeding, for customers with usage of less than 500 CCF, the customer charge alone will represent nearly 50% of the customer's monthly bill, an increase from roughly 30% under the existing rates. For customers with usage between 500 and 1,000 CCF, the increased customer charge yields a fixed bill, i.e., one that cannot be reduced through energy efficiency, of nearly 30%, twice as high as the 15% under existing rates. Even customers with consumption between 1,000 and 2,000 CCF will have an irreducible portion of their bill equal to nearly 20%, up from less than 10% under existing rates.

Q. WHY IS THIS INCREASE IN THE IRREDUCIBLE PORTION OF A BILL OF PARTICULAR CONCERN TO LOW-INCOME CUSTOMERS?

A. Low-income customers have a particularly high implicit discount rate for investments in energy efficiency measures. While residential customers in general have been found to have an implicit discount rate of roughly 30% for energy efficiency, low-income customers have been found to have an implicit discount rate of 100% (meaning that they need to have their money returned in one year in order for them to make the investment). As UGI Gas increases the portion of the customer's bill that cannot be reduced as a result of the installation or implementation of energy efficiency, the amount of available bill savings that can contribute to achieving the demanded hurdle rate is reduced as well. This reduction makes it less likely that the discount rate can be achieved and, as a result, less likely that energy efficiency investments will be made. One impact of this impediment, therefore, is that households who are facing affordability issues or bill payment problems cannot turn to usage reduction measures as a way to address those problems.

Q. HAVE YOU HAD OCCASION TO CONSIDER ANY EMPIRICAL DATA ON THE ABILITY OF LOW-INCOME CUSTOMERS TO ENGAGE IN ENERGY EFFICIENCY INVESTMENTS?

A. Yes. The U.S. Department of Energy's Energy Information Administration ("DOE/EIA") publishes its periodic Residential Energy Consumption Survey ("RECS"). The most recent RECS data publicly available is from 2009. Using that 2009 RECS data, I have examined the extent to which low-income households have engaged in specific energy efficiency investments that would likely reduce natural gas consumption. There were eleven factors I examined. I examined seven specific energy efficiency investments: (1) well insulated home; (2) adequately insulated home; (3) insulation age less than 10 years old; (4) heating equipment age less than 10 years old; (5) hot water heater age less than 10 years old; (6) programmable thermostat; and (7) weather-stripping age less than 10 years. In addition, I considered two related electric measures that, while not reducing natural gas consumption, are commonly viewed as typical energy efficiency investments (Energy Star refrigerator, refrigerator age 10 years old or less). I considered one negative efficiency factor, whether the home was "drafty" most or all of the time. Finally, I considered the age of the home (home built subsequent to 2000).

I examined data for the Mid-Atlantic Census Division,[17] which includes Pennsylvania, New York and New Jersey. I examined both the population with income less than 150% of Federal Poverty Level ("FPL") and the population with income less than 100% of FPL in addition to the population with income greater than 150% of FPL.

Q. WHAT DID YOU FIND?

A. Not surprisingly, low-income homes have far fewer efficiency measures than do non-low-income homes. The data is set forth in Schedule RDC-5. The data shows:

- Non-low-income households live in recently-constructed homes at twice the rate as low-income households do.

[17] While the RECS reports some state-specific data for Pennsylvania, the sample size was insufficiently large to allow me to segregate out low-income households exclusively for Pennsylvania.

- While there are roughly equal proportions of refrigerators purchased in the last ten years, there are significantly fewer Energy Star refrigerators in the low-income population.
- While there are moderately more recent heating systems (i.e., less than 10 years old) in the non-low-income population, there are substantially more very old heating systems (i.e., more than 15 years old) in the low-income population.
- Low-income households have a substantially lower rate of programmable thermostats installed for their primary heating system.
- While non-low-income households report "adequate" insulation at a modestly higher rate, there are substantially fewer "well-insulated" homes in the low-income population. Low-income households have recent insulation (less than ten years old) at half the rate as non-low-income households.
- Low-income households report that their home is "drafty" most or all of the time at twice the rate that non-low-income households do.
- Low-income households have had weather-stripping recently installed at a substantially lower rate than non-low-income households have.

Q. ARE THESE RESULTS CONSISTENT WITH RESEARCH YOU HAVE OTHERWISE PERFORMED REGARDING MARKET BARRIERS TO LOW-INCOME PURSUIT OF ENERGY EFFICIENCY MEASURES?

A. Yes. I have studied low-income market barriers for energy efficiency in some detail over the past 30-plus years. I have found that low-income households face market barriers that are different from, and more extensive than, those which residential households face in general. These market barriers impede the availability of energy efficiency to low-income customers, even if such efficiency would be an effective, and cost-effective, mechanism to use in controlling home energy costs. Other market barriers prevent low-income customers from being able to realize the bill reductions generated by energy efficiency.

Q. DO THESE ADVERSE IMPACTS AFFECT A SIGNIFICANT NUMBER OF LOW-INCOME CUSTOMERS?

A. Yes. The PUC's Bureau of Consumer Services publishes both the number of confirmed low-income customers and the number of estimated low-income customers for Pennsylvania utilities in its annual Report on Universal Service Programs and Collections Performance. UGI has more than 15,500 more low-income customers in its service territory in 2014 than it had as recently as 2007. The Company's confirmed low-income population has grown by nearly 20,000 customers since 2005. Similarly, the number of estimated UGI Gas low-income customers has grown by nearly 45,000 since 2005.

Number of Confirmed Low-Income Customers: UGI Gas									
2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
22,053	26,378	26,096	31,156	35,839	34,933	39,092	39,447	39,571	41,639
Number of Estimated Low-Income Customers: UGI Gas									
39,930	39,930	39,930	39,930	68,043	68,043	68,043	68,043	68,043	84,809

Moreover, this single aggregate number does not fully reflect the needs of low-income customers in the UGI service territory. Schedule RDC-6 presents a disaggregation of

Poverty for each county in the UGI service territory for which data is available.[18] As Schedule RDC-6 indicates, the penetration of deep poverty is extensive. For UGI, the proportion of the low-income population with income below 50% of Poverty (called "deep poverty") exceeds the proportion of the low-income population with income in any other range of income to Poverty level for incomes below 200% of Poverty in every county except Carbon. The proportion of the low-income population with income below 100% of Poverty exceeds 10% in every UGI county except Bucks (6.5%), Chester (7.4%), Cumberland (9.1%), Montgomery (7.2%) and Northhampton (9.8%). In contrast, however, counties such as Berks (14.7%), Dauphin (13.6%), Luzerne (16.0%), Monroe (13.4%) and Schuylkill (13.1%) have penetration rates of households below 100% of Poverty significantly exceeding 10%. Similarly, in virtually every county, for virtually every Poverty range below 100%, the percentage of households with income in the below-Poverty incomes ranges was higher in 2014 than it was just ten years prior (in 2006). In short, the number of customers harmed by UGI's proposed increased customer charge is not only substantial, it is increasing.

Q. HAS UGI UNDERTAKEN ANY RECENT ANALYSIS OF THE IMPACT THAT MOVING INCREASED BILLINGS TO THE FIXED CUSTOMER CHARGE WILL HAVE ON THE COST-EFFECTIVENESS OF ENERGY EFFICIENCY MEASURES?

A. No. The Company has conducted no such studies for itself. (OCA-III-22). Neither does it have within its possession or control studies done by any other utility examining what

[18] No distinction is made between counties fully served by UGI and counties partially served by UGI. If any part of a county is listed as served by UGI Gas in the UGI tariff, it is included in this analysis.

impact increasing the residential fixed monthly customer charge will have on the ability of low-income customers, and particularly low-income residential customers, to control their energy bills through an investment in energy efficiency. (OCA-III-23 and OCA-III-24).

Q. PLEASE SUMMARIZE YOUR FINDINGS BASED ON THE ABOVE DISCUSSION REGARDING UGI'S PROPOSED CUSTOMER CHARGE.

A. In the sections above, I document how UGI is proposing to impose the greatest rate increases on the population of customers who can least afford to pay those rate increases. That result will increase not only the universal service costs to be paid by non-CAP participants, but will also increase other ordinary expenses to be paid by all customers, including working capital, uncollectibles and credit and collection expenses.

I further explained how the substantial increase that the Company proposes for its customer charge will impede the ability of low-income households to reduce their bills by reducing their consumption. This occurs because the Company proposes to move a much higher proportion of its cost recovery to a fixed bill component that cannot be reduced as a result of reduced usage.

I conclude that the Company is imposing higher costs on consumers, both low-income and non-low-income, while at the same time erecting further barriers for customers who wish to respond to their inability to pay higher bills by reducing their consumption. This inability to reduce consumption through energy efficiency investments harms both CAP participants and the CAP non-participants who pay the universal service surcharges.

Ultimately, my findings and recommendations related to UGI's customer charge support the reasonableness of customer charge recommendations presented in the testimony of OCA witness Watkins.

Part 3. Customer Service Issues.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I consider certain customer service issues that should be addressed and remedied within the context of a rate case. Quality customer service is an appropriate rate case inquiry since quality customer service is one of the things that customers have purchased through their rates. The Company acknowledges the role that customer service plays when it argues that the Commission should consider what the Company claims to be exemplary customer service. (Stoyko, at pages 15 et seq.).

Q. PLEASE EXPLAIN THE FIRST CUSTOMER SERVICE ISSUE THAT YOU WISH TO ADDRESS.

A. UGI Gas should do a better job of enrolling confirmed low-income customers in its CAP program. The Company consistently experiences a lower participation rate than Pennsylvania's other natural gas utilities. UGI Gas has not enrolled more than 20% of its confirmed low-income customers in CAP since 2010. Since 2011, according to the

PUC's Bureau of Consumer Services annual report on collections performance and universal service, the Company's CAP participation rate has been as follows:

2011	2012	2013	2014
17%	13%	11%	18%

In contrast, other gas utilities enroll between 30% and 50% of their confirmed low-income customers in their respective CAPs; PECO Gas is an outlier with significantly higher enrollment.

It's not as though UGI is enrolling its confirmed low-income customers, who happen to be in arrears, onto deferred payment arrangements rather than putting them in CAP. In the last three years, more than twice the number of confirmed low-income customers in arrears were *__not__* on payment arrangements as were on payment arrangements.

	2012	2013	2014
Monthly avg # in arrears no agreement	9,026	10,493	11,216
Monthly avg # in arrears on agreement	3,339	4,225	5,086
SOURCE: CAUSE-PA-I-14			

And the confirmed low-income customers who *__do__* enter into deferred payment agreements with UGI do not successfully complete them. In the most recent three years for which data is available, the highest success rate of confirmed low-income deferred payment agreements has been 42.2% (2013). In 2012 and 2014, the success rate was closer to 30%.

	2012	2013	2014
Total # LI payment agreements	30,023	24,416	29,896
# successful LI payment agreements	10,447	10,313	9,321
Percentage of payment agreements successful	34.8%	42.2%	31.2%

SOURCE: CAUSE-PA-I-14

In contrast, CAP participants tend to make their payments. In 2014, 63.5% of all CAP bills were paid in full by year end (35,892 of 56,559). CAP participants made cash payments of 75.5% of their bills ($4,348,982 of $5,757,623), while another $1,034,459 was received in LIHEAP benefits.

Q. WHAT DO YOU CONCLUDE?

A. While UGI claims that it offers superior customer service as measured by high marks on JD Powers customer satisfaction surveys, there are specific elements of customer service on which the Company can and should seek substantial improvement. First, the Company should undertake greater efforts to enroll its confirmed low-income customers not participating in CAP in successful deferred payment arrangements. Second, the Company should undertake greater efforts to enroll confirmed low-income customers in arrears into the Company's CAP program. Both such efforts would benefit from a collaborative effort involving the OCA, the Company, the BCS, low-income stakeholders, and other parties who might express an interest. I recommend that the issues of how to improve the success of payment plans and how to increase enrollment in CAP amongst low-income customers in arrears be assigned to such a collaborative process.

Q. PLEASE EXPLAIN THE SECOND CUSTOMER SERVICE ISSUE THAT YOU WISH TO ADDRESS.

A. In this section of my testimony, I examine the way in which UGI Gas implements the PUC's winter termination restrictions. The Commission's regulations state that "Unless otherwise authorized by the Commission, during the period of December 1 through March 31, an electric distribution utility or natural gas distribution utility may not terminate service to customers with household incomes at or below 250% of the Federal poverty level except as provided in this section or in §56.98." (52 Pa. Code § 56.100).[19] The Company has implemented a very limited way through which customers may demonstrate that they have household incomes at or below 250% of the Federal poverty level. Moreover, in some ways, the Company's tariff is incomplete while in other ways, the tariff is internally inconsistent. The Company's tariff provides:

> (b) For Residential Customers, the Company will accept the following as verification of household income in determining the eligibility of an account under Chapter 56 for termination during the period of December 1 through March 31: (i) recent pay stubs or W-2 forms, (ii) access card or statement from Department of Public Welfare ("DPW"), (iii) if a source of income is rental income, then a verified copy of rent receipt(s), (iv) if the Residential Customer receives social security payments, pension payments, disability payments, Supplemental Security Income (SSI) payments, or any other source of fixed income with direct deposit, then a copy of bank statement or benefit letter, (v) child support and/or alimony support verification letter, (vi) if the Residential Customer receives payments from unemployment benefits or workers' compensation, then a copy of the determination letter or check stub, (vii) previous year's income tax statement, (viii) a filed 1099 form showing any interest income, annuity or dividends, and (ix) a verification letter from DPW of any approved cash or crisis grant applicable to the current heating season.

[19] Section 56.98 governs situations involving (1) unauthorized use of the service delivered on or about the affected dwelling; (2) fraud or material misrepresentation of the customer's identity for the purpose of obtaining service; (3) tampering with meters or other public utility equipment; and (4) violating tariff provisions on file with the Commission which endanger the safety of a person or the integrity of the public utility's delivery system. Terminations pursuant to this section are set aside for purposes of this discussion.

I have several concerns regarding this tariff language. First, the Company's tariff seems to be unduly restrictive in the documentation it seeks customers to produce. We know from experience through the State's CAP programs, both electric and natural gas, as well as from public benefit programs in general, that increasing the complexity of any application process has the direct result of decreasing participation. Given the purpose of this Commission regulation, to provide cold weather shutoff protections to customers who may have an inability to pay, the exclusion of customers for administrative rather than for substantive reasons should be avoided whenever possible.

Other Pennsylvania utilities have not found it necessary to use the restrictive approach adopted by UGI Gas. For example, the tariffs of the FirstEnergy companies (Metropolitan Edison, Penelec, Penn Power, West Penn Power) state simply that "to determine if a Customer exceeds the 250% of federal poverty level threshold, the Company will utilize financial information provided by the Customer. The Company may elect to send to the Customer an income verification form for completion and return." (see e.g., Met Ed Rule 11(e), "Winter Termination – Determining Income Eligibility for Winter Termination"). Columbia Gas follows a similar approach, stating that "the Company will use financial information from the customer provided within the most recent twelve (12) month period to determine if a customer exceeds the 250% federal poverty level threshold." (CGPA Rule 18.7, "Winter Termination"). In contrast, PECO Energy (electricity and gas) articulates a list of acceptable documentation, but includes on that list "other forms to be accepted at the Company's discretion." (PECO Rule 17.1 "Non-Payment Shutoff"). At the other end of the spectrum, Peoples Gas acknowledges that it will "not terminate service to customers with household income at or below the qualifying level as determined by Commission regulation or PA Statute," without articulating how it will assess the customer's income. (Peoples Natural Gas Rule 5, "Discontinuance and Termination of Service").

I recommend the approach adopted by CGPA and the FirstEnergy companies, with one exception. In the event that a customer has otherwise established income eligibility within the past year (e.g., through receipt of LIHEAP), no reason exists for the customer to be called upon to again independently establish his or her income eligibility for the cold weather shutoff protections for the current winter heating season.

Q. DOES ADOPTING YOUR RECOMMENDED APPROACH TO VERIFYING INCOME ELIGIBILITY FOR WINTER SHUTOFF PROTECTIONS ADDRESS OTHER PROBLEMS YOU HAVE IDENTIFIED IN THE UGI TARIFF?

A. Yes. The current tariff language referencing the use of income tax returns and a "filed" income tax Form 1099 would seem to indicate that UGI requires an *annual* income to be at or below 250% of the Federal Poverty Level. As I note above, the intent of the PUC regulation is to provide cold weather shutoff protections to customers who might otherwise not be able to retire arrears. UGI should accept an *annualized* income (e.g., 30-days, 90-days) to establish eligibility. In this regard, the tariff is internally inconsistent. Other aspects of the language quoted above do not involve documenting the customer's annual income.

Moreover, the use of a "previous year's income tax statement" as allowed by the current UGI tariff could allow a customer to qualify for cold weather protections based on income documentation that is more than a year old. This requirement is internally inconsistent with other aspects of the tariff. For example, the tariff requires that pay stubs be "recent" (without defining what comprises a "recent" stub).

Not all public benefits that would document that a customer has income at or below 250% of Federal Poverty Level are delivered by the Department of Public Welfare ("DPW"). Limiting the receipt of documentation to DPW, for example, unreasonably restricts customers who may receive medical or housing benefits through a non-DPW government agency. Any government income eligibility determination provided by a customer should suffice.

Q. DO YOU HAVE ANY FINAL CONCERNS ABOUT UGI'S IMPLEMENTATION OF THE COMMISSION'S COLD WEATHER PROTECTION RULE?

A. UGI's tariff language appears to require a customer to document their eligibility for the PUC's cold weather protections at the time they receive a shutoff notice. For customers with income at or below 150% of Poverty, however, this seems unnecessary and unduly limiting. The Company reports that it has identified a monthly average of 41,639 "confirmed low-income customers" in 2014. (CAUSE-PA-I-14(1)). While "confirmed low-income" does not reach customers with income in excess of 150% of Poverty Level, no reasonable reason exists to require someone who the Company has previously identified, to the Company's satisfaction, to be "low-income" to re-certify or re-verify their income through a new and separate process.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS:

A. I recommend that UGI modify its winter shutoff protection tariff to reflect the following changes:

- UGI adopt language that mirrors the language of CGPA and/or the FirstEnergy companies providing greater flexibility in the documentation that will be accepted to establish income eligibility;
- UGI adopt language providing that income verification from any public agency, not simply DPW, is sufficient to establish income eligibility;
- UGI adopt language providing that any customer identified as "confirmed low-income" in the Company's records shall not be required to re-certify or re-verify income to gain the protections of the winter shutoff protections.
- UGI adopt language providing that any customer having established income eligibility for cold weather protections within the 12 months preceding the start of the cold weather season shall not be required to re-certify or re-verify their income for that heating season; and
- UGI adopt language providing that income eligibility for the cold weather protections may be established using 30-day annualized income rather than being based on an annual income.

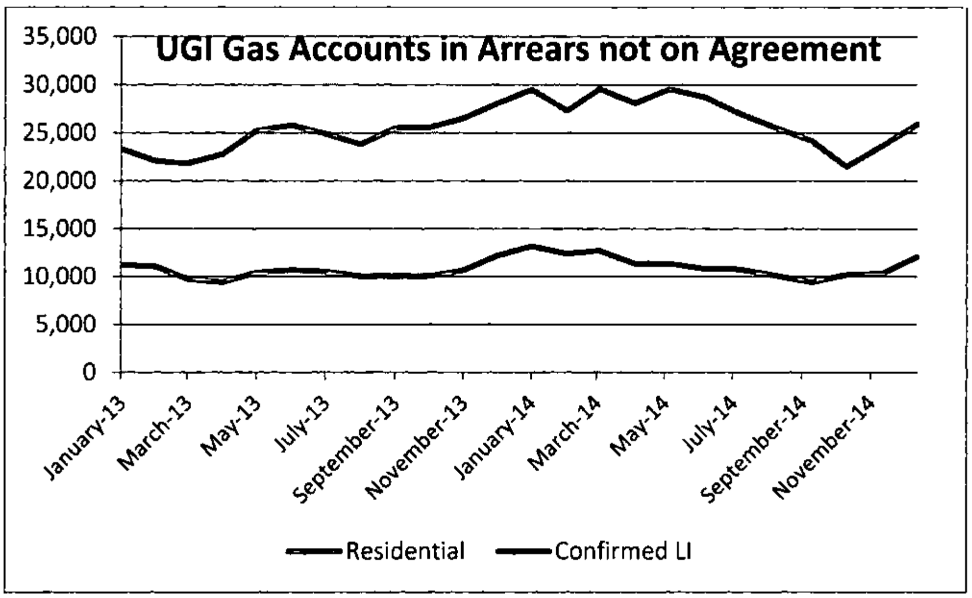
Q. IS THERE A GENERALLY-ACCEPTED STRATEGY TO MINIMIZE NON-PAYMENT DURING COLD WEATHER?

A. Yes. Levelized budget billing is a generally-accepted strategy to help payment-troubled customers be more likely pay their home energy bills. The Company's most recent Universal Service Evaluation, for example, reported that CAP participants identified "budget billing / even payments" as the second most important attribute of CAP (behind only "lower gas bills").[20] The benefits of budget billing arise primarily because it makes the level of bills, which might otherwise substantially seasonally fluctuate, more consistent. As a result, customers can plan what to expect to devote from their household budget to pay their natural gas bills.

While UGI is not required to report data on customer participation in budget billing, the data that *is* reported would seem to indicate that budget billing can be of help to customers (low-income or non-low-income) who might otherwise be in arrears. The Company's 2014 data indicates, for example, there is little overlap between the receipt of hardship fund grants and CAP (173 CAP participants of 652 hardship fund recipients). (CAUSE-PA-I-14-1). This may well be because hardship fund recipients may not be CAP-eligible, with primary income sources being from employment or pension/retirement (407 of 652). (Id.). Nonetheless, only 152 of the 652 hardship fund recipients received grants during the cold-weather months; in contrast, 352 of the 652 hardship fund recipients received grants in September through November, an ideal time to enroll customers in budget billing.

[20] APPRISE, Inc. (2012). "UGI Utilities, Inc. – Gas Division and UGI Penn Natural Gas, Inc., Universal Service Program, Final Evaluation Report," at 44-45.

The advantage of taking an aggressive tact in pursuing budget billing can be seen in the chart below of both residential customers and confirmed low-income customers in arrears and *not* on payment plans. The uptick in cold weather accounts in arrears (not on payment plans) could be reduced, particularly if customers would enter into levelized budget billing in the months before cold weather bills are received.



My recommendation would *not* be to focus attention exclusively on enrolling customers receiving hardship grants on budget billing, or to focus attention exclusively on enrolling customers in arrears on budget billing. However, I would recommend that UGI not exclude customers on arrears from enrolling in budget billing.[21] I would further recommend that UGI adopt budget billing as an affirmative strategy through which to reduce the impacts of cold weather arrears (both accounts in arrears and dollars of arrears).

[21] UGI's tariff provisions on budget billing (Section 9, Supplement 91, Second Revised Page 21) does not exclude customers in arrears by tariff. I do not know what UGI practices entail.

Part 4. UGI's Proposed Energy Efficiency and Conservation ("EE&C") Plan.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I consider several essential elements of the Company's proposed Energy Efficiency and Conservation Plan (EE&CP). My review of UGI's EE&CP is limited to issues involving low-income customers and multi-family buildings.

A. Low-Income Issues in UGI's EE&CP.

Q. PLEASE IDENTIFY THE STARTING POINT OF YOUR ANALYSIS OF LOW-INCOME ISSUES IN UGI'S EE&CP.

A. In Central Penn Gas Company's 2010 rate case (Docket R-2010-2214415), UGI presented an EE&CP for consideration. Several parties, including the OCA, objected to the proposed EE&CP on the grounds that the Plan inadequately addressed low-income customers. The Commission rejected the proposed EE&CP in part based on these objections. The Commission stated: "Low-income programs: CPG is to clearly describe what program measures are targeted toward low-income customers, and how these program measures 'supplement' the existing Low-Income Usage Reduction Program of CPG." This Commission language has two critical aspects within it that I will address below:

- The UGI EE&CP should have specific program measures, "clearly described," which should be "***targeted*** toward low-income customers" (emphasis added); and

- These specific program measures are to "supplement the existing Low-Income Usage Reduction Program. . ."

If, in other words, the Company merely offers residential energy efficiency programs that are somehow, in some unspecified way, merely available to low-income customers in the same fashion they are available to all residential customers, the Commission's stated objective has not been met. Moreover, the fact that the Company may already operate a LIURP program does not excuse it from its obligations to "clearly describe. . .program measures targeted toward low-income customers. . ."

Q. PLEASE EXPLAIN THE BASIS FOR YOUR CONCLUSION THAT THE COMPANY DOES NOT INCLUDE CLEARLY DESCRIBED PROGRAM MEASURES TARGETED TOWARD LOW-INCOME CUSTOMERS.

A. UGI includes no measures in its Plan directed toward low-income customers. UGI explicitly acknowledges as much when it states:

- "As mentioned on Love, page 9, the EE&C plan does not specifically target the low-income sector, and so no assumptions have been made as to the estimated proportion of participants in the Residential Prescriptive Program that would be low-income, non-LIURP." (OCA-V-12(a)).
- "As mentioned on Love, page 9, the EE&C plan does not specifically target the low-income sector, and so no assumptions have been made as to the estimated proportion of participants in the Residential Retrofit Program that would be low-income, non-LIURP." (OCA-V-12(b)).

Love's testimony states: "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'). . ." (Love, at 9).

Q. IS THERE REASON TO BELIEVE THAT THE UGI RESIDENTIAL PROGRAMS WILL HAVE THE EFFECT OF DISPROPORTIONATELY EXCLUDING LOW-INCOME CUSTOMERS FROM PARTICIPATION?

A. Yes. The Company has undertaken no assessment of the extent to which, if at all, low-income customers will participate in its residential programs. The Company concedes that "no assumptions around low-income participation have been built in to the EE&C Plan's projections." (OCA-V-10). The Company acknowledges that residential customers face certain "market barriers" to the installation of energy efficiency measures. (OCA-V-22). When asked to provide a "comprehensive list" of market barriers for low-income customers, however, the most the Company could say is, that in addition to all of the market barriers faced by residential customers generally, "low-income customers have additional barriers, mainly associated with costs, such as: (1) "increased sensitivity to upfront costs"; (2) "reduced access to credit"; and (3) "larger percentage of population with split-incentives due to higher penetration of population renting." (OCA-V-22).

In fact, there are additional substantial market barriers that will prevent low-income customers from being able to avail themselves of residential energy efficiency programs. Low-income customers do not merely have an "increased sensitivity to upfront costs" as asserted by the Company. The high capital costs of energy efficiency measures, combined with the lack of access to capital, generally push energy efficiency investments to be made by low-income households out-of-reach. In addition, as I discussed above, low-income households have substantially greater implicit discount rates (often called "hurdle rates"), generally approaching 100%, an impediment impossible for most efficiency investments to overcome.

Contrary to the Company's seeming belief that "split incentives" between landlords and tenants address motivations, which can be overcome by "messaging," (OCA-V-15), investments for major gas-consuming systems such as hot water and space heating systems (particularly applicable to natural gas efficiency investments) present the problem of the lack of "dominion interest." Low-income households, in other words, who are disproportionately tenants, lack the authority to make decisions with respect to major gas consuming systems, even if they had the financial wherewithal to implement those decisions (which they do not).

Low-income customers also have a substantially higher mobility rate than do non-low-income customers, a barrier not considered by the Company's EE&C Plan. If the mobility rate results in a customer expecting to move before the investment results in a payback, the customer will not make the efficiency investment. A low-income customer, in other words, will not invest in an energy efficiency measure having a three-year payback if that customer expects to change residences in two years.

Q. IS THERE ANY ADDITIONAL REASON FOR UGI TO OFFER ENERGY EFFICIENCY PROGRAMS SPECIFICALLY TARGETED TO LOW-INCOME CUSTOMERS?

A. Yes. Energy efficiency investments targeted toward low-income customers have the effect of helping those customers reduce their arrears. While the Company has not undertaken any such analysis of this result on its own system (OCA-V-6), the Company concedes that the impact has been documented in a long-term study of Pennsylvania's LIURP program. (OCA-V-1). The Company's witness has not participated in any study of such an effect. (OCA-V-2). The offer of energy efficiency programs to low-income CAP customers also helps reduce the level of CAP credits that are charged to CAP non-participants. This financial benefit was neither sought by UGI nor studied since the Company's EE&C Plan does not have a component targeted to low-income customers. (OCA-V-13; OCA-V-21). While I do not propose that UGI adopt a benefit-cost process which explicitly takes these benefits into account, it would be inappropriate not to acknowledge the existence of such benefits.[22]

Q. WHAT DO YOU CONCLUDE?

A. The Company failed to take into account these market barriers that impede, if not completely prevent, low-income participation in the Company's residential energy efficiency programs. Accordingly, the Company errs when it states that its residential programs are "available" to low-income customers. In fact, it is precisely due to this unavailability that the Commission had directed UGI-CPG to include specific "program

[22] Failing to acknowledge such benefits has the same effect as setting the value of such benefits to zero ($0), a result we know to be inaccurate.

measures targeted toward low-income customers," and to have those program measures be "clearly described" in the Plan, as a supplement to LIURP. The Company here, however, stated that "the UGI Gas EE&C Plan is not specifically targeted to low-income customers and the EE&C Plan is not specifically designed to supplement LIURP." (OCA-V-23).

Q. WHAT DO YOU RECOMMEND?

A. I recommend that UGI Gas follow an approach such as that which the Commission adopted for low-income programs in the electric industry's compliance with Act 129 requirements. In making this recommendation, I do not assert that Act 129 is directly applicable to the natural gas industry, but merely that the Commission's reasoning and analysis in deciding how to implement that state statute can be applied to UGI as well. In its consideration of electric utility Act 129 programs, the Commission held that utilities should have a specific carve-out of savings to be generated from each utility's low-income[23] customer base.[24] The low-income savings carve-out approved by the Commission in its Phase I and Phase II Act 129 proceedings was 4.5% for electric utilities.[25] This approach is a reasonable way to address low-income issues. It does not require the Company to spend a certain amount of money on low-income customers; nor does it require the Company to reach a certain number of low-income customers. By establishing a savings carve-out, above and beyond LIURP, the Commission allows the

[23] "Low-income" is a term defined by Commission regulation.
[24] The June 11, 2015 Implementation Order disallowed the inclusion of low-income participation in standard, non-low-income-specific residential programs in the calculation of savings towards the 5.5% low-income carve-out. *See June 11, 2015 Implementation Order at 69.*
[25] Using the Phase I and II low-income carve-out recognizes that the UGI program is a newly-proposed energy efficiency initiative.

Company to structure both its program design and its budget to reach its low-income carve-out in the most efficient and effective way practicable.

B. Multi-Family Issues in UGI's EE&CP.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I address the extent to which UGI adequately addresses the needs of multi-family dwelling units in its EE&C Plan. I conclude that the Company fails to provide appropriate attention to multi-family dwellings.

Q. HAVE YOU HISTORICALLY ENGAGED IN ANY PROFESSIONAL WORK REGARDING THE OFFER OF ENERGY EFFICIENCY TO MULTI-FAMILY HOUSING?

A. Yes. In 2014, I was retained by the Natural Resources Defense Council ("NRDC") to develop an objective definition of "equitable investment" for application to utility investments in energy efficiency; and to develop a mechanism through which the equities of utility investments in multi-family housing in particular could be measured. After a year-long study, my final report, titled "The Equities of Efficiency: Distributing Utility Usage Reduction Dollars for Affordable Multi-Family Housing," was released for use nationwide by efficiency advocates. I am, in other words, no stranger to the need for added utility investment in efficiency for multi-family housing.

Q. PLEASE EXPLAIN YOUR CONCERNS ABOUT THE COMPANY'S GENERAL TREATMENT OF MULTI-FAMILY HOUSING IN ITS EE&C PLAN.

A. The Company's plans with respect to multi-family buildings are limited at best. For example, when asked to provide a detailed description of how UGI plans to engage the active participation of owners/operators of multi-family buildings, the new construction of which is subsidized by various public programs,[26] the most the Company could say was that it would "reach out. . .to see if there is an opportunity to include program information. . ." (OCA-V-3(a) (LIHTC); OCA-V-3(b) (HOME); OCA-V-3(c) (PHFA)).

The Company does not distinguish, in any of its residential or non-residential programs, between the needs of a multi-family building consisting of two-units and a multi-family building consisting of more than 20 units. (OCA-V-8). The Company did not respond to whether the definition of "multi-family" differs based on whether the building is individually-metered or master-metered. (OCA-V-9). The Company has no specific plans on how it must modify its program approach based on the size of the multi-family building. (OCA-V-24). In fact, while the Company acknowledges that "multi-family" includes a two-unit housing building (OCA-V-9(a)) and a housing building with three or four units (OCA-V-9(b)), the only specific marketing of multi-family opportunities involves the Company's assertion that "the program will specifically market to '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.'" (OCA-V-25(d)) (emphasis added).

[26] For example, the Low-Income Housing Tax Credit; the federal Home Investment Partnership Program (HOME); state PHFA (Pennsylvania Housing Finance Authority) financing.

Consider the Residential Prescriptive Program as one further example. The Company could merely say that all aspects of the Residential Prescriptive Program "also apply to the multi-family sector." (OCA-V-25). The Company asserts that "the classification as multi-family *does not preclude* the participation in any specific program." (OCA-V-25). Accordingly, the Company fails to consider the special needs of multi-family buildings. For example:

- Multi-family housing has a much lower ratio of exposed-walls to conditioned floor area (and usually only a floor *or* a ceiling, or neither) exposed to the exterior. As a result, more efficiency potential comes from water heating rather than space heating (or cooling).

- Rather than being concerned about air infiltration to the exterior of the building, multi-family usage reduction often needs to focus on heating and air transfer from dwelling unit to dwelling unit (as well as from dwelling units to common space).

- Many "leaky" systems in multi-family housing units are common systems, such as, for example, ventilation systems used to exhaust kitchens, bathrooms and laundry rooms.

- Multi-family housing is difficult to generalize. The multi-family sector has been found to be "exceedingly diverse in several meaningful ways" (Berkeley, 17), including whether it is high-rise or low-rise, exclusively residential or mixed-use, and whether there is the presence or absence of central systems.

Multi-family housing is substantially less efficient than other housing types. One study, for example, examined the prevalence of Energy Efficiency Features ("EEFs"), defined to be "physical attributes that reduce the amount or cost of energy required for a given level of energy service."[27] The study concluded that "multifamily rentals were less

[27] Pivo, Gary (2012). Energy Efficiency and its Relationship to Household Income in Multifamily Rental Housing. Fannie Mae: Washington D.C.

energy efficient than other housing in 2005 and. . .the gap persisted into 2009." Some improvement occurred from 2005 to 2009 "but it was modest." The study reported:

> Overall, 87.5 percent of the EEFs (21 of 24) were significantly less common in multifamily rentals than in other housing in 2005 (at the .10 significance level or better). By 2009, this difference had been reduced to 75 percent, though clearly the deficiency in multifamily housing remained.
>
> In the 2005 sample, every HVAC EEF, all but 1 building envelope EEF, and 9 of the 11 appliance EEFs were significantly less common in multifamily rentals. Only 1 feature was more common in multifamily rentals (2000+ vintage clothes dryers), and only 1 was equally common (natural gas cook top). In the 2009 sample, all but one HVAC EEF (2000+ vintage ac), every building envelope EEF, and 6 of 11 appliance EEFs were significantly less common in multifamily rentals, compared to other housing.

Despite these special needs, rather than affirmatively responding to such needs, UGI Gas only stated that "the classification as multi-family *does not preclude participation* in any specific program." (OCA-V-25).

Consider the Residential Retrofit Program as yet another example. While the Company denied that the Residential Retrofit Program "generally assumes a customer living in a one-family detached housing unit," (OCA-V-17), it has no specific differences in financial incentives for multi-family buildings. (OCA-V-26(c)). When asked about its "marketing approach" to multi-family buildings for the Residential Retrofit Program, it could only cite to the "New Construction Program" (OCA-V-26(d) citing OCA-V-3) and to the "*Non*-Residential Retrofit Program" (OCA-V-26(d), citing OCA-V-7).

Q. DO YOU HAVE A FINAL CONCERN REGARDING THE COMPANY'S TREATMENT OF MULTI-FAMILY HOUSING IN ITS EE&C PLAN?

A. Yes. UGI witness Love states specifically that ". . .UGI Gas's [residential retrofit] program will target high use customers while also allowing self-selected participation." (Love, at 8). While the Residential Retrofit program is not the single biggest energy efficiency program in the Company's proposed portfolio, it is the second biggest, behind only the Residential Prescriptive Program (and setting aside the Behavior and Education program). (EE&C Plan, at 12).[28]

Targeting residential retrofit investments primarily to the highest usage customers will have the effect of disproportionately excluding residents of multi-family housing. In reaching this conclusion, it is important to remember that "multi-family housing" includes not merely large developments, but includes buildings with as few as two to four housing units in them. (OCA-V-9). According to the Residential Energy Consumption Survey ("RECS"), prepared by the Energy Information Administration of the U.S. Department of Energy ("EIA/DOE"), the natural gas usage of multi-family dwelling residents is systematically less than the natural gas usage of single-family homes. To target energy efficiency investment based on high usage, in other words, is to, in effect, target single-family dwellings, whether or not that targeting principle is explicitly stated.

When asked for a detailed explanation of "how targeting energy efficiency investments to 'high users' avoids systematically excluding individually metered customers who live in

[28] Over the five years of the program, the Residential Retrofit program is projected to have a budget of $3,720,000 in nominal dollars, behind only the Residential Prescriptive budget of $10,324,000. (EE&C Plan, Table 10, at 12).

multi-family buildings," the Company could not provide such an explanation for the Residential Retrofit program. The Company merely stated that "UGI Gas's proposed EE&C portfolio allows for the use of like-to-like comparisons of multi-family building stock *in its New Construction Program and Nonresidential Retrofit Program*. Such like-to-like comparisons can target 'high users' without systematically excluding individually-metered customers who live in multi-family buildings." (OCA-V-7) (emphasis added). The Nonresidential Retrofit Program, of course, would not serve individually-metered residential customers in multi-family buildings. The New Construction Program has a budget, spread over both residential and non-residential customers, of only $2,307,000 for the five years of the EE&C Plan. (EE&C Plan, Table 10, at 12).

When asked to provide a detailed explanation of how the Residential Retrofit program would reach multi-family housing disaggregated by the size of housing, the Company could not provide such an explanation. (OCA-V-24, citing OCA-V-8 and OCA-V-9). When asked how the Company would change its marketing to address the special needs of multi-family housing in the Residential Retrofit Program, the Company could not do so. Instead, it cited its New Construction Program (OCA-V-3 and OCA-V-7), which is not directed toward individually-metered multi-family housing; its Nonresidential Retrofit Program (OCA-V-7), which is not directed toward individually-metered housing; and its treatment of "split incentives" (OCA-V-15), which does not address the issue of how targeting high use customers has the effect of systematically excluding customers living in individually-metered multi-family housing. (OCA-V-26(d)).

In sum, the Company specifically and explicitly states that it will target its Residential Retrofit program –its second biggest residential efficiency program—based on high usage but this does not adequately address the multi-family housing issues.

Q. WHAT DO YOU RECOMMEND?

A. The purpose of my testimony today is not to develop, design and propose residential energy efficiency programs for UGI Gas. In its consideration of electric efficiency programs submitted pursuant to Act 129, however, the Commission has specifically stated that special efforts must be extended to ensure that energy efficiency investments should be made available, not merely in theory or on paper but in reality, to residents of multi-family housing.

Ample opportunity exists to extend UGI's gas energy efficiency programs to multi-family housing. The entry points for introducing energy efficiency are substantial. For example, multi-family housing receives inspections and/or "property needs assessments" at a much higher frequency than do single-family homes. Renovations and repairs resulting from these inspections are more frequent as well. In addition, Pennsylvania provides additional positive weighting points to developments exceeding energy standards specified in the "selection criteria" for housing receiving Low-Income Housing Tax Credits ("LIHTC"). (Tax Credit and PennHOMES Selection Criteria, Section B).[29] Given the competitiveness of these funding streams, a project proposal that simply meets the mandatory design standards would not be competitive for LIHTC funding. While

[29] PennHOMES combines federal HOME funding with state funding to provide low-cost financing for affordable housing development.

UGI would need to be careful not to provide funding for energy efficiency upgrades that would be otherwise installed simply to be competitive for the funding subsidies, the LIHTC (and similar programs) present an opportunity for UGI to pursue larger multi-family partnerships. Care would be needed, as well, because an exclusive focus on such housing subsidy programs would disproportionately exclude smaller multi-family housing. Nonetheless, opportunities exist to introduce efficiency investments into multi-family housing that UGI Gas does not recognize in its multi-family program design.

I recommend that UGI be directed to develop a residential program and designate a portion of the budget from that program to specifically serve multifamily properties. (I/M/O Philadelphia Gas Works, Docket No. M-2013-2366301, Final Decision, issued August 21, 2014).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	**Docket No. R-2015-2518438**
v.	:	
	:	
UGI UTILITIES, INC. – GAS DIVISION	:	

APPENDIX ACCOMPANYING THE

DIRECT TESTIMONY OF

ROGER D. COLTON

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

April 12, 2016

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Past Member:	Board of Directors, Belmont Housing Trust, Inc.
Past Chair:	Waverley Square Fire Station Re-use Study Committee (Belmont MA)
Past Member:	Belmont (MA) Energy and Facilities Work Group
Past Member:	Belmont (MA) Uplands Advisory Committee
Past Member:	Advisory Board: Fair Housing Center of Greater Boston.
Past Chair:	Fair Housing Committee, Town of Belmont (MA)
Past Member:	Aggregation Advisory Committee, New York State Energy Research and Development Authority.
Past Member:	Board of Directors, Vermont Energy Investment Corporation.
Past Member:	Board of Directors, National Fuel Funds Network
Past Member:	Board of Directors, Affordable Comfort, Inc. (ACI)
Past Member:	National Advisory Committee, U.S. Department of Health and Human Services, Administration for Children and Families, Performance Goals for Low-Income Home Energy Assistance.
Past Member:	Editorial Advisory Board, International Library, *Public Utility Law Anthology*.
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Past Member:	National Advisory Committee, U.S. Department of Housing and Urban Development, Calculation of Utility Allowances for Public Housing.

Past Member: National Advisory Board: Energy Financing Alternatives for Subsidized Housing, New York State Energy Research and Development Authority.

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Colton (2000). ***Outreach Strategies for Iowa's LIHEAP Program Innovation in Improved Targeting***, prepared for Iowa Department of Human Rights.

COLTON EXPERIENCE AS EXPERT WITNESS

2000 – PRESENT

CASE NAME	CLIENT NAME	Docket No. (if available)	TOPIC	JURIS.	YEAR
I/M/O PPL Utilities	Office of Consumer Advocate	R-2015-2469275	Rate design / customer service	Pennsylvania	15
I/M/O Columbia Gas Company	Office of Consumer Advocate	R-2015-2468056	Rate design / customer service	Pennsylvania	15
I/M/O PECO Energy Company	Office of Consumer Advocate	R-2015-2468981	Rate design / customer service	Pennsylvania	15
I/M/O Philadelphia Gas Works	Office of Consumer Advocate	P-2014-2459362	Demand Side Management	Pennsylvania	15
I/M/O SBG Management v. Philadelphia Gas Works	SBG Management	C-2012-2308454	Customer service	Pennsylvania	15
I/M/O Manitoba Hydro	Resource Action Centre		Low-income affordability	Manitoba	15
I/M/O FirstEnergy Companies (Met Ed, WPP, Penelec, Penn Power)	Office of Consumer Advocate	R-2014-2428742 (8743, 8744, 8745)	Rate design / customer service / storm communications	Pennsylvania	14
I/M/O Xcel Energy Company	Energy CENTS Coalition	E002/GR-13-868	Rate design / energy conservation	Minnesota	14
I/M/O Peoples Gas Light and Coke Company / North Shore Gas	Office of Attorney General	14-0224 / 14--0225	Rate design / customer service	Illinois	14
I/M/O Columbia Gas of Pennsylvania	Office of Consumer Advocate	R-2014-2406274	Rate design / customer service	Pennsylvania	14
I/M/O Duquesne Light Company Rates	Office of Consumer Advocate	R-2013-2372129	Rate design / customer service / storm communications	Pennsylvania	13
I/M/O Duquesne Light Company Universal Service	Office of Consumer Advocate	M-2013-2350946	Low-income program design	Pennsylvania	13
I/M/O Peoples-TWP	Office of Consumer Advocate	P-2013-2355886	Low-income program design / rate design	Pennsylvania	13
I/M/O PECO CAP Shopping Plan	Office of Consumer Advocate	P-2013-2283641	Retail shopping	Pennsylvania	13

CASE NAME	CLIENT NAME	Docket No. (if available)	TOPIC	JURIS.	YEAR
I/M/O PECO Universal Service Programs	Office of Consumer Advocate	M-201202290911	Low-income program design	Pennsylvania	13
I/M/O Privacy of Consumer Information	Legal Services Advocacy Project	CI-12-1344	Privacy of SSNs & consumer information	Minnesota	13
I/M/O Atlantic City Electric Company	Division of Rate Counsel	BPU-12121071	Customer service / Storm communications	New Jersey	13
I/M/O Jersey Central Power and Light Company	Division of Rate counsel	BPU-12111052	Customer service / Storm communications	New Jersey	13
I/M/O Columbia Gas Company	Office of Consumer Advocate	R-2012-2321748	Universal service	Pennsylvania	13
I/M/O Public Service Company of Colorado Low-Income Program Design	Xcel Energy d/b/a PSCo	12A--EG	Low-income program design / cost recovery	Colorado	12
I/M/O Philadelphia Water Department.	Philadelphia Public Advocate	No. Docket No.	Customer service	Philadelphia	12
I/M/O PPL Electric Power Corporation	Office of Consumer Advocate	R-2012-2290597	Rate design / low-income programs	Pennsylvania	12
I/M/O Peoples Natural Gas Company	Office of Consumer Advocate	R-2012-2285985	Rate design / low-income programs	Pennsylvania	12
I/M/O Merger of Constellation/Exelon	Office of Peoples Counsel	CASE 9271	Customer Service	Maryland	11
I/M/O Duke Energy Carolinas	North Carolina Justice Center	E-7, SUB-989	Customer service/low-income rates	North Carolina	11
Re. Duke Energy/Progress Energy merger	NC Equal Justice foundation	E-2, SUB 998	Low-income merger impacts	North Carolina	11
Re. Atlantic City Electric Company	Division of Rate Counsel	ER1186469	Customer Service	New Jersey	11
Re. Camelot Utilities	Office of Attorney General	11-0549	Rate shock	Illinois	11
Re. UGI—Central Penn Gas	Office of Consumer Advocate	R-2010-2214415	Low-income program design/cost recovery	Pennsylvania	11
Re. National Fuel Gas	Office of Consumer Advocate	M-2010-2192210	Low-income program cost recovery	Pennsylvania	11
Re. Philadelphia Gas Works	Office of Consumer Advocate	P-2010-2178610	Program design	Pennsylvania	11
Re. PPL	Office of Consumer Advocate	M-2010-2179796	Low-income program cost recovery	Pennsylvania	11
Re. Columbia Gas Company	Office of Consumer Advocate	R-2010-2215623	Rate design/Low-income program cost recovery	Pennsylvania	11
Crowder et al. v. Village of Kauffman	Crowder (plaintiffs)	3:09-CV-02181-M	Section 8 utility allowances	Texas Fed Court	11
I/M/O Peoples Natural Gas Company.	Office of Consumer Advocate	T-2010-220172	Low-income program design/cost recovery	Pennsylvania	11
I/M/O Commonwealth Edison	Office of Attorney General	10-0467	Rate design/revenue requirement	Illinois	10

CASE NAME	CLIENT NAME	Docket No. (if available)	TOPIC	JURIS.	YEAR
I/M/O National Grid d/b/a Energy North	NH Legal Assistance	DG-10-017	Rate design/revenue requirement	New Hampshire	10
I/M/O Duquesne Light Company	Office of Consumer Advocate	R-2010-2179522	Low-income program cost recovery	Pennsylvania	10
I/M/O Avista Natural Gas Corporation	The Opportunity Council	UE-100467	Low-income assistance/rate design	Washington	10
I/M/O Manitoba Hydro	Resource Conservation Manitoba (RCM)	CASE NO. 17/10	Low-income program design	Manitoba	10
I/M/O TW Phillips	Office of Consumer Advocate	R-2010-2167797	Low-income program cost recovery	Pennsylvania	10
I/M/O PECO Energy—Gas Division	Office of Consumer Advocate	R-2010-2161592	Low-income program cost recovery	Pennsylvania	10
I/M/O PECO Energy—Electric Division	Office of Consumer Advocate	R-2010-2161575	Low-income program cost recovery	Pennsylvania	10
I/M/O PPL Energy	Office of Consumer Advocate	R-2010-2161694	Low-income program cost recovery	Pennsylvania	10
I/M/O Columbia Gas Company	Office of Consumer Advocate	R-2009-2149262	Low-income program design/cost recovery	Pennsylvania	10
I/M/O Atlantic City Electric Company	Office of Rate Council	R09080664	Customer service	New Jersey	10
I/M/O Philadelphia Gas Works	Office of Consumer Advocate	R-2009-2139884	Low-income program cost recovery	Pennsylvania	10
I/M/O Philadelphia Gas Works	Office of Consumer Advocates	R-2009-2097639	Low-income program design	Pennsylvania	10
I/M/O Xcel Energy Company	Xcel Energy Company (PSCo)	085-146G	Low-income program design	Colorado	09
I/M/O Atmos Energy Company	Atmos Energy Company	09AL-507G	Low-income program funding	Colorado	09
I/M/O New Hampshire CORE Energy Efficiency Programs	New Hampshire Legal Assistance	D-09-170	Low-income efficiency funding	New Hampshire	09
I/M/O Public Service Company of New Mexico (electric)	Community Action of New Mexico	08-00273-UT	Rate Design	New Mexico	09
I/M/O UGI Pennsylvania Natural Gas Company (PNG)	Office of Consumer Advocate	R-2008-2079675	Low-income program	Pennsylvania	09
I/M/O UGI Central Penn Gas Company (CPG)	Office of Consumer Advocate	R-2008-2079660	Low-income program	Pennsylvania	09
I/M/O PECO Electric (provider of last resort)	Office of Consumer Advocate	R-2008-2028394	Low-income program	Pennsylvania	08
I/M/O Equitable Gas Company	Office of Consumer Advocate	R-2008-2029325	Low-income program	Pennsylvania	08
I/M/O Columbia Gas Company	Office of Ohio Consumers' Counsel	08-072-GA-AIR	Rate design	Ohio	08
I/M/O Dominion East Ohio Gas Company	Office of Ohio Consumers' Counsel	07-829-GA-AIR	Rate design	Ohio	08

CASE NAME	CLIENT NAME	Docket No. (if available)	TOPIC	JURIS.	YEAR
I/M/O Vectren Energy Delivery Company	Office of Ohio Consumers' Counsel	07-1080-GA-AIR	Rate design	Ohio	08
I/M/O Public Service Company of North Carolina	NC Department of Justice	G-5, SUB 495	Rate design	North Carolina	08
I/M/O Piedmont Natural Gas Company	NC Department of Justice	G-9, SUB 550	Rate design	North Carolina	08
I/M/O National Grid	New Hampshire Legal Assistance	DG-08-009	Low-income rate assistance	New Hampshire	08
I/M/O EmPower Maryland	Office of Peoples Counsel	PC-12	Low-income energy efficiency	Maryland	08
I/M/O Duke Energy Carolinas Save-a-Watt Program	NC Equal Justice Foundation	E-7, SUB 831	Low-income energy efficiency	North Carolina	08
I/M/O Zia Natural Gas Company	Community Action New Mexico	08-00036-UT	Low-income/low-use rate design	New Mexico	08
I/M/O Universal Service Fund Support for the Affordability of Local Rural Telecomm Service	Office of Consumer Advocate	I-0004010	Telecomm service affordability	Pennsylvania	08
I/M/O Philadelphia Water Department	Public Advocate	No Docket No.	Credit and Collections	Philadelphia	08
I/M/O Portland General Electric Company	Community Action--Oregon	UE-197	General rate case	Oregon	08
I/M/O Philadelphia Electric Company (electric)	Office of Consumer Advocate	M-00061945	Low-income program	Pennsylvania	08
I/M/O Philadelphia Electric Company (gas)	Office of Consumer Advocate	R-2008-2028394	Low-income program	Pennsylvania	08
I/M/O Columbia Gas Company	Office of Consumer Advocate	R-2008-2011621	Low-income program	Pennsylvania	08
I/M/O Public Service Company of New Mexico	Community Action New Mexico	08-00092-UT	Fuel adjustment clause	New Mexico	08
I/M/O Petition of Direct Energy for Low-Income Aggregation	Office of Peoples Counsel	CASE 9117	Low-income electricity aggregation	Maryland	07
I/M/O Office of Consumer Advocate et al. v. Verizon and Verizon North	Office of Consumer Advocate	C-20077197	Lifeline telecommunications rates	Pennsylvania	07
I/M/O Pennsylvania Power Company	Office of Consumer Advocate	P-00072437	Low-income program	Pennsylvania	07
I/M/O National Fuel Gas Distribution Corporation	Office of Consumer Advocate	M-00072019	Low-income program	Pennsylvania	07
I/M/O Public Service of New Mexico--Electric	Community Action New Mexico	07-00077-UT	Low-income programs	New Mexico	07
I/M/O Citizens Gas/NIPSCO/Vectren for Universal Service Program	Citizens Gas & Coke Utility/Northern Indiana Public Service/Vectren Energy	CASE 43077	Low-income program design	Indiana	07

CASE NAME	CLIENT NAME	Docket No. (if available)	TOPIC	JURIS.	YEAR
I/M/O PPL Electric	Office of Consumer Advocate	R-00072155	Low-income program	Pennsylvania	07
I/M/O Section 15 Challenge to NSPI Rates	Energy Affordability Coalition	P-886	Discrimination in utility regulation	Nova Scotia	07
I/M/O Philadelphia Gas Works	Office of Consumer Advocate	R-00049157	Low-income and residential collections	Pennsylvania	07
I/M/O Equitable Gas Company	Office of Consumer Advocate	M-00061959	Low-income program	Pennsylvania	07
I/M/O Public Service Company of New Mexico	Community Action of New Mexico	Case No. 06-000210-UT	Late charges / winter moratorium / decoupling	New Mexico	06
I/M?O Verizon Massachusetts	ABCD	Case NO. DTE 06-26	Late charges	Massachusetts	06
I/M/O Section 11 Proceeding, Energy Restructuring	Office of Peoples Counsel	PC9074	Low-income needs and responses	Maryland	06
I/M/O Citizens Gas/NIPSCO/Vectren for Univ. Svc. Program	Citizens Gas & Coke Utility/Northern Indiana Public Service/Vectren Energy	Case No. 43077	Low-income program design	Indiana	06
I/M/O Public Service Co. of North Carolina	North Carolina Attorney General/Dept. of Justice	G-5, Sub 481	Low-income energy usage	North Carolina	06
I/M/O Electric Assistance Program	New Hampshire Legal Assistance	DE 06-079	Electric low-income program design	New Hampshire	06
I/M/O Verizon Petition for Alternative Regulation	New Hampshire Legal Assistance	DM-06-072	Basic local telephone service	New Hampshire	06
I/M/O Pennsylvania Electric Co/Metropolitan Edison Co.	Office of Consumer Advocate	N/A	Universal service cost recovery	Pennsylvania	06
I/M/O Duquesne Light Company	Office of Consumer Advocates	R-00061346	Universal service cost recovery	Pennsylvania	06
I/M/O Natural Gas DSM Planning	Low-Income Energy Network	EB-2006-0021	Low-income gas DSM program.	Ontario	06
I/M/O Union Gas Co.	Action Centre for Tenants Ontario (ACTO)	EB-2005-0520	Low-income program design	Ontario	06
I/M/O Public Service of New Mexico merchant plant	Community Action New Mexico	05-00275-UT	Low-income energy usage	New Mexico	06
I/M/O Customer Assistance Program design and cost recovery	Office of Consumer Advocate	M-00051923	Low-income program design	Pennsylvania	06
I/M/O NIPSCO Proposal to Extend Winter Warmth Program	Northern Indiana Public Service Company	Case 42927	Low-income energy program evaluation	Indiana	05
I/M/O Piedmont Natural Gas	North Carolina Attorney General/Dept. of Justice	G-9, Sub 499	Low-income energy usage	North Carolina	05

CASE NAME	CLIENT NAME	Docket No. (if available)	TOPIC	JURIS.	YEAR
I/M/O PSEG merger with Exelon Corp.	Division of Ratepayer Advocate	EM05020106	Low-income issues	New Jersey	05
Re. Philadelphia Water Department	Public Advocate	No docket number	Water collection factors	Philadelphia	05
I/M/O statewide natural gas universal service program	New Hampshire Legal Assistance	N/A	Universal service	New Hampshire	05
I/M/O Sub-metering requirements for residential rental properties	Tenants Advocacy Centre of Ontario	EB-2005-0252	Sub-metering consumer protections	Ontario	05
I/M/O National Fuel Gas Distribution Corp.	Office of Consumer Advocate	R-00049656	Universal service	Pennsylvania	05
I/M/O Nova Scotia Power, Inc.	Dalhousie Legal Aid Service	NSUARB-P-881	Universal service	Nova Scotia	04
I/M/O Lifeline Telephone Service	National Ass'n State Consumer Advocates (NASUCA)	WC 03-109	Lifeline rate eligibility	FCC	04
Mackay v. Verizon North	Office of Consumer Advocate	C20042544	Lifeline rates—vertical services	Pennsylvania	04
I/M/O PECO Energy	Office of Consumer Advocate	N/A	Low-income rates	Pennsylvania	04
I/M/O Philadelphia Gas Works	Office of Consumer Advocate	P00042090	Credit and collections	Pennsylvania	04
I/M/O Citizens Gas & Coke/Vectren	Citizens Action Coalition of Indiana	Case 42590	Universal service	Indiana	04
I/M/O PPL Electric Corporation	Office of Consumer Advocate	R00049255	Universal service	Pennsylvania	04
I/M/O Consumers New Jersey Water Company	Division of Ratepayer Advocate	N/A	Low-income water rate	New Jersey	04
I/M/O Washington Gas Light Company	Office of Peoples Counsel	Case 8982	Low-income gas rate	Maryland	04
I/M/O National Fuel Gas	Office of Consumer Advocate	R-00038168	Low-income program design	Pennsylvania	03
I/M/O Washington Gas Light Company	Office of Peoples Counsel	Case 8959	Low-income gas rate	Maryland	03
Golden v. City of Columbus	Helen Golden	C2-01-710	ECOA disparate impacts	Ohio	02
Huegel v. City of Easton	Phyllis Huegel	00-CV-5077	Credit and collection	Pennsylvania	02
I/M/O Universal Service Fund	Public Utility Commission staff	N/A	Universal service funding	New Hampshire	02
I/M/O Philadelphia Gas Works	Office of Consumer Advocate	M-00021612	Universal service	Pennsylvania	02
I/M/O Washington Gas Light Company	Office of Peoples Counsel	Case 8920	Rate design	Maryland	02

CASE NAME	CLIENT NAME	Docket No. (if available)	TOPIC	JURIS.	YEAR
I/M/O Consumers Illinois Water Company	Illinois Citizens Utility Board	02-155	Credit and collection	Illinois	02
I/M/O Public Service Electric & Gas Rates	Division of Ratepayer Advocate	GR01050328	Universal service	New Jersey	01
I/M/O Pennsylvania-American Water Company	Office of Consumer Advocate	R-00016339	Low-income rates and water conservation	Pennsylvania	01
I/M/O Louisville Gas & Electric Prepayment Meters	Kentucky Community Action Association	200-548	Low-income energy	Kentucky	01
I/M/O NICOR Budget Billing Plan Interest Charge	Cook County State's Attorney	01-0175	Rate Design	Illinois	01
I/M/O Rules Re. Payment Plans for High Natural Gas Prices	Cook County State's Attorney	01-0789	Budget Billing Plans	Illinois	01
I/M/O Philadelphia Water Department	Office of Public Advocate	No docket number	Credit and collections	Philadelphia	01
I/M/O Missouri Gas Energy	Office of Peoples Counsel	GR-2001-292	Low-income rate relief	Missouri	01
I/M/O Bell Atlantic--New Jersey Alternative Regulation	Division of Ratepayer Advocate	T001020095	Telecommunications universal service	New Jersey	01
I/M/O Entergy Merger	Low-Income Intervenors	2000-UA925	Consumer protections	Mississippi	01
I/M/O T.W. Phillips Gas and Oil Co.	Office of Consumer Advocate	R00994790	Ratemaking of universal service costs.	Pennsylvania	00
I/M/O Peoples Natural Gas Company	Office of Consumer Advocate	R-00994782	Ratemaking of universal service costs.	Pennsylvania	00
I/M/O UGI Gas Company	Office of Consumer Advocate	R-00994786	Ratemaking of universal service costs.	Pennsylvania	00
I/M/O PFG Gas Company	Office of Consumer Advocate	R00994788	Ratemaking of universal service costs.	Pennsylvania	00
Armstrong v. Gallia Metropolitan Housing Authority	Equal Justice Foundation	2:98-CV-373	Public housing utility allowances	Ohio	00
I/M/O Bell Atlantic--New Jersey Alternative Regulation	Division of Ratepayer Advocate	T099120934	Telecommunications universal service	New Jersey	00
I/M/O Universal Service Fund for Gas and Electric Utilities	Division of Ratepayer Advocate	EX00200091	Design and funding of low-income programs	New Jersey	00
I/M/O Consolidated Edison Merger with Northeast Utilities	Save Our Homes Organization	DE 00-009	Merger impacts on low-income	New Hampshire	00
I/M/O UtiliCorp Merger with St. Joseph Light & Power	Missouri Dept. of Natural Resources	EM2000-292	Merger impacts on low-income	Missouri	00
I/M/O UtiliCorp Merger with Empire District Electric	Missouri Dept. of Natural Resources	EM2000-369	Merger impacts on low-income	Missouri	00
I/M/O PacifiCorp	The Opportunity Council	UE-991832	Low-income energy affordability	Washington	00

CASE NAME	CLIENT NAME	Docket No. (if available)	TOPIC	JURIS.	YEAR
I/M/O Public Service Co. of Colorado	Colorado Energy Assistance Foundation	99S-609G	Natural gas rate design	Colorado	00
I/M/O Avista Energy Corp.	Spokane Neighborhood Action Program	UE9911606	Low-income energy affordability	Washington	00
I/M/O TW Phillips Energy Co.	Office of Consumer Advocate	R-00994790	Universal service	Pennsylvania	00
I/M/O PECO Energy Company	Office of Consumer Advocate	R-00994787	Universal service	Pennsylvania	00
I/M/O National Fuel Gas Distribution Corp.	Office of Consumer Advocate	R-00994785	Universal service	Pennsylvania	00
I/M/O PFG Gas Company/Northern Penn Gas	Office of Consumer Advocate	R-00005277	Universal service	Pennsylvania	00
I/M/O UGI Energy Company	Office of Consumer Advocate	R-00994786	Universal service	Pennsylvania	00
Re. PSCO/NSP Merger	Colorado Energy Assistance Foundation	99A-377EG	Merger impacts on low-income	Colorado	99 - 00

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	**Docket No. R-2015-2518438**
v.	:	
	:	
UGI UTILITIES, INC. – GAS DIVISION	:	

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY OF

ROGER D. COLTON

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

April 12, 2016

Schedule RDC-1

Without CAP	Annual CAP Credit	Arrears 31-60	61-90	91-120	121+	Total
CAP Credit	$100					
Number of participants	1					
Total current bill	$100	$100	$100	$100	$100	
Percent low-income bills in arrears (BCS)	18.5%					
Total bill minus percent bills in arrears by aging	81.5%	5%	3%	2%	9%	
Unpaid from current bill		$5	$3	$2	$9	
Curent bill (in increments of $100)	0.0	0.0	0.0	0.0	0.1	
Working capital (wkg cap until charge-off) per $100 current bill	$5.87	$29.62	$41.67	$53.84	$84.79	
Working capital savings--current bill charged off	$0.00	$1.37	$1.16	$1.00	$7.84	$11.36

With CAP	Annual CAP Credit	Arrears 31-60	61-90	91-120	121+	Total
Current bill	$100					
Number of participants	1					
Total current bill	$100	$100	$100	$100	$100	
Percent residential bills in arrears (1 minus coverage)	4.4%					
Total bill minus percent bills in arrears by aging	96%	1%	1%	0%	2%	
Unpaid from current bill		$1	$1	$0	$2	
Curent bill (in increments of $100)	0.0	0.0	0.0	0.0	0.0	
Working capital (wkg cap until charge-off) per $100 current bill	$5.87	$29.62	$41.67	$53.84	$84.79	
Working capital savings--current bill (charged off and in arrears)	$0.00	$0.28	$0.24	$0.21	$2.07	$2.80

Wkg cap as pct of bill: no CAP	11.4%
Wkg cap as pct of bill: with CAP	2.8%
CAP credit working capital savings	8.6%

Without CAP

	Annual CAP Credit	Arrears 31-60	61-90	91-120	121+	Total
CAP Credit	$100					
Number of participants	1					
Total current bill	$100	$100	$100	$100	$100	
Percent low-income bills in arrears (BCS)	100.0%					
Total bill minus percent bills in arrears by aging	0%	25%	15%	10%	50%	
Unpaid from current bill	$0	$25	$15	$10	$50	
Curent bill (in increments of $100)	0.0	0.3	0.2	0.1	0.5	
Working capital (wkg cap until charge-off) per $100 current bill	$7.83	$29.62	$41.67	$53.84	$72.32	
Working capital savings--current bill charged off	$0.00	$7.41	$6.25	$5.38	$36.16	$55.20

With CAP

	Annual CAP Credit	31-60	61-90	91-120	121+	Total
Current bill	$100					
Number of participants	1					
Total current bill	$100	$100	$100	$100	$100	
Percent residential bills in arrears (1 minus coverage)	4.4%					
Total bill minus percent bills in arrears by aging	96%	1%	1%	0%	2%	
Unpaid from current bill	$96	$1	$1	$0	$2	
Curent bill (in increments of $100)	1.0	0.0	0.0	0.0	0.0	
Working capital (wkg cap until charge-off) per $100 current bill	$7.83	$29.62	$41.67	$53.84	$72.32	
Working capital savings--current bill (charged off and in arrears)	$7.49	$0.32	$0.27	$0.23	$1.58	$9.89

Wkg cap as pct of bill: no CAP	55.2%
Wkg cap as pct of bill: with CAP	9.9%
CAP credit working capital savings	45.3%

Schedule RDC-2
(page 1 of 2)

Annual Usage	# Customers	Avg annual usage	Bill at Current Rates	Bill at Proposed Rates	Difference	Aggregate Difference
5000-5999	2	5,326	$3,903.06	$4,185.49	$282.43	$565
4000-4999	8	4,326	$3,196.75	$3,439.06	$242.31	$1,938
3000-3999	49	3,306	$2,476.33	$2,677.70	$201.37	$9,867
2000-2999	747	2,283	$1,753.00	$1,914.10	$161.10	$120,342
1000-1999	12,630	1,312	$1,062.17	$1,189.32	$127.15	$1,605,905
500-999	17,560	745	$656.72	$766.09	$109.37	$1,920,537
<500	11,156	296	$330.20	$430.94	$100.74	$1,123,855
Total aggregate loss due to increased rates						$4,783,009

Schedule RDC-2
(page 2 of 2)

Annual Usage	# Confirmed LI Customers	Existing CC	Proposed CC	Proposed Increase in CC	Months/Year	Aggregate Increase
5000-5999	2	$8.55	$17.50	$8.95	12	$214.80
4000-4999	8	$8.55	$17.50	$8.95	12	$859.20
3000-3999	49	$8.55	$17.50	$8.95	12	$5,262.60
2000-2999	747	$8.55	$17.50	$8.95	12	$80,227.80
1000-1999	12,630	$8.55	$17.50	$8.95	12	$1,356,462.00
500-999	17,560	$8.55	$17.50	$8.95	12	$1,885,944.00
<500	11,156	$8.55	$17.50	$8.95	12	$1,198,154.40
Total aggregate loss due to increased customer charge						$4,527,125

Schedule RDC-3

	All (with CAP)				All (without CAP)			
Annual Usage	Bill at Current Rates	Bill at Proposed Rates	Difference	Pct Increase	Bill at Current Rates	Bill at Proposed Rates	Difference	Pct Increase
5000-5999	$3,903.06	$4,185.49	$282.43	7.2%	$3,903.06	$4,185.49	$282.43	7.2%
4000-4999	$3,196.75	$3,439.06	$242.31	7.6%	$3,196.75	$3,420.25	$223.50	7.0%
3000-3999	$2,476.33	$2,677.70	$201.37	8.1%	$2,476.33	$2,672.50	$196.17	7.9%
2000-2999	$1,753.00	$1,914.10	$161.10	9.2%	$1,753.00	$1,904.69	$151.69	8.7%
1000-1999	$1,062.17	$1,189.32	$127.15	12.0%	$1,062.17	$1,173.55	$111.38	10.5%
500-999	$656.72	$766.09	$109.37	16.7%	$656.72	$762.33	$105.61	16.1%
<500	$330.20	$430.94	$100.74	30.5%	$330.20	$429.87	$99.67	30.2%

Schedule RDC-4

Customer Charge (CC) as Percent of Total Bill by Usage Level (Proposed CC)

	Month CC	Ann CC	All with CAP	CAP	Non-CAP LI
5000-5999	$17.50	$210.00	5.0%	NA	5.0%
4000-4999	$17.50	$210.00	6.1%	6.1%	6.1%
3000-3999	$17.50	$210.00	7.8%	7.8%	7.9%
2000-2999	$17.50	$210.00	11.0%	10.9%	11.0%
1000-1999	$17.50	$210.00	17.7%	17.1%	17.9%
500-999	$17.50	$210.00	27.4%	26.7%	27.5%
<500	$17.50	$210.00	48.7%	47.6%	48.9%

Customer Charge (CC) as Percent of Total Bill by Usage Level (Existing CC)

	Month CC	Ann CC	All with CAP	CAP	Non-CAP LI
5000-5999	$8.55	$102.60	2.6%	NA	2.6%
4000-4999	$8.55	$102.60	3.2%	3.2%	3.2%
3000-3999	$8.55	$102.60	4.1%	4.1%	4.2%
2000-2999	$8.55	$102.60	5.9%	5.8%	5.9%
1000-1999	$8.55	$102.60	9.7%	9.3%	9.8%
500-999	$8.55	$102.60	15.6%	15.1%	15.7%
<500	$8.55	$102.60	31.1%	30.1%	31.2%

Schedule RDC-5

Energy Efficiency Attributes by Ratio of Income to Federal Poverty Level

Energy Efficiency Attribute	Ratio of Income to Federal Poverty Level		
	Over 150%	Under 150%	Under 100%
Home built subsequent to 2000	9.3%	4.1%	4.2%
Refrigerator less than 10 years old	66.8%	64.0%	63.4%
Energy Star refrigerator	42.9%	27.7%	22.3%
Heating system less than 10 years old	43.4%	36.1%	37.2%
Heating system more than 15 years old	39.1%	51.5%	52.0%
Programmable Thermostat for main heating	41.5%	14.4%	14.5%
Water heater age less than 10 years old	63.5%	59.1%	59.0%
Adequately insulated home	44.3%	38.6%	41.4%
Well-Insulated home	37.3%	31.7%	30.6%
Insulation age less than 10 years old	16.3%	8.3%	8.1%
Home drafty either all or most of the time /a/	13.2%	25.3%	25.1%
Home drafty all the time	5.9%	13.7%	12.1%
Home drafty most of the time	7.3%	11.6%	13.0%
Weather-stripping age less than 10 years old	26.9%	16.7%	11.4%

/a/ This is not a separately reported data point. It is the sum of the two preceding data points.

Schedule RDC-6

Percent Households by Poverty Range (2006 and 2014) (UGI Gas Counties)									
		Under .50	.50 to .74	.75 to .99	1.00 to 1.24	1.25 to 1.49	1.50 to 1.74	1.75 to 1.84	1.85 to 1.99
Berks	2006	4.1%	2.7%	3.8%	4.1%	3.4%	4.6%	1.7%	2.8%
Bucks	2006	2.2%	1.1%	1.3%	2.5%	1.9%	2.3%	0.9%	1.5%
Carbon	2006	xxx	xxx	xxx	xxx	xxx	xxx	xxx	Xxx
Chester	2006	3.2%	1.7%	2.0%	1.5%	2.3%	2.4%	1.3%	2.1%
Cumberland	2006	2.8%	1.4%	1.3%	2.1%	3.2%	3.3%	1.6%	3.5%
Dauphin	2006	5.1%	2.5%	2.5%	3.3%	4.6%	3.4%	1.4%	2.4%
Franklin	2006	3.6%	1.4%	2.1%	2.6%	3.8%	4.3%	2.5%	2.8%
Lancaster	2006	4.8%	1.8%	2.6%	2.7%	4.8%	3.7%	2.0%	3.4%
Lebanon	2006	3.7%	1.2%	3.4%	3.6%	3.4%	2.3%	1.8%	3.5%
Lehigh	2006	4.3%	4.0%	4.1%	4.2%	3.9%	4.5%	1.7%	1.9%
Luzerne	2006	4.9%	4.3%	4.1%	3.9%	5.9%	5.6%	2.0%	2.6%
Monroe	2006	4.6%	3.3%	2.6%	2.7%	3.0%	5.4%	2.5%	3.9%
Montgomery	2006	2.9%	1.4%	1.4%	1.9%	2.2%	2.3%	1.1%	1.8%
Northampton	2006	4.0%	2.0%	2.4%	2.8%	3.6%	3.3%	2.5%	2.8%
Schuylkill	2006	4.6%	3.2%	4.6%	5.0%	6.6%	6.1%	1.9%	3.1%
York	2006	3.8%	1.6%	2.6%	3.4%	2.9%	3.7%	1.4%	2.3%
		Under .50	.50 to .74	.75 to .99	1.00 to 1.24	1.25 to 1.49	1.50 to 1.74	1.75 to 1.84	1.85 to 1.99
Berks	2014	6.3%	3.6%	4.7%	4.6%	4.6%	4.0%	1.6%	2.7%
Bucks	2014	2.8%	1.2%	2.4%	1.8%	3.1%	2.7%	1.1%	1.8%
Carbon	2014	3.9%	4.6%	4.4%	4.3%	7.2%	3.0%	1.9%	4.0%
Chester	2014	3.3%	2.3%	1.9%	3.2%	2.4%	2.4%	0.9%	1.5%
Cumberland	2014	4.2%	2.0%	3.0%	3.4%	4.4%	3.3%	1.5%	2.3%
Dauphin	2014	6.4%	3.5%	3.6%	5.2%	4.7%	3.9%	1.2%	2.2%
Franklin	2014	4.7%	3.6%	4.6%	4.7%	4.4%	6.3%	1.2%	2.6%
Lancaster	2014	4.5%	2.2%	3.7%	3.3%	4.9%	5.1%	1.0%	2.9%
Lebanon	2014	4.8%	2.4%	3.1%	4.7%	5.2%	5.3%	2.6%	3.1%
Lehigh	2014	5.6%	4.1%	3.2%	4.2%	4.9%	5.0%	1.3%	2.2%
Luzerne	2014	6.7%	3.9%	5.4%	4.4%	5.1%	5.7%	1.7%	2.5%

Percent Households by Poverty Range (2006 and 2014) (UGI Gas Counties)									
Monroe	2014	6.3%	3.3%	3.8%	2.7%	2.4%	6.0%	2.4%	1.9%
Montgomery	2014	3.3%	1.6%	2.2%	2.2%	2.3%	2.4%	1.2%	2.0%
Northampton	2014	3.7%	2.4%	3.6%	3.7%	3.3%	4.1%	1.9%	2.4%
Schuylkill	2014	6.0%	3.5%	3.6%	5.2%	3.8%	6.0%	2.9%	3.2%
York	2014	5.0%	2.6%	2.6%	3.8%	3.6%	4.2%	1.1%	3.8%

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2015-2518438
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts above set forth in my Direct Testimony, OCA St. No. 4, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: ______________________
Roger D. Colton

Consultant Address: Fisher, Sheehan & Colton
34 Warwick Road
Belmont, MA 02478

DATED: April 12, 2016

OCA St. No. 4-SR
6/2/16 Hg

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2015-2518438**
	:	
UGI Utilities, Inc. – Gas Division	:	

SURREBUTTAL TESTIMONY OF

ROGER D. COLTON

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

May 25, 2016

Table of Contents

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Roger Colton. My business address is 34 Warwick Road, Belmont, MA 02478.

Q. ARE YOU THE SAME ROGER COLTON WHO PREVIOUSLY SUBMITTED DIRECT TESTIMONY ON BEHALF OF THE OFFICE OF CONSUMER ADVOCATE IN THIS PROCEEDING?

A. Yes.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY.

A. The purpose of my Surrebuttal Testimony is as follows.

- First, I respond to the Rebuttal Testimony of UGI Gas witness Ann Kelly;
- Second, I respond to the Rebuttal Testimony of UGI Gas witness Theodore Love;
- Third, I respond to the Rebuttal Testimony of UGI Gas witness Ann Rossi; and
- Finally, I respond to the Rebuttal Testimony of CAUSE-PA witness Mitchell Miller.

Part 1. Response to UGI Witness Ann Kelly.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to the Rebuttal Testimony of Ann Kelly (UGI Statement 2-R) regarding my proposed universal service cost offsets.

Q. PLEASE RESPOND TO MS. KELLY'S REBUTTAL TESTIMONY REGARDING YOUR PROPOSED UNIVERSAL SERVICE COST OFFSET INVOLVING BAD DEBT AND EMBEDDED LOST REVENUES.

A. Ms. Kelly argues that since the Company records its CAP Credits and its provision for uncollectible accounts in separate FERC accounts (Account 903 for CAP Credits and Account 904 for uncollectibles), there is no need to further reduce the CAP Credits to be collected through the Universal Service Rider. (Statement 2R, at 37-38). Her argument, however, does nothing to refute the documentation of double-collection that I presented in my Direct Testimony.

Q. PLEASE EXPLAIN THE DOUBLE COLLECTION.

A. When a confirmed low-income customer is not a CAP participant, and is billed $100, not all of that $100 will be collected. Part of that $100 will result in bad debt. The Company's bad debt write-off rate for confirmed low-income customers in 2014 was 12.8%. To keep the Company whole, that 12.8% of the confirmed low-income customers' bills is booked as an uncollectible and included in distribution rates. In this manner, the full $100 is collected.

When that confirmed low-income customer is enrolled in CAP, the $100 is split into two parts (let's hypothetically say that the two parts are $60 in CAP Bill and $40 in CAP credits). The $60 CAP Bill is the portion of the $100 to be charged to the CAP participant. The $40 CAP Credit is the portion of the $100 that is collected through the Universal Service rider. These two parts sum to the total of $100.

The double recovery occurs because 12.80% of that $100 is already included in rates in a different place. It does not matter that the different place is Account 904 rather than Account 903. The fact remains that that 12.80% is still already included in rates.

Without the adjustment I propose, the Company will include the $60 CAP Bill; the $40 CAP Credit; and the $12.80 of confirmed low-income bad debt in rates. The reason for the double collection is that in calculating the CAP Credit, the Company assumes that 100% of that bill would be collected in the absence of the customer's CAP participation. We know that to be wrong and that fact has already been incorporated into rates.

Q. WHAT DO YOU CONCLUDE?

A. I conclude that both the offset for embedded lost revenue and the bad debt adjustment I proposed in my Direct Testimony should be adopted.

Q. PLEASE RESPOND TO MS. KELLY'S REBUTTAL TESTIMONY REGARDING YOUR CASH WORKING CAPITAL ADJUSTMENT.

A. Ms. Kelly's primary argument in opposition to my proposed working capital offset is that, in her opinion, I failed to show that non-CAP customers would have fewer collection lag days than CAP customers. (Statement 2R, at 38-39).[1]

In fact, I demonstrated, in several ways, that confirmed low-income customers would impose a greater number of lag days than residential customers in general. As a result, by moving part of the Company's revenue from being billed to confirmed low-income customers to being billed to residential customers generally, the amount of collection lag will decrease, as will the associated costs. Consider, for example, that, as the Company reported to the Pennsylvania Public Utility Commission's ("PUC") Bureau of Consumer Services ("BCS"), in 2014 for UGI Gas:

- the bad debt rate for confirmed low-income customers was 12.8%, while the bad debt rate for residential customers as a whole was only 3.0%. For the difference (9.8%), the time period it takes for billings "to reach the uncollectible stage" is, by definition, shorter because that 9.80% (12.80% - 3.0% = 9.8%) *never* reaches the uncollectible stage.
- while 10% of residential accounts were in debt, 35% of confirmed low-income accounts were in debt. Confirmed low-income accounts clearly have a greater lag because a substantially higher proportion do not pay before the due date.
- while 4% of residential dollars are in arrears, 18% of confirmed low-income dollars are in arrears. The residential dollars have a lesser lag because a higher proportion are paid before their due date.

[1] While Ms. Kelly consistently refers only to CAP customers, my Direct Testimony refers to confirmed low-income customers, a broader category of customers.

Finally, even Ms. Kelly's aging numbers show that confirmed low-income customers are slower to pay than residential customers in general. (Statement 2R, at 41). Contrary to Ms. Kelly's discussion of how long it takes for a customer payment to get to become uncollectible, there can be no question for UGI Gas but that residential customers (non-CAP participants) pay quicker than CAP customers do and, as a result, impose less of a working capital requirement on the Company.

Q. PLEASE RESPOND TO MS. KELLY'S CRITIQUE OF YOUR WORKING CAPITAL OFFSET.

A. To ensure that we are working from a common base, I accept the percentages that Ms. Kelly sets forth for UGI Gas' aging buckets. I set forth a revised Schedule for a working capital adjustment based on those numbers in Schedule RDC-1SR (page 1 of 2). This Revised Schedule should replace and supplant my original Schedule RDC-1. Accepting Ms. Kelly's aging bucket numbers reduces my proposed working capital adjustment for CAP Credits to 6.9%. Accepting those numbers allows us to focus on the policy differences presented by Ms. Kelly.

Q. WOULD YOU ALSO ACCEPT MS. KELLY'S FIGURES FOR PURPOSES OF CALCULATING A WORKING CAPITAL OFFSET FOR ARREARAGE FORGIVENESS?

A. Yes. Accepting Ms. Kelly's aging bucket numbers reduces my proposed working capital adjustment for arrearage forgiveness to 45.7%. I have set forth this revision in Schedule RDC-1SR (page 2 of 2).

Q. PLEASE EXPLAIN WHY YOU DO NOT INCLUDE A CURRENT BILL COMPONENT IN YOUR CALCULATION?

A. Effectively, I do include a current bill component. I assess the difference in the extent to which bills are overdue. To the extent that there is a difference in the percent of accounts overdue, which Ms. Kelly expressly said she agreed with (Statement 2R, at 40:9), the current bills are taken into account.

Q. PLEASE EXPLAIN WHY IT IS APPROPRIATE TO ADD 30 DAYS TO EACH AGING BUCKET?

A. Ms. Kelly proposes to add 20 days rather than 30 days to the midpoint of each aging bucket. That would not result in reaching the mid-point of each aging bucket. To get from the mid-point of one aging bucket to the mid-point of the next aging bucket, it is necessary to add 30 days.

Moreover, for current bills, even though the due date may be set at Day 20, UGI does not report arrearages beginning at Day 21. According to BCS, " the PUC considers day zero to be the bill due date and the applicable regulations require companies to report arrearages *beginning at 30 days overdue*." (BCS, 2014 Report on Universal Service and Collection Practices, at page 54). UGI reports that it does not vary from the BCS interpretation that bills become overdue at Day 30 (Id.), not at Day 21 as argued by Ms. Kelly.

Q. PLEASE EXPLAIN WHY IT IS APPROPRIATE TO USE 210 DAYS AS THE INCREMENTAL AGE OF THE OVER-120 DAY AGING BUCKET.

A. Ms. Kelly begins with the statement that an account is written-off 110 days *after the final bill*, unless the customer is on a payment plan. (Statement 2R, at 41) (emphasis added). She later mistakenly changes that statement to say that UGI Gas writes off accounts 110 days *after the bill due date*. (Statement 2R, at 43) (emphasis added). That's not correct; her first statement was correct. Ms. Kelly, for example, even later states that "*inactive debt* is 'written off' at 110 days." (Statement 2R, at 22) (emphasis added). Ms. Kelly's reference to write-offs 110 days after the bill due date is simply wrong.

A UGI Gas account does not even become inactive until terminated or discontinued, irrespective of the age of arrears. (BCS, 2014 Report on Universal Service and Collection Practices, at 55). According to BCS data, the average active low-income customer in arrears is roughly six bills-behind; the average active residential customer in arrears is roughly 5.3 bills-behind.[2] Based on that BCS data, the incremental age I use for the top aging bucket is eminently reasonable.

Q. PLEASE EXPLAIN WHY IT IS APPROPRIATE TO USE THE EQUITY RETURN IN YOUR CALCULATION.

A. My offset accounts for changes on a between-rate-case basis. Changes in Company expenses on a between-rate-case basis occur at the equity level. Ms. Kelly's proposal to artificially reduce that return should be rejected.

[2] Bills-behind is a metric developed by BCS to show how many months of bills resides in an unpaid balance. It can be used to estimate the age of an arrearage when the precise aging of accounts for that arrearage is not available.

Q. PLEASE EPXLAIN WHY IT IS INAPPROPRIATE TO ELIMINATE THE ANNUALIZATION FACTOR.

A. Eliminating the annualization would limit the offset to the average arrears in one average month. It would not take into account the flow of arrearages and payments over a full twelve-month period. Eliminating the annualization to determine an average one month impact would understate what the offset should be over the course of a full year.

Q. DO YOUR SAME CONCLUSIONS APPLY TO MS. KELLY'S DISCUSSION OF A WORKING CAPITAL OFFSET FOR ARREARAGE FORGIVENESS AS WELL?

A. Yes. In fact, Ms. Kelly simply incorporates her same critiques for the working capital offset for arrearage forgiveness that she had advanced for the working capital offset for CAP Credits. (Statement 2R, at 44 – 45). They should be rejected for the same reasons.

Q. WHAT IS YOUR ULTIMATE CONCLUSION?

A. Accepting Ms. Kelly's distribution of arrearages over aging buckets, I modify my proposed working capital offset to 6.9% for CAP Credits and 45.7% for arrearage forgiveness.

Part 2. Response to UGI Gas Witness Theodore Love.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to the Rebuttal Testimony of Theodore Love (Statement 11R) regarding energy efficiency for low-income customers and for multi-family buildings.

Q. WHAT IS MR. LOVE'S PRIMARY RESPONSE TO YOUR TESTIMONY REGARDING LOW-INCOME ENERGY EFFICIENCY PROGRAMS?

A. Mr. Love argues that "low-income customers are ***allowed*** to participate in any of the programs available to residential customers" and that "there is no *per se restriction preventing* low-income customers from participating." (Statement 11R, at 21) (emphasis added). Mr. Love never disputes the fact that due to market barriers unique to the poor, low-income customers are *effectively* barred from participating in the Company's proposed Energy Efficiency and Conservation (EE&C) programs. As a result, UGI Gas is using low-income rates to fund programs that low-income customers have no effective opportunity to participate in or take advantage of.

Q. PLEASE RESPOND TO MR. LOVE'S COMMENTS ABOUT THE SIGNIFICANCE OF LIURP.

A. Mr. Love states that he disagrees with me that the Company's EE&C Plan should specifically target low-income customers. (Statement 11R, at 21). In stating this disagreement, however, it is not simply me that Mr. Love disagrees with, it is the Pennsylvania PUC. It was the Pennsylvania PUC that rejected the EE&C Plan for UGI Gas's sister utility (UGI-CPG). In so doing, it was the Pennsylvania PUC that said "low-income programs: CPG is to clearly describe what program measures are targeted toward low-income customers and how those program measures supplement the existing Low-Income Usage Reduction Program of CPG." (Colton Direct, OCA Statement 4, at 46 – 47). Mr. Love's argument that UGI Gas is adequately addressing the energy efficiency needs of low-income customers through LIURP is in direct conflict with this prior PUC decision.

Q. PLEASE RESPOND TO MR. LOVE'S COMMENT THAT UGI GAS HAS RECENTLY INCREASED ITS LIURP FUNDING.

A. Mr. Love testified that, notwithstanding the PUC's directive to UGI-CPG that that company's EE&C program have a program component specifically targeted toward low-income customers, and which component would supplement LIURP, there is no need for UGI Gas to have such a low-income component because the Company recently increased its LIURP funding by $450,000. (Statement 11R, at 21). As a result, Mr. Love urges that the Company is "sufficiently addressing" the energy efficiency needs of its low-income customers. (Statement 11R, at 21). This is an unreasonable conclusion to reach. The Company concedes that its additional LIURP funding will result in only 64 additional jobs being completed. (OCA-XXI-7). Even with this extra funding, the Company concedes further that it would take 59 years to reach all of the confirmed low-income customers on its system; this assumes that no housing unit would need to be re-weatherized in that 59 years. (OCA-XXI-17).

Q. WOULD ADOPTING A LOW-INCOME EE&C PROGRAM PERHAPS MAKE OTHER PROGRAMS NOT COST-EFFECTIVE?

A. No. The PUC has clear guidelines on how to ensure that EE&C programs, including low-income programs, are to be cost-effective. Nothing in my proposal would make the Company's EE&C portfolio, or any program within that portfolio, fail to meet the TRC test. The Company concedes that it installs LIURP measures that comply with the payback requirements set forth in PUC regulations. (OCA-XXI-18). No low-income program developed by Mr. Love for a Pennsylvania utility has failed to meet a cost-benefit test. (OCA-XXI-11). Moreover, Mr. Love has performed no cost-benefit test that would indicate that a low-income program would make the total portfolio, or any program within that portfolio, fail to meet a cost-benefit test. (OCA-XXI-13).

Q. PLEASE RESPOND TO MR. LOVE'S OBJECTION THAT THE COMPANY WOULD NOT BE ABLE TO COUNT SAVINGS FROM LOW-INCOME CUSTOMERS PARTICIPATING IN NON-LOW-INCOME SPECIFIC RESIDENTIAL PROGRAMS TOWARD A LOW-INCOME SAVINGS CARVE-OUT?

A. UGI Witness Love objects to providing specific programs for low-income customers through the UGI Gas EE&C Plan. According to Mr. Love, "the Company would be unable to count savings from low-income customers participating in non-low-income residential programs. This would require the Company to develop programs specifically for low-income customers. . ." (Statement 11R, at 22). Mr. Love is correct that the Company would be unable to count "savings from low-income customers participating in non-low-income programs" toward a low-income carve-out, but there is no low-income carve out for gas utilities that would affect my recommendations. The requirement that

UGI Gas "develop programs specifically for low-income customers," rather than being objectionable, is precisely what the Commission required of UGI-CPG, when it stated: "CPG is to clearly describe what program measures are targeted toward low-income customers and how those program measures supplement the existing Low-Income Usage Reduction Program of CPG." (Colton Direct, OCA Statement 4, at 46 – 47). Moreover, Mr. Love concedes that he has not worked with any other utility in Pennsylvania that "counts" savings from low-income customers participating in non-low-income programs toward a low-income savings carve-out. (OCA-XII-19). He has never filed testimony on behalf of a Pennsylvania natural gas or electric utility recommending that the utility count such savings toward a low-income savings carve-out. (OCA-XII-21).

Q. HOW DOES MR. LOVE RESPOND TO YOUR TESTIMONY REGARDING MULTI-FAMILY HOUSING?

A. Mr. Love responds to my multi-family housing testimony in much the same way he responds to my low-income testimony. He argues that "nothing in the EE&C Plan *expressly prohibits* customers living in multi-family buildings from participating in the available EE&C programs." (Statement 11R, at 22) (emphasis added). He later acknowledges, however, that "the Residential Retrofit Program is geared toward high usage customers" (Statement 11R, at 23), which has the effect of excluding multi-family customers. Mr. Love's argument that individually-metered customers in a multi-family building would avail themselves of funds from the New Construction Program (Statement 11R, at 23) is without merit. Individual residents of multi-family housing do not construct the multi-family building in which they live.

Mr. Love's argument that "the Nonresidential Retrofit Program is specifically designed to be able to address the more complex issues found in many multi-family buildings" (Statement 11R, at 23) does not acknowledge that the Nonresidential Retrofit Program would be available only to master-metered multi-family buildings, thus excluding most of the smaller multi-family buildings that are individually-metered.

Q. WHAT DO YOU CONCLUDE?

A. The recommendations I set forth in my Direct Testimony regarding low-income customers and multi-family buildings should be adopted.

Part 3. Response to UGI Witness Chris Ann Rossi.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to the Rebuttal Testimony of Company witness Chris Ann Rossi (Statement 12R) on various universal service issues.

Q. IS IT APPROPRIATE TO USE CAP PARTICIPANTS AS A SURROGATE FOR ALL LOW-INCOME CUSTOMERS IN ASSESSING WHETHER LOW-INCOME CUSTOMERS ARE LOW USE?

A. No. UGI Gas operates (in large part) a percentage of income program. By definition, such a program will target higher users. If confirmed low-income customers are low use, they have an affordable burden without participation in the Company's CAP. This is particularly true given that UGI Gas also targets payment-troubled customers; payment-troubled customers which tend to be higher users. Either of these targeting principles alone, but certainly both in combination, would lead to the CAP population being higher use customers than low-income customers generally.

Company witness Rossi states that my testimony is "predicated on the assumption that low income customers are low usage customers." (Statement 12R, at 8 – 9). On the contrary, using data provided by the Company, itself, in response to discovery, I presented hard data on the extent of low usage amongst confirmed low-income customers.

Ms. Rossi finally dismisses my discussion of the harms to low-income customers arising from the increased customer charge by saying that I had given "insufficient weight to the impact of the Company's CAP in mitigating the impact of a higher fixed customer charge on low-income customers." (Statement 12R, at 9). That statement completely ignores my testimony that "low use low-income customers disproportionately tend *not* to participate in CAP. As a result, the entire increase in bills to these customers will be borne by the customers themselves." (OCA Statement 4, at 28). Moreover, Ms. Rossi's testimony ignores the fact that UGI Gas has a CAP participation rate of substantially less than 20% of its confirmed low-income customers, which would be an even smaller percentage of its estimated low-income customers. (OCA Statement 4, at 37).

Q. PLEASE RESPOND TO MS. ROSSI'S DISCUSSION OF WHETHER LOW-INCOME CUSTOMERS ARE "HARMED" BY INCREASES IN THE UGI RATES, DRIVEN LARGELY BY INCREASES IN THE CUSTOMER CHARGE.

A. Ms. Rossi argues that low-income customers are not harmed by the Company's proposed increase in rates –driven largely by the increase in the customer charge—so long as the customers' bills are at or below the "range approved by the Commission's regulations." She argues that "those customers are still capped at the percentage of income level." (Statement 12R, at 11). A bill increase exceeding 30% for customers with usage less than 500 CCF (OCA Statement 4, Schedule RDC-3) certainly represents a "harm" to those customers. An annual bill increase of more than $105 for customers with usage between 500 and 999 CCF, representing a bill increase of more than 16% (OCA Statement 4, Schedule RDC-3), is a significant increase to those ratepayers. Not only would such bill increases harm those low-income customers, but, as I discuss immediately above, Ms. Rossi focuses exclusively on CAP participants despite the fact that between 80% and 90% of confirmed low-income customers (and an even higher percentage of estimated low-income customers) do not participate in CAP.

Q. PLEASE RESPOND TO MS. ROSSI'S DISCUSSION OF NON-CAP PARTICIPANTS.

A. Ms. Rossi states quite explicitly that she "disagree(s) with the conclusion that the proposed base rate increase will unfairly burden low-income customers not on CAP." (Statement 12R, at 12). She argues that the Company would solicit those customers for CAP or that these customers could contact the Company on their own. (Statement 12R, at

12). She acknowledges, however, that this would happen only "if the rate increase causes an increase in the number of payment-troubled customers." (Statement 12R, at 12). It is not clear how Ms. Rossi can conclude that the base rate increase could result in an increase in low-income payment troubles, but at the same time conclude that those customers are not "harmed." Ms. Rossi's testimony that an increase in low income payment troubles does not harm confirmed low-income customers is particularly troubling given that, according to BCS, UGI Gas disconnected 8,018 confirmed low-income customers for nonpayment in 2014, a 24.7% increase over the 6,429 confirmed low-income customers disconnected in 2012. (BCS, 2014 Report on Universal Service and Collections Performance, at 11). Moreover, UGI Gas reconnected only 40% of the confirmed low-income customers it disconnected. (Id., at 16). UGI Gas' rate of reconnections is decreasing. (Id.). UGI's percentage of confirmed low-income customers in debt has also increased from 31.4% in 2012, to 37.3% in 2013, to 39.1% in 2014.

Particularly in light of these historic trends for UGI's confirmed low-income customers, the PUC should reject Ms. Rossi's conclusion that low-income customers facing an increase in their UGI Gas bill are not harmed simply because those customers have faced circumstances in which they are harmed even more because "the cost of all other goods and services have increased substantially over the same time period." (Statement 12R, at 13). More low-income customers are being disconnected. Fewer of those low-income customers who are disconnected are being reconnected. More low-income customers are in debt. Moreover, these results are occurring even *before* rates to low-income customers are increased.

Q. PLEASE RESPOND TO MS. ROSSI'S COMMENTS ABOUT THE INTERACTION OF THE COMPANY'S PROPOSED RATE INCREASE AND THE DISTRIBUTION OF LIHEAP.

A. While I do not question that "the Company's LIHEAP outreach is a net benefit to its customers" (Statement 12R, at 15), that does not detract from the fact that the increased rates proposed by UGI Gas will reduce the spendable income of the confirmed low-income customers of UGI Gas by nearly $4.8 million. LIHEAP cannot replace this increased cost to confirmed low-income customers.

Ms. Rossi misunderstands the role of LIHEAP. LIHEAP is what is called a "block grant" program. Through a block grant, the state receives a fixed amount of dollars to distribute as benefits. When those dollars are exhausted, irrespective of unmet need, the program closes. At the federal level, since LIHEAP is a federally-funded program, LIHEAP is allocated state-by-state based on a formula set by statute. The "need" within a state, as manifested by changes in utility prices, is not part of the formula. Pennsylvania's LIHEAP allocation has substantially decreased in recent years. The Pennsylvania LIHEAP allocation since 2011 has been as follows:

Federal Fiscal Year	PA LIHEAP Allocation ($000)
2011	$280,478
2012	$209,458
2013	$184,642
2014	$175,603
2015	$204,099

The LIHEAP appropriations to Pennsylvania have clearly been trending downward in recent years. Even given the slight uptick in 2015 LIHEAP allocations to Pennsylvania, in other words, Pennsylvania's LIHEAP allocation is only 72% of what it was in 2011.

Even if what Ms. Rossi says is accurate, that "an increase in utility rates likely would, over time, result in an increase in the LIHEAP CASH benefit," (Statement 12R, at 16), that does *not* mean that more LIHEAP benefits would be available. Even if one were to accept Ms. Rossi speculation (and it is mere speculation) as accurate, the result would simply mean that fewer UGI Gas customers would be able to access LIHEAP at all. One cannot match an increasing per-customer benefit with decreasing appropriations and conclude that more LIHEAP benefits will be available to help offset the increased gas rates imposed on low-income UGI customers. If the LIHEAP cash grant increases on a per-recipient basis, while the state's LIHEAP allocation is decreasing, by definition, fewer customers will receive such cash grants.

Ms. Rossi cannot say with certainty that "an increase in utility rates likely would, over time, result in an increase in the LIHEAP CASH benefit." She does not know what the total LIHEAP allocation to Pennsylvania has been; what portion of that allocation is devoted to cash grants;[3] what portion of that allocation gets allocated to natural gas customers; or what number of Pennsylvania LIHEAP recipients apply their LIHEAP toward natural gas bills. (OCA-XXI-5). She has no information on the extent to which LIHEAP cash grants have increased or decreased when natural gas rates increased or decreased respectively. (OCA-XXI-6). Nor does she have any document from the Pennsylvania LIHEAP office stating that an increase or decrease in natural gas rates would result in an increase or decrease in LIHEAP benefits directed toward natural gas accounts. (OCA-XXI-6).

Q. PLEASE RESPOND TO MS. ROSSI'S SUPPORT FOR USING AN AVERAGE CAP PARTICIPATION RATE OF 10,000 IN APPLYING COST OFFSETS.

A. Ms. Rossi offers no new evidence or argument in support of the CAP participation level that UGI Gas proposes as a base for applying CAP cost offsets. She instead merely references Mr. Stoyko's direct testimony. (Statement 12R, at 21). I responded to Mr. Stoyko in my Direct Testimony and do not repeat that data and analysis here.

Q. PLEASE RESPOND TO MS. ROSSI'S DISCUSSION OF THE USE OF "GROSS" AND "NET" UNCOLLECTIBLES AS A BASIS FOR A BAD DEBT OFFSET.

A. Ms. Rossi's argument on the use of "net" uncollectibles is predicated on her assertion that customers who are disconnected are reconnected and reactivated. (Statement 12R, at 22). She asserts that "typically, customers who do not reconnect during the summer seek reconnection prior to the winter heating season at which time they pay their delinquency

[3] LIHEAP money is also spent on weatherization, on crisis grants, and on administrative costs. Moreover, some portion of a state's LIHEAP allocation is rolled-over until the next year as "start-up" money for the beginning of the year, given that LIHEAP appropriations historically have not been made until after the start of the program year.

and are reactivated." (Statement 12R, at 22). The numbers simply do not bear out what Ms. Rossi states "typically" occurs. Quite to the contrary, as I note above, UGI Gas reconnected only 40% of the confirmed low-income customers in 2014. (Id., at 16). Moreover, UGI Gas' rate of reconnections is decreasing. (Id.). Ms. Rossi's argument is based on incorrect factual information.

Q. DO YOU HAVE ANY FINAL COMMENTS ON THE REBUTTAL TESTIMONY OF MS. ROSSI?

A Ms. Rossi offered testimony in which UGI Gas agreed with certain revisions that I proposed in my Direct Testimony. Based on that agreement, I offer no further information on those issues. Issues that Ms. Rossi agreed that UGI would address include:

- My proposal to modify the Company's tariff to expand the information that documents a customer's income for purposes of eligibility for cold weather protections. (Statement 12R, at 29).
- My proposal to clarify tariff language to reflect the fact that the Company will not require any provision of customer information to prove income if the customer has established income within the past 12 months through receipt of LIHEAP or if the customer is currently participating in CAP. (Statement 12R, at 29).
- My proposal to revise tariff language to clarify that the Company will accept annualized 30-day income (rather than requiring annual income) in applying cold weather protections. (Statement 12R, at 29).

Q. **HAS MS. ROSSI OFFERED ANY OTHER CUSTOMER SERVICE MODIFICATION TO ADDRESS ISSUES YOU RAISED IN YOUR DIRECT TESTIMONY?**

A. Yes. While these proposals were not specifically offered in my Direct Testimony, they adequately and appropriately address issues that I raised in my Direct Testimony:

- To send collection notices only to customers with unknown income or with income known to exceed 250% of Poverty Level, thus not requiring a previously confirmed low-income customers to re-certify or re-verify income for purposes of cold weather protections. (Statement 12R, at 30).
- To modify the manner in which UGI Gas reports deferred payment plans to BCS to conform UGI Gas reporting to the reporting of other Pennsylvania utilities. (Statement 12R, at 17-18).

I accept these two additional proposals as a reasonable resolution of the issues that I raised in my Direct Testimony.

Part 4. Response to CAUSE-PA Witness Mitchell Miller.

Q. **PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.**

A. In this section of my testimony, I respond to Mr. Miller's Rebuttal Testimony to the extent that he responds to issues that I raised in my Direct Testimony. There are three major issues I wish to address.

First, I absolutely agree with Mr. Miller when he states that the collaborative process I recommend should not be a barrier or impediment to the "specific aspects of UGI's policies and procedures with respect to the identification of low income customers and its CAP enrollment that can be adopted without a collaborative." (CAUSE-PA Statement 1-R, at 9). The purpose of a collaborative is to help identify those changes that could and should be made. To the extent that Mr. Miller has already identified specific changes that could and should be made, a collaborative should not impede their adoption.

Second, Mr. Miller states the targeting I recommended in my Direct Testimony "should be reversed." I absolutely agree that "if a customer is low income, and is in arrears, they are necessarily eligible for CAP and should be targeted for CAP enrollment." (CAUSE-PA Statement 1R, at 9). I also agree with Mr. Miller's reasoning when he states, in relevant part, that "payment arrangements –while helpful at avoiding imminent termination—do nothing to address the unaffordability of rates. . .Thus, confirmed low-income customers not in CAP should only be targeted for payment arrangements if the customer determines that they do not wish to enroll in CAP or are otherwise ineligible for CAP."

Finally, I agree with Mr. Miller when he states that referring low income customers with arrears to budget billing "is. . .inappropriate unless combined with CAP." (CAUSE-PA Statement 1R, at 10). I agree that "rather than target low income households for enrollment in budget billing, UGI should target its confirmed low income population for enrollment in CAP. . ." (CAUSE-PA Statement 1R, at 10).

Q. DO YOU PLACE ANY CAVEATS ON THE EXTENT OF YOUR AGREEMENTS EXPRESSED ABOVE WITH MR. MILLER?

A. Yes. Having set forth my agreement with Mr. Miller as he applies the recommendations of my Direct Testimony to CAP-eligible customers,[4] I note that my recommendations on budget billing were not limited exclusively to low-income customers. I reaffirm and reassert my conclusion, based on the data and analysis presented in my Direct Testimony, that for non-low-income customers, "I would recommend that UGI not exclude customers on arrears from enrolling in budget billing. I would further recommend that UGI adopt budget billing as an affirmative strategy through which to reduce the impacts of cold weather arrears (both accounts in arrears and dollars of arrears)." (OCA Statement 4, at 45) (footnotes omitted).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

[4] In referencing Hardship Fund customers, I would note that not all Hardship Fund recipients qualify for CAP.

Colton Schedules

Schedule RDC-1SR
(page 1 of 2)

Without CAP	Annual CAP Credit	Arrears 1-30	31-60	61-90	91-120	121+	Total
CAP Credit	$100						
Number of participants	1						
Total current bill	$100	$100	$100	$100	$100	$100	
Percent low-income bills in arrears (BCS)	18.5%						
Total bill minus percent bills in arrears by aging	81.5%	5%	4%	3%	1%	6%	
Unpaid from current bill		$5	$4	$3	$1	$6	
Curent bill (in increments of $100)	0.0	0.0	0.0	0.0	0.0	0.1	
Working capital (wkg cap until charge-off) per $100 current bill	$5.87	$17.69	$29.62	$41.67	$53.84	$84.79	
Working capital savings--current bill charged off	$0.00	$0.85	$1.10	$1.08	$0.60	$5.17	$8.80

With CAP	Annual CAP Credit	1-30	31-60	61-90	91-120	121+	Total
Current bill	$100						
Number of participants	1						
Total current bill	$100	$100	$100	$100	$100	$100	
Percent residential bills in arrears (1 minus coverage)	4.4%						
Total bill minus percent bills in arrears by aging	96%	2%	1%	1%	0%	1%	
Unpaid from current bill		$2	$1	$1	$0	$1	
Curent bill (in increments of $100)	0.0	0.0	0.0	0.0	0.0	0.0	
Working capital (wkg cap until charge-off) per $100 current bill	$5.87	$17.69	$29.62	$41.67	$53.84	$84.79	
Working capital savings--current bill (charged off and in arrears)	$0.00	$0.28	$0.26	$0.24	$0.12	$0.96	$1.85

Wkg cap as pct of bill: no CAP	9%
Wkg cap as pct of bill: with CAP	2%
CAP credit working capital savings	6.9%

Schedule RDC-1SR
(page 2 of 2)

Without CAP	Annual CAP Credit	Arrears 1-30	31-60	61-90	91-120	121+	Total
CAP Credit	$100						
Number of participants	1						
Total current bill	$100	$100	$100	$100	$100	$100	
Percent low-income bills in arrears (BCS)	100.0%						
Total bill minus percent bills in arrears by aging	0.0%	26%	20%	14%	6%	33%	
Unpaid from current bill		$26	$20	$14	$6	$33	
Curent bill (in increments of $100)	0.0	0.3	0.2	0.1	0.1	0.3	
Working capital (wkg cap until charge-off) per $100 current bill	$5.87	$17.69	$29.62	$41.67	$53.84	$84.79	
Working capital savings--current bill charged off	$0.00	$4.60	$5.92	$5.83	$3.23	$27.98	$47.57

With CAP	Annual CAP Credit	1-30	31-60	61-90	91-120	121+	Total
Current bill	$100						
Number of participants	1						
Total current bill	$100	$100	$100	$100	$100	$100	
Percent residential bills in arrears (1 minus coverage)	4.4%						
Total bill minus percent bills in arrears by aging	96%	2%	1%	1%	0%	1%	
Unpaid from current bill		$2	$1	$1	$0	$1	
Curent bill (in increments of $100)	0.0	0.0	0.0	0.0	0.0	0.0	
Working capital (wkg cap until charge-off) per $100 current bill	$5.87	$17.69	$29.62	$41.67	$53.84	$84.79	
Working capital savings--current bill (charged off and in arrears)	$0.00	$0.28	$0.26	$0.24	$0.12	$0.96	$1.85

Wkg cap as pct of bill: no CAP	48%
Wkg cap as pct of bill: with CAP	2%
CAP credit working capital savings	45.7%

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2015-2518438
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA St. No. 4-SR, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: ______________________
Roger D. Colton

Consultant Address: Fisher, Sheehan & Colton
34 Warwick Road
Belmont, MA 02478

DATED: May 25, 2016

OCA Statement No. 5
6/2/16 [illegible]

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	**Docket No. R-2015-2518438**
v.	:	
	:	
UGI UTILITIES, INC. – GAS DIVISION	:	

DIRECT TESTIMONY OF

JAMES S. GARREN

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

APRIL 12, 2016

DIRECT TESTIMONY AND EXHIBITS
OF JAMES S. GARREN

A. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is James S. Garren. I am an analyst with the economic consulting firm of Snavely King Majoros & Associates, Inc. ("Snavely King").

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Attachment A is a summary of my qualifications and experience.

Q. Q. PLEASE DESCRIBE YOUR BACKGROUND IN UTILITY DEPRECIATION.

A. Since my employment at Snavely King in 2010, I have participated as an analyst in approximately 30 separate depreciation studies of electric, gas and water utilities on behalf of the firm's clients, most of which are state commissions or state-funded consumer advocate agencies. In that role, I have worked closely with the firm's principals in performing life and net salvage analyses, calculation of depreciation rates, and preparation of testimony. Additionally, I am familiar with the Company's proprietary depreciation software, the Snavely Comprehensive Investment Analysis System ("**SCIAS**"). I am also recognized as a Certified Depreciation Professional by the Society of Depreciation Professionals.[1]

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Pennsylvania Office of Consumer Advocate

Q. WHAT IS THE OBJECTIVE OF YOUR TESTIMONY?

A. In Docket No. R-2015-2518438 docketed with this Commission, UGI Utilities, Inc. – Gas Division (the "**Company**" or "**UGI**") submitted a filing for approval of changes in its depreciation rates. The objective of my testimony is to detail my analysis of the Company's depreciation study with regard to average service lives and net salvage.

Q. CAN YOU EXPLAIN THE SIGNIFICANCE OF DEPRECIATION IN THE CONTEXT OF A RATE CASE?

A. Depreciation is important in the ratemaking context because it involves a direct pass-through of cash from the customers to the utility that the utility retains for non-utility

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[1] "The Society of Depreciation Professionals was organized in 1987 to recognize the professional field of depreciation analysis and individuals contributing to this field; to promote the professional development and professional ethics of practitioners in the field of depreciation analysis; to collect and exchange information about depreciation analysis; and to provide a national forum of programs and publications concerning depreciation." http://www.depr.org/?page=AboutUs . For certification, an applicant must have at least 5 years of full time professional depreciation experience, at least 2 years of which must be in the area of depreciation administration. Among other requirements, the applicant must pass a two part (Technical and Ethics) closed book examination which includes questions about, *inter alia*, Plant and Reserve Accounting, Life Analysis Concepts, Life Analysis Using Actuarial Models, Life Analysis Using Simulation Models, Salvage and Cost of Retiring Analysis, Technology Forecasting and Depreciation Calculations. http://www.depr.org/?page=Certification

purposes. Rate base/rate of return ratemaking assumes that the utilities' investors make the investment in plant and equipment, and customers provide a return on, and return of, the capital over the service life of the plant or equipment.

In practice, this means that depreciation expense provides a company with a source of free cash flow. This can incentivize a company to overcharge for depreciation by understating the period over which the depreciation is allocated, or overstating a future cost of removal allowance. In theory, these kinds of overcharges should be corrected over the life of a utility's plant investment. However, because utilities have constantly growing plant in service, these forms of accelerated depreciation essentially never even out, and current customers are consistently overcharged for current plant in service.

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONJUNCTION WITH THIS TESTIMONY?

A. Yes, I am sponsoring four exhibits.

Exhibit JSG-1: Comparison of Recommended Lives and Curves

Exhibit JSG-2: Calculation and Comparison of OCA Depreciation Rates

Exhibit JSG-3: OCA Life Analysis

Exhibit JSG-4: Calculated Reserve

Q. WHAT ARE YOUR CONCLUSIONS REGARDING UGI'S DEPRECIATION?

A. Primarily, I have concluded that Mr. Wiedmayer has significantly understated the average service lives of its gas division accounts. I conclude that Mr. Wiedmayer's depreciation study is insufficient. He excludes significant data from the graphical representation of his proposed average service lives and curves. He also excludes the results of his curve fitting analysis from the depreciation study. I also conclude that the Company's net salvage methodology is reasonable.

B. SUMMARY

Q. WHAT INFORMATION HAVE YOU REVIEWED IN PREPARATION FOR THIS TESTIMONY?

A. I have reviewed the prefiled written direct testimonies and exhibits of Mr. John Wiedmayer of Gannett Fleming, who presents a depreciation study of UGI's distribution and general plant which he prepared. Upon examination of his testimony and the depreciation study, I prepared numerous data requests which were propounded to UGI by the OCA at my request. I have now had the opportunity to review UGI's responses to these data requests as well as the documents attached to UGI's filing. In response to some of the data requests, we have been provided the depreciation data used by Mr. Wiedmayer to perform his studies. Utilizing this data, and my own analysis, I have proposed adjustments to the depreciation rates and accruals utilized for plant depreciation.

Q. WOULD YOU PLEASE SUMMARIZE THE TOTAL IMPACT OF THE AVERAGE SERVICE LIFE ADJUSTMENTS YOU HAVE MADE?

Yes. Please refer to the table below for comparison of the depreciation rates and expenses:

TABLE 1
Summary of Depreciation Rates and Expenses

($) in Millions
Based on December 31, 2016

	Wiedmayer Rate	Expense	OCA Rate	Expense
GAS				
Distribution	2.10%	$32,551,703	1.63%	$25,154,955
General	3.91%	$1,876,943	3.76%	$1,804,760
Allocated Plant	7.58%	$4,401,798	7.03%	$4,073,169

My testimony will primarily address Mr. Wiedmayer's recommendations regarding average service lives for UGI's gas plant. However, I will also be addressing UGI's utilization of Equal Life Group ("ELG") remaining life calculations, UGI's theoretical reserve, and Mr. Wiedmayer's proposed treatment of net salvage.

C. DISCUSSION OF AVERAGE SERVICE LIFE ANALYSIS.

Q WOULD YOU PLEASE SUMMARIZE YOUR FINDINGS WITH RESPECT TO UGI'S DEPRECIATION?

A. Yes. Based on my analysis of the available data, I have identified issues with eleven of the average service lives and curve shapes proposed by Mr. Wiedmayer.

Q. DO YOU HAVE A SCHEDULE THAT SHOWS YOUR PROPOSED SERVICE LIVES AND CURVES?

A. Yes. I have prepared Exhibit JSG-1 which sets forth our firm's recommended lives and curves compared to the lives and curves selected by Mr. Wiedmayer. Additionally,

Exhibit JSG-2 sets forth the depreciation rates and expenses proposed by Mr. Wiedmayer and myself for plant investment.

Q. WOULD YOU PLEASE DESCRIBE THE PROCESS AND PROCEDURES OF ACTUARIAL ANALYSIS?

A. Yes. I have analyzed UGI's mass property accounts using an actuarial life analysis process called the retirement rate method. The retirement rate method is an actuarial technique used to study plant lives, much like the actuarial techniques used in the insurance industry to study human lives. It requires a record of the dates of placement (birth) and retirement (death) for each asset unit studied. It is the most sophisticated of the statistical life analysis methods because it relies on the most refined level of data. Aged retirements and exposures data from a company's records are used to construct an observed or original life table ("**OLT**"). Importantly, the OLT represents the life of a single average vintage. The analysis smoothes and extends the OLT by fitting a family of 31 standardized survivor curves ("**Iowa Curves**"). The curve-fitting uses the least squared differences approach to find a best fit life for each curve.[2] Numerous interactive calculations are required for a retirement rate analysis. In the end, the analysis produces a life and Iowa curve best fit for a single average vintage.

[2] Sum of least squared difference is a common means of fitting curves (in this case the Iowa curves) to a set of data (in this case the OLT data). The idea is essentially that the difference between each point of data and a point on a line is squared, and the square of all of those differences is summed to provide the total difference between the set of data and the line. The line that produces the least difference from the set of data is considered the "best fit." The purpose of squaring the difference is to make sure that negative differences contribute to the overall difference, rather than canceling out positive differences.

Q. WHAT ARE IOWA CURVES?

A. An Iowa curve is a surrogate or standardized OLT based on a specific pattern of retirements around an average service life. The Iowa curves were devised over 60 years ago at Iowa State University. The curves provide a set of standard patterns of retirement dispersion. Retirement dispersion merely recognizes that accounts are comprised of individual assets or units having different lives. Retirement dispersion is the scattering of retirements by age for the individual assets around the average service life for the entire group assets. If one thinks in terms of a "bell shaped" curve, dispersion represents the scattering of events around the average.

There are left-skewed, symmetrical and right-skewed curves known, respectively, as the "L curves," "S curves" and "R curves." There is also a set of Origin Modal ("**O**") curves which are essentially negative exponential curves.[3] A number identifies the range of dispersion. A low number represents a wide pattern and a high number a narrow pattern. The combination of one letter and one number (e.g. 5S0 life and curve) defines a

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[3] In mathematics, the logarithm of a number is the exponent to which another fixed value, the base, must be raised to produce that number. For example, the logarithm of 1000 to base 10 is 3, because10 to the power 3 is 1000 (as $1000 = 10 \times 10 \times 10 = 10^3$). More precisely, for any two positive real numbers b and x where b is not equal to 1, the logarithm of x to *base* b, denoted $\log_b(x)$, is the unique real number y such that

$$b^y = x.$$

For example, as $64 = 4^3$, we have

$$\log_4(64) = 3$$

The inverse of an exponential function is a logarithmic function and the inverse of a logarithmic function is an exponential function.

dispersion pattern. The combination of an average service life with an Iowa curve provides a survivor curve depicting how a group of assets will survive, or conversely be retired, over the average service life.

The table below contains curves with a 5 year life, S0 shape, and 10 year life, S0 shape. I have included these two combinations to demonstrate different iterations with the same curve. The percent surviving represents the amount surviving at each age interval shown in the first column. The 5S0 life and curve sums to the five-year average service life, while the 10S0 life and curve sums to a ten-year average service life.

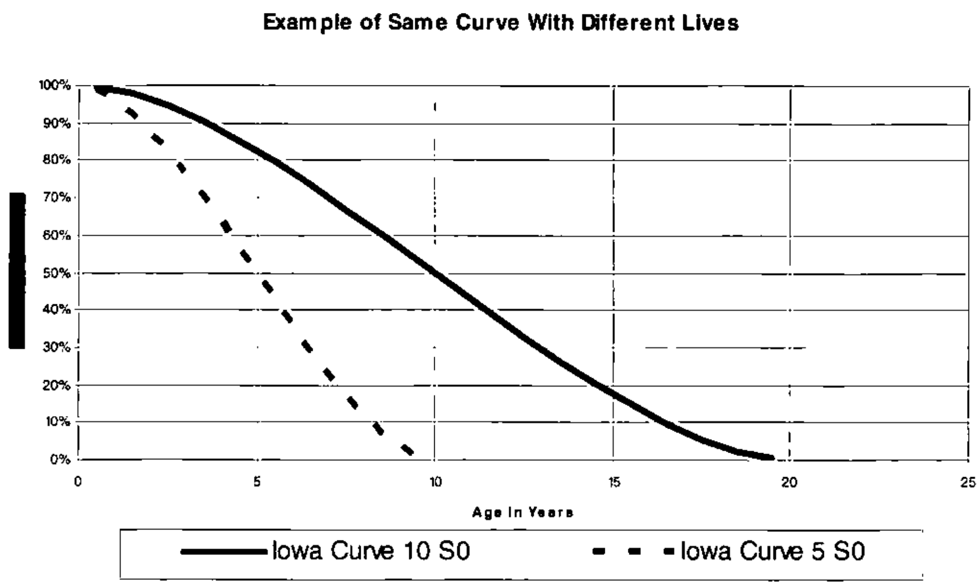
Table 2

Survivor Curves

Age	5 S0 Curve Percent Surviving	10 S0 Curve Percent Surviving
0.5	0.99	1.00
1.5	0.92	0.98
2.5	0.83	0.94
3.5	0.70	0.90
4.5	0.57	0.85
5.5	0.43	0.80
6.5	0.30	0.74
7.5	0.17	0.67
8.5	0.08	0.60
9.5	0.01	0.53
10.5		0.47
11.5		0.40
12.5		0.33
13.5		0.26
14.5		0.20
15.5		0.15
16.5		0.10
17.5		0.06
18.5		0.02
19.5		0.00
Total	**5.00**	**10.00**

These are called "curves" because when plotted on charts with the x-axis representing "age" and the y-axis representing "percent surviving" they appear as shown below in Graph 1.

Graph 1



Q. DO YOU NECESSARILY FIT ALL OF THE AVAILABLE DATA POINTS TAKEN FROM THE OLT?

A. No. In many cases it is appropriate to disregard many of the oldest aged data. This is because actuarial data that the company keeps often has long lived assets that are not statistically significant or often represent anomalies, such as retirements that were never recorded. This process, which is represented in the graphs below, is called a "T-cut". While there is no hard and fast rule for where a T-cut is appropriate, I will generally make a T-cut where the remaining data diverges from the established pattern of retirements seen to that point.

As will be discussed in detail below, the decision to make a T-cut, and at what point in the data set to make the cut, is one of the most important subjective elements to an actuarial analysis. In most cases, making a "larger" T-cut, and therefore fitting to less of the actuarial data, will result in a shorter estimated average service life, because you are disregarding the longest lived assets in the set of data.

Additionally, if data points are eliminated from an OLT with a limited data set, it can result in an inconclusive analysis. Typically, the portion of an Iowa curve between 85% surviving and 15% surviving most distinguishes one curve from another. If a T-cut eliminates too much of the OLT data, the matching of that data to an Iowa curve will be ambiguous and misleading.

Q. CAN YOU SUM UP WHY IOWA CURVES ARE IMPORTANT TO DEPRECIATION ANALYSIS?

A. Yes. Simply put, Iowa curves are how we express the expected patterns of retirement for a given account. They are used to calculate the remaining life for each account. Depending on the surviving vintage balances using a L5 dispersion curve as opposed to a R5 dispersion curve can make a difference of several years to the remaining life of the account. Ultimately, depreciation accruals for plant investment are calculated from remaining lives, so it is important, in addition to selecting the correct average service life, to select the correct Iowa curve.

Q. DID YOU ENCOUNTER ANY ISSUES WITH THE DEPRECIATION DATA PROVIDED TO OCA BY UGI?

A. Yes. The available depreciation data was sufficient to perform reliable actuarial analyses for most accounts. However, there are numerous accounts where, in my judgment, there is insufficient retirement data available to reach a meaningful conclusion regarding the average service life of the account based on actuarial analyses.

Q. DO YOU DISAGREE WITH ANY ASPECT OF MR. WIEDMAYER'S DEPRECIATION STUDY?

A. Yes. Mr. Wiedmayer's depreciation study, as presented in UGI's filing is incomplete and insufficient to justify Mr. Wiedmayer's service life recommendations. Part VI of UGI Gas Exhibit C (Future) purports to present the service life statistical analysis of historical depreciation data. However, this is only a narrow portion of the complete life analysis conducted by Mr. Wiedmayer.

Q. IN WHAT WAY IS THE PRESENTATION OF STATISTICAL LIFE ANALYSIS PRESENTED IN PART VI INCOMPLETE?

A. Part VI of the Depreciation Study provides, for each account Mr. Wiedmayer studied, a graph comparing his proposed average service life and curve superimposed on a subset of points corresponding to the "Pct Surv Begin of Interval" shown in the Original Life Table ("OLT") which follows the graph for each account. However, each graph presented in the depreciation study only plots a percent surviving.

Taking UGI's largest account, Account 380 – Services as an example, Mr. Wiedmayer includes the percent surviving through approximately age 50.5.[4] However, the OLT continues well past age 50 with the final retirement for this account taking place at age

[4] UGI Gas Exhibit C (Future), page VI-32.

120.5.[5] This leaves approximately 70 years of data uncharted on Mr. Wiedmayer's graph. As a result of this truncation, it is more difficult to evaluate the appropriateness of Mr. Wiedmayer's proposed average service life and Iowa curve visually.

Q. IS THE DEPRECIATION STUDY INCOMPLETE IN ANY OTHER REGARD?

A. Yes. Mr. Wiedmayer has provided OLTs as part of his depreciation study, however, that is only a part of a statistical life analysis. As discussed above, in order to arrive at a life indication based on OLT survivor data, it is necessary to match that data to an average service life and an Iowa curve.

Ideally, this is done through mathematical fitting analysis, which compares each point on the OLT to each point on the curve to arrive at a sum of squared differences. The life and curve pair that produces the lowest sum of squared difference is considered the "best fit" to that set of data.

Mr. Wiedmayer's Depreciation Study does not present any results of mathematical curve fitting analysis for review.

Q. WHAT IS THE NET EFFECT OF THESE OMISSIONS ON MR. WIEDMAYER'S STUDY?

A. Both the truncation of the data, and the exclusion of any mathematical fitting analysis from the study have the effect of making it substantially more difficult to evaluate the appropriateness of the average service lives and Iowa curve shapes that he has selected for each account.

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[5] Ibid, page VI-35.

Truncation of the OLT data makes it more difficult to visually see how good a fit the data is to Mr. Wiedmayer's proposed life and curve. Exclusion of the curve fit analysis makes it impossible to compare Mr. Wiedmayer's selected life and curve to other possible life and curve combinations.

Q. HAS MR. WIEDMAYER CONDUCTED CURVE FITTING ANALYSIS IN PREPARATION OF HIS DEPRECIATION STUDY?

A. Yes. In response to Attachment 2 to the Company's response to OCA Set VI DR 49, Mr. Wiedmayer provided his complete life analysis, including his curve fitting analysis. Gannett Fleming's curve fitting analysis utilizes Residual Measure as its indicator of fit. Residual Measure is a derivative of the sum of squared differences, with the lowest Residual Measure indicating the best fit.

Table 3

UGI Proposed lives and curves v. Wiedmayer's best fit survivor curves

ACCOUNT		UGI Proposed Survivor Curve	Wiedmayer Best Fit Survivor Curve
(1)		(2)	(3)
DISTRIBUTION PLANT			
375	STRUCTURES AND IMPROVEMENTS	55-S0.5	63.1-L0.5
376.1	MAINS - PRIMARILY STEEL	72-R2.5	87.3-L2
376.2	MAINS - CAST IRON	70-R1	82.1-L0.5
378	MEAS. AND REG. STATION EQUIPMENT – GENERAL	50S0.5	61.9-L0
379	MEAS. AND REG. STATION EQUIPMENT - CITY GATE	40-R3	64.1-L1
380	SERVICES	47-R2	54-L1
381	METERS	47-R1.5	36-R1
385	IND. MEAS. AND REG. STATION EQUIPMENT	47-R2	144.6-O1
387	OTHER EQUIPMENT	47-L2	45.8-L0
GENERAL PLANT			
392.1	TRANSPORTATION EQUIPMENT – CARS	7-L2.5	6.3-S2

392.2	TRANSPORTATION EQUIPMENT – TRUCKS	11-L3	10.4-L3
392.4	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	14-L4	13.6-L3
396	POWER OPERATED EQUIPMENT	14-L2.5	18.5-O4

The above table shows Wiedmayer's best fitting curves for the 1960-2011 band life analysis for each of the accounts studied as part of Mr. Wiedmayer's depreciation study.

Q. HAVE YOU PROVIDED THE RESULTS OF YOUR MATHEMATICAL FITTING ANALYSYS?

A. Yes, in Exhibit JSG-3, a page entitled "Best Fit Curve Results" for each account studied shows our mathematical curve fitting analysis. Except in limited cases, the "best fit" here defined as the life-curve combination with the least sum of squared differences has been selected as our proposed average service life and retirement dispersion curve for that account. These differ from the best fits resulting from Mr. Wiedmayer's analysis because I am using the full band of depreciation data available, rather than only the data from 1960 forward.

Q. CAN YOU WALK THROUGH THE ANALYSIS OF A PARTICULAR ACCOUNT AS AN EXAMPLE?

A. Yes. Taking Account 380, and looking at the Observed Life Table Results, we can see the age in the first column, the exposures at each age in the next column, followed by the retirements at each. Retirement ratio is simply retirements per age as a percentage of exposures. The survivor ratio is then 100%- the retirement ratio. Cumulative survivors are an iterative calculation that begins at 100% and then is multiplied by the previous year's survivor ratio to arrive at a forecast of the percent of exposures that would be likely to still be in service at that age. Cumulative survivors are equivalent to the "Pct

Surv Begin of Interval", which are then compared to the points on each Iowa curve by an algorithm to arrive at the best fit. For Account 380 – Services, the account with the lowest Sum of Squared Differences is a S1 curve with a 50 year average service life with a sum of squared differences of 444.878. Looking further down the curve fitting results, we can see that the best fit results for each curve shape fall around 50 years. On the next page, we can see the 50-S1 curve graphed against Mr. Wiedmayer's proposed 47-R2 curve. Both are plotted against the points in the complete cumulative survivors column of the OLT. Here, we can plainly see that the 50-S1 curve is a better fit to the data than the 47-R2 curve.

Q. ARE THERE INSTANCES WHERE THE MATHEMATICAL BEST FIT LIFE AND CURVE ARE NOT APPROPRIATE?

A. Certainly. The mathematical best fit is appropriate in most cases where the future depreciation can reasonably be expected to follow historical experience. However, this is not always the case. There are numerous factors that might lead a utility depreciation expert, familiar with the particular plant account for a given company for a given account, to deem that future depreciation expectations are different than historical experience. These factors, including major replacement or maintenance projects, differing life expectations of new technologies, or simply economic or engineering decisions of utility management might significantly affect the expectations for future retirement rates.

Q. IS IT THE CASE HERE WHERE THE MATHEMATICAL BEST FIT LIFE AND CURVE ARE INAPPROPRIATE?

No, Mr. Wiedmayer provides an elaboration on his recommendation of a 47-R2 for Account 380 - Services.[6] However, there is no suggestion of why the details provided make Mr. Wiedmayer's proposed average service life and curve more appropriate than the best fit to the historical data.

Q. FOR WHICH ACCOUNTS ARE YOU RECOMMENDING ALTERNATIVE LIVES AND CURVES?

A. I am proposing adjustments to accounts: 375 – Structures and Improvements; 376.1 – Mains, Primary Steel; 376.2 – Mains, Cast Iron; 378 – Measuring and Regulating Station Equipment – General; 379 – Measuring and Regulating Station Equipment – City Gate; 380 – Services; and 385 – Industrial Measuring and Regulating Station Equipment. Additionally, I have accepted Mr. Wiedmayer's proposal to utilize the average service life and curve from: Account 380 – Services for Accounts; 382 – Meter Installations; 383 – House Regulators; 384 – House Regulator Installations; and 386.1 – Other Property on Customers' Premises – Farm Taps.

Again, Exhibit JSG-1 provides a comparison of my proposed lives and curves with those proposed by Mr. Wiedmayer.

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[6] Ibid, page III-5-III-6.

D. EQUAL LIFE GROUP REMAINING LIFE CALCULATIONS

Q. WHAT IS MR. WIEDMAYER PROPOSING REGARDING THE CALCULATION OF REMAINING LIVES?

A. Mr. Wiedmayer proposes to utilize Average Service Life ("ASL") procedure for plant installed prior to 1982, and Equal Life Group ("ELG") procedure for plant installed in 1982 and thereafter.[7] This practice was initially accepted as part of the Company's 1984 rate filing.[8] The practice was not specifically addressed by the Commission's August 17, 1995 order accepting the stipulation in UGI's most recent rate case.

Q. CAN YOU DISCUSS THE RELATIVE MERITS OF ASL V. ELG?

A. The ELG procedure is a more precise application of the same life and retirement pattern assumed in the ASL procedure. The ELG procedure statistically disaggregates the anticipated retirements within the average vintage, and then establishes a separate individual depreciation rate for each of the assets within the average vintage.

Due to this precision, ELG is much more susceptible to errors resulting from forecasting inaccuracies. Because of this, ELG makes it necessary for the Company to file for annual updates to its average service lives in order to remain accurate. Given that UGI only performs service life studies every five years, ELG is not a good fit for UGI. Finally, ELG remaining life calculations tend to understate the remaining lives of recent vintages

[7] Ibid, page I-3.
[8] Response to OCA Set XVI, Question 1.

when not updated frequently. As a result, the practical effect of this disaggregation is higher depreciation rates.

Q. ARE YOU RECOMMENDING THE CONTINUED USE OF ELG?

A. No, I do not think it is the best interest of ratepayers for UGI to continue using ELG remaining lives.

E. DISCUSSION OF NET SALVAGE ANALYSIS AND CALCULATIONS

Q. HOW IS MR. WIEDMAYER PROPOSING TO COLLECT FOR NET SALVAGE?

A. Mr. Wiedmayer has proposed an amortization of incurred net salvage for the period 2012-2016, with estimated net salvage amounts for 2016. The average of the net salvage amounts for this period are then averaged to arrive at a net salvage accrual of $4,325,958.[9]

Q. IS THIS NET SALVAGE ACCRUAL METHODOLOGY APPROPRIATE?

A. Yes. This net salvage methodology is consistent with net salvage practices in Pennsylvania. Moreover, it accomplishes the goal of allowing the Company to account for its cost of removal, while ensuring that UGI's collection for cost of removal is tied to its actual incurred costs.

F. CALCULATED RESERVE

Q. WHAT IS A CALCULATED RESERVE CALCULATION?

A. Calculated reserve is an estimate of what a given company should have accrued for depreciation, given a particular set of life, curve, remaining life, and net salvage

[9] Ibid, page I-5.

parameters. It is used to determine whether a Company has, in the past, incidentally over collected or under collected for depreciation, based on the current best estimate of the depreciation parameters.

The utilization of remaining life depreciation accrual calculations theoretically ensures that both the Company is made whole for its investments, and that the ratepayer is not over-charged for those investments. However, from rate case to rate case, estimates of the appropriate rate of depreciation collection can change. Mr. Wiedmayer is proposing numerous changes to the Company's existing depreciation rates, which were determined in 1995.

Q. WHAT DOES MR. WIEDMAYER'S CALCULATED RESERVE CALCULATION SHOW?

A. As part of its filing requirements, Mr. Wiedmayer provided his estimate of the calculated accrued depreciation compared to the Company's book reserves for the periods ending 2015, 2016, and 2017.[10] The totals for each period are shown in the table below.

Table JSG-2

Year	Total Calculated Reserve	Total Book Reserve	Excess/(Deficiency)
(1)	(2)	(3)	(3)
2015	$425,070,731	$442,830,243	$17,759,512
2016	$434,116,843	$444,953,474	$10,836,631
2017	$451,217,978	$456,873,209	$5,655,231

[10] Attachment I-A-5, Pages 1-3.

Mr. Wiedmayer's calculated reserve comparison shows that by his own estimates UGI currently has had a book depreciation reserve excess. Given that it has been over two decades since UGI's last rate case, it is not unexpected that the Company would have a large excess or deficiency.

Q. HAVE YOU PERFORMED YOUR OWN CALCULATED RESERVE ESTIMATE?

A. Yes. Exhibit JSG-4 contains my calculated reserve calculation for 2017, using the life parameters that I am proposing for UGI. As a result of my utilization of longer average service lives than those proposed by Mr. Wiedmayer, my calculated reserve estimate shows a larger reserve excess of $85.5 million.

Q. WHAT DO YOU CONCLUDE ON THE BASIS OF THIS RESERVE EXCESS?

A. It is impossible to project the most appropriate depreciation rates over a long period of time. It is natural that any company will have reserve excesses or deficiencies. UGI's current reserve excess is very substantial. I am not recommending that UGI be required to amortize this excess back to ratepayers, because the reserve excess is only approximately 5% of UGI's overall plant in service. However, the Commission should require UGI to adopt longer average service lives in order to reduce its depreciation expense. By decreasing UGI's depreciation expense, its depreciation reserve should fall back into line with calculated reserves, and therefore reduce its reserve excess. The Commission should closely monitor the Company's depreciation reserve in its review of UGI's annual depreciation reports, and its full service life study reports every five years.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

OCA Statement No. 5

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	**Docket No. R-2015-2518438**
v.	:	
	:	
UGI UTILITIES, INC. – GAS DIVISION	:	

APPENDICES ACCOMPANYING THE

DIRECT TESTIMONY OF

JAMES S. GARREN

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

APRIL 12, 2016

James S. Garren

Experience

Snavely, King, Majoros, and Associates, Inc.

Consultant (2010-Present)

Mr. Garren provides expert witness testimony to clients, specializing in the area of depreciation. Mr. Garren also provides analytical support to SK clients and principals including quantitative and qualitative analysis, preparation of client presentations, and case management. Mr. Garren works primarily in the areas of depreciation but has also prepared exhibits for use in the revenue requirement, cost-allocation, rate design, and rate of return aspects of regulatory proceedings.

Mr. Garren is a member of, and has been made a Certified Depreciation Professional, by the Society of Depreciation Professionals.

Issue Advocacy Organization

State Policies Assistant 2009

Assisted with a wide variety of tasks including, but not limited to research, updating organization website with current news, extensive member/supporter communication, and database maintenance.

Binder and Binder, LLC

Client Advocate/Non-Attorney Representative 2007-2008

Mr. Garren's primary duties at Binder were legal writing; producing client and ALJ correspondence, case memoranda, expert witness interrogatories, and arguments in favor of appeal. From July 2007 acted as the company president's primary legal writer. In June of 2007, Mr. Garren became certified as a non-attorney representative. From that time, responsibilities included performing three to five Social Security Disability hearings per week.

Mr. Garren was also responsible for thoroughly developing medical and vocational evidence from the initial filing phase, through Administrative hearing.

Education

Marlboro College, Marlboro, Vermont, B.A. - Literature and Philosophy

Mr. Garren fulfilled Marlboro College's graduation requirement with a thesis on ethical issues in the works of Dostoevsky and Nietzsche. Exploring early post-modern ethical thinking in literature and philosophy.

James Shay Garren

PROJECTS AND APPEARANCES

Testified

In the Matter of: Georgia Power Company's 2013 Rate Case - Docket No. 36989

In the matter of the verified petition of Rockland Electric Company for approval of changes in electric rates, its tariff for electric service, and its depreciation rate. - BPU Docket No. ER13111135

Rule 42T Tariff Filing to Increase Rates and Charges and Proposed Charges in Depreciation Rates. West Virginia Case No. 15-0048-G-D.

Case No. 9355: In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates

In the Matter of Application of Maryland-American Water Company for Authority to Adjust its Existing Schedule Tariffs and Rates.

Assisted with Analysis and Testimony

Appalachian Power Company and Wheeling Power Company: Application to Change Depreciation Rates. West Virginia Case No. 14-1151-E-D.

Monongahela Power Company and The Potomac Edison Company Application to Change in Depreciation Rates. West Virginia Case No 14-0701-E-D.

Sandpiper Energy, Inc.-Application to Revise the Depreciation Rates and the Level of Depreciation Reserve, MD Case No. 9350.

In the Matter of Enmax Power Company's 2014 Distribution Tariff Application and 2014-2015 Transmission General Tariff. Appication NO.: 1609784 Proceeding ID NO.: 2739

Pacific Gas and Electric Company (PG&E) submits for filing, for Federal Energy Regulatory Commission (FERC or Commission) acceptance, proposed rate changes for wholesale and retail electric transmission rates shown in Appendices I, II and III of PG&E's Transmission Owner (TO) Tariff, FERC Electric Tariff Volume No. 5. ER13-2022

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service. Case 13-E-0030, Case 13-G-0031 & Case 13-S-0032

In the matter of the Application of Rocky Mountain Power for an Order authorizing a change in depreciation rates applicable to its depreciable electric property. Docket No. 20000-427-EA-13.

In the Matter of the *Alberta Utilities Commission Act,* S.A. 2007, c. A-37.2 and in the Matter of

James Shay Garren

ATCO Pipelines 2013-2014 General Rate Application Application 1609158; Proceeding ID 2322

Ameren Illinois Company Proposed Increase in Transmission Distribution Rates Docket Nos. ER13-312

Application of Kentucky Utilities Company for an Adjustment of its electric rates. Case No. 2012-00221

Application of Louisville Gas and Electric Company for an Adjustment of its electric and Gas rats, a certificant of public convenience and necessity, approval of ownership of gas service lines and risers, and a gas line surcharge. Case No. 2012-00222

In the matter of application of Michigan Consolidated Gas Company for approval of depreciation accrual rates proposed rates and charges for gas utility plant. Case No. U-16769

Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts, pursuant to General Laws Chapter 164, § 94, and 220 C.M.R. §§5.00 et seq. D.P.U. 12-25

In the Matter of The Investigation Into The Reasonableness of Washington Gas Light Company's Existing Rates and Charges For Gas Service Formal Case No. 1093

New Jersey American Water Company - 2011 RATE CASE
BPU Docket No. WR11070460

In The Matter Of The Application Of Artesian Water Company, INC. For a Revision Of Rates PSC Docket No. 11-207

Pacific Gas and Electric Company Type of Filing Code 80: Compliance Filing to Revise Rates Pursuant to Order Accepting and Suspending Proposed Tariff Changes PG&E FERC Electric Tariff Volume Docket No. 5 ER12-2701-000

PENNSYLVANIA PUBLIC UTILITY COMMISSION v. CITY OF LANCASTER WATER FUND Docket No. R-2010-2179103

IN THE MATTER OF THE PETITION OF SOUTH JERSEY GAS COMPANY FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE AND OTHER TARIFF REVISIONS BPU DOCKET NO. GR10010035

In the Matter of the Application of Hawaii Electric Light Company, Inc. For approval of Changes in its Depreciation Rates, its CAIC Amortization Period and Approval of Vintage Amortization Accounting. Dock No. 2009-0321.

In the Matter of the Application Maui Electric Company, Limited. For approval of Changes in its Depreciation Rates, its CAIC Amortization Period and Approval of Vintage Amortization Accounting. Dock No. 2009-0286.

James Shay Garren

In the Matter of the Application of KAUAI ISLAND UTILITY COOPERATIVE For Approval of Rate Changes and Increases, Revised Rate Schedules and Rules, and Other Ratemaking Matters. Docket No. 2009-0050.

OCA Statement No. 5

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	**Docket No. R-2015-2518438**
v.	:	
	:	
UGI UTILITIES, INC. – GAS DIVISION	:	

EXHIBITS ACCOMPANYING THE

DIRECT TESTIMONY OF

JAMES S. GARREN

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

APRIL 12, 2016

UGI Utilities, Inc., Gas Division
PA Docket # R-2015-2518438
Comparison of proposed average service lives

ACCOUNT (1)		OCA SURVIVOR CURVE (2)	WIEDMAYER SURVIVOR CURVE (3)
DISTRIBUTION PLANT			
375	STRUCTURES AND IMPROVEMENTS	60 - L0.5	55 - S0.5
376.1	MAINS - PRIMARILY STEEL	76 - R2.5	72 - R2.5
376.2	MAINS - CAST IRON	82 - L0.5	70 - R1
376.3	MAINS - PLASTIC	68 - R3	65 - R3
376.5	MAINS - PRIMARILY WROUGHT IRON	70 - R1	70 - R1
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	61 - L0.5	50 - S0.5
378.1	MEASURING AND REGULATING STATION EQUIPMENT - SCADA	13 - S2	13 - S2
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	44 - R2.5	40 - R3
380	SERVICES	50 - S1	47 - R2
381	METERS	37 - S0.5	36 - R1.5
381.2	ELECTRONIC METERS	20 - S2	20 - S2
382	METER INSTALLATIONS	50 - S1	47 - R2
383	HOUSE REGULATORS	50 - S1	47 - R2
384	HOUSE REGULATOR INSTALLATIONS	50 - S1	47 - R2
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	55 - R2.5	42 - R2
386	OTHER PROPERTY ON CUSTOMERS PREMISES	50 - S1	47 - R2
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	50 - S1	47 - R2
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	25 - R3	25 - R3
386.3	OTHER PROPERTY ON CUSTOMER PREMISES - CNG REFUELING STATION		
387	OTHER EQUIPMENT	32 - L2	32 - L2
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	25 - SQ	25 - SQ
TOTAL DISTRIBUTION PLANT			
GENERAL PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	/ARIOUS*	VARIOUS*
390.2	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	SQUARE	SQUARE
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	20 - SQ	20 - SQ
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	5 - SQ	5 - SQ
392.1	TRANSPORTATION EQUIPMENT - CARS	7 - L2.5	7 - L2.5
392.2	TRANSPORTATION EQUIPMENT - TRUCKS	11 - L3	11 - L3
392.4	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	14 - L4	14 - L4
394	TOOLS, SHOP AND GARAGE EQUIPMENT	20 - SQ	20 - SQ
396	POWER OPERATED EQUIPMENT	14 - L2.5	14 - L2.5
397	COMMUNICATION EQUIPMENT	10 - SQ	10 - SQ
398	MISCELLANEOUS EQUIPMENT	10 - SQ	10 - SQ
TOTAL GENERAL PLANT			
TOTAL DEPRECIABLE GAS PLANT			
NONDEPRECIABLE PLANT			
302.1	FRANCHISES AND CONSENTS - PERPETUAL		
302.2	FRANCHISES AND CONSENTS - LIMITED TERM		
304.1	LAND AND LAND RIGHTS - LAND		
304.2	LAND AND LAND RIGHTS - LAND RIGHTS		
374.1	LAND AND LAND RIGHTS - LAND		
374.2	LAND AND LAND RIGHTS - LAND RIGHTS		
389.1	LAND AND LAND RIGHTS - LAND		

UGI Utilities, Inc., Gas Division
PA Docket # R-2015-2518438
Comparison of proposed average service lives

ACCOUNT		OCA SURVIVOR CURVE	WIEDMAYER SURVIVOR CURVE
(1)		(2)	(3)
389.2	LAND AND LAND RIGHTS - LAND RIGHTS		
TOTAL NONDEPRECIABLE PLANT			
COMMON PLANT			
301	ORGANIZATION (NONDEPRECIABLE)		
390.2	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	SQUARE	SQUARE
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	20 - SQ	20 - SQ
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	5 - SQ	5 - SQ
392.1	TRANSPORTATION EQUIPMENT - CARS	7 - L2.5	7 - L2.5
TOTAL COMMON PLANT			
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISION - 15.36%			
INFORMATION SERVICES (IS)			
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	20 - SQ	20 - SQ
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	5 - SQ	5 - SQ
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEAF	10 - SQ	10 - SQ
391.4	OFFICE FURNITURE & EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS *	15 - SQ	15 - SQ
TOTAL INFORMATION SERVICES			
TOTAL INFORMATION SERVICES ALLOCATED TO GAS DIVISION - 48.83%			
390.1	STRUCTURES AND IMPROVEMENTS	100 - R1	100 - R1

UGI Utilities, Inc., Gas Division
PA Docket # R-2015-2518438
Calculation of Depreciation Rates and Accruals

ACCOUNT		SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	REMAINING LIFE	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
DISTRIBUTION PLANT								
375	STRUCTURES AND IMPROVEMENTS	60 - L0.5	2,185,833	1,446,653	739,180	34.2	0.99%	21,645
376.1	MAINS - PRIMARILY STEEL	76 - R2.5	231,294,934	78,311,541	152,983,393	53.6	1.24%	2,856,833
376.2	MAINS - CAST IRON	82 - L0.5	2,733,094	788,879	1,944,215	44.8	1.59%	43,398
376.3	MAINS - PLASTIC	68 - R3	515,422,589	112,315,208	403,107,381	55.9	1.40%	7,207,355
376.5	MAINS - PRIMARILY WROUGHT IRON	70 - R1	294,940	254,942	39,998	12.3	1.10%	3,241
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	61 - L0.5	34,124,579	5,149,506	28,975,073	54.9	1.55%	527,971
378.1	MEASURING AND REGULATING STATION EQUIPMENT - SCADA	13 - S2	1,316,613	660,294	656,319	7.1	7.06%	92,963
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	44 - R2.5	4,794,310	3,093,712	1,700,598	17.4	2.03%	97,511
380	SERVICES	50 - S1	592,758,055	159,613,547	433,144,508	38.9	1.88%	11,131,959
381	METERS	37 - S0.5	48,498,754	17,159,112	31,339,642	28.6	2.26%	1,096,559
381.2	ELECTRONIC METERS	20 - S2	11,046,136	6,264,387	4,781,749	11.1	3.92%	432,737
382	METER INSTALLATIONS	50 - S1	65,196,088	23,154,952	42,041,136	36.8	1.75%	1,143,354
383	HOUSE REGULATORS	50 - S1	7,404,361	1,667,308	5,737,053	37.4	2.07%	153,274
384	HOUSE REGULATOR INSTALLATIONS	50 - S1	11,149,494	4,220,552	6,928,942	36.7	1.69%	188,851
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	55 - R2.5	6,163,336	3,586,364	2,576,972	35.8	1.17%	72,083
386	OTHER PROPERTY ON CUSTOMERS PREMISES	50 - S1	337,967	131,585	206,382	36.9	1.65%	5,591
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	50 - S1	946,896	583,957	362,939	28.3	1.35%	12,825
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	25 - R3	24,705	23,592	1,113	4.5	1.00%	247
386.3	OTHER PROPERTY ON CUSTOMER PREMISES - CNG REFUELING STATION			1,036	(1,036)			0
387	OTHER EQUIPMENT	32 - L2	2,178,778	848,337	1,330,441	21.2	2.88%	62,727
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	25 - SQ	1,490,664	1,446,389	44,275	11.6	0.26%	3,830
TOTAL DISTRIBUTION PLANT			**1,539,362,126**	**420,721,853**	**1,118,640,273**		1.63%	**25,154,955**
GENERAL PLANT								
390.1	STRUCTURES AND IMPROVEMENTS	VARIOUS*	32,047,414	15,682,103	16,365,311		3.25%	1,042,799
390.2	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	SQUARE	11,241	5,878	5,363		19.71%	2,216
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	20 - SQ	2,255,193	998,122	1,257,071	15.6	3.58%	80,685
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	5 - SQ	109,246	138,845	(29,599)		0.00%	0
392.1	TRANSPORTATION EQUIPMENT - CARS	7 - L2.5	40,643	40,635	8	1.4	0.01%	6
392.2	TRANSPORTATION EQUIPMENT - TRUCKS	11 - L3	809,748	89,061	720,687	9.7	9.15%	74,069
392.4	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	14 - L4	12,549	12,549	0		0.00%	0
394	TOOLS, SHOP AND GARAGE EQUIPMENT	20 - SQ	9,958,664	3,331,267	6,627,397	16.6	5.04%	501,958
396	POWER OPERATED EQUIPMENT	14 - L2.5	1,370,792	1,315,394	55,398	2.4	1.70%	23,276
397	COMMUNICATION EQUIPMENT	10 - SQ	506,885	416,447	90,438	5.9	3.04%	15,433
398	MISCELLANEOUS EQUIPMENT	10 - SQ	854,715	339,529	515,186	8.0	7.53%	64,318
TOTAL GENERAL PLANT			**47,977,090**	**22,369,830**	**25,607,260**		3.76%	**1,804,760**
TOTAL DEPRECIABLE GAS PLANT			**1,587,339,216**	**443,091,683**	**1,144,247,533**		1.70%	**26,959,715**
NONDEPRECIABLE PLANT								
302.1	FRANCHISES AND CONSENTS - PERPETUAL		20,149					
302.2	FRANCHISES AND CONSENTS - LIMITED TERM		8,107					
304.1	LAND AND LAND RIGHTS - LAND		375,198					
304.2	LAND AND LAND RIGHTS - LAND RIGHTS		6,454					
374.1	LAND AND LAND RIGHTS - LAND		232,579					
374.2	LAND AND LAND RIGHTS - LAND RIGHTS		2,040,764					
389.1	LAND AND LAND RIGHTS - LAND		1,491,454					
389.2	LAND AND LAND RIGHTS - LAND RIGHTS		1,313					
TOTAL NONDEPRECIABLE PLANT			**4,176,018**					
			1,591,515,234					

UGI Utilities, Inc., Gas Division
PA Docket # R-2015-2518438
Calculation of Depreciation Rates and Accruals

ACCOUNT		SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	REMAINING LIFE	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
COMMON PLANT								
301	ORGANIZATION (NONDEPRECIABLE)		138,964					
390.2	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	SQUARE	159,895	139,250	20,645		8.61%	13,764
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	20 - SQ	840,391	164,240	676,151	15.9	5.05%	42,472
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	5 - SQ	155,038	112,023	43,015	2.9	9.53%	14,782
392.1	TRANSPORTATION EQUIPMENT - CARS	7 - L2.5	71,637	61,742	9,895	2.4	5.83%	4,175
TOTAL COMMON PLANT			**1,365,925**	**477,255**	**749,706**		**613.00%**	**75,193**
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISION - 15.36%			**209,806**	**73,306**	**115,155**			**11,550**
INFORMATION SERVICES (IS)								
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	20 - SQ	71,395	59,106	12,289	11.7	1.47%	1,049
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	5 - SQ	2,868,843	1,746,659	1,122,184	3.4	11.61%	332,992
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEAF	10 - SQ	18,937,625	4,843,763	14,093,862	8.8	8.51%	1,610,727
391.4	OFFICE FURNITURE & EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS '	15 - SQ	98,801,617	6,654,743	92,146,874	14.3	6.53%	6,452,862
TOTAL INFORMATION SERVICES			**120,679,480**	**13,304,271**	**107,375,209**		6.96%	**8,397,631**
TOTAL INFORMATION SERVICES ALLOCATED TO GAS DIVISION - 48.83%			**58,927,790**	**6,496,476**	**52,431,315**			**4,100,563**
390.1	STRUCTURES AND IMPROVEMENTS	100 - R1	2,097,073	1,176,645	920,428		3.59%	75,268
TOTAL READING SERVICE CENTER ALLOCATED TO OTHER DIVISIONS - 51.74%			**1,085,026**	**608,796**	**476,229**			**38,944**
TOTAL OTHER UTILITY PLANT ALLOCATED TO GAS DIVISION			**58,052,570**	**5,960,986**	**52,070,241**		7.02%	**4,073,169**
TOTAL PLANT IN SERVICE			**1,649,567,804**	**449,052,669**	**1,196,317,774**		1.88%	**31,032,884**
ENVIRONMENTAL EXPENDITURES FOR SITE REMEDIATION - ACCOUNT 305				(316,923)				
AMORTIZATION OF NEGATIVE NET SALVAGE								*4,995,504*
GRAND TOTAL			**1,649,567,804**	**448,735,746**	**1,196,317,774**		2.18%	**36,028,388**

* SURVIVOR CURVES FOR ACCOUNT 390.1 ARE INTERIM SURVIVOR CURVES. INDIVIDUAL BUILDINGS ARE LIFE SPANNED.
** ASSETS IN ACCOUNTS 391.3 AND 391.4 ARE INDIVIDUALLY DEPRECIATED BASED ON THE SERVICE LIVES SHOWN IN THIS REPORT. ALSO, UGI PLANS TO REPLACE THEIR CUSTOMER INFORMATION SYSTEM (CIS) IN ACCOUNT 391.3 IN 2017. UGI PLANS TO AMORTIZE THE UNRECOVERED COSTS RELATED TO CIS PROJECTS OVER THEIR ESTIMATED REMAINING LIVES. CIS IS EXPECTED TO BE RETIRED IN SEPTEMBER 2017.

Observed Life Table Results
UGI Gas
Account: 375.00 -

Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors
BAND		1850 - 2011			
0	1,059,672	0	0.0000	100.0000	1.0000
0.5	1,104,911	0	0.0000	100.0000	1.0000
1.5	1,113,387	0	0.0000	100.0000	1.0000
2.5	1,116,076	89	0.0079	99.9921	1.0000
3.5	1,114,800	137	0.0123	99.9877	0.9999
4.5	1,084,814	2,999	0.2765	99.7235	0.9998
5.5	1,072,647	423	0.0395	99.9605	0.9970
6.5	1,058,458	0	0.0000	100.0000	0.9966
7.5	1,048,976	2,023	0.1929	99.8071	0.9966
8.5	1,038,446	4,738	0.4563	99.5437	0.9947
9.5	1,034,389	5,219	0.5046	99.4954	0.9902
10.5	946,228	639	0.0675	99.9325	0.9852
11.5	931,073	1,822	0.1957	99.8043	0.9845
12.5	905,762	38,830	4.2870	95.7130	0.9826
13.5	873,450	9,540	1.0922	98.9078	0.9405
14.5	863,977	7,843	0.9077	99.0923	0.9302
15.5	828,227	1,227	0.1482	99.8518	0.9218
16.5	854,468	7,417	0.8680	99.1320	0.9204
17.5	864,955	2,633	0.3044	99.6956	0.9124
18.5	857,900	5,612	0.6541	99.3459	0.9096
19.5	855,886	6,838	0.7989	99.2011	0.9037
20.5	849,048	20,937	2.4659	97.5341	0.8965
21.5	830,219	2,033	0.2449	99.7551	0.8743
22.5	817,042	0	0.0000	100.0000	0.8722
23.5	825,082	2,775	0.3363	99.6637	0.8722
24.5	811,970	1,812	0.2232	99.7768	0.8693
25.5	825,252	13,439	1.6285	98.3715	0.8673
26.5	831,915	12,929	1.5541	98.4459	0.8532
27.5	723,312	2,939	0.4063	99.5937	0.8399
28.5	708,880	6,043	0.8524	99.1476	0.8365
29.5	724,633	1,976	0.2727	99.7273	0.8294
30.5	718,761	43,930	6.1119	93.8881	0.8271
31.5	672,312	685	0.1018	99.8982	0.7766
32.5	665,661	1,350	0.2028	99.7972	0.7758
33.5	650,922	2,166	0.3327	99.6673	0.7742
34.5	649,215	6,619	1.0196	98.9804	0.7716
35.5	643,527	16,098	2.5015	97.4985	0.7638
36.5	544,645	1,384	0.2542	99.7458	0.7447
37.5	532,325	14,093	2.6475	97.3525	0.7428
38.5	524,239	2,804	0.5349	99.4651	0.7231

39.5	530,626	20,796	3.9192	96.0808	0.7192
40.5	479,662	4,646	0.9687	99.0313	0.6911
41.5	501,006	12,333	2.4616	97.5384	0.6844
42.5	483,985	17,071	3.5271	96.4729	0.6675
43.5	466,483	34,989	7.5005	92.4995	0.6440
44.5	435,472	4,708	1.0811	98.9189	0.5957
45.5	435,836	6,685	1.5337	98.4663	0.5892
46.5	489,775	3,036	0.6199	99.3801	0.5802
47.5	599,960	410	0.0684	99.9316	0.5766
48.5	615,537	1,636	0.2658	99.7342	0.5762
49.5	701,402	61,152	8.7185	91.2815	0.5747
50.5	925,973	23,895	2.5805	97.4195	0.5246
51.5	1,092,626	5,151	0.4715	99.5285	0.5110
52.5	1,063,972	3,076	0.2891	99.7109	0.5086
53.5	1,044,497	127	0.0122	99.9878	0.5072
54.5	1,045,516	3,504	0.3351	99.6649	0.5071
55.5	1,008,747	5,769	0.5719	99.4281	0.5054
56.5	981,270	5,449	0.5553	99.4447	0.5025
57.5	893,073	10,704	1.1985	98.8015	0.4997
58.5	818,472	9,305	1.1369	98.8631	0.4937
59.5	796,463	3,211	0.4032	99.5968	0.4881
60.5	675,686	6,162	0.9120	99.0880	0.4861
61.5	354,750	5,610	1.5814	98.4186	0.4817
62.5	193,724	2,436	1.2575	98.7425	0.4741
63.5	179,680	24,558	13.6676	86.3324	0.4681
64.5	153,910	6,254	4.0636	95.9364	0.4041
65.5	123,414	4,834	3.9168	96.0832	0.3877
66.5	111,316	9,876	8.8722	91.1278	0.3725
67.5	114,972	1,502	1.3068	98.6932	0.3395
68.5	109,997	22,509	20.4628	79.5372	0.3350
69.5	87,054	16,084	18.4759	81.5241	0.2665
70.5	70,880	3,262	4.6020	95.3980	0.2173
71.5	69,405	498	0.7170	99.2830	0.2073
72.5	68,000	18	0.0269	99.9731	0.2058
73.5	80,559	0	0.0000	100.0000	0.2057
74.5	80,353	0	0.0000	100.0000	0.2057
75.5	84,950	0	0.0000	100.0000	0.2057
76.5	123,609	0	0.0000	100.0000	0.2057
77.5	123,009	200	0.1626	99.8374	0.2057
78.5	117,964	0	0.0000	100.0000	0.2054
79.5	134,681	2,347	1.7425	98.2575	0.2054
80.5	132,340	249	0.1878	99.8122	0.2018
81.5	128,180	425	0.3316	99.6684	0.2014
82.5	125,968	0	0.0000	100.0000	0.2008
83.5	131,053	0	0.0000	100.0000	0.2008
84.5	118,419	256	0.2158	99.7842	0.2008
85.5	116,725	660	0.5654	99.4346	0.2003

86.5	106,515	0	0.0000	100.0000	0.1992
87.5	57,033	0	0.0000	100.0000	0.1992
88.5	56,681	0	0.0000	100.0000	0.1992
89.5	55,137	0	0.0000	100.0000	0.1992
90.5	37,729	0	0.0000	100.0000	0.1992
91.5	35,196	0	0.0000	100.0000	0.1992
92.5	33,858	0	0.0000	100.0000	0.1992
93.5	29,114	0	0.0000	100.0000	0.1992
94.5	23,859	0	0.0000	100.0000	0.1992
95.5	24,924	0	0.0000	100.0000	0.1992
96.5	24,924	0	0.0000	100.0000	0.1992
97.5	24,924	0	0.0000	100.0000	0.1992
98.5	25,990	0	0.0000	100.0000	0.1992
99.5	25,633	0	0.0000	100.0000	0.1992
100.5	25,633	0	0.0000	100.0000	0.1992
101.5	24,952	0	0.0000	100.0000	0.1992
102.5	24,048	0	0.0000	100.0000	0.1992
103.5	23,346	0	0.0000	100.0000	0.1992
104.5	23,346	0	0.0000	100.0000	0.1992
105.5	21,211	0	0.0000	100.0000	0.1992
106.5	20,384	0	0.0000	100.0000	0.1992
107.5	20,384	0	0.0000	100.0000	0.1992
108.5	20,384	9,167	44.9713	55.0287	0.1992
109.5	9,472	0	0.0000	100.0000	0.1096
110.5	9,472	0	0.0000	100.0000	0.1096
111.5	9,472	67	0.7067	99.2933	0.1096
112.5	9,405	0	0.0000	100.0000	0.1088
113.5	9,245	0	0.0000	100.0000	0.1088
114.5	9,067	0	0.0000	100.0000	0.1088
115.5	9,067	975	10.7539	89.2461	0.1088
116.5	8,092	418	5.1704	94.8296	0.0971
117.5	7,673	2,117	27.5879	72.4121	0.0921
118.5	5,556	0	0.0000	100.0000	0.0667
119.5	5,556	0	0.0000	100.0000	0.0667
120.5	5,556	0	0.0000	100.0000	0.0667
121.5	5,556	0	0.0000	100.0000	0.0667
122.5	1,363	0	0.0000	100.0000	0.0667
123.5	1,363	0	0.0000	100.0000	0.0667
124.5	1,363	0	0.0000	100.0000	0.0667
125.5	1,363	0	0.0000	100.0000	0.0667
126.5	1,363	0	0.0000	100.0000	0.0667
127.5	1,363	0	0.0000	100.0000	0.0667
128.5	1,363	0	0.0000	100.0000	0.0667
129.5	1,363	0	0.0000	100.0000	0.0667
130.5	1,363	0	0.0000	100.0000	0.0667
131.5	1,363	0	0.0000	100.0000	0.0667
132.5	1,436	0	0.0000	100.0000	0.0667

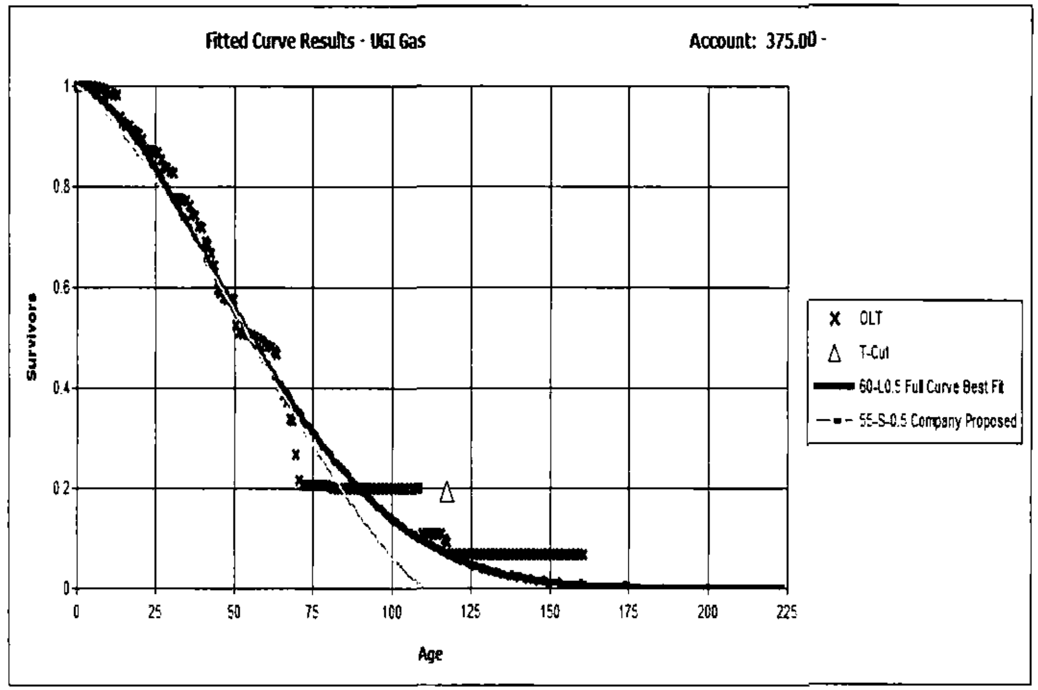
133.5	1,436	0	0.0000	100.0000	0.0667
134.5	1,436	0	0.0000	100.0000	0.0667
135.5	1,436	0	0.0000	100.0000	0.0667
136.5	1,436	0	0.0000	100.0000	0.0667
137.5	1,436	0	0.0000	100.0000	0.0667
138.5	1,436	0	0.0000	100.0000	0.0667
139.5	1,436	0	0.0000	100.0000	0.0667
140.5	1,436	0	0.0000	100.0000	0.0667
141.5	1,436	0	0.0000	100.0000	0.0667
142.5	1,436	0	0.0000	100.0000	0.0667
143.5	1,363	0	0.0000	100.0000	0.0667
144.5	1,363	0	0.0000	100.0000	0.0667
145.5	1,363	0	0.0000	100.0000	0.0667
146.5	1,363	0	0.0000	100.0000	0.0667
147.5	1,363	0	0.0000	100.0000	0.0667
148.5	1,363	0	0.0000	100.0000	0.0667
149.5	1,363	0	0.0000	100.0000	0.0667
150.5	2,795	0	0.0000	100.0000	0.0667
151.5	2,795	0	0.0000	100.0000	0.0667
152.5	2,795	0	0.0000	100.0000	0.0667
153.5	2,795	0	0.0000	100.0000	0.0667
154.5	2,795	0	0.0000	100.0000	0.0667
155.5	2,795	0	0.0000	100.0000	0.0667
156.5	2,795	0	0.0000	100.0000	0.0667
157.5	2,795	0	0.0000	100.0000	0.0667
158.5	2,795	0	0.0000	100.0000	0.0667
159.5	2,795	0	0.0000	100.0000	0.0667
160.5	2,795	0	0.0000	100.0000	0.0667

Best Fit Curve Results
UGI Gas
Account: 375.00 -

Curve	Life	Sum of Squared Differences
BAND	**1850 - 2011**	
L0.5	60.0	2,686.514
L1	60.0	2,853.188
L0	60.0	3,498.996
L1.5	60.0	3,726.086
O2	61.0	4,689.754
S-0.5	59.0	5,229.149
S0	59.0	5,755.466
L2	60.0	5,788.908
R0.5	58.0	5,946.901
O1	59.0	6,584.862
S0.5	59.0	6,955.770
R1	58.0	7,682.262
S1	59.0	9,281.038
R1.5	57.0	9,347.915
O3	73.0	10,861.608
S1.5	58.0	11,866.987
R2	57.0	12,511.964
L3	59.0	13,437.274
O4	93.0	15,311.279
S2	58.0	15,419.146
R2.5	57.0	15,773.691
R3	57.0	20,376.590
S3	58.0	23,043.317
L4	58.0	25,848.368
R4	58.0	29,572.713
S4	58.0	34,084.466
L5	58.0	37,637.006
R5	58.0	42,204.963
S5	58.0	45,749.089
S6	59.0	56,973.192
SQ	58.0	79,477.815

Analytical Parameters

OLT Placement Band:	1850 - 2011
OLT Experience Band:	1850 - 2011
Minimum Life Parameter	1
Maximum Life Paramete	100
Life Increment Paramete	1
Max Age (T-Cut):	117.5



Analytical Parameters

OLT Placement Band:	1850 - 2011
OLT Experience Band:	1850 - 2011
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	119.0

UGI Gas 2017 GAs

375 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 60 S-0.5

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	0	60.00	59.63	0	0
2016	1.5	0	60.00	58.90	0	0
2015	2.5	0	60.00	58.19	0	0
2014	3.5	195,330	60.00	57.50	3,255	187,187
2013	4.5	103,922	60.00	56.81	1,732	98,405
2012	5.5	0	60.00	56.14	0	0
2011	6.5	27,987	60.00	55.48	466	25,878
2010	7.5	0	60.00	54.82	0	0
2009	8.5	0	60.00	54.18	0	0
2008	9.5	20,559	60.00	53.54	343	18,345
2007	10.5	55,196	60.00	52.91	920	48,671
2006	11.5	17,523	60.00	52.28	292	15,269
2005	12.5	14,063	60.00	51.67	234	12,110
2004	13.5	14,151	60.00	51.06	236	12,041
2003	14.5	8,507	60.00	50.45	142	7,153
2002	15.5	6,262	60.00	49.85	104	5,203
2001	16.5	34,305	60.00	49.26	572	28,165
2000	17.5	23,960	60.00	48.67	399	19,437
1999	18.5	24,771	60.00	48.09	413	19,855
1998	19.5	37,254	60.00	47.52	621	29,502
1997	20.5	0	60.00	46.94	0	0
1996	21.5	28,054	60.00	46.38	468	21,683
1995	22.5	3,606	60.00	45.81	60	2,753
1994	23.5	0	60.00	45.25	0	0
1993	24.5	4,422	60.00	44.70	74	3,294
1992	25.5	0	60.00	44.15	0	0
1991	26.5	0	60.00	43.60	0	0
1990	27.5	3,723	60.00	43.06	62	2,672
1989	28.5	18,115	60.00	42.52	302	12,838
1988	29.5	0	60.00	41.99	0	0

1987	30.5	11,800	60.00	41.45	197	8,153
1986	31.5	0	60.00	40.93	0	0
1985	32.5	3,251	60.00	40.40	54	2,189
1984	33.5	107,313	60.00	39.88	1,789	71,323
1983	34.5	0	60.00	39.36	0	0
1982	35.5	4,195	60.00	38.84	70	2,716
1981	36.5	3,896	60.00	38.33	65	2,489
1980	37.5	2,626	60.00	37.82	44	1,655
1979	38.5	6,025	60.00	37.31	100	3,746
1978	39.5	13,389	60.00	36.81	223	8,213
1977	40.5	8,040	60.00	36.30	134	4,865
1976	41.5	4,599	60.00	35.80	77	2,744
1975	42.5	87,664	60.00	35.31	1,461	51,584
1974	43.5	25,525	60.00	34.81	425	14,809
1973	44.5	11,871	60.00	34.32	198	6,790
1972	45.5	0	60.00	33.83	0	0
1971	46.5	36,050	60.00	33.34	601	20,031
1970	47.5	5,742	60.00	32.85	96	3,144
1969	48.5	8,772	60.00	32.37	146	4,732
1968	49.5	4,279	60.00	31.89	71	2,274
1967	50.5	4,719	60.00	31.41	79	2,470
1966	51.5	5,039	60.00	30.93	84	2,597
1965	52.5	18,536	60.00	30.45	309	9,407
1964	53.5	4,880	60.00	29.98	81	2,438
1963	54.5	14,914	60.00	29.50	249	7,333
1962	55.5	27,754	60.00	29.03	463	13,429
1961	56.5	30,405	60.00	28.56	507	14,473
1960	57.5	28,812	60.00	28.09	480	13,491
1959	58.5	36,120	60.00	27.63	602	16,631
1958	59.5	16,399	60.00	27.16	273	7,424
1957	60.5	17,020	60.00	26.70	284	7,573
1956	61.5	33,265	60.00	26.24	554	14,546
1955	62.5	21,708	60.00	25.78	362	9,326
1954	63.5	82,748	60.00	25.32	1,379	34,914
1953	64.5	64,035	60.00	24.86	1,067	26,530
1952	65.5	14,011	60.00	24.40	234	5,698
1951	66.5	117,566	60.00	23.95	1,959	46,920
1950	67.5	314,774	60.00	23.49	5,246	123,241
1949	68.5	155,416	60.00	23.04	2,590	59,675
1948	69.5	11,814	60.00	22.59	197	4,447
1947	70.5	1,212	60.00	22.13	20	447
1946	71.5	24,242	60.00	21.68	404	8,761
1945	72.5	7,388	60.00	21.24	123	2,615
1944	73.5	480	60.00	20.79	8	166
1943	74.5	3,799	60.00	20.34	63	1,288
1942	75.5	1,322	60.00	19.89	22	438
1941	76.5	1,498	60.00	19.45	25	486

1940	77.5	0	60.00	19.00	0	0
1939	78.5	941	60.00	18.56	16	291
1938	79.5	0	60.00	18.12	0	0
1937	80.5	206	60.00	17.67	3	61
1936	81.5	0	60.00	17.23	0	0
1935	82.5	0	60.00	16.79	0	0
1934	83.5	599	60.00	16.35	10	163
1933	84.5	4,846	60.00	15.91	81	1,285
1932	85.5	691	60.00	15.47	12	178
1931	86.5	887	60.00	15.03	15	222
1930	87.5	6,131	60.00	14.59	102	1,491
1929	88.5	1,787	60.00	14.15	30	422
1928	89.5	169	60.00	13.71	3	39
1927	90.5	12,635	60.00	13.28	211	2,796
1926	91.5	1,438	60.00	12.84	24	308
1925	92.5	9,551	60.00	12.40	159	1,974
1924	93.5	49,482	60.00	11.96	825	9,866
1923	94.5	445	60.00	11.52	7	85
1922	95.5	1,545	60.00	11.09	26	285
1921	96.5	17,408	60.00	10.65	290	3,090
1920	97.5	2,532	60.00	10.21	42	431
1919	98.5	2,219	60.00	9.77	37	361
1918	99.5	4,744	60.00	9.33	79	738
1917	100.5	5,255	60.00	8.89	88	779
1916	101.5	122	60.00	8.45	2	17
1915	102.5	0	60.00	8.01	0	0
1914	103.5	0	60.00	7.57	0	0
1913	104.5	0	60.00	7.13	0	0
1912	105.5	357	60.00	6.69	6	40
1911	106.5	0	60.00	6.25	0	0
1910	107.5	681	60.00	5.80	11	66
1909	108.5	1,064	60.00	5.36	18	95
1908	109.5	880	60.00	4.91	15	72
1907	110.5	0	60.00	4.46	0	0
1906	111.5	2,135	60.00	4.01	36	143
1905	112.5	1,322	60.00	3.56	22	78
1904	113.5	0	60.00	3.10	0	0
1903	114.5	0	60.00	2.64	0	0
1902	115.5	1,745	60.00	2.19	29	64
1901	116.5	0	60.00	1.73	0	0
1900	117.5	0	60.00	1.27	0	0
1899	118.5	0	60.00	0.82	0	0
1898	119.5	159	60.00	0.50	3	1
1897	120.5	179	60.00	0.50	3	1
1896	121.5	0	60.00	0.50	0	0
1895	122.5	0	60.00	0.50	0	0
1894	123.5	0	60.00	0.50	0	0

1893	124.5	0	60.00	0.50	0	0
1892	125.5	0	60.00	0.50	0	0
1891	126.5	0	60.00	0.50	0	0
1890	127.5	0	60.00	0.50	0	0
1889	128.5	4,193	60.00	0.50	70	35
1888	129.5	0	60.00	0.50	0	0
1887	130.5	0	60.00	0.50	0	0
1886	131.5	0	60.00	0.50	0	0
1885	132.5	0	60.00	0.50	0	0
1884	133.5	0	60.00	0.50	0	0
1883	134.5	0	60.00	0.50	0	0
1882	135.5	0	60.00	0.50	0	0
1881	136.5	0	60.00	0.50	0	0
1880	137.5	0	60.00	0.50	0	0
1879	138.5	0	60.00	0.50	0	0
1878	139.5	0	60.00	0.50	0	0
1877	140.5	0	60.00	0.50	0	0
1876	141.5	0	60.00	0.50	0	0
1875	142.5	0	60.00	0.50	0	0
1874	143.5	0	60.00	0.50	0	0
1873	144.5	0	60.00	0.50	0	0
1872	145.5	0	60.00	0.50	0	0
1871	146.5	0	60.00	0.50	0	0
1870	147.5	0	60.00	0.50	0	0
1869	148.5	0	60.00	0.50	0	0
1868	149.5	72	60.00	0.50	1	1
1867	150.5	0	60.00	0.50	0	0
1866	151.5	0	60.00	0.50	0	0
1865	152.5	0	60.00	0.50	0	0
1864	153.5	0	60.00	0.50	0	0
1863	154.5	0	60.00	0.50	0	0
1862	155.5	0	60.00	0.50	0	0
1861	156.5	0	60.00	0.50	0	0
1860	157.5	0	60.00	0.50	0	0
1859	158.5	0	60.00	0.50	0	0
1858	159.5	0	60.00	0.50	0	0
1857	160.5	0	60.00	0.50	0	0
1856	161.5	0	60.00	0.50	0	0
1855	162.5	0	60.00	0.50	0	0
1854	163.5	0	60.00	0.50	0	0
1853	164.5	0	60.00	0.50	0	0
1852	165.5	0	60.00	0.50	0	0
1851	166.5	0	60.00	0.50	0	0
1850	167.5	2,795	60.00	0.50	47	23
		2,185,833			36,431	1,244,182

AVERAGE SERVICE LIFE	60.00
AVERAGE REMAINING LIFE	34.15

Observed Life Table Results
UGI Gas
Account: 376.1 - Mains - Primarily Steel

Age	Exposures	Retiremen	Retiremen Ratio (%)	Survivor Ratio (%)	Cumulative Survivors
BAND		1852 - 2011			
0	189,068,790	9,253	0.0049	99.9951	1.0000
0.5	189,162,291	158,132	0.0836	99.9164	1.0000
1.5	186,921,849	168,061	0.0899	99.9101	0.9991
2.5	184,710,678	183,944	0.0996	99.9004	0.9982
3.5	182,828,183	394,626	0.2158	99.7842	0.9972
4.5	181,981,467	324,798	0.1785	99.8215	0.9951
5.5	179,592,190	354,808	0.1976	99.8024	0.9933
6.5	178,449,197	115,515	0.0647	99.9353	0.9913
7.5	176,661,779	411,017	0.2327	99.7673	0.9907
8.5	173,032,165	263,832	0.1525	99.8475	0.9884
9.5	171,919,839	460,967	0.2681	99.7319	0.9869
10.5	169,245,269	466,819	0.2758	99.7242	0.9842
11.5	166,173,041	227,294	0.1368	99.8632	0.9815
12.5	164,922,993	393,559	0.2386	99.7614	0.9802
13.5	162,305,307	406,690	0.2506	99.7494	0.9778
14.5	159,982,758	309,588	0.1935	99.8065	0.9754
15.5	154,738,587	414,917	0.2681	99.7319	0.9735
16.5	149,099,406	294,945	0.1978	99.8022	0.9709
17.5	147,853,258	498,535	0.3372	99.6628	0.9690
18.5	146,339,568	362,275	0.2476	99.7524	0.9657
19.5	143,426,014	480,708	0.3352	99.6648	0.9633
20.5	139,876,933	275,236	0.1968	99.8032	0.9601
21.5	136,237,283	516,363	0.3790	99.6210	0.9582
22.5	132,217,075	456,411	0.3452	99.6548	0.9546
23.5	127,518,471	423,646	0.3322	99.6678	0.9513
24.5	125,064,841	486,594	0.3891	99.6109	0.9481
25.5	119,606,935	415,973	0.3478	99.6522	0.9444
26.5	116,104,229	364,016	0.3135	99.6865	0.9411
27.5	113,286,078	543,605	0.4799	99.5201	0.9382
28.5	110,862,681	430,098	0.3880	99.6120	0.9337
29.5	103,228,849	258,429	0.2503	99.7497	0.9301
30.5	95,864,558	317,421	0.3311	99.6689	0.9277
31.5	85,710,651	225,110	0.2626	99.7374	0.9247
32.5	80,738,398	264,953	0.3282	99.6718	0.9222
33.5	77,589,348	260,376	0.3356	99.6644	0.9192
34.5	74,513,895	237,578	0.3188	99.6812	0.9161
35.5	72,059,162	345,270	0.4791	99.5209	0.9132
36.5	69,271,242	250,904	0.3622	99.6378	0.9088
37.5	65,727,409	264,875	0.4030	99.5970	0.9055
38.5	62,369,633	296,523	0.4754	99.5246	0.9019

39.5	58,961,846	280,882	0.4764	99.5236	0.8976
40.5	55,360,763	194,273	0.3509	99.6491	0.8933
41.5	51,799,539	285,759	0.5517	99.4483	0.8902
42.5	47,452,008	184,670	0.3892	99.6108	0.8853
43.5	43,603,611	234,228	0.5372	99.4628	0.8818
44.5	40,087,428	265,418	0.6621	99.3379	0.8771
45.5	36,664,498	259,272	0.7071	99.2929	0.8713
46.5	33,466,539	264,890	0.7915	99.2085	0.8651
47.5	30,789,184	261,809	0.8503	99.1497	0.8583
48.5	28,053,560	258,228	0.9205	99.0795	0.8510
49.5	25,780,026	293,015	1.1366	98.8634	0.8431
50.5	23,585,426	277,922	1.1784	98.8216	0.8336
51.5	20,328,743	301,623	1.4837	98.5163	0.8237
52.5	18,189,678	194,376	1.0686	98.9314	0.8115
53.5	14,902,642	177,344	1.1900	98.8100	0.8028
54.5	13,130,183	155,131	1.1815	98.8185	0.7933
55.5	11,044,474	90,480	0.8192	99.1808	0.7839
56.5	9,698,781	109,430	1.1283	98.8717	0.7775
57.5	8,123,685	97,733	1.2031	98.7969	0.7687
58.5	7,180,808	113,823	1.5851	98.4149	0.7595
59.5	6,357,361	117,782	1.8527	98.1473	0.7474
60.5	5,841,311	90,865	1.5556	98.4444	0.7336
61.5	3,971,076	75,501	1.9013	98.0987	0.7222
62.5	3,737,761	85,169	2.2786	97.7214	0.7084
63.5	3,535,610	43,980	1.2439	98.7561	0.6923
64.5	3,395,842	62,399	1.8375	98.1625	0.6837
65.5	2,949,157	56,684	1.9221	98.0779	0.6711
66.5	2,875,376	87,310	3.0365	96.9635	0.6582
67.5	2,783,873	26,082	0.9369	99.0631	0.6382
68.5	2,750,638	37,282	1.3554	98.6446	0.6323
69.5	2,674,006	41,983	1.5700	98.4300	0.6237
70.5	2,582,753	45,131	1.7474	98.2526	0.6139
71.5	2,506,103	45,429	1.8127	98.1873	0.6032
72.5	2,429,715	54,269	2.2336	97.7664	0.5922
73.5	2,354,575	81,469	3.4600	96.5400	0.5790
74.5	2,237,774	67,120	2.9994	97.0006	0.5590
75.5	2,142,117	32,570	1.5205	98.4795	0.5422
76.5	2,087,651	52,457	2.5127	97.4873	0.5340
77.5	2,040,022	18,553	0.9094	99.0906	0.5205
78.5	2,003,472	14,665	0.7320	99.2680	0.5158
79.5	1,950,287	22,108	1.1336	98.8664	0.5120
80.5	1,691,778	42,459	2.5097	97.4903	0.5062
81.5	1,261,392	29,320	2.3244	97.6756	0.4935
82.5	1,010,484	20,575	2.0361	97.9639	0.4821
83.5	750,488	30,481	4.0616	95.9384	0.4722
84.5	630,520	23,291	3.6939	96.3061	0.4531
85.5	245,798	7,963	3.2396	96.7604	0.4363

86.5	207,276	3,407	1.6435	98.3565	0.4222
87.5	28,776	1,596	5.5450	94.4550	0.4153
88.5	16,325	840	5.1441	94.8559	0.3922
89.5	11,274	1,058	9.3820	90.6180	0.3721
90.5	4,297	604	14.0612	85.9388	0.3371
91.5	3,693	313	8.4728	91.5272	0.2897
92.5	3,380	463	13.7066	86.2934	0.2652
93.5	2,917	122	4.1762	95.8238	0.2288
94.5	2,795	352	12.6074	87.3926	0.2193
95.5	3,684	459	12.4677	87.5323	0.1916
96.5	3,224	292	9.0647	90.9353	0.1677
97.5	2,932	105	3.5703	96.4297	0.1525
98.5	2,827	172	6.0775	93.9225	0.1471
99.5	2,655	390	14.6839	85.3161	0.1382
100.5	2,266	510	22.4911	77.5089	0.1179
101.5	1,756	189	10.7414	89.2586	0.0914
102.5	1,567	350	22.3359	77.6641	0.0815
103.5	1,217	136	11.1821	88.8179	0.0633
104.5	1,081	8	0.7760	99.2240	0.0562
105.5	1,376	171	12.4323	87.5677	0.0558
106.5	1,205	60	4.9617	95.0383	0.0489
107.5	1,145	0	0.0000	100.0000	0.0464
108.5	1,145	495	43.1911	56.8089	0.0464
109.5	651	306	47.0078	52.9922	0.0264
110.5	345	69	20.0945	79.9055	0.0140
111.5	276	35	12.8552	87.1448	0.0112
112.5	240	115	48.0197	51.9803	0.0097
113.5	125	0	0.0000	100.0000	0.0051
114.5	125	0	0.0000	100.0000	0.0051
115.5	125	0	0.0000	100.0000	0.0051
116.5	125	82	65.6758	34.3242	0.0051
117.5	43	0	0.0000	100.0000	0.0017
118.5	43	53	122.8058	-22.8058	0.0017
119.5	-10	0	0.0000	100.0000	-0.0004
120.5	-10	0	0.0000	100.0000	-0.0004
121.5	-10	0	0.0000	100.0000	-0.0004
122.5	-10	0	0.0000	100.0000	-0.0004
123.5	-10	5	-55.0665	155.0665	-0.0004
124.5	-15	0	0.0000	100.0000	-0.0006
125.5	-15	0	0.0000	100.0000	-0.0006
126.5	-15	0	0.0000	100.0000	-0.0006
127.5	-15	0	0.0000	100.0000	-0.0006
128.5	-15	0	0.0000	100.0000	-0.0006
129.5	0	0	0.0000	100.0000	-0.0006
130.5	0	0	0.0000	100.0000	-0.0006
131.5	0	0	0.0000	100.0000	-0.0006
132.5	0	0	0.0000	100.0000	-0.0006

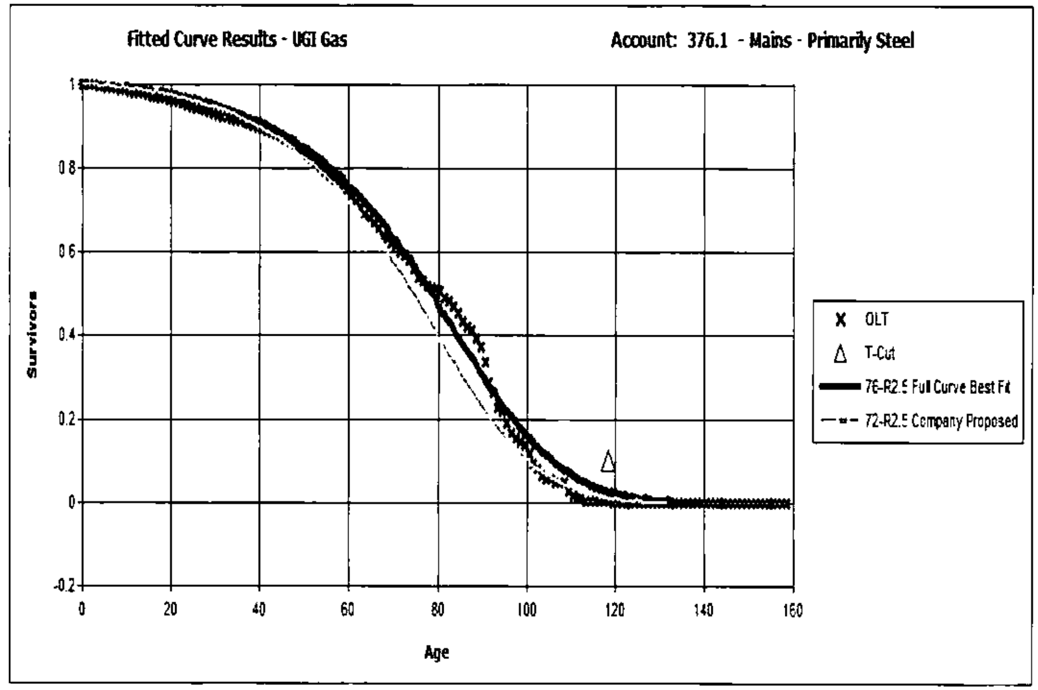
133.5	0	0	0.0000	100.0000	-0.0006
134.5	0	0	0.0000	100.0000	-0.0006
135.5	0	0	0.0000	100.0000	-0.0006
136.5	0	0	0.0000	100.0000	-0.0006
137.5	0	0	0.0000	100.0000	-0.0006
138.5	0	0	0.0000	100.0000	-0.0006
139.5	0	0	0.0000	100.0000	-0.0006
140.5	0	0	0.0000	100.0000	-0.0006
141.5	0	0	0.0000	100.0000	-0.0006
142.5	0	0	0.0000	100.0000	-0.0006
143.5	0	0	0.0000	100.0000	-0.0006
144.5	0	0	0.0000	100.0000	-0.0006
145.5	0	0	0.0000	100.0000	-0.0006
146.5	0	0	0.0000	100.0000	-0.0006
147.5	0	0	0.0000	100.0000	-0.0006
148.5	0	13,671	0.0000	100.0000	-0.0006
149.5	-13,671	0	0.0000	100.0000	-0.0006
150.5	-13,671	0	0.0000	100.0000	-0.0006
151.5	-13,671	0	0.0000	100.0000	-0.0006
152.5	-13,671	0	0.0000	100.0000	-0.0006
153.5	-13,671	0	0.0000	100.0000	-0.0006
154.5	-13,671	0	0.0000	100.0000	-0.0006
155.5	0	0	0.0000	100.0000	-0.0006
156.5	0	0	0.0000	100.0000	-0.0006
157.5	0	0	0.0000	100.0000	-0.0006
158.5	0	0	0.0000	100.0000	-0.0006

Best Fit Curve Results
UGI Gas
Account: 376.1 - Mains - Primarily Steel

Curve	Life	Sum of Squared Differences
BAND	**1852 - 2011**	
R2.5	76.0	897.856
R2	74.0	1,490.616
R3	77.0	1,679.941
S2	77.0	2,041.797
S1.5	76.0	2,504.766
R1.5	73.0	3,760.071
S3	78.0	3,795.521
S1	75.0	4,042.611
L3	78.0	4,545.604
S0.5	74.0	6,552.413
R4	78.0	6,661.910
L4	79.0	6,760.359
L2	78.0	7,019.359
R1	72.0	7,510.106
L1.5	78.0	9,493.226
S0	73.0	10,158.266
S4	79.0	10,546.698
L1	77.0	13,283.433
R0.5	71.0	14,112.568
L5	80.0	14,322.525
S-0.5	72.0	15,744.599
L0.5	78.0	17,275.290
R5	80.0	17,316.491
S5	80.0	20,878.891
L0	79.0	22,248.230
O1	70.0	22,980.049
O2	80.0	25,384.720
S6	81.0	32,774.423
O3	100.0	38,573.388
O4	100.0	57,515.349
SQ	81.0	60,565.064

Analytical Parameters

OLT Placement Band:	1852 - 2011
OLT Experience Band	1852 - 2011
Minimum Life Paramei	1
Maximum Life Parame	100
Life Increment Parame	1
Max Age (T-Cut):	118.5



Analytical Parameters

OLT Placement Band:	1852 - 2011
OLT Experience Band:	1852 - 2011
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	120.0

UGI Gas 2017 GAs

376.1 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 76 R2.5

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	23,299,770	76.00	75.53	306,576	23,154,274
2016	1.5	21,923,165	76.00	74.58	288,463	21,514,024
2015	2.5	10,575,799	76.00	73.64	139,155	10,247,479
2014	3.5	5,148,850	76.00	72.70	67,748	4,925,413
2013	4.5	3,330,518	76.00	71.77	43,823	3,144,961
2012	5.5	2,598,683	76.00	70.83	34,193	2,421,989
2011	6.5	1,834,419	76.00	69.90	24,137	1,687,231
2010	7.5	2,263,301	76.00	68.97	29,780	2,054,068
2009	8.5	2,549,754	76.00	68.05	33,549	2,283,019
2008	9.5	2,243,813	76.00	67.13	29,524	1,981,877
2007	10.5	921,037	76.00	66.21	12,119	802,386
2006	11.5	2,689,839	76.00	65.29	35,393	2,310,935
2005	12.5	1,059,942	76.00	64.38	13,947	897,920
2004	13.5	1,746,348	76.00	63.47	22,978	1,458,530
2003	14.5	3,306,023	76.00	62.57	43,500	2,721,794
2002	15.5	1,054,783	76.00	61.67	13,879	855,884
2001	16.5	2,853,402	76.00	60.77	37,545	2,281,659
2000	17.5	2,571,363	76.00	59.88	33,834	2,025,902
1999	18.5	1,167,953	76.00	58.99	15,368	906,537
1998	19.5	2,325,917	76.00	58.10	30,604	1,778,234
1997	20.5	1,952,884	76.00	57.22	25,696	1,470,396
1996	21.5	4,977,538	76.00	56.35	65,494	3,690,382
1995	22.5	5,127,882	76.00	55.47	67,472	3,743,011
1994	23.5	975,759	76.00	54.61	12,839	701,098
1993	24.5	1,066,984	76.00	53.74	14,039	754,533
1992	25.5	2,499,517	76.00	52.89	32,888	1,739,353
1991	26.5	3,117,492	76.00	52.03	41,020	2,134,374
1990	27.5	3,330,467	76.00	51.18	43,822	2,243,016
1989	28.5	3,531,739	76.00	50.34	46,470	2,339,395
1988	29.5	4,142,583	76.00	49.50	54,508	2,698,317

1987	30.5	2,025,630	76.00	48.67	26,653	1,297,216
1986	31.5	4,823,505	76.00	47.84	63,467	3,036,475
1985	32.5	3,039,387	76.00	47.02	39,992	1,880,460
1984	33.5	2,284,380	76.00	46.20	30,058	1,388,786
1983	34.5	1,765,943	76.00	45.39	23,236	1,054,767
1982	35.5	6,906,680	76.00	44.59	90,877	4,052,048
1981	36.5	6,649,623	76.00	43.79	87,495	3,831,240
1980	37.5	9,444,785	76.00	42.99	124,273	5,343,130
1979	38.5	4,480,867	76.00	42.21	58,959	2,488,485
1978	39.5	2,734,762	76.00	41.42	35,984	1,490,624
1977	40.5	2,629,702	76.00	40.65	34,601	1,406,540
1976	41.5	2,055,426	76.00	39.88	27,045	1,078,575
1975	42.5	2,237,608	76.00	39.12	29,442	1,151,695
1974	43.5	3,079,575	76.00	38.36	40,521	1,554,408
1973	44.5	2,861,499	76.00	37.61	37,651	1,416,099
1972	45.5	2,927,466	76.00	36.87	38,519	1,420,091
1971	46.5	3,014,796	76.00	36.13	39,668	1,433,232
1970	47.5	3,176,712	76.00	35.40	41,799	1,479,707
1969	48.5	3,769,505	76.00	34.68	49,599	1,719,954
1968	49.5	3,340,385	76.00	33.96	43,952	1,492,684
1967	50.5	2,964,440	76.00	33.25	39,006	1,297,061
1966	51.5	2,797,049	76.00	32.55	36,803	1,198,000
1965	52.5	2,680,914	76.00	31.86	35,275	1,123,770
1964	53.5	2,112,420	76.00	31.17	27,795	866,413
1963	54.5	2,139,993	76.00	30.49	28,158	858,617
1962	55.5	1,729,889	76.00	29.82	22,762	678,800
1961	56.5	1,603,123	76.00	29.16	21,094	615,103
1960	57.5	2,614,927	76.00	28.51	34,407	980,824
1959	58.5	1,574,594	76.00	27.86	20,718	577,223
1958	59.5	2,585,653	76.00	27.22	34,022	926,226
1957	60.5	1,314,587	76.00	26.60	17,297	460,054
1956	61.5	1,564,274	76.00	25.98	20,583	534,692
1955	62.5	1,012,527	76.00	25.37	13,323	337,986
1954	63.5	1,165,432	76.00	24.77	15,335	379,837
1953	64.5	631,931	76.00	24.18	8,315	201,051
1952	65.5	561,500	76.00	23.60	7,388	174,360
1951	66.5	308,351	76.00	23.03	4,057	93,442
1950	67.5	1,389,220	76.00	22.47	18,279	410,757
1949	68.5	116,242	76.00	21.92	1,529	33,531
1948	69.5	120,280	76.00	21.39	1,583	33,845
1947	70.5	67,427	76.00	20.86	887	18,505
1946	71.5	282,696	76.00	20.34	3,720	75,666
1945	72.5	13,257	76.00	19.84	174	3,461
1944	73.5	4,572	76.00	19.34	60	1,164
1943	74.5	3,594	76.00	18.86	47	892
1942	75.5	25,402	76.00	18.39	334	6,147
1941	76.5	29,984	76.00	17.93	395	7,075

1940	77.5	17,785	76.00	17.49	234	4,092
1939	78.5	18,440	76.00	17.05	243	4,137
1938	79.5	12,490	76.00	16.63	164	2,732
1937	80.5	18,274	76.00	16.21	240	3,898
1936	81.5	12,694	76.00	15.81	167	2,641
1935	82.5	10,093	76.00	15.42	133	2,048
1934	83.5	12,504	76.00	15.04	165	2,475
1933	84.5	8,198	76.00	14.67	108	1,583
1932	85.5	17,043	76.00	14.31	224	3,210
1931	86.5	95,027	76.00	13.97	1,250	17,461
1930	87.5	129,899	76.00	13.63	1,709	23,291
1929	88.5	55,957	76.00	13.30	736	9,791
1928	89.5	36,268	76.00	12.98	477	6,193
1927	90.5	222	76.00	12.67	3	37
		231,294,934			3,043,354	162,962,298

AVERAGE SERVICE LIFE 76.00
AVERAGE REMAINING LIFE 53.55

Observed Life Table Results
UGI Gas
Account: 376.20 - Mains - Cast Iron

Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors
BAND		1848 - 2011			
0	410,050	0	0.0000	100.0000	1.0000
0.5	685,996	0	0.0000	100.0000	1.0000
1.5	1,002,583	3,376	0.3367	99.6633	1.0000
2.5	1,270,889	3,473	0.2733	99.7267	0.9966
3.5	1,473,887	525	0.0356	99.9644	0.9939
4.5	1,696,303	11,504	0.6782	99.3218	0.9936
5.5	1,957,646	5,158	0.2635	99.7365	0.9868
6.5	2,152,936	2,734	0.1270	99.8730	0.9842
7.5	2,351,060	6,671	0.2838	99.7162	0.9830
8.5	2,546,390	1,972	0.0774	99.9226	0.9802
9.5	2,713,582	3,127	0.1152	99.8848	0.9794
10.5	2,839,616	14,625	0.5150	99.4850	0.9783
11.5	2,945,197	8,394	0.2850	99.7150	0.9733
12.5	2,999,051	31,594	1.0535	98.9465	0.9705
13.5	2,993,753	86,763	2.8982	97.1018	0.9603
14.5	2,918,478	13,483	0.4620	99.5380	0.9324
15.5	2,968,218	15,246	0.5136	99.4864	0.9281
16.5	2,984,707	22,057	0.7390	99.2610	0.9233
17.5	3,047,593	19,803	0.6498	99.3502	0.9165
18.5	3,068,594	27,053	0.8816	99.1184	0.9106
19.5	3,084,958	18,325	0.5940	99.4060	0.9025
20.5	3,103,659	9,333	0.3007	99.6993	0.8972
21.5	3,126,222	18,431	0.5896	99.4104	0.8945
22.5	3,132,621	21,917	0.6996	99.3004	0.8892
23.5	3,127,151	12,031	0.3847	99.6153	0.8830
24.5	3,129,432	35,122	1.1223	98.8777	0.8796
25.5	3,133,527	16,511	0.5269	99.4731	0.8697
26.5	3,142,416	33,572	1.0683	98.9317	0.8651
27.5	3,158,393	9,579	0.3033	99.6967	0.8559
28.5	3,288,495	10,891	0.3312	99.6688	0.8533
29.5	3,478,118	16,633	0.4782	99.5218	0.8505
30.5	3,660,502	18,628	0.5089	99.4911	0.8464
31.5	3,861,223	15,339	0.3973	99.6027	0.8421
32.5	4,135,861	8,873	0.2145	99.7855	0.8388
33.5	4,430,951	26,216	0.5917	99.4083	0.8370
34.5	4,927,974	19,471	0.3951	99.6049	0.8320
35.5	5,248,483	18,688	0.3561	99.6439	0.8287
36.5	5,375,844	43,775	0.8143	99.1857	0.8258
37.5	5,407,572	29,070	0.5376	99.4624	0.8190
38.5	5,467,381	56,405	1.0317	98.9683	0.8146

39.5	5,471,685	45,625	0.8338	99.1662	0.8062
40.5	5,463,588	108,904	1.9933	98.0067	0.7995
41.5	5,429,388	52,367	0.9645	99.0355	0.7836
42.5	5,472,576	26,783	0.4894	99.5106	0.7760
43.5	5,522,163	71,766	1.2996	98.7004	0.7722
44.5	5,484,544	55,266	1.0077	98.9923	0.7622
45.5	5,469,161	64,868	1.1861	98.8139	0.7545
46.5	5,471,650	49,773	0.9097	99.0903	0.7456
47.5	5,471,505	78,203	1.4293	98.5707	0.7388
48.5	5,437,138	54,614	1.0045	98.9955	0.7282
49.5	5,423,314	117,470	2.1660	97.8340	0.7209
50.5	5,327,033	73,049	1.3713	98.6287	0.7053
51.5	5,295,038	158,239	2.9884	97.0116	0.6956
52.5	4,975,818	78,385	1.5753	98.4247	0.6748
53.5	4,782,757	52,948	1.1071	98.8929	0.6642
54.5	4,578,456	62,696	1.3694	98.6306	0.6568
55.5	4,376,038	51,257	1.1713	98.8287	0.6478
56.5	4,222,227	56,109	1.3289	98.6711	0.6403
57.5	4,083,981	61,120	1.4966	98.5034	0.6317
58.5	3,949,600	80,732	2.0441	97.9559	0.6223
59.5	3,790,185	55,876	1.4742	98.5258	0.6096
60.5	3,638,400	43,725	1.2018	98.7982	0.6006
61.5	3,469,459	33,878	0.9765	99.0235	0.5934
62.5	3,394,572	28,248	0.8321	99.1679	0.5876
63.5	3,328,050	30,220	0.9080	99.0920	0.5827
64.5	3,235,397	28,460	0.8796	99.1204	0.5774
65.5	3,203,731	28,905	0.9022	99.0978	0.5723
66.5	3,179,586	61,714	1.9409	98.0591	0.5672
67.5	3,124,815	23,987	0.7676	99.2324	0.5561
68.5	3,119,121	25,860	0.8291	99.1709	0.5519
69.5	3,100,329	59,954	1.9338	98.0662	0.5473
70.5	3,019,117	29,009	0.9609	99.0391	0.5367
71.5	2,982,166	29,299	0.9825	99.0175	0.5316
72.5	2,949,106	29,893	1.0136	98.9864	0.5263
73.5	2,913,292	35,406	1.2153	98.7847	0.5210
74.5	2,871,383	28,980	1.0093	98.9907	0.5147
75.5	2,842,312	34,051	1.1980	98.8020	0.5095
76.5	2,816,762	33,491	1.1890	98.8110	0.5034
77.5	2,788,673	34,848	1.2496	98.7504	0.4974
78.5	2,750,309	32,928	1.1972	98.8028	0.4912
79.5	2,713,776	47,112	1.7360	98.2640	0.4853
80.5	2,650,562	47,969	1.8098	98.1902	0.4769
81.5	2,530,334	27,518	1.0875	98.9125	0.4682
82.5	2,364,297	46,625	1.9720	98.0280	0.4631
83.5	2,232,862	41,201	1.8452	98.1548	0.4540
84.5	2,077,242	31,072	1.4958	98.5042	0.4456
85.5	1,885,421	24,574	1.3034	98.6966	0.4390

86.5	1,718,109	25,940	1.5098	98.4902	0.4332
87.5	1,486,470	23,389	1.5734	98.4266	0.4267
88.5	1,347,034	15,238	1.1312	98.8688	0.4200
89.5	1,235,597	19,402	1.5702	98.4298	0.4152
90.5	1,184,001	21,980	1.8565	98.1435	0.4087
91.5	1,126,891	11,381	1.0100	98.9900	0.4011
92.5	1,077,369	19,745	1.8327	98.1673	0.3971
93.5	1,039,730	30,857	2.9678	97.0322	0.3898
94.5	972,176	17,775	1.8284	98.1716	0.3782
95.5	907,169	8,702	0.9593	99.0407	0.3713
96.5	860,900	12,264	1.4246	98.5754	0.3678
97.5	835,201	18,199	2.1790	97.8210	0.3625
98.5	809,630	11,554	1.4271	98.5729	0.3546
99.5	767,011	10,325	1.3461	98.6539	0.3496
100.5	732,735	15,300	2.0880	97.9120	0.3449
101.5	684,311	19,249	2.8129	97.1871	0.3377
102.5	638,729	14,273	2.2346	97.7654	0.3282
103.5	597,334	16,489	2.7605	97.2395	0.3208
104.5	563,017	15,572	2.7658	97.2342	0.3120
105.5	527,368	9,567	1.8141	98.1859	0.3033
106.5	492,463	12,911	2.6216	97.3784	0.2978
107.5	456,679	14,513	3.1779	96.8221	0.2900
108.5	417,349	10,654	2.5528	97.4472	0.2808
109.5	393,316	15,392	3.9135	96.0865	0.2736
110.5	350,454	8,907	2.5415	97.4585	0.2629
111.5	314,654	7,261	2.3076	97.6924	0.2562
112.5	293,870	8,299	2.8242	97.1758	0.2503
113.5	277,403	4,655	1.6781	98.3219	0.2433
114.5	264,118	7,196	2.7245	97.2755	0.2392
115.5	245,291	4,796	1.9551	98.0449	0.2327
116.5	226,285	8,340	3.6855	96.3145	0.2281
117.5	213,118	1,744	0.8184	99.1816	0.2197
118.5	203,623	3,856	1.8936	98.1064	0.2179
119.5	197,184	2,255	1.1439	98.8561	0.2138
120.5	188,609	2,901	1.5379	98.4621	0.2113
121.5	178,467	5,957	3.3380	96.6620	0.2081
122.5	168,124	7,947	4.7270	95.2730	0.2011
123.5	155,809	2,154	1.3823	98.6177	0.1916
124.5	149,871	2,719	1.8141	98.1859	0.1890
125.5	141,309	5,123	3.6251	96.3749	0.1856
126.5	134,418	4,694	3.4921	96.5079	0.1788
127.5	127,801	4,538	3.5511	96.4489	0.1726
128.5	117,346	5,215	4.4437	95.5563	0.1665
129.5	109,692	2,312	2.1073	97.8927	0.1591
130.5	104,317	3,016	2.8909	97.1091	0.1557
131.5	99,009	919	0.9284	99.0716	0.1512
132.5	95,567	3,082	3.2249	96.7751	0.1498

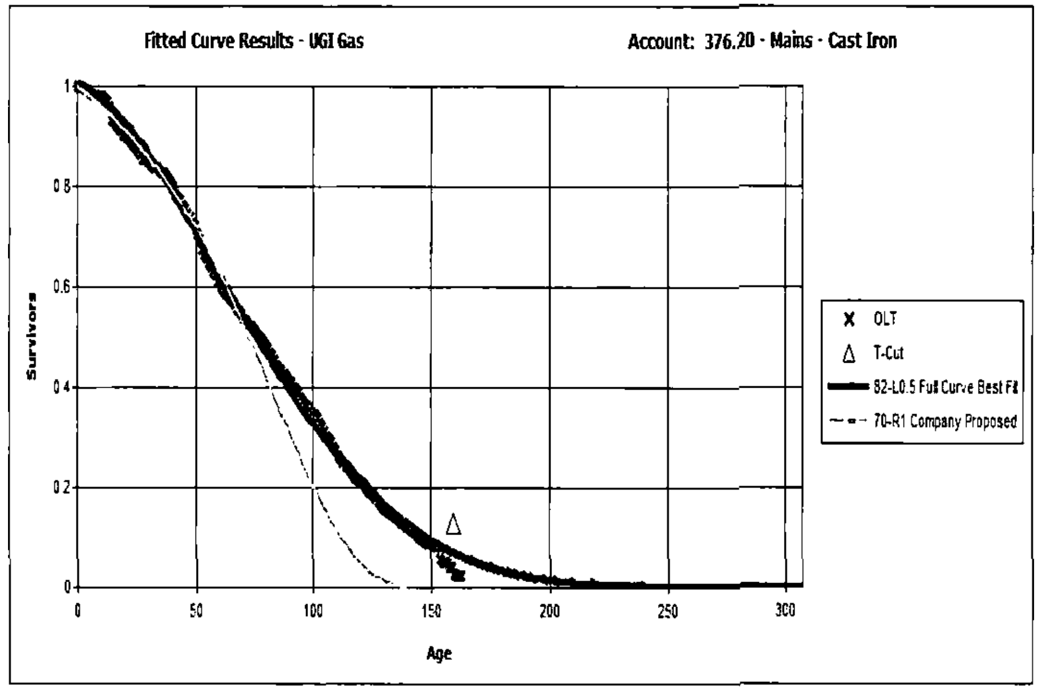
133.5	89,221	1,140	1.2772	98.7228	0.1450
134.5	82,273	2,002	2.4333	97.5667	0.1431
135.5	72,765	1,470	2.0199	97.9801	0.1396
136.5	66,470	3,144	4.7306	95.2694	0.1368
137.5	62,971	1,078	1.7116	98.2884	0.1303
138.5	45,966	1,903	4.1399	95.8601	0.1281
139.5	31,681	1,040	3.2820	96.7180	0.1228
140.5	29,283	874	2.9854	97.0146	0.1188
141.5	23,869	880	3.6855	96.3145	0.1152
142.5	22,567	639	2.8322	97.1678	0.1110
143.5	19,656	992	5.0480	94.9520	0.1078
144.5	17,701	434	2.4535	97.5465	0.1024
145.5	16,904	663	3.9220	96.0780	0.0999
146.5	14,916	582	3.9044	96.0956	0.0960
147.5	13,914	672	4.8290	95.1710	0.0922
148.5	13,242	196	1.4794	98.5206	0.0878
149.5	13,334	0	0.0000	100.0000	0.0865
150.5	13,325	92	0.6888	99.3112	0.0865
151.5	9,469	466	4.9215	95.0785	0.0859
152.5	7,324	2,133	29.1182	70.8818	0.0816
153.5	5,350	699	13.0673	86.9327	0.0579
154.5	4,651	0	0.0000	100.0000	0.0503
155.5	4,393	53	1.2064	98.7936	0.0503
156.5	4,340	836	19.2670	80.7330	0.0497
157.5	2,667	0	0.0000	100.0000	0.0401
158.5	2,860	827	28.9271	71.0729	0.0401
159.5	1,657	272	16.3891	83.6109	0.0285
160.5	218	0	0.0000	100.0000	0.0238
161.5	82	0	0.0000	100.0000	0.0238
162.5	85	0	0.0000	100.0000	0.0238

Best Fit Curve Results
UGI Gas
Account: 376.20 - Mains - Cast Iron

Curve	Life	Sum of Squared Differences
BAND	**1848 - 2011**	
L0.5	82.0	316.594
S-0.5	80.0	770.810
L0	82.0	855.632
L1	82.0	1,107.445
O1	79.0	1,313.811
R0.5	80.0	1,341.164
O2	84.0	2,214.970
S0	81.0	2,561.199
L1.5	82.0	3,475.500
R1	81.0	4,490.010
S0.5	82.0	5,467.409
L2	83.0	7,443.160
R1.5	81.0	8,656.410
S1	82.0	9,887.899
O3	98.0	11,377.457
R2	82.0	14,936.891
S1.5	82.0	15,133.848
L3	83.0	20,208.794
S2	83.0	21,747.336
R2.5	82.0	21,939.500
O4	100.0	24,377.736
R3	82.0	30,871.535
S3	82.0	35,919.507
L4	82.0	40,587.743
R4	82.0	47,909.853
S4	82.0	55,262.731
L5	81.0	60,197.941
R5	81.0	68,731.493
S5	81.0	73,717.378
S6	80.0	89,592.256
SQ	77.0	118,414.209

Analytical Parameters

OLT Placement Band:	1848 - 2011
OLT Experience Band	1848 - 2011
Minimum Life Paramet	1
Maximum Life Parame	100
Life Increment Parame	1
Max Age (T-Cut):	159.5



Analytical Parameters	
OLT Placement Band:	1848 - 2011
OLT Experience Band:	1848 - 2011
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	161.0

UGI Gas 2017 GAs

376.2 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 82 L0.5

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	0	82.00	81.52	0	0
2016	1.5	0	82.00	80.64	0	0
2015	2.5	0	82.00	79.79	0	0
2014	3.5	35,528	82.00	78.96	433	34,210
2013	4.5	0	82.00	78.15	0	0
2012	5.5	5,980	82.00	77.35	73	5,641
2011	6.5	0	82.00	76.58	0	0
2010	7.5	0	82.00	75.82	0	0
2009	8.5	0	82.00	75.07	0	0
2008	9.5	0	82.00	74.34	0	0
2007	10.5	0	82.00	73.61	0	0
2006	11.5	0	82.00	72.90	0	0
2005	12.5	0	82.00	72.21	0	0
2004	13.5	0	82.00	71.52	0	0
2003	14.5	0	82.00	70.85	0	0
2002	15.5	0	82.00	70.19	0	0
2001	16.5	0	82.00	69.54	0	0
2000	17.5	0	82.00	68.90	0	0
1999	18.5	0	82.00	68.28	0	0
1998	19.5	0	82.00	67.66	0	0
1997	20.5	0	82.00	67.06	0	0
1996	21.5	0	82.00	66.46	0	0
1995	22.5	0	82.00	65.88	0	0
1994	23.5	0	82.00	65.31	0	0
1993	24.5	0	82.00	64.75	0	0
1992	25.5	0	82.00	64.20	0	0
1991	26.5	0	82.00	63.66	0	0
1990	27.5	0	82.00	63.13	0	0
1989	28.5	0	82.00	62.61	0	0
1988	29.5	0	82.00	62.10	0	0

1987	30.5	0	82.00	61.60	0	0
1986	31.5	0	82.00	61.11	0	0
1985	32.5	0	82.00	60.63	0	0
1984	33.5	0	82.00	60.16	0	0
1983	34.5	0	82.00	59.69	0	0
1982	35.5	0	82.00	59.24	0	0
1981	36.5	0	82.00	58.79	0	0
1980	37.5	0	82.00	58.35	0	0
1979	38.5	0	82.00	57.92	0	0
1978	39.5	0	82.00	57.50	0	0
1977	40.5	0	82.00	57.08	0	0
1976	41.5	0	82.00	56.67	0	0
1975	42.5	0	82.00	56.27	0	0
1974	43.5	0	82.00	55.87	0	0
1973	44.5	0	82.00	55.47	0	0
1972	45.5	0	82.00	55.08	0	0
1971	46.5	0	82.00	54.70	0	0
1970	47.5	0	82.00	54.32	0	0
1969	48.5	0	82.00	53.94	0	0
1968	49.5	306	82.00	53.56	4	200
1967	50.5	0	82.00	53.19	0	0
1966	51.5	0	82.00	52.82	0	0
1965	52.5	0	82.00	52.46	0	0
1964	53.5	0	82.00	52.09	0	0
1963	54.5	8,126	82.00	51.73	99	5,126
1962	55.5	11,525	82.00	51.37	141	7,220
1961	56.5	51	82.00	51.01	1	32
1960	57.5	6,075	82.00	50.66	74	3,753
1959	58.5	178,957	82.00	50.31	2,182	109,787
1958	59.5	111,790	82.00	49.96	1,363	68,104
1957	60.5	160,083	82.00	49.61	1,952	96,846
1956	61.5	148,653	82.00	49.26	1,813	89,306
1955	62.5	115,644	82.00	48.92	1,410	68,992
1954	63.5	99,146	82.00	48.58	1,209	58,737
1953	64.5	140,980	82.00	48.24	1,719	82,939
1952	65.5	82,145	82.00	47.91	1,002	47,990
1951	66.5	87,061	82.00	47.57	1,062	50,508
1950	67.5	92,943	82.00	47.24	1,133	53,544
1949	68.5	41,139	82.00	46.91	502	23,535
1948	69.5	51,804	82.00	46.58	632	29,430
1947	70.5	52,902	82.00	46.26	645	29,844
1946	71.5	16,019	82.00	45.94	195	8,974
1945	72.5	3,545	82.00	45.62	43	1,972
1944	73.5	13,200	82.00	45.30	161	7,292
1943	74.5	4,611	82.00	44.98	56	2,529
1942	75.5	2,673	82.00	44.67	33	1,456
1941	76.5	26,085	82.00	44.36	318	14,110

1940	77.5	11,565	82.00	44.05	141	6,212
1939	78.5	19,522	82.00	43.74	238	10,413
1938	79.5	11,422	82.00	43.43	139	6,050
1937	80.5	9,243	82.00	43.13	113	4,862
1936	81.5	8,322	82.00	42.83	101	4,346
1935	82.5	5,545	82.00	42.53	68	2,876
1934	83.5	3,136	82.00	42.23	38	1,615
1933	84.5	6,886	82.00	41.93	84	3,522
1932	85.5	6,993	82.00	41.64	85	3,551
1931	86.5	8,326	82.00	41.35	102	4,198
1930	87.5	51,697	82.00	41.06	630	25,886
1929	88.5	93,368	82.00	40.77	1,139	46,424
1928	89.5	59,998	82.00	40.49	732	29,623
1927	90.5	76,701	82.00	40.20	935	37,604
1926	91.5	101,279	82.00	39.92	1,235	49,306
1925	92.5	101,439	82.00	39.64	1,237	49,037
1924	93.5	172,018	82.00	39.36	2,098	82,572
1923	94.5	76,365	82.00	39.09	931	36,399
1922	95.5	78,218	82.00	38.81	954	37,020
1921	96.5	36,776	82.00	38.54	448	17,284
1920	97.5	30,394	82.00	38.27	371	14,184
1919	98.5	25,427	82.00	38.00	310	11,783
1918	99.5	13,420	82.00	37.73	164	6,175
1917	100.5	24,161	82.00	37.46	295	11,039
1916	101.5	31,648	82.00	37.20	386	14,358
1915	102.5	22,349	82.00	36.94	273	10,068
1914	103.5	9,527	82.00	36.68	116	4,261
1913	104.5	7,250	82.00	36.42	88	3,220
1912	105.5	17,937	82.00	36.16	219	7,910
1911	106.5	15,947	82.00	35.91	194	6,983
1910	107.5	19,563	82.00	35.66	239	8,506
1909	108.5	14,008	82.00	35.40	171	6,048
1908	109.5	17,860	82.00	35.15	218	7,657
1907	110.5	11,057	82.00	34.91	135	4,707
1906	111.5	8,378	82.00	34.66	102	3,541
1905	112.5	10,431	82.00	34.41	127	4,378
1904	113.5	10,137	82.00	34.17	124	4,224
1903	114.5	6,749	82.00	33.93	82	2,792
1902	115.5	1,062	82.00	33.69	13	436
		2,733,094			33,330	1,493,147

AVERAGE SERVICE LIFE 82.00
AVERAGE REMAINING LIFE 44.80

Observed Life Table Results
UGI Gas
Account: 376.30 - Mains - Plastic

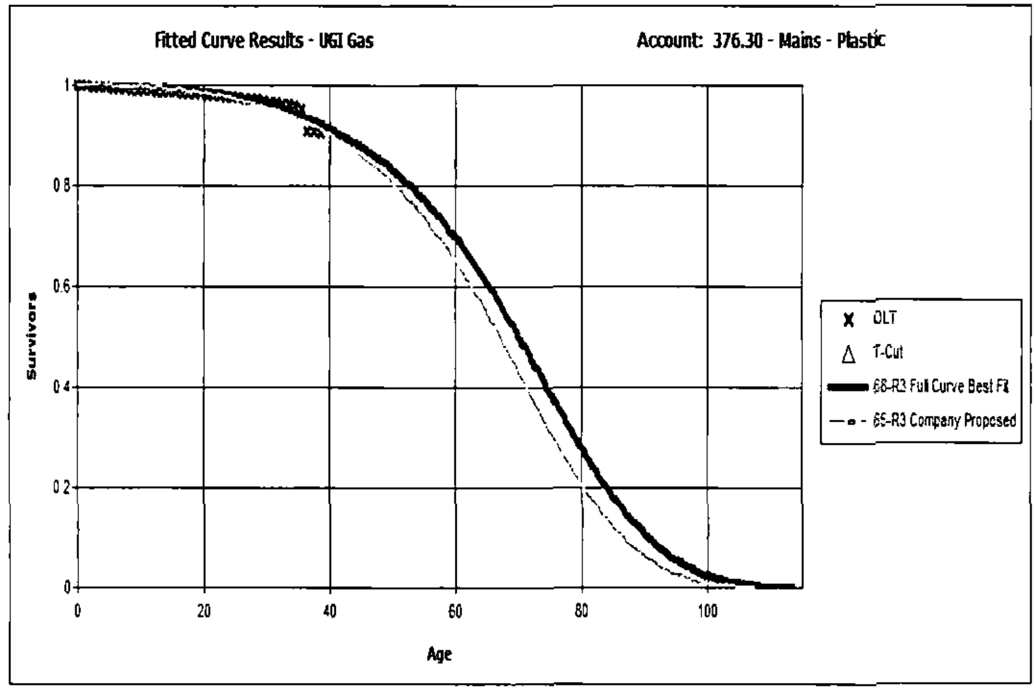
Age	Exposures	Retiremen	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors
BAND		1972 - 2011			
0	322,168,729	291	0.0001	99.9999	1.0000
0.5	306,719,011	229,432	0.0748	99.9252	1.0000
1.5	294,696,641	364,407	0.1237	99.8763	0.9993
2.5	282,479,763	230,045	0.0814	99.9186	0.9980
3.5	269,964,100	261,620	0.0969	99.9031	0.9972
4.5	255,403,445	470,392	0.1842	99.8158	0.9962
5.5	239,887,276	263,918	0.1100	99.8900	0.9944
6.5	225,108,086	250,147	0.1111	99.8889	0.9933
7.5	211,260,111	230,939	0.1093	99.8907	0.9922
8.5	196,755,962	56,196	0.0286	99.9714	0.9911
9.5	186,419,548	181,125	0.0972	99.9028	0.9908
10.5	175,045,555	90,297	0.0516	99.9484	0.9899
11.5	163,773,863	230,326	0.1406	99.8594	0.9894
12.5	152,764,174	230,265	0.1507	99.8493	0.9880
13.5	142,435,135	91,509	0.0642	99.9358	0.9865
14.5	128,008,669	57,525	0.0449	99.9551	0.9858
15.5	118,349,820	148,631	0.1256	99.8744	0.9854
16.5	102,692,182	67,887	0.0661	99.9339	0.9842
17.5	92,937,324	54,302	0.0584	99.9416	0.9835
18.5	87,502,366	68,878	0.0787	99.9213	0.9829
19.5	80,186,365	96,957	0.1209	99.8791	0.9822
20.5	70,711,292	76,169	0.1077	99.8923	0.9810
21.5	55,354,628	93,458	0.1688	99.8312	0.9799
22.5	41,562,821	23,304	0.0561	99.9439	0.9783
23.5	30,432,075	72,742	0.2390	99.7610	0.9777
24.5	22,362,252	12,540	0.0561	99.9439	0.9754
25.5	17,674,844	16,845	0.0953	99.9047	0.9748
26.5	13,918,327	13,549	0.0973	99.9027	0.9739
27.5	10,317,225	13,213	0.1281	99.8719	0.9730
28.5	7,692,122	22,562	0.2933	99.7067	0.9717
29.5	5,493,414	11,191	0.2037	99.7963	0.9689
30.5	3,901,255	7,558	0.1937	99.8063	0.9669
31.5	2,710,831	7,642	0.2819	99.7181	0.9650
32.5	2,070,669	1,887	0.0911	99.9089	0.9623
33.5	1,281,512	3,581	0.2794	99.7206	0.9614
34.5	772,528	4,944	0.6400	99.3600	0.9587
35.5	209,122	10,036	4.7991	95.2009	0.9526
36.5	116,199	0	0.0000	100.0000	0.9069
37.5	78,055	142	0.1817	99.8183	0.9069
38.5	25,153	25	0.1010	99.8990	0.9052

Best Fit Curve Results
UGI Gas
Account: 376.30 - Mains - Plastic

Curve	Life	Sum of Squared Differences
BAND	**1972 - 2011**	
R3	68.0	29.623
L2	82.0	32.423
S1.5	78.0	34.007
S1	89.0	35.563
L1.5	100.0	37.057
L3	63.0	37.704
R2.5	84.0	38.928
R4	54.0	39.019
S2	67.0	39.696
R2	100.0	52.480
S3	56.0	54.999
L4	53.0	59.820
S0.5	100.0	63.742
R5	46.0	87.874
S4	49.0	88.555
L5	47.0	95.416
S5	45.0	140.479
L1	100.0	161.713
S6	42.0	198.829
R1.5	100.0	228.012
S0	100.0	273.023
SQ	39.0	440.704
R1	100.0	638.197
L0.5	100.0	712.543
S-0.5	100.0	1,142.660
R0.5	100.0	1,476.864
L0	100.0	1,699.938
O1	100.0	2,678.368
O2	100.0	3,644.470
O3	100.0	8,871.319
O4	100.0	17,485.575

Analytical Parameters

OLT Placement Band:	1972 - 2011
OLT Experience Band:	1972 - 2011
Minimum Life Parametei	1
Maximum Life Paramete	100
Life Increment Paramete	1
Max Age (T-Cut):	38.5



Analytical Parameters

OLT Placement Band:	1972 - 2011
OLT Experience Band:	1972 - 2011
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	40.0

UGI Gas 2017 GAs

376.3 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 68 R3

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	41,410,360	68.00	67.51	608,976	41,109,642
2016	1.5	43,683,664	68.00	66.52	642,407	42,734,654
2015	2.5	25,049,460	68.00	65.54	368,374	24,143,709
2014	3.5	33,631,584	68.00	64.56	494,582	31,931,033
2013	4.5	30,170,971	68.00	63.58	443,691	28,211,798
2012	5.5	22,785,961	68.00	62.61	335,088	20,979,577
2011	6.5	17,050,394	68.00	61.64	250,741	15,454,888
2010	7.5	12,229,607	68.00	60.67	179,847	10,910,767
2009	8.5	11,855,902	68.00	59.70	174,352	10,408,802
2008	9.5	12,193,022	68.00	58.74	179,309	10,531,897
2007	10.5	14,260,882	68.00	57.78	209,719	12,116,602
2006	11.5	15,100,310	68.00	56.82	222,063	12,617,197
2005	12.5	14,488,832	68.00	55.86	213,071	11,903,102
2004	13.5	13,567,819	68.00	54.91	199,527	10,956,900
2003	14.5	14,498,521	68.00	53.97	213,214	11,506,847
2002	15.5	10,328,767	68.00	53.03	151,894	8,054,438
2001	16.5	11,193,844	68.00	52.09	164,615	8,574,733
2000	17.5	11,096,390	68.00	51.16	163,182	8,347,864
1999	18.5	10,701,848	68.00	50.23	157,380	7,904,978
1998	19.5	10,081,785	68.00	49.31	148,262	7,310,113
1997	20.5	14,301,323	68.00	48.39	210,314	10,176,512
1996	21.5	9,580,343	68.00	47.47	140,887	6,688,601
1995	22.5	15,446,307	68.00	46.57	227,152	10,577,831
1994	23.5	9,639,918	68.00	45.67	141,763	6,473,766
1993	24.5	5,370,541	68.00	44.77	78,979	3,535,852
1992	25.5	7,184,846	68.00	43.88	105,660	4,636,375
1991	26.5	9,240,171	68.00	43.00	135,885	5,842,535
1990	27.5	15,153,529	68.00	42.12	222,846	9,386,097
1989	28.5	13,565,217	68.00	41.25	199,488	8,228,468
1988	29.5	11,014,805	68.00	40.38	161,982	6,541,453

1987	30.5	7,900,465	68.00	39.53	116,183	4,592,230
1986	31.5	4,575,293	68.00	38.67	67,284	2,602,196
1985	32.5	3,668,657	68.00	37.83	53,951	2,041,006
1984	33.5	3,497,525	68.00	36.99	51,434	1,902,755
1983	34.5	2,491,682	68.00	36.16	36,642	1,325,143
1982	35.5	2,137,397	68.00	35.34	31,432	1,110,871
1981	36.5	1,561,510	68.00	34.53	22,963	792,852
1980	37.5	1,203,022	68.00	33.72	17,691	596,541
1979	38.5	607,475	68.00	32.92	8,933	294,085
1978	39.5	736,918	68.00	32.13	10,837	348,162
1977	40.5	482,828	68.00	31.34	7,100	222,551
1976	41.5	531,781	68.00	30.57	7,820	239,041
1975	42.5	61,494	68.00	29.80	904	26,948
1974	43.5	15,820	68.00	29.04	233	6,756
1973	44.5	51,502	68.00	28.29	757	21,426
1972	45.5	22,298	68.00	27.55	328	9,033
		515,422,589			7,579,744	423,928,626

AVERAGE SERVICE LIFE 68.00
AVERAGE REMAINING LIFE 55.93

UGI Gas 2017 GAs

376.5 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 70 R1

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	0	70.00	69.63	0	0
2016	1.5	0	70.00	68.89	0	0
2015	2.5	0	70.00	68.15	0	0
2014	3.5	0	70.00	67.42	0	0
2013	4.5	0	70.00	66.69	0	0
2012	5.5	0	70.00	65.96	0	0
2011	6.5	0	70.00	65.23	0	0
2010	7.5	0	70.00	64.51	0	0
2009	8.5	0	70.00	63.80	0	0
2008	9.5	0	70.00	63.08	0	0
2007	10.5	0	70.00	62.37	0	0
2006	11.5	0	70.00	61.66	0	0
2005	12.5	0	70.00	60.95	0	0
2004	13.5	0	70.00	60.25	0	0
2003	14.5	0	70.00	59.55	0	0
2002	15.5	0	70.00	58.85	0	0
2001	16.5	0	70.00	58.15	0	0
2000	17.5	0	70.00	57.46	0	0
1999	18.5	0	70.00	56.76	0	0
1998	19.5	0	70.00	56.07	0	0
1997	20.5	0	70.00	55.39	0	0
1996	21.5	0	70.00	54.70	0	0
1995	22.5	0	70.00	54.02	0	0
1994	23.5	0	70.00	53.34	0	0
1993	24.5	0	70.00	52.66	0	0
1992	25.5	0	70.00	51.98	0	0
1991	26.5	0	70.00	51.31	0	0
1990	27.5	0	70.00	50.64	0	0
1989	28.5	0	70.00	49.97	0	0
1988	29.5	0	70.00	49.30	0	0

1987	30.5	0	70.00	48.64	0	0
1986	31.5	0	70.00	47.97	0	0
1985	32.5	0	70.00	47.32	0	0
1984	33.5	0	70.00	46.66	0	0
1983	34.5	0	70.00	46.01	0	0
1982	35.5	0	70.00	45.36	0	0
1981	36.5	0	70.00	44.72	0	0
1980	37.5	0	70.00	44.08	0	0
1979	38.5	0	70.00	43.44	0	0
1978	39.5	0	70.00	42.81	0	0
1977	40.5	0	70.00	42.18	0	0
1976	41.5	0	70.00	41.55	0	0
1975	42.5	0	70.00	40.93	0	0
1974	43.5	0	70.00	40.31	0	0
1973	44.5	0	70.00	39.70	0	0
1972	45.5	0	70.00	39.09	0	0
1971	46.5	0	70.00	38.49	0	0
1970	47.5	0	70.00	37.89	0	0
1969	48.5	0	70.00	37.30	0	0
1968	49.5	0	70.00	36.71	0	0
1967	50.5	0	70.00	36.12	0	0
1966	51.5	0	70.00	35.54	0	0
1965	52.5	0	70.00	34.97	0	0
1964	53.5	0	70.00	34.40	0	0
1963	54.5	0	70.00	33.83	0	0
1962	55.5	0	70.00	33.27	0	0
1961	56.5	0	70.00	32.72	0	0
1960	57.5	0	70.00	32.17	0	0
1959	58.5	0	70.00	31.62	0	0
1958	59.5	0	70.00	31.08	0	0
1957	60.5	0	70.00	30.55	0	0
1956	61.5	0	70.00	30.01	0	0
1955	62.5	0	70.00	29.49	0	0
1954	63.5	0	70.00	28.97	0	0
1953	64.5	0	70.00	28.45	0	0
1952	65.5	0	70.00	27.94	0	0
1951	66.5	0	70.00	27.44	0	0
1950	67.5	0	70.00	26.94	0	0
1949	68.5	0	70.00	26.44	0	0
1948	69.5	0	70.00	25.95	0	0
1947	70.5	0	70.00	25.46	0	0
1946	71.5	0	70.00	24.98	0	0
1945	72.5	0	70.00	24.51	0	0
1944	73.5	0	70.00	24.03	0	0
1943	74.5	0	70.00	23.57	0	0
1942	75.5	0	70.00	23.11	0	0
1941	76.5	0	70.00	22.65	0	0

1940	77.5	0	70.00	22.19	0	0
1939	78.5	0	70.00	21.75	0	0
1938	79.5	0	70.00	21.30	0	0
1937	80.5	0	70.00	20.86	0	0
1936	81.5	0	70.00	20.43	0	0
1935	82.5	0	70.00	20.00	0	0
1934	83.5	0	70.00	19.57	0	0
1933	84.5	0	70.00	19.15	0	0
1932	85.5	0	70.00	18.73	0	0
1931	86.5	0	70.00	18.32	0	0
1930	87.5	0	70.00	17.91	0	0
1929	88.5	0	70.00	17.50	0	0
1928	89.5	0	70.00	17.10	0	0
1927	90.5	0	70.00	16.70	0	0
1926	91.5	0	70.00	16.31	0	0
1925	92.5	0	70.00	15.92	0	0
1924	93.5	43,233	70.00	15.54	618	9,595
1923	94.5	14,827	70.00	15.15	212	3,210
1922	95.5	14,231	70.00	14.78	203	3,004
1921	96.5	9,356	70.00	14.40	134	1,925
1920	97.5	2,322	70.00	14.03	33	466
1919	98.5	5,274	70.00	13.67	75	1,030
1918	99.5	4,098	70.00	13.30	59	779
1917	100.5	3,880	70.00	12.94	55	717
1916	101.5	19,636	70.00	12.59	281	3,531
1915	102.5	24,229	70.00	12.24	346	4,235
1914	103.5	52,379	70.00	11.89	748	8,896
1913	104.5	19,952	70.00	11.54	285	3,290
1912	105.5	12,488	70.00	11.20	178	1,998
1911	106.5	19,368	70.00	10.86	277	3,006
1910	107.5	9,002	70.00	10.53	129	1,354
1909	108.5	6,566	70.00	10.20	94	957
1908	109.5	6,471	70.00	9.87	92	912
1907	110.5	3,012	70.00	9.54	43	411
1906	111.5	4,635	70.00	9.22	66	611
1905	112.5	2,829	70.00	8.90	40	360
1904	113.5	6,859	70.00	8.59	98	842
1903	114.5	2,784	70.00	8.27	40	329
1902	115.5	858	70.00	7.97	12	98
1901	116.5	1,823	70.00	7.66	26	199
1900	117.5	216	70.00	7.35	3	23
1899	118.5	935	70.00	7.05	13	94
1898	119.5	237	70.00	6.75	3	23
1897	120.5	70	70.00	6.45	1	6
1896	121.5	200	70.00	6.16	3	18
1895	122.5	64	70.00	5.86	1	5
1894	123.5	1	70.00	5.57	0	0

1893	124.5	226	70.00	5.27	3	17
1892	125.5	8	70.00	4.97	0	1
1891	126.5	191	70.00	4.67	3	13
1890	127.5	30	70.00	4.37	0	2
1889	128.5	230	70.00	4.06	3	13
1888	129.5	55	70.00	3.74	1	3
1887	130.5	0	70.00	3.41	0	0
1886	131.5	2	70.00	3.08	0	0
1885	132.5	0	70.00	2.74	0	0
1884	133.5	0	70.00	2.40	0	0
1883	134.5	81	70.00	2.07	1	2
1882	135.5	506	70.00	1.74	7	13
1881	136.5	229	70.00	1.42	3	5
1880	137.5	911	70.00	1.10	13	14
1879	138.5	2	70.00	0.81	0	0
1878	139.5	0	70.00	0.58	0	0
1877	140.5	0	70.00	0.50	0	0
1876	141.5	0	70.00	0.50	0	0
1875	142.5	2	70.00	0.50	0	0
1874	143.5	25	70.00	0.50	0	0
1873	144.5	46	70.00	0.50	1	0
1872	145.5	0	70.00	0.50	0	0
1871	146.5	0	70.00	0.50	0	0
1870	147.5	14	70.00	0.50	0	0
1869	148.5	5	70.00	0.50	0	0
1868	149.5	18	70.00	0.50	0	0
1867	150.5	31	70.00	0.50	0	0
1866	151.5	0	70.00	0.50	0	0
1865	152.5	0	70.00	0.50	0	0
1864	153.5	0	70.00	0.50	0	0
1863	154.5	0	70.00	0.50	0	0
1862	155.5	0	70.00	0.50	0	0
1861	156.5	0	70.00	0.50	0	0
1860	157.5	148	70.00	0.50	2	1
1859	158.5	2	70.00	0.50	0	0
1858	159.5	341	70.00	0.50	5	2
		294,940			4,213	52,011

AVERAGE SERVICE LIFE 70.00
AVERAGE REMAINING LIFE 12.34

Observed Life Table Results
UGI Gas
Account: 378 - Meas and Reg Eqpmt

Age	Exposures	Retiremen	Retiremen Ratio (%)	Survivor Ratio (%)	Cumulative Survivors
BAND		1887 - 2011			
0	19,366,033	0	0.0000	100.0000	1.0000
0.5	17,982,781	4,823	0.0268	99.9732	1.0000
1.5	17,490,629	1,463	0.0084	99.9916	0.9997
2.5	16,941,103	81,227	0.4795	99.5205	0.9996
3.5	15,390,628	197,675	1.2844	98.7156	0.9949
4.5	14,450,436	22,397	0.1550	99.8450	0.9821
5.5	13,556,409	27,246	0.2010	99.7990	0.9806
6.5	12,638,566	30,686	0.2428	99.7572	0.9786
7.5	11,389,485	29,301	0.2573	99.7427	0.9762
8.5	9,108,945	21,431	0.2353	99.7647	0.9737
9.5	8,820,055	38,664	0.4384	99.5616	0.9714
10.5	8,259,296	38,520	0.4664	99.5336	0.9671
11.5	7,552,927	76,168	1.0085	98.9915	0.9626
12.5	7,301,884	32,780	0.4489	99.5511	0.9529
13.5	6,773,606	25,359	0.3744	99.6256	0.9487
14.5	6,451,245	17,299	0.2681	99.7319	0.9451
15.5	5,498,314	14,027	0.2551	99.7449	0.9426
16.5	5,065,132	28,680	0.5662	99.4338	0.9402
17.5	4,865,268	28,035	0.5762	99.4238	0.9348
18.5	4,738,617	172,246	3.6349	96.3651	0.9295
19.5	4,267,066	19,744	0.4627	99.5373	0.8957
20.5	4,043,234	87,103	2.1543	97.8457	0.8915
21.5	3,768,368	23,678	0.6283	99.3717	0.8723
22.5	3,384,107	28,299	0.8362	99.1638	0.8668
23.5	3,175,973	67,191	2.1156	97.8844	0.8596
24.5	2,945,977	15,664	0.5317	99.4683	0.8414
25.5	2,731,848	110,986	4.0627	95.9373	0.8369
26.5	2,435,335	34,768	1.4276	98.5724	0.8029
27.5	2,312,896	31,293	1.3530	98.6470	0.7915
28.5	2,244,064	73,644	3.2817	96.7183	0.7808
29.5	1,975,526	18,405	0.9317	99.0683	0.7551
30.5	1,745,248	6,440	0.3690	99.6310	0.7481
31.5	1,634,657	14,676	0.8978	99.1022	0.7453
32.5	1,586,949	39,437	2.4851	97.5149	0.7386
33.5	1,487,478	20,191	1.3574	98.6426	0.7203
34.5	1,424,387	11,413	0.8013	99.1987	0.7105
35.5	1,338,751	25,017	1.8686	98.1314	0.7048
36.5	1,255,219	23,055	1.8367	98.1633	0.6916
37.5	1,170,842	21,700	1.8534	98.1466	0.6789
38.5	1,132,968	3,374	0.2978	99.7022	0.6664

39.5	1,077,108	26,281	2.4400	97.5600	0.6644
40.5	859,315	13,114	1.5261	98.4739	0.6482
41.5	793,442	4,504	0.5676	99.4324	0.6383
42.5	762,146	1,743	0.2286	99.7714	0.6347
43.5	715,237	31,405	4.3909	95.6091	0.6332
44.5	631,691	11,188	1.7711	98.2289	0.6054
45.5	597,268	9,254	1.5494	98.4506	0.5947
46.5	572,282	8,405	1.4687	98.5313	0.5855
47.5	544,580	11,024	2.0243	97.9757	0.5769
48.5	508,266	6,300	1.2395	98.7605	0.5652
49.5	462,456	5,749	1.2431	98.7569	0.5582
50.5	419,103	2,167	0.5171	99.4829	0.5512
51.5	382,780	3,589	0.9377	99.0623	0.5484
52.5	374,822	558	0.1487	99.8513	0.5432
53.5	336,549	11,722	3.4831	96.5169	0.5424
54.5	301,892	2,006	0.6644	99.3356	0.5235
55.5	205,915	2,784	1.3519	98.6481	0.5201
56.5	178,898	1,848	1.0328	98.9672	0.5130
57.5	118,496	1,270	1.0720	98.9280	0.5077
58.5	95,438	1,355	1.4194	98.5806	0.5023
59.5	70,534	1,661	2.3555	97.6445	0.4952
60.5	57,873	405	0.6990	99.3010	0.4835
61.5	39,311	3,472	8.8316	91.1684	0.4801
62.5	34,555	1,520	4.3981	95.6019	0.4377
63.5	31,304	0	0.0000	100.0000	0.4185
64.5	28,698	1,378	4.8014	95.1986	0.4185
65.5	26,440	1,269	4.8008	95.1992	0.3984
66.5	24,508	722	2.9444	97.0556	0.3793
67.5	23,787	0	0.0000	100.0000	0.3681
68.5	22,836	0	0.0000	100.0000	0.3681
69.5	20,584	0	0.0000	100.0000	0.3681
70.5	20,517	60	0.2924	99.7076	0.3681
71.5	20,091	0	0.0000	100.0000	0.3670
72.5	20,091	0	0.0000	100.0000	0.3670
73.5	20,091	0	0.0000	100.0000	0.3670
74.5	18,767	388	2.0660	97.9340	0.3670
75.5	17,507	0	0.0000	100.0000	0.3594
76.5	17,455	0	0.0000	100.0000	0.3594
77.5	17,455	599	3.4336	96.5664	0.3594
78.5	16,855	283	1.6790	98.3210	0.3471
79.5	16,572	0	0.0000	100.0000	0.3413
80.5	12,851	0	0.0000	100.0000	0.3413
81.5	12,091	647	5.3522	94.6478	0.3413
82.5	10,795	0	0.0000	100.0000	0.3230
83.5	10,749	0	0.0000	100.0000	0.3230
84.5	8,273	774	9.3597	90.6403	0.3230
85.5	5,834	0	0.0000	100.0000	0.2928

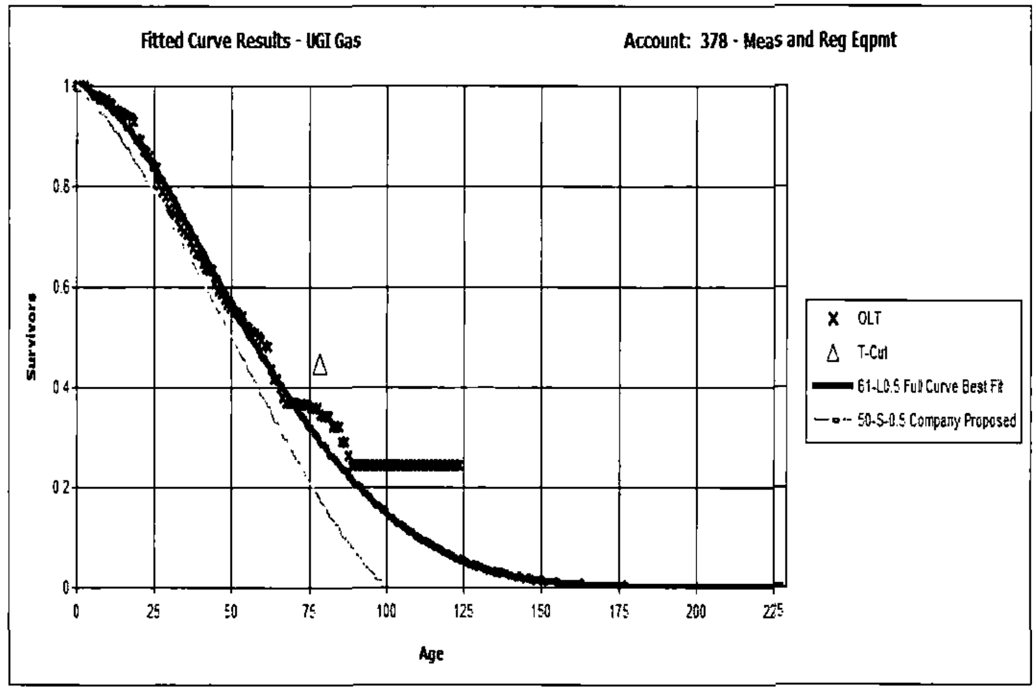
86.5	5,834	574	9.8387	90.1613	0.2928
87.5	2,560	206	8.0567	91.9433	0.2640
88.5	2,009	0	0.0000	100.0000	0.2427
89.5	2,009	0	0.0000	100.0000	0.2427
90.5	1,948	0	0.0000	100.0000	0.2427
91.5	1,108	0	0.0000	100.0000	0.2427
92.5	241	0	0.0000	100.0000	0.2427
93.5	241	0	0.0000	100.0000	0.2427
94.5	241	0	0.0000	100.0000	0.2427
95.5	60	0	0.0000	100.0000	0.2427
96.5	60	0	0.0000	100.0000	0.2427
97.5	60	0	0.0000	100.0000	0.2427
98.5	60	0	0.0000	100.0000	0.2427
99.5	60	0	0.0000	100.0000	0.2427
100.5	60	0	0.0000	100.0000	0.2427
101.5	0	0	0.0000	100.0000	0.2427
102.5	0	0	0.0000	100.0000	0.2427
103.5	0	0	0.0000	100.0000	0.2427
104.5	0	0	0.0000	100.0000	0.2427
105.5	0	0	0.0000	100.0000	0.2427
106.5	0	0	0.0000	100.0000	0.2427
107.5	0	0	0.0000	100.0000	0.2427
108.5	0	0	0.0000	100.0000	0.2427
109.5	0	0	0.0000	100.0000	0.2427
110.5	0	0	0.0000	100.0000	0.2427
111.5	0	0	0.0000	100.0000	0.2427
112.5	0	0	0.0000	100.0000	0.2427
113.5	0	0	0.0000	100.0000	0.2427
114.5	0	0	0.0000	100.0000	0.2427
115.5	0	0	0.0000	100.0000	0.2427
116.5	0	0	0.0000	100.0000	0.2427
117.5	0	0	0.0000	100.0000	0.2427
118.5	0	0	0.0000	100.0000	0.2427
119.5	0	0	0.0000	100.0000	0.2427
120.5	0	0	0.0000	100.0000	0.2427
121.5	0	0	0.0000	100.0000	0.2427
122.5	0	0	0.0000	100.0000	0.2427
123.5	0	0	0.0000	100.0000	0.2427

Best Fit Curve Results
UGI Gas
Account: 378 - Meas and Reg Eqpmt

Curve	Life	Sum of Squared Differences
BAND	**1887 - 2011**	
L0.5	61.0	355.384
L0	63.0	360.069
S-0.5	58.0	533.386
R0.5	57.0	815.973
L1	60.0	909.632
O1	58.0	1,033.930
O2	65.0	1,037.373
S0	57.0	1,093.461
R1	57.0	1,715.158
O3	86.0	1,971.345
S0.5	57.0	2,481.657
L1.5	59.0	2,482.423
R1.5	57.0	3,583.690
O4	100.0	3,718.717
S1	57.0	4,591.863
L2	59.0	4,918.690
R2	57.0	6,444.941
S1.5	58.0	7,435.304
R2.5	58.0	10,411.038
S2	58.0	10,976.123
L3	58.0	12,280.176
R3	58.0	15,361.874
S3	59.0	19,397.271
L4	59.0	23,501.757
R4	60.0	26,302.904
S4	59.0	31,934.476
L5	59.0	35,836.348
R5	60.0	41,213.175
S5	60.0	44,889.674
S6	59.0	56,281.473
SQ	59.0	78,165.666

Analytical Parameters

OLT Placement Band:	1887 - 2011
OLT Experience Band	1887 - 2011
Minimum Life Paramet	1
Maximum Life Parame	100
Life Increment Parame	1
Max Age (T-Cut):	78.5



Analytical Parameters

OLT Placement Band:	1887 - 2011
OLT Experience Band:	1887 - 2011
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	80.0

UGI Gas 2017 GAs

378 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 61 L0.5

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	5,026,329	61.00	60.53	82,399	4,987,570
2016	1.5	5,292,010	61.00	59.66	86,754	5,175,598
2015	2.5	3,737,198	61.00	58.82	61,266	3,603,692
2014	3.5	1,371,741	61.00	58.01	22,488	1,304,553
2013	4.5	843,404	61.00	57.23	13,826	791,225
2012	5.5	2,242,144	61.00	56.46	36,756	2,075,252
2011	6.5	1,576,390	61.00	55.71	25,842	1,439,777
2010	7.5	544,137	61.00	54.98	8,920	490,479
2009	8.5	532,133	61.00	54.27	8,723	473,445
2008	9.5	1,425,436	61.00	53.58	23,368	1,251,997
2007	10.5	717,596	61.00	52.90	11,764	622,290
2006	11.5	838,987	61.00	52.24	13,754	718,435
2005	12.5	853,737	61.00	51.59	13,996	722,004
2004	13.5	1,133,299	61.00	50.95	18,579	946,671
2003	14.5	2,107,236	61.00	50.34	34,545	1,738,903
2002	15.5	248,321	61.00	49.74	4,071	202,464
2001	16.5	403,354	61.00	49.15	6,612	324,977
2000	17.5	624,906	61.00	48.57	10,244	497,612
1999	18.5	140,135	61.00	48.02	2,297	110,306
1998	19.5	459,690	61.00	47.47	7,536	357,731
1997	20.5	274,061	61.00	46.94	4,493	210,892
1996	21.5	830,135	61.00	46.42	13,609	631,754
1995	22.5	368,758	61.00	45.92	6,045	277,587
1994	23.5	155,209	61.00	45.43	2,544	115,587
1993	24.5	78,676	61.00	44.95	1,290	57,974
1992	25.5	255,435	61.00	44.48	4,187	186,268
1991	26.5	177,216	61.00	44.03	2,905	127,908
1990	27.5	165,553	61.00	43.58	2,714	118,284
1989	28.5	295,715	61.00	43.15	4,848	209,180
1988	29.5	135,543	61.00	42.73	2,222	94,937

1987	30.5	127,308	61.00	42.31	2,087	88,302
1986	31.5	168,829	61.00	41.90	2,768	115,976
1985	32.5	153,701	61.00	41.50	2,520	104,578
1984	33.5	68,803	61.00	41.11	1,128	46,371
1983	34.5	30,308	61.00	40.73	497	20,235
1982	35.5	138,857	61.00	40.34	2,276	91,838
1981	36.5	144,184	61.00	39.97	2,364	94,472
1980	37.5	81,553	61.00	39.60	1,337	52,937
1979	38.5	25,352	61.00	39.23	416	16,303
1978	39.5	26,485	61.00	38.86	434	16,872
1977	40.5	30,177	61.00	38.50	495	19,045
1976	41.5	49,583	61.00	38.14	813	31,000
1975	42.5	37,882	61.00	37.78	621	23,464
1974	43.5	39,812	61.00	37.43	653	24,428
1973	44.5	7,138	61.00	37.08	117	4,339
1972	45.5	29,434	61.00	36.73	483	17,725
1971	46.5	88,617	61.00	36.39	1,453	52,865
1970	47.5	15,273	61.00	36.05	250	9,026
1969	48.5	6,697	61.00	35.71	110	3,921
1968	49.5	102	61.00	35.38	2	59
		34,124,579			559,419	30,699,107

AVERAGE SERVICE LIFE 61.00
AVERAGE REMAINING LIFE 54.88

UGI Gas 2017 GAs

378.1 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 13 S2

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	28,431	13.00	12.50	2,187	27,336
2016	1.5	30,000	13.00	11.50	2,308	26,540
2015	2.5	14,530	13.00	10.51	1,118	11,748
2014	3.5	0	13.00	9.55	0	0
2013	4.5	73,899	13.00	8.62	5,685	49,011
2012	5.5	138,327	13.00	7.75	10,641	82,511
2011	6.5	891,346	13.00	6.95	68,565	476,731
2010	7.5	28,510	13.00	6.22	2,193	13,645
2009	8.5	0	13.00	5.56	0	0
2008	9.5	44,009	13.00	4.96	3,385	16,805
2007	10.5	0	13.00	4.43	0	0
2006	11.5	0	13.00	3.95	0	0
2005	12.5	9,595	13.00	3.51	738	2,591
2004	13.5	25,287	13.00	3.12	1,945	6,064
2003	14.5	0	13.00	2.76	0	0
2002	15.5	0	13.00	2.43	0	0
2001	16.5	0	13.00	2.13	0	0
2000	17.5	0	13.00	1.86	0	0
1999	18.5	0	13.00	1.60	0	0
1998	19.5	10,973	13.00	1.36	844	1,150
1997	20.5	0	13.00	1.14	0	0
1996	21.5	11,952	13.00	0.94	919	863
1995	22.5	0	13.00	0.76	0	0
1994	23.5	9,755	13.00	0.60	750	448
		1,316,613			101,278	715,444

AVERAGE SERVICE LIFE 13.00
AVERAGE REMAINING LIFE 7.06

Observed Life Table Results
UGI Gas
Account: 379 - Meas and Reg Eqpmnt - City Gate

Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors
BAND		1950 - 2009			
0	4,201,831	0	0.0000	100.0000	1.0000
0.5	4,201,831	0	0.0000	100.0000	1.0000
1.5	4,201,831	0	0.0000	100.0000	1.0000
2.5	4,184,351	946	0.0226	99.9774	1.0000
3.5	4,039,171	12,486	0.3091	99.6909	0.9998
4.5	4,026,685	23,023	0.5718	99.4282	0.9967
5.5	4,003,662	24,641	0.6155	99.3845	0.9910
6.5	3,979,022	26,736	0.6719	99.3281	0.9849
7.5	3,952,286	3,606	0.0912	99.9088	0.9783
8.5	3,948,679	11,766	0.2980	99.7020	0.9774
9.5	3,936,914	11,576	0.2940	99.7060	0.9745
10.5	3,925,338	7,507	0.1912	99.8088	0.9716
11.5	3,917,831	26,220	0.6693	99.3307	0.9697
12.5	3,891,610	1,979	0.0508	99.9492	0.9632
13.5	3,881,230	8,773	0.2260	99.7740	0.9628
14.5	3,872,457	6,119	0.1580	99.8420	0.9606
15.5	3,476,294	6,414	0.1845	99.8155	0.9591
16.5	3,204,595	11,235	0.3506	99.6494	0.9573
17.5	3,187,163	23,328	0.7319	99.2681	0.9539
18.5	3,130,849	31,661	1.0112	98.9888	0.9470
19.5	2,900,945	16,455	0.5672	99.4328	0.9374
20.5	2,626,751	955	0.0364	99.9636	0.9321
21.5	2,497,310	8,252	0.3304	99.6696	0.9317
22.5	2,451,252	41,032	1.6739	98.3261	0.9286
23.5	2,391,455	42,959	1.7964	98.2036	0.9131
24.5	1,556,909	6,296	0.4044	99.5956	0.8967
25.5	1,284,878	6,487	0.5049	99.4951	0.8931
26.5	844,930	3,887	0.4600	99.5400	0.8886
27.5	641,117	23,255	3.6273	96.3727	0.8845
28.5	611,061	6,783	1.1101	98.8899	0.8524
29.5	462,332	12,366	2.6747	97.3253	0.8429
30.5	369,790	4,359	1.1789	98.8211	0.8204
31.5	360,793	6,167	1.7093	98.2907	0.8107
32.5	353,083	6,313	1.7879	98.2121	0.7969
33.5	342,528	27,058	7.8995	92.1005	0.7826
34.5	315,322	6,902	2.1888	97.8112	0.7208
35.5	295,602	6,544	2.2137	97.7863	0.7050
36.5	263,728	2,835	1.0751	98.9249	0.6894
37.5	241,874	82	0.0338	99.9662	0.6820
38.5	203,597	117	0.0574	99.9426	0.6818

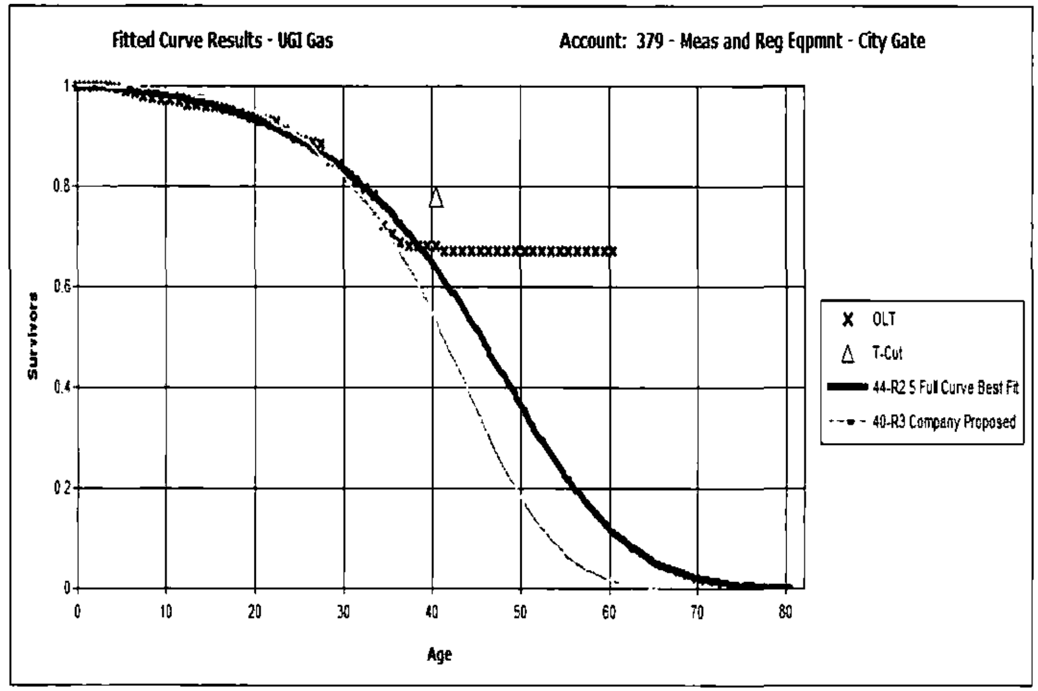
39.5	166,790	313	0.1874	99.8126	0.6814
40.5	166,477	2,345	1.4086	98.5914	0.6801
41.5	163,579	0	0.0000	100.0000	0.6705
42.5	147,647	0	0.0000	100.0000	0.6705
43.5	146,828	0	0.0000	100.0000	0.6705
44.5	132,453	0	0.0000	100.0000	0.6705
45.5	112,874	0	0.0000	100.0000	0.6705
46.5	71,278	0	0.0000	100.0000	0.6705
47.5	71,278	0	0.0000	100.0000	0.6705
48.5	71,247	0	0.0000	100.0000	0.6705
49.5	69,908	0	0.0000	100.0000	0.6705
50.5	67,992	0	0.0000	100.0000	0.6705
51.5	40,904	0	0.0000	100.0000	0.6705
52.5	36,511	0	0.0000	100.0000	0.6705
53.5	27,993	0	0.0000	100.0000	0.6705
54.5	22,621	0	0.0000	100.0000	0.6705
55.5	1,331	0	0.0000	100.0000	0.6705
56.5	1,331	0	0.0000	100.0000	0.6705
57.5	0	0	0.0000	100.0000	0.6705
58.5	0	0	0.0000	100.0000	0.6705
59.5	0	0	0.0000	100.0000	0.6705
60.5	0	0	0.0000	100.0000	0.6705

Best Fit Curve Results
UGI Gas
Account: 379 - Meas and Reg Eqpmnt - City Gate

Curve	Life	Sum of Squared Differences
BAND	**1950 - 2011**	
R2.5	44.0	90.599
L1.5	54.0	94.215
S1	49.0	99.623
L2	51.0	112.494
S1.5	47.0	113.476
R2	46.0	150.573
L1	60.0	179.283
S0.5	52.0	181.773
R3	42.0	188.799
S2	45.0	233.991
S0	57.0	328.652
R1.5	50.0	364.570
L0.5	66.0	374.292
L3	45.0	477.762
L0	76.0	590.837
R1	56.0	623.579
S-0.5	66.0	670.289
S3	42.0	719.424
R4	41.0	768.049
R0.5	67.0	873.557
O2	92.0	1,013.044
O1	82.0	1,013.905
L4	42.0	1,189.850
S4	41.0	1,798.764
O3	100.0	1,933.434
R5	40.0	2,367.714
L5	41.0	2,439.469
S5	40.0	3,340.614
S6	40.0	5,156.837
O4	100.0	6,099.945
SQ	41.0	9,609.002

Analytical Parameters

OLT Placement Band	1950 - 2009
OLT Experience Band	1950 - 2011
Minimum Life Paramet	1
Maximum Life Parame	100
Life Increment Parame	1
Max Age (T-Cut):	40.5



Analytical Parameters

OLT Placement Band:	1950 - 2011
OLT Experience Band:	1950 - 2011
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	42.0

UGI Gas 2017 GAs

379 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 44 R2.5

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	0	44.00	43.53	0	0
2016	1.5	0	44.00	42.58	0	0
2015	2.5	0	44.00	41.65	0	0
2014	3.5	0	44.00	40.71	0	0
2013	4.5	0	44.00	39.79	0	0
2012	5.5	0	44.00	38.86	0	0
2011	6.5	0	44.00	37.95	0	0
2010	7.5	0	44.00	37.03	0	0
2009	8.5	0	44.00	36.13	0	0
2008	9.5	0	44.00	35.23	0	0
2007	10.5	0	44.00	34.34	0	0
2006	11.5	0	44.00	33.45	0	0
2005	12.5	0	44.00	32.58	0	0
2004	13.5	0	44.00	31.71	0	0
2003	14.5	0	44.00	30.84	0	0
2002	15.5	0	44.00	29.99	0	0
2001	16.5	0	44.00	29.15	0	0
2000	17.5	0	44.00	28.31	0	0
1999	18.5	0	44.00	27.48	0	0
1998	19.5	0	44.00	26.66	0	0
1997	20.5	0	44.00	25.86	0	0
1996	21.5	0	44.00	25.06	0	0
1995	22.5	0	44.00	24.27	0	0
1994	23.5	0	44.00	23.49	0	0
1993	24.5	0	44.00	22.73	0	0
1992	25.5	194,722	44.00	21.97	4,425	97,237
1991	26.5	252,698	44.00	21.23	5,743	121,916
1990	27.5	125,723	44.00	20.50	2,857	58,563
1989	28.5	36,916	44.00	19.78	839	16,591
1988	29.5	18,280	44.00	19.07	415	7,922

1987	30.5	769,137	44.00	18.37	17,480	321,155
1986	31.5	257,468	44.00	17.69	5,852	103,517
1985	32.5	418,689	44.00	17.02	9,516	161,977
1984	33.5	192,455	44.00	16.37	4,374	71,595
1983	34.5	6,522	44.00	15.73	148	2,331
1982	35.5	135,551	44.00	15.11	3,081	46,538
1981	36.5	76,213	44.00	14.50	1,732	25,113
1980	37.5	4,386	44.00	13.91	100	1,386
1979	38.5	1,450	44.00	13.34	33	440
1978	39.5	3,965	44.00	12.78	90	1,152
1977	40.5	137	44.00	12.24	3	38
1976	41.5	11,805	44.00	11.73	268	3,146
1975	42.5	23,135	44.00	11.23	526	5,904
1974	43.5	17,214	44.00	10.75	391	4,205
1973	44.5	34,226	44.00	10.29	778	8,005
1972	45.5	32,527	44.00	9.85	739	7,283
1971	46.5	0	44.00	9.43	0	0
1970	47.5	479	44.00	9.03	11	98
1969	48.5	13,605	44.00	8.65	309	2,676
1968	49.5	689	44.00	8.29	16	130
1967	50.5	11,922	44.00	7.95	271	2,153
1966	51.5	15,981	44.00	7.62	363	2,767
1965	52.5	33,392	44.00	7.31	759	5,545
1964	53.5	0	44.00	7.01	0	0
1963	54.5	24	44.00	6.72	1	4
1962	55.5	1,018	44.00	6.45	23	149
1961	56.5	1,427	44.00	6.18	32	201
1960	57.5	19,760	44.00	5.93	449	2,662
1959	58.5	3,134	44.00	5.68	71	405
1958	59.5	5,936	44.00	5.44	135	733
1957	60.5	3,647	44.00	5.20	83	431
1956	61.5	14,047	44.00	4.96	319	1,585
1955	62.5	0	44.00	4.74	0	0
1954	63.5	806	44.00	4.51	18	83
		2,739,084			62,252	1,085,634

AVERAGE SERVICE LIFE	44.00
AVERAGE REMAINING LIFE	17.44

Observed Life Table Results
UGI Gas
Account: 380 - Services

Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors
BAND		1870 - 2011			
0	413,643,122	336,960	0.0815	99.9185	1.0000
0.5	390,440,264	1,735,909	0.4446	99.5554	0.9992
1.5	373,829,009	1,146,718	0.3067	99.6933	0.9947
2.5	358,099,400	1,214,218	0.3391	99.6609	0.9917
3.5	342,435,012	1,121,095	0.3274	99.6726	0.9883
4.5	330,317,928	1,185,934	0.3590	99.6410	0.9851
5.5	317,666,292	1,186,944	0.3736	99.6264	0.9816
6.5	305,620,204	1,152,800	0.3772	99.6228	0.9779
7.5	292,602,909	1,019,854	0.3485	99.6515	0.9742
8.5	280,368,110	1,075,564	0.3836	99.6164	0.9708
9.5	268,058,416	1,008,055	0.3761	99.6239	0.9671
10.5	255,940,914	1,212,936	0.4739	99.5261	0.9634
11.5	244,110,469	1,037,309	0.4249	99.5751	0.9589
12.5	232,488,535	1,047,405	0.4505	99.5495	0.9548
13.5	221,121,821	1,131,671	0.5118	99.4882	0.9505
14.5	207,196,482	1,203,378	0.5808	99.4192	0.9456
15.5	193,651,059	1,213,524	0.6267	99.3733	0.9401
16.5	177,894,239	1,158,614	0.6513	99.3487	0.9343
17.5	163,529,868	1,109,491	0.6785	99.3215	0.9282
18.5	155,089,173	1,016,408	0.6554	99.3446	0.9219
19.5	143,212,111	1,192,924	0.8330	99.1670	0.9158
20.5	131,281,068	1,165,345	0.8877	99.1123	0.9082
21.5	118,057,176	1,092,898	0.9257	99.0743	0.9001
22.5	105,931,420	1,011,406	0.9548	99.0452	0.8918
23.5	97,011,901	948,169	0.9774	99.0226	0.8833
24.5	89,360,356	939,827	1.0517	98.9483	0.8747
25.5	82,723,380	917,066	1.1086	98.8914	0.8655
26.5	75,953,111	855,579	1.1265	98.8735	0.8559
27.5	69,969,835	859,672	1.2286	98.7714	0.8462
28.5	64,152,874	966,428	1.5064	98.4936	0.8358
29.5	56,257,803	807,756	1.4358	98.5642	0.8232
30.5	47,480,919	741,449	1.5616	98.4384	0.8114
31.5	38,999,694	603,095	1.5464	98.4536	0.7987
32.5	33,445,079	513,412	1.5351	98.4649	0.7864
33.5	30,025,513	478,680	1.5942	98.4058	0.7743
34.5	26,442,809	481,829	1.8222	98.1778	0.7620
35.5	24,285,915	467,631	1.9255	98.0745	0.7481
36.5	22,336,214	418,711	1.8746	98.1254	0.7337
37.5	19,961,560	422,791	2.1180	97.8820	0.7199
38.5	17,730,838	373,063	2.1040	97.8960	0.7047

39.5	15,946,325	386,512	2.4238	97.5762	0.6899
40.5	14,318,001	372,201	2.5995	97.4005	0.6731
41.5	12,833,732	364,323	2.8388	97.1612	0.6556
42.5	11,459,606	265,342	2.3155	97.6845	0.6370
43.5	10,172,421	282,647	2.7786	97.2214	0.6223
44.5	9,038,920	241,208	2.6686	97.3314	0.6050
45.5	7,938,975	228,441	2.8775	97.1225	0.5888
46.5	6,922,218	215,301	3.1103	96.8897	0.5719
47.5	6,072,899	193,604	3.1880	96.8120	0.5541
48.5	5,295,069	169,926	3.2091	96.7909	0.5364
49.5	4,591,771	170,181	3.7062	96.2938	0.5192
50.5	3,891,810	157,835	4.0556	95.9444	0.5000
51.5	3,252,601	156,880	4.8232	95.1768	0.4797
52.5	2,717,917	119,901	4.4115	95.5885	0.4566
53.5	2,370,825	120,315	5.0748	94.9252	0.4364
54.5	2,082,803	110,212	5.2915	94.7085	0.4143
55.5	1,834,120	92,400	5.0378	94.9622	0.3924
56.5	1,653,636	90,595	5.4785	94.5215	0.3726
57.5	1,505,009	79,835	5.3046	94.6954	0.3522
58.5	1,380,173	93,462	6.7717	93.2283	0.3335
59.5	1,234,680	70,067	5.6749	94.3251	0.3109
60.5	1,124,962	60,440	5.3726	94.6274	0.2933
61.5	1,027,066	52,360	5.0980	94.9020	0.2775
62.5	945,864	47,196	4.9897	95.0103	0.2634
63.5	871,297	46,132	5.2947	94.7053	0.2502
64.5	799,752	41,066	5.1348	94.8652	0.2370
65.5	749,600	41,352	5.5165	94.4835	0.2248
66.5	704,120	35,910	5.1000	94.9000	0.2124
67.5	661,691	39,621	5.9878	94.0122	0.2016
68.5	618,186	35,595	5.7579	94.2421	0.1895
69.5	576,582	35,677	6.1877	93.8123	0.1786
70.5	530,224	29,985	5.6551	94.3449	0.1675
71.5	493,761	33,392	6.7629	93.2371	0.1581
72.5	455,637	28,980	6.3604	93.6396	0.1474
73.5	417,961	27,341	6.5415	93.4585	0.1380
74.5	384,248	25,444	6.6217	93.3783	0.1290
75.5	351,404	18,385	5.2319	94.7681	0.1204
76.5	328,667	26,082	7.9356	92.0644	0.1141
77.5	298,613	19,342	6.4772	93.5228	0.1051
78.5	274,884	16,344	5.9459	94.0541	0.0983
79.5	255,601	15,085	5.9016	94.0984	0.0924
80.5	234,345	14,183	6.0522	93.9478	0.0870
81.5	209,548	15,512	7.4025	92.5975	0.0817
82.5	179,484	11,636	6.4829	93.5171	0.0757
83.5	157,954	10,413	6.5924	93.4076	0.0708
84.5	133,930	8,670	6.4736	93.5264	0.0661
85.5	114,296	6,717	5.8766	94.1234	0.0618

86.5	94,261	5,367	5.6935	94.3065	0.0582
87.5	79,722	4,196	5.2629	94.7371	0.0549
88.5	67,112	3,916	5.8354	94.1646	0.0520
89.5	58,707	4,065	6.9241	93.0759	0.0489
90.5	50,896	3,507	6.8910	93.1090	0.0456
91.5	45,554	3,616	7.9388	92.0612	0.0424
92.5	39,688	2,915	7.3442	92.6558	0.0391
93.5	34,203	2,885	8.4335	91.5665	0.0362
94.5	27,674	2,045	7.3893	92.6107	0.0331
95.5	22,948	1,248	5.4397	94.5603	0.0307
96.5	19,828	1,024	5.1631	94.8369	0.0290
97.5	17,254	724	4.1970	95.8030	0.0275
98.5	15,650	1,034	6.6087	93.3913	0.0264
99.5	13,590	850	6.2576	93.7424	0.0246
100.5	11,545	876	7.5886	92.4114	0.0231
101.5	9,552	532	5.5670	94.4330	0.0213
102.5	8,071	541	6.7027	93.2973	0.0201
103.5	6,312	214	3.3948	96.6052	0.0188
104.5	5,322	139	2.6069	97.3931	0.0182
105.5	4,452	167	3.7456	96.2544	0.0177
106.5	3,769	112	2.9592	97.0408	0.0170
107.5	3,196	107	3.3389	96.6611	0.0165
108.5	2,645	215	8.1456	91.8544	0.0160
109.5	2,214	51	2.3218	97.6782	0.0147
110.5	2,026	245	12.0665	87.9335	0.0143
111.5	1,450	20	1.3497	98.6503	0.0126
112.5	1,378	38	2.7233	97.2767	0.0124
113.5	947	38	4.0003	95.9997	0.0121
114.5	821	25	3.0204	96.9796	0.0116
115.5	673	12	1.8412	98.1588	0.0113
116.5	205	5	2.2147	97.7853	0.0110
117.5	176	7	4.1910	95.8090	0.0108
118.5	169	3	1.6041	98.3959	0.0103
119.5	153	4	2.5288	97.4712	0.0102
120.5	139	2	1.7108	98.2892	0.0099
121.5	89	0	0.0000	100.0000	0.0098
122.5	62	0	0.0000	100.0000	0.0098
123.5	1	0	0.0000	100.0000	0.0098
124.5	1	0	0.0000	100.0000	0.0098
125.5	1	0	0.0000	100.0000	0.0098
126.5	0	0	0.0000	100.0000	0.0098
127.5	0	0	0.0000	100.0000	0.0098
128.5	0	0	0.0000	100.0000	0.0098
129.5	0	0	0.0000	100.0000	0.0098
130.5	0	0	0.0000	100.0000	0.0098
131.5	0	0	0.0000	100.0000	0.0098
132.5	0	0	0.0000	100.0000	0.0098

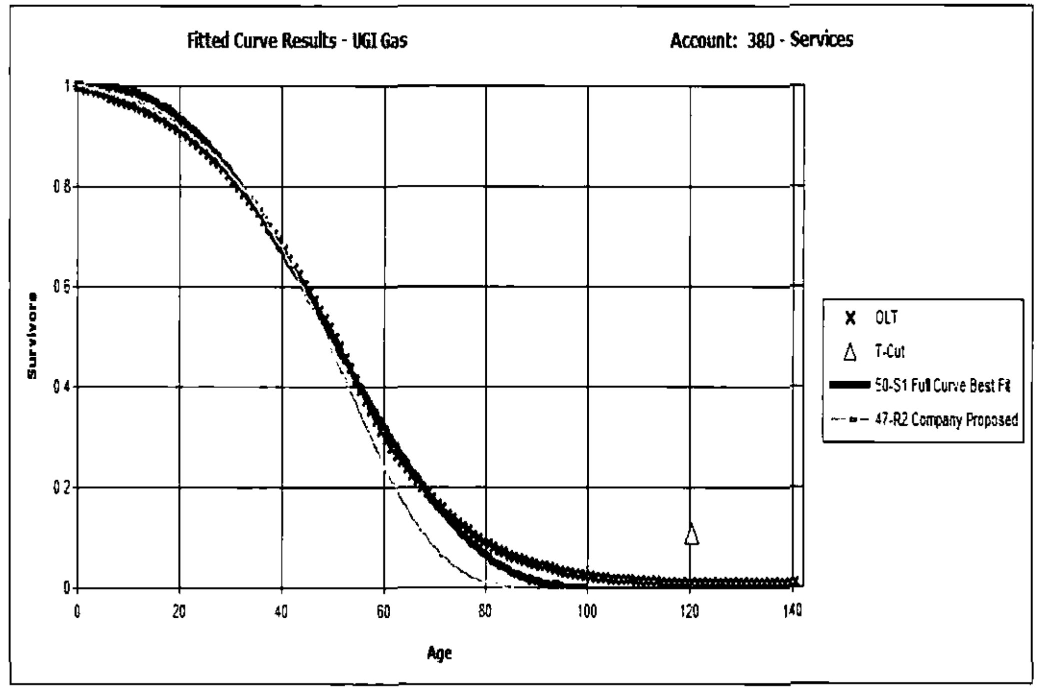
133.5	0	0	0.0000	100.0000	0.0098
134.5	0	0	0.0000	100.0000	0.0098
135.5	0	0	0.0000	100.0000	0.0098
136.5	0	0	0.0000	100.0000	0.0098
137.5	0	0	0.0000	100.0000	0.0098
138.5	0	0	0.0000	100.0000	0.0098
139.5	0	0	0.0000	100.0000	0.0098
140.5	0	0	0.0000	100.0000	0.0098

Best Fit Curve Results
UGI Gas
Account: 380 - Services

Curve	Life	Sum of Squared Differences
BAND	1870 - 2011	
S1	50.0	444.878
S0.5	50.0	466.300
R1.5	49.0	498.276
L2	51.0	708.532
L1.5	51.0	1,060.966
R1	49.0	1,071.126
S1.5	50.0	1,107.798
R2	50.0	1,177.549
S0	49.0	1,321.164
L1	50.0	2,396.779
L3	52.0	2,500.365
S2	51.0	2,526.789
R2.5	50.0	2,603.863
R0.5	48.0	2,966.336
S-0.5	48.0	3,374.646
L0.5	50.0	4,397.795
R3	50.0	5,206.973
O1	47.0	6,681.769
S3	51.0	6,773.735
L0	50.0	7,304.838
L4	51.0	8,592.937
O2	50.0	10,207.711
R4	51.0	11,269.802
S4	51.0	14,203.650
L5	51.0	16,499.227
R5	51.0	20,219.047
S5	51.0	22,590.977
O3	58.0	25,680.514
S6	51.0	30,810.016
O4	73.0	35,694.299
SQ	51.0	49,399.476

Analytical Parameters

OLT Placement Band:	1870 - 2011
OLT Experience Band	1870 - 2011
Minimum Life Paramet	1
Maximum Life Parame	100
Life Increment Parame	1
Max Age (T-Cut):	120.5



Analytical Parameters

OLT Placement Band:	1870 - 2011
OLT Experience Band:	1870 - 2011
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	122.0

UGI Gas 2017 GAs

380 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 50 S1

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	47,475,618	50.00	49.50	949,512	46,998,791
2016	1.5	49,966,574	50.00	48.50	999,331	48,467,993
2015	2.5	43,295,387	50.00	47.51	865,908	41,138,254
2014	3.5	40,904,983	50.00	46.53	818,100	38,062,624
2013	4.5	41,972,910	50.00	45.55	839,458	38,239,825
2012	5.5	32,272,466	50.00	44.59	645,449	28,782,160
2011	6.5	22,115,443	50.00	43.65	442,309	19,304,704
2010	7.5	14,430,755	50.00	42.71	288,615	12,327,510
2009	8.5	14,205,943	50.00	41.80	284,119	11,874,794
2008	9.5	13,927,047	50.00	40.89	278,541	11,390,542
2007	10.5	10,661,310	50.00	40.01	213,226	8,530,820
2006	11.5	10,777,083	50.00	39.14	215,542	8,436,209
2005	12.5	10,289,346	50.00	38.29	205,787	7,879,076
2004	13.5	11,524,823	50.00	37.45	230,496	8,632,633
2003	14.5	9,986,791	50.00	36.63	199,736	7,317,104
2002	15.5	10,769,829	50.00	35.83	215,397	7,718,117
2001	16.5	10,401,796	50.00	35.05	208,036	7,290,999
2000	17.5	10,239,310	50.00	34.28	204,786	7,019,624
1999	18.5	9,975,525	50.00	33.52	199,510	6,688,559
1998	19.5	9,811,716	50.00	32.79	196,234	6,434,056
1997	20.5	12,159,274	50.00	32.07	243,185	7,797,951
1996	21.5	11,575,781	50.00	31.36	231,516	7,260,129
1995	22.5	13,518,112	50.00	30.67	270,362	8,291,254
1994	23.5	12,430,816	50.00	29.99	248,616	7,455,910
1993	24.5	6,426,226	50.00	29.33	128,525	3,769,119
1992	25.5	9,994,854	50.00	28.68	199,897	5,732,280
1991	26.5	9,804,785	50.00	28.04	196,096	5,498,425
1990	27.5	10,932,583	50.00	27.42	218,652	5,994,488
1989	28.5	9,900,420	50.00	26.80	198,008	5,307,502
1988	29.5	7,054,239	50.00	26.21	141,085	3,697,167

1987	30.5	5,809,208	50.00	25.62	116,184	2,976,397
1986	31.5	4,943,832	50.00	25.04	98,877	2,476,064
1985	32.5	4,791,704	50.00	24.48	95,834	2,345,733
1984	33.5	4,253,353	50.00	23.92	85,067	2,035,045
1983	34.5	4,106,728	50.00	23.38	82,135	1,920,224
1982	35.5	5,646,351	50.00	22.85	112,927	2,579,839
1981	36.5	6,351,316	50.00	22.32	127,026	2,835,369
1980	37.5	6,184,950	50.00	21.81	123,699	2,697,433
1979	38.5	3,815,684	50.00	21.30	76,314	1,625,545
1978	39.5	2,208,270	50.00	20.80	44,165	918,819
1977	40.5	2,406,196	50.00	20.32	48,124	977,674
1976	41.5	1,271,027	50.00	19.84	25,421	504,236
1975	42.5	1,109,193	50.00	19.36	22,184	429,562
1974	43.5	1,497,764	50.00	18.90	29,955	566,136
1973	44.5	1,413,510	50.00	18.44	28,270	521,374
1972	45.5	1,060,737	50.00	17.99	21,215	381,715
1971	46.5	858,354	50.00	17.55	17,167	301,286
1970	47.5	754,695	50.00	17.11	15,094	258,322
1969	48.5	718,411	50.00	16.69	14,368	239,734
1968	49.5	667,800	50.00	16.26	13,356	217,195
1967	50.5	586,179	50.00	15.85	11,724	185,762
1966	51.5	590,304	50.00	15.43	11,806	182,218
1965	52.5	504,454	50.00	15.03	10,089	151,629
1964	53.5	397,314	50.00	14.63	7,946	116,250
1963	54.5	377,499	50.00	14.24	7,550	107,476
1962	55.5	333,310	50.00	13.85	6,666	92,302
1961	56.5	336,776	50.00	13.46	6,736	90,676
1960	57.5	305,000	50.00	13.08	6,100	79,809
1959	58.5	227,468	50.00	12.71	4,549	57,818
1958	59.5	127,287	50.00	12.34	2,546	31,413
1957	60.5	87,636	50.00	11.97	1,753	20,988
1956	61.5	70,769	50.00	11.61	1,415	16,437
1955	62.5	41,680	50.00	11.26	834	9,384
1954	63.5	26,161	50.00	10.90	523	5,705
1953	64.5	15,474	50.00	10.56	309	3,267
1952	65.5	15,830	50.00	10.21	317	3,233
1951	66.5	14,056	50.00	9.87	281	2,775
1950	67.5	12,860	50.00	9.53	257	2,451
1949	68.5	9,097	50.00	9.20	182	1,674
1948	69.5	5,655	50.00	8.87	113	1,003
1947	70.5	2,419	50.00	8.54	48	413
1946	71.5	0	50.00	8.22	0	0
1945	72.5	0	50.00	7.89	0	0
1944	73.5	0	50.00	7.58	0	0
1943	74.5	0	50.00	7.26	0	0
1942	75.5	0	50.00	6.95	0	0
1941	76.5	0	50.00	6.64	0	0

1940	77.5	0	50.00	6.33	0	0
1939	78.5	0	50.00	6.03	0	0
1938	79.5	0	50.00	5.73	0	0
1937	80.5	0	50.00	5.43	0	0
1936	81.5	0	50.00	5.13	0	0
1935	82.5	338	50.00	4.84	7	33
		592,758,393			11,855,168	461,309,035

AVERAGE SERVICE LIFE 50.00
AVERAGE REMAINING LIFE 38.91

Observed Life Table Results
UGI Gas
Account: 381 - Meters

Age	Exposures	Retiremen	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors
BAND		1895 - 2011			
0	48,694,974	3,313	0.0068	99.9932	1.0000
0.5	45,735,160	99,732	0.2181	99.7819	0.9999
1.5	43,941,032	65,262	0.1485	99.8515	0.9978
2.5	42,388,471	127,498	0.3008	99.6992	0.9963
3.5	39,205,628	184,911	0.4716	99.5284	0.9933
4.5	38,208,735	145,096	0.3797	99.6203	0.9886
5.5	36,346,356	230,237	0.6335	99.3665	0.9848
6.5	34,986,833	294,427	0.8415	99.1585	0.9786
7.5	33,716,345	254,292	0.7542	99.2458	0.9704
8.5	32,391,631	241,269	0.7449	99.2551	0.9630
9.5	31,181,295	345,261	1.1073	98.8927	0.9559
10.5	29,454,473	297,240	1.0092	98.9908	0.9453
11.5	27,987,408	307,205	1.0977	98.9023	0.9357
12.5	26,452,170	310,215	1.1727	98.8273	0.9255
13.5	25,127,317	479,208	1.9071	98.0929	0.9146
14.5	23,484,390	463,621	1.9742	98.0258	0.8972
15.5	22,140,021	380,942	1.7206	98.2794	0.8795
16.5	20,520,955	414,915	2.0219	97.9781	0.8643
17.5	18,943,620	290,636	1.5342	98.4658	0.8469
18.5	17,797,381	259,603	1.4587	98.5413	0.8339
19.5	16,385,987	248,961	1.5194	98.4806	0.8217
20.5	14,947,064	272,525	1.8233	98.1767	0.8092
21.5	13,446,128	248,989	1.8518	98.1482	0.7945
22.5	12,446,157	246,078	1.9771	98.0229	0.7798
23.5	11,659,966	220,065	1.8874	98.1126	0.7643
24.5	10,843,035	216,293	1.9948	98.0052	0.7499
25.5	10,192,687	202,119	1.9830	98.0170	0.7350
26.5	9,529,494	178,433	1.8724	98.1276	0.7204
27.5	9,173,510	191,702	2.0897	97.9103	0.7069
28.5	8,937,956	174,164	1.9486	98.0514	0.6921
29.5	8,471,496	187,877	2.2178	97.7822	0.6786
30.5	7,734,193	178,201	2.3041	97.6959	0.6636
31.5	6,603,911	165,576	2.5072	97.4928	0.6483
32.5	6,223,162	182,863	2.9384	97.0616	0.6320
33.5	5,861,357	177,517	3.0286	96.9714	0.6135
34.5	5,612,478	217,477	3.8749	96.1251	0.5949
35.5	5,350,341	224,495	4.1959	95.8041	0.5718
36.5	5,037,429	214,450	4.2571	95.7429	0.5478
37.5	4,704,816	213,232	4.5322	95.4678	0.5245
38.5	4,377,326	203,444	4.6477	95.3523	0.5007

39.5	4,104,411	202,348	4.9300	95.0700	0.4775
40.5	3,762,500	198,331	5.2713	94.7287	0.4539
41.5	3,304,974	195,827	5.9252	94.0748	0.4300
42.5	2,804,355	174,917	6.2373	93.7627	0.4045
43.5	2,289,186	148,658	6.4939	93.5061	0.3793
44.5	1,870,629	118,805	6.3511	93.6489	0.3547
45.5	1,566,796	107,449	6.8579	93.1421	0.3321
46.5	1,329,429	94,009	7.0714	92.9286	0.3094
47.5	1,161,179	85,212	7.3384	92.6616	0.2875
48.5	1,018,206	82,868	8.1387	91.8613	0.2664
49.5	907,721	66,370	7.3117	92.6883	0.2447
50.5	830,769	63,807	7.6804	92.3196	0.2268
51.5	755,610	93,546	12.3802	87.6198	0.2094
52.5	649,228	52,584	8.0995	91.9005	0.1835
53.5	589,792	60,775	10.3044	89.6956	0.1686
54.5	523,544	62,382	11.9154	88.0846	0.1512
55.5	452,052	48,418	10.7108	89.2892	0.1332
56.5	398,030	45,251	11.3687	88.6313	0.1189
57.5	349,866	41,639	11.9014	88.0986	0.1054
58.5	302,403	29,679	9.8143	90.1857	0.0929
59.5	264,436	35,112	13.2780	86.7220	0.0838
60.5	223,220	26,652	11.9398	88.0602	0.0726
61.5	192,094	21,423	11.1521	88.8479	0.0640
62.5	165,689	17,228	10.3980	89.6020	0.0568
63.5	146,120	12,043	8.2418	91.7582	0.0509
64.5	130,552	17,293	13.2462	86.7538	0.0467
65.5	110,441	23,059	20.8785	79.1215	0.0405
66.5	85,964	18,900	21.9857	78.0143	0.0321
67.5	65,793	13,642	20.7344	79.2656	0.0250
68.5	51,698	12,417	24.0177	75.9823	0.0198
69.5	37,732	10,195	27.0198	72.9802	0.0151
70.5	23,488	5,372	22.8712	77.1288	0.0110
71.5	15,312	2,877	18.7870	81.2130	0.0085
72.5	10,011	1,072	10.7106	89.2894	0.0069
73.5	7,065	755	10.6915	89.3085	0.0062
74.5	4,461	590	13.2326	86.7674	0.0055
75.5	2,810	805	28.6583	71.3417	0.0048
76.5	1,369	300	21.9427	78.0573	0.0034
77.5	782	164	20.9618	79.0382	0.0027
78.5	570	57	9.9905	90.0095	0.0021
79.5	368	18	4.7821	95.2179	0.0019
80.5	215	8	3.9301	96.0699	0.0018
81.5	102	0	0.0000	100.0000	0.0017
82.5	38	0	0.0000	100.0000	0.0017
83.5	29	0	0.0000	100.0000	0.0017
84.5	20	0	0.0000	100.0000	0.0017
85.5	20	0	0.0000	100.0000	0.0017

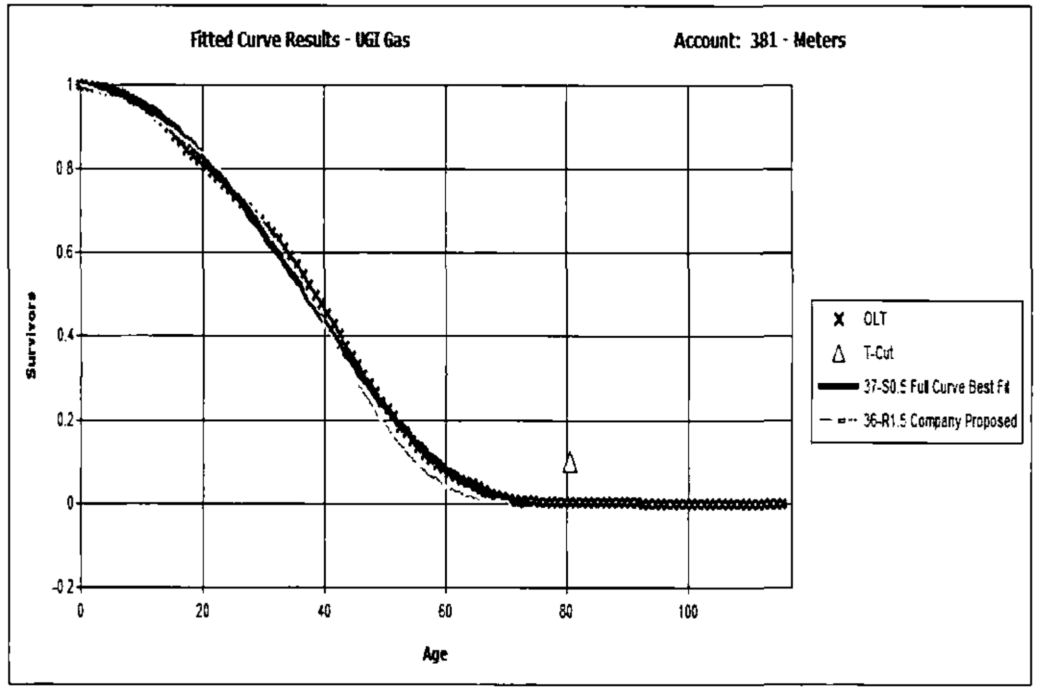
86.5	20	0	0.0000	100.0000	0.0017
87.5	20	0	0.0000	100.0000	0.0017
88.5	20	0	0.0000	100.0000	0.0017
89.5	20	2	11.1168	88.8832	0.0017
90.5	17	0	0.0000	100.0000	0.0015
91.5	17	7	37.4640	62.5360	0.0015
92.5	11	0	0.0000	100.0000	0.0010
93.5	11	0	0.0000	100.0000	0.0010
94.5	11	0	0.0000	100.0000	0.0010
95.5	9	0	0.0000	100.0000	0.0010
96.5	9	0	0.0000	100.0000	0.0010
97.5	9	0	0.0000	100.0000	0.0010
98.5	9	0	0.0000	100.0000	0.0010
99.5	9	0	0.0000	100.0000	0.0010
100.5	9	0	0.0000	100.0000	0.0010
101.5	9	0	0.0000	100.0000	0.0010
102.5	9	0	0.0000	100.0000	0.0010
103.5	9	0	0.0000	100.0000	0.0010
104.5	9	0	0.0000	100.0000	0.0010
105.5	9	9	100.0000	0.0000	0.0010
106.5	0	0	0.0000	100.0000	0.0000
107.5	0	0	0.0000	100.0000	0.0000
108.5	0	0	0.0000	100.0000	0.0000
109.5	0	0	0.0000	100.0000	0.0000
110.5	0	0	0.0000	100.0000	0.0000
111.5	0	0	0.0000	100.0000	0.0000
112.5	0	0	0.0000	100.0000	0.0000
113.5	0	0	0.0000	100.0000	0.0000
114.5	0	0	0.0000	100.0000	0.0000
115.5	0	0	0.0000	100.0000	0.0000

Best Fit Curve Results
UGI Gas
Account: 381 - Meters

Curve	Life	Sum of Squared Differences
BAND	**1895 - 2011**	
S0.5	37.0	204.746
R1	37.0	210.411
R1.5	37.0	210.867
S0	37.0	449.237
S1	38.0	502.410
R2	38.0	1,071.268
L1.5	38.0	1,116.007
L2	39.0	1,293.957
R0.5	36.0	1,317.233
S1.5	38.0	1,379.451
S-0.5	36.0	1,633.576
L1	38.0	1,693.583
R2.5	38.0	2,607.693
S2	39.0	2,857.547
L0.5	38.0	2,997.002
L3	39.0	3,321.246
O1	35.0	3,700.638
L0	37.0	4,895.262
R3	39.0	5,001.664
S3	39.0	6,736.096
O2	38.0	6,812.574
L4	39.0	8,492.046
R4	39.0	10,380.349
S4	39.0	13,108.286
L5	39.0	15,061.191
O3	44.0	16,909.078
R5	39.0	18,020.490
S5	39.0	19,994.935
O4	57.0	22,816.530
S6	39.0	26,537.359
SQ	39.0	41,102.800

Analytical Parameters

OLT Placement Band:	1895 - 2011
OLT Experience Band	1895 - 2011
Minimum Life Paramet	1
Maximum Life Parame	100
Life Increment Parame	1
Max Age (T-Cut):	80.5



Analytical Parameters

OLT Placement Band:	1895 - 2011
OLT Experience Band:	1895 - 2011
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	82.0

UGI Gas 2017 GAs

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Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 37 S-0.5

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	1,986,268	37.00	36.63	53,683	1,966,517
2016	1.5	2,087,188	37.00	35.92	56,410	2,026,069
2015	2.5	2,470,863	37.00	35.22	66,780	2,352,236
2014	3.5	3,209,856	37.00	34.55	86,753	2,997,195
2013	4.5	3,130,141	37.00	33.89	84,598	2,866,966
2012	5.5	2,542,607	37.00	33.24	68,719	2,284,477
2011	6.5	2,969,485	37.00	32.61	80,256	2,617,246
2010	7.5	1,676,275	37.00	31.99	45,305	1,449,291
2009	8.5	1,470,647	37.00	31.38	39,747	1,247,235
2008	9.5	3,005,608	37.00	30.78	81,233	2,500,237
2007	10.5	766,719	37.00	30.19	20,722	625,546
2006	11.5	1,497,470	37.00	29.60	40,472	1,198,156
2005	12.5	1,076,335	37.00	29.03	29,090	844,481
2004	13.5	911,268	37.00	28.46	24,629	701,008
2003	14.5	998,596	37.00	27.90	26,989	753,075
2002	15.5	913,053	37.00	27.35	24,677	674,916
2001	16.5	1,277,228	37.00	26.80	34,520	925,244
2000	17.5	1,007,974	37.00	26.26	27,243	715,467
1999	18.5	1,096,593	37.00	25.73	29,638	762,520
1998	19.5	898,797	37.00	25.20	24,292	612,129
1997	20.5	1,040,200	37.00	24.68	28,114	693,703
1996	21.5	745,101	37.00	24.16	20,138	486,452
1995	22.5	1,076,429	37.00	23.64	29,093	687,808
1994	23.5	1,034,996	37.00	23.13	27,973	647,078
1993	24.5	754,073	37.00	22.63	20,380	461,147
1992	25.5	968,946	37.00	22.13	26,188	579,428
1991	26.5	1,021,876	37.00	21.63	27,618	597,350
1990	27.5	1,056,266	37.00	21.14	28,548	603,369
1989	28.5	639,780	37.00	20.65	17,291	356,992
1988	29.5	428,250	37.00	20.16	11,574	233,332

1987	30.5	493,940	37.00	19.68	13,350	262,676
1986	31.5	342,675	37.00	19.20	9,261	177,790
1985	32.5	405,674	37.00	18.72	10,964	205,249
1984	33.5	133,065	37.00	18.25	3,596	65,619
1983	34.5	35,036	37.00	17.78	947	16,831
1982	35.5	250,598	37.00	17.31	6,773	117,217
1981	36.5	437,479	37.00	16.84	11,824	199,122
1980	37.5	759,982	37.00	16.38	20,540	336,391
1979	38.5	162,424	37.00	15.92	4,390	69,869
1978	39.5	149,135	37.00	15.46	4,031	62,303
1977	40.5	57,920	37.00	15.00	1,565	23,481
1976	41.5	38,991	37.00	14.55	1,054	15,328
1975	42.5	72,324	37.00	14.09	1,955	27,546
1974	43.5	97,269	37.00	13.64	2,629	35,861
1973	44.5	94,736	37.00	13.19	2,560	33,776
1972	45.5	57,206	37.00	12.74	1,546	19,703
1971	46.5	106,014	37.00	12.30	2,865	35,234
1970	47.5	199,226	37.00	11.85	5,384	63,815
1969	48.5	225,016	37.00	11.41	6,082	69,376
1968	49.5	235,834	37.00	10.96	6,374	69,889
1967	50.5	156,311	37.00	10.52	4,225	44,456
1966	51.5	87,224	37.00	10.08	2,357	23,768
1965	52.5	37,031	37.00	9.64	1,001	9,650
1964	53.5	10,157	37.00	9.20	275	2,526
1963	54.5	8,034	37.00	8.76	217	1,903
1962	55.5	8,973	37.00	8.33	243	2,019
1961	56.5	6,404	37.00	7.89	173	1,365
1960	57.5	4,982	37.00	7.45	135	1,003
1959	58.5	8,814	37.00	7.01	238	1,671
1958	59.5	4,133	37.00	6.58	112	735
1957	60.5	3,400	37.00	6.14	92	564
1956	61.5	3,444	37.00	5.70	93	530
1955	62.5	3,183	37.00	5.26	86	453
1954	63.5	1,745	37.00	4.82	47	227
1953	64.5	4,744	37.00	4.38	128	562
1952	65.5	6,011	37.00	3.94	162	640
1951	66.5	4,247	37.00	3.50	115	401
1950	67.5	3,536	37.00	3.05	96	291
1949	68.5	3,854	37.00	2.60	104	271
1948	69.5	1,799	37.00	2.15	49	105
1947	70.5	2,671	37.00	1.70	72	123
1946	71.5	2,073	37.00	1.25	56	70
1945	72.5	1,030	37.00	0.82	28	23
1944	73.5	911	37.00	0.50	25	12
1943	74.5	318	37.00	0.50	9	4
1942	75.5	1,061	37.00	0.50	29	14
1941	76.5	2,695	37.00	0.50	73	36

1940	77.5	1,813	37.00	0.50	49	25
1939	78.5	1,536	37.00	0.50	42	21
1938	79.5	1,146	37.00	0.50	31	15
1937	80.5	1,103	37.00	0.50	30	15
1936	81.5	603	37.00	0.50	16	8
1935	82.5	338	37.00	0.50	9	5
		48,498,754			1,310,777	37,467,258

AVERAGE SERVICE LIFE	37.00
AVERAGE REMAINING LIFE	28.58

UGI Gas 2017 GAs

381.2 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 20 S2

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	1,326,780	20.00	19.50	66,339	1,293,553
2016	1.5	1,399,986	20.00	18.50	69,999	1,294,947
2015	2.5	0	20.00	17.50	0	0
2014	3.5	0	20.00	16.51	0	0
2013	4.5	0	20.00	15.53	0	0
2012	5.5	0	20.00	14.58	0	0
2011	6.5	0	20.00	13.65	0	0
2010	7.5	0	20.00	12.75	0	0
2009	8.5	0	20.00	11.90	0	0
2008	9.5	15,192	20.00	11.08	760	8,420
2007	10.5	0	20.00	10.32	0	0
2006	11.5	5,184,317	20.00	9.60	259,216	2,487,312
2005	12.5	206,381	20.00	8.92	10,319	92,040
2004	13.5	229,134	20.00	8.29	11,457	94,943
2003	14.5	233,963	20.00	7.70	11,698	90,035
2002	15.5	612,886	20.00	7.15	30,644	218,959
2001	16.5	494,946	20.00	6.63	24,747	164,086
2000	17.5	423,253	20.00	6.15	21,163	130,143
1999	18.5	297,835	20.00	5.70	14,892	84,882
1998	19.5	156,945	20.00	5.28	7,847	41,423
1997	20.5	144,490	20.00	4.88	7,225	35,281
1996	21.5	141,247	20.00	4.51	7,062	31,865
1995	22.5	178,779	20.00	4.16	8,939	37,203
		11,046,136			552,307	6,105,090

AVERAGE SERVICE LIFE 20.00
AVERAGE REMAINING LIFE 11.05

UGI Gas 2017 GAs

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Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 50 S1

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	3,039,470	50.00	49.50	60,789	3,008,943
2016	1.5	3,201,350	50.00	48.50	64,027	3,105,336
2015	2.5	2,697,750	50.00	47.51	53,955	2,563,338
2014	3.5	2,022,974	50.00	46.53	40,459	1,882,404
2013	4.5	2,725,670	50.00	45.55	54,513	2,483,248
2012	5.5	2,211,227	50.00	44.59	44,225	1,972,080
2011	6.5	1,792,011	50.00	43.65	35,840	1,564,257
2010	7.5	1,431,034	50.00	42.71	28,621	1,222,465
2009	8.5	2,205,672	50.00	41.80	44,113	1,843,728
2008	9.5	3,007,535	50.00	40.89	60,151	2,459,779
2007	10.5	7,147,679	50.00	40.01	142,954	5,719,331
2006	11.5	1,353,096	50.00	39.14	27,062	1,059,192
2005	12.5	1,289,069	50.00	38.29	25,781	987,106
2004	13.5	1,115,393	50.00	37.45	22,308	835,482
2003	14.5	1,420,082	50.00	36.63	28,402	1,040,463
2002	15.5	1,021,042	50.00	35.83	20,421	731,722
2001	16.5	1,765,230	50.00	35.05	35,305	1,237,314
2000	17.5	1,818,603	50.00	34.28	36,372	1,246,755
1999	18.5	1,784,604	50.00	33.52	35,692	1,196,571
1998	19.5	1,817,407	50.00	32.79	36,348	1,191,769
1997	20.5	1,643,453	50.00	32.07	32,869	1,053,975
1996	21.5	1,395,092	50.00	31.36	27,902	874,977
1995	22.5	1,498,178	50.00	30.67	29,964	918,899
1994	23.5	1,354,597	50.00	29.99	27,092	812,477
1993	24.5	954,156	50.00	29.33	19,083	559,633
1992	25.5	1,227,494	50.00	28.68	24,550	703,996
1991	26.5	1,308,502	50.00	28.04	26,170	733,795
1990	27.5	1,313,808	50.00	27.42	26,276	720,379
1989	28.5	1,052,524	50.00	26.80	21,050	564,246
1988	29.5	968,794	50.00	26.21	19,376	507,750

1987	30.5	751,416	50.00	25.62	15,028	384,995
1986	31.5	670,849	50.00	25.04	13,417	335,987
1985	32.5	655,127	50.00	24.48	13,103	320,711
1984	33.5	466,245	50.00	23.92	9,325	223,078
1983	34.5	532,189	50.00	23.38	10,644	248,841
1982	35.5	511,912	50.00	22.85	10,238	233,895
1981	36.5	636,819	50.00	22.32	12,736	284,290
1980	37.5	563,482	50.00	21.81	11,270	245,751
1979	38.5	297,977	50.00	21.30	5,960	126,943
1978	39.5	94,765	50.00	20.80	1,895	39,430
1977	40.5	80,956	50.00	20.32	1,619	32,894
1976	41.5	46,786	50.00	19.84	936	18,561
1975	42.5	89,739	50.00	19.36	1,795	34,754
1974	43.5	130,179	50.00	18.90	2,604	49,206
1973	44.5	122,279	50.00	18.44	2,446	45,103
1972	45.5	89,694	50.00	17.99	1,794	32,277
1971	46.5	97,417	50.00	17.55	1,948	34,194
1970	47.5	110,502	50.00	17.11	2,210	37,823
1969	48.5	124,407	50.00	16.69	2,488	41,515
1968	49.5	121,060	50.00	16.26	2,421	39,373
1967	50.5	104,826	50.00	15.85	2,097	33,220
1966	51.5	94,994	50.00	15.43	1,900	29,323
1965	52.5	91,147	50.00	15.03	1,823	27,397
1964	53.5	73,978	50.00	14.63	1,480	21,645
1963	54.5	65,030	50.00	14.24	1,301	18,514
1962	55.5	56,060	50.00	13.85	1,121	15,524
1961	56.5	63,096	50.00	13.46	1,262	16,988
1960	57.5	72,726	50.00	13.08	1,455	19,030
1959	58.5	75,221	50.00	12.71	1,504	19,120
1958	59.5	68,916	50.00	12.34	1,378	17,008
1957	60.5	73,332	50.00	11.97	1,467	17,562
1956	61.5	70,465	50.00	11.61	1,409	16,367
1955	62.5	64,493	50.00	11.26	1,290	14,520
1954	63.5	51,914	50.00	10.90	1,038	11,321
1953	64.5	37,677	50.00	10.56	754	7,954
1952	65.5	43,371	50.00	10.21	867	8,857
1951	66.5	38,942	50.00	9.87	779	7,687
1950	67.5	33,357	50.00	9.53	667	6,359
1949	68.5	27,778	50.00	9.20	556	5,110
1948	69.5	23,058	50.00	8.87	461	4,089
1947	70.5	24,461	50.00	8.54	489	4,178
1946	71.5	11,524	50.00	8.22	230	1,894
1945	72.5	7,225	50.00	7.89	144	1,141
1944	73.5	6,877	50.00	7.58	138	1,042
1943	74.5	5,179	50.00	7.26	104	752
1942	75.5	7,045	50.00	6.95	141	979
1941	76.5	8,812	50.00	6.64	176	1,170

1940	77.5	7,246	50.00	6.33	145	918
1939	78.5	5,216	50.00	6.03	104	629
1938	79.5	4,268	50.00	5.73	85	489
1937	80.5	5,196	50.00	5.43	104	564
1936	81.5	2,977	50.00	5.13	60	306
1935	82.5	2,852	50.00	4.84	57	276
1934	83.5	2,144	50.00	4.55	43	195
1933	84.5	1,717	50.00	4.26	34	146
1932	85.5	3,116	50.00	3.97	62	248
1931	86.5	4,316	50.00	3.69	86	318
1930	87.5	5,497	50.00	3.41	110	374
1929	88.5	8,744	50.00	3.13	175	547
1928	89.5	8,056	50.00	2.85	161	459
1927	90.5	8,733	50.00	2.57	175	449
1926	91.5	7,138	50.00	2.30	143	328
1925	92.5	10,007	50.00	2.03	200	406
1924	93.5	8,816	50.00	1.76	176	310
1923	94.5	6,499	50.00	1.50	130	195
1922	95.5	5,028	50.00	1.24	101	124
1921	96.5	3,903	50.00	0.98	78	77
1920	97.5	3,701	50.00	0.74	74	55
1919	98.5	1,885	50.00	0.54	38	20
1918	99.5	206	50.00	0.50	4	2
1917	100.5	30	50.00	0.50	1	0
		65,196,088			1,303,922	47,947,219

AVERAGE SERVICE LIFE 50.00
AVERAGE REMAINING LIFE 36.77

UGI Gas 2017 GAs

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Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 50 S1

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	989,324	50.00	49.50	19,786	979,387
2016	1.5	1,040,955	50.00	48.50	20,819	1,009,735
2015	2.5	0	50.00	47.51	0	0
2014	3.5	0	50.00	46.53	0	0
2013	4.5	64,425	50.00	45.55	1,288	58,695
2012	5.5	184,223	50.00	44.59	3,684	164,299
2011	6.5	0	50.00	43.65	0	0
2010	7.5	535,061	50.00	42.71	10,701	457,077
2009	8.5	430,986	50.00	41.80	8,620	360,263
2008	9.5	536,821	50.00	40.89	10,736	439,051
2007	10.5	0	50.00	40.01	0	0
2006	11.5	0	50.00	39.14	0	0
2005	12.5	193,257	50.00	38.29	3,865	147,987
2004	13.5	201,556	50.00	37.45	4,031	150,975
2003	14.5	225,881	50.00	36.63	4,518	165,498
2002	15.5	130,737	50.00	35.83	2,615	93,692
2001	16.5	53,720	50.00	35.05	1,074	37,654
2000	17.5	166,656	50.00	34.28	3,333	114,252
1999	18.5	90,699	50.00	33.52	1,814	60,813
1998	19.5	101,825	50.00	32.79	2,036	66,772
1997	20.5	54,370	50.00	32.07	1,087	34,868
1996	21.5	87,705	50.00	31.36	1,754	55,007
1995	22.5	43,291	50.00	30.67	866	26,552
1994	23.5	153,409	50.00	29.99	3,068	92,014
1993	24.5	140,213	50.00	29.33	2,804	82,238
1992	25.5	92,746	50.00	28.68	1,855	53,192
1991	26.5	74,814	50.00	28.04	1,496	41,955
1990	27.5	203,901	50.00	27.42	4,078	111,802
1989	28.5	202,471	50.00	26.80	4,049	108,542
1988	29.5	165,679	50.00	26.21	3,314	86,833

1987	30.5	128,556	50.00	25.62	2,571	65,867
1986	31.5	131,193	50.00	25.04	2,624	65,707
1985	32.5	114,659	50.00	24.48	2,293	56,130
1984	33.5	54,375	50.00	23.92	1,088	26,016
1983	34.5	57,925	50.00	23.38	1,159	27,085
1982	35.5	117,893	50.00	22.85	2,358	53,866
1981	36.5	77,029	50.00	22.32	1,541	34,387
1980	37.5	156,956	50.00	21.81	3,139	68,453
1979	38.5	75,616	50.00	21.30	1,512	32,214
1978	39.5	20,458	50.00	20.80	409	8,512
1977	40.5	15,486	50.00	20.32	310	6,292
1976	41.5	6,104	50.00	19.84	122	2,422
1975	42.5	28,471	50.00	19.36	569	11,026
1974	43.5	20,424	50.00	18.90	408	7,720
1973	44.5	17,859	50.00	18.44	357	6,587
1972	45.5	25,029	50.00	17.99	501	9,007
1971	46.5	34,191	50.00	17.55	684	12,001
1970	47.5	36,838	50.00	17.11	737	12,609
1969	48.5	22,860	50.00	16.69	457	7,628
1968	49.5	21,368	50.00	16.26	427	6,950
1967	50.5	25,450	50.00	15.85	509	8,065
1966	51.5	21,891	50.00	15.43	438	6,757
1965	52.5	15,042	50.00	15.03	301	4,521
1964	53.5	12,565	50.00	14.63	251	3,676
1963	54.5	0	50.00	14.24	0	0
1962	55.5	1,400	50.00	13.85	28	388
		7,404,361			148,087	5,543,040

AVERAGE SERVICE LIFE 50.00
AVERAGE REMAINING LIFE 37.43

UGI Gas 2017 GAs

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Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 50 S1

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	751,121	50.00	49.50	15,022	743,577
2016	1.5	791,045	50.00	48.50	15,821	767,320
2015	2.5	455,139	50.00	47.51	9,103	432,462
2014	3.5	464,932	50.00	46.53	9,299	432,626
2013	4.5	416,163	50.00	45.55	8,323	379,149
2012	5.5	511,747	50.00	44.59	10,235	456,401
2011	6.5	309,217	50.00	43.65	6,184	269,917
2010	7.5	212,524	50.00	42.71	4,250	181,549
2009	8.5	188,235	50.00	41.80	3,765	157,347
2008	9.5	796,376	50.00	40.89	15,928	651,334
2007	10.5	0	50.00	40.01	0	0
2006	11.5	269,312	50.00	39.14	5,386	210,815
2005	12.5	458,165	50.00	38.29	9,163	350,840
2004	13.5	578,305	50.00	37.45	11,566	433,177
2003	14.5	459,751	50.00	36.63	9,195	336,850
2002	15.5	176,548	50.00	35.83	3,531	126,522
2001	16.5	173,696	50.00	35.05	3,474	121,750
2000	17.5	128,408	50.00	34.28	2,568	88,031
1999	18.5	161,279	50.00	33.52	3,226	108,137
1998	19.5	240,266	50.00	32.79	4,805	157,555
1997	20.5	181,485	50.00	32.07	3,630	116,389
1996	21.5	144,323	50.00	31.36	2,886	90,517
1995	22.5	222,551	50.00	30.67	4,451	136,500
1994	23.5	156,997	50.00	29.99	3,140	94,166
1993	24.5	108,728	50.00	29.33	2,175	63,771
1992	25.5	191,161	50.00	28.68	3,823	109,635
1991	26.5	125,781	50.00	28.04	2,516	70,537
1990	27.5	196,710	50.00	27.42	3,934	107,859
1989	28.5	241,229	50.00	26.80	4,825	129,320
1988	29.5	173,372	50.00	26.21	3,467	90,865

1987	30.5	164,810	50.00	25.62	3,296	84,442
1986	31.5	139,806	50.00	25.04	2,796	70,021
1985	32.5	153,682	50.00	24.48	3,074	75,233
1984	33.5	94,215	50.00	23.92	1,884	45,078
1983	34.5	137,857	50.00	23.38	2,757	64,459
1982	35.5	185,110	50.00	22.85	3,702	84,577
1981	36.5	107,421	50.00	22.32	2,148	47,955
1980	37.5	127,380	50.00	21.81	2,548	55,554
1979	38.5	66,603	50.00	21.30	1,332	28,374
1978	39.5	39,373	50.00	20.80	787	16,382
1977	40.5	29,297	50.00	20.32	586	11,904
1976	41.5	19,918	50.00	19.84	398	7,902
1975	42.5	27,373	50.00	19.36	547	10,601
1974	43.5	39,525	50.00	18.90	790	14,940
1973	44.5	44,592	50.00	18.44	892	16,448
1972	45.5	36,319	50.00	17.99	726	13,070
1971	46.5	30,483	50.00	17.55	610	10,700
1970	47.5	23,396	50.00	17.11	468	8,008
1969	48.5	28,470	50.00	16.69	569	9,500
1968	49.5	27,476	50.00	16.26	550	8,936
1967	50.5	22,964	50.00	15.85	459	7,277
1966	51.5	21,261	50.00	15.43	425	6,563
1965	52.5	19,892	50.00	15.03	398	5,979
1964	53.5	18,857	50.00	14.63	377	5,517
1963	54.5	16,536	50.00	14.24	331	4,708
1962	55.5	13,469	50.00	13.85	269	3,730
1961	56.5	13,004	50.00	13.46	260	3,501
1960	57.5	19,525	50.00	13.08	390	5,109
1959	58.5	25,845	50.00	12.71	517	6,569
1958	59.5	18,104	50.00	12.34	362	4,468
1957	60.5	18,927	50.00	11.97	379	4,533
1956	61.5	17,152	50.00	11.61	343	3,984
1955	62.5	13,291	50.00	11.26	266	2,992
1954	63.5	8,124	50.00	10.90	162	1,772
1953	64.5	9,573	50.00	10.56	191	2,021
1952	65.5	11,754	50.00	10.21	235	2,400
1951	66.5	11,214	50.00	9.87	224	2,213
1950	67.5	8,520	50.00	9.53	170	1,624
1949	68.5	8,088	50.00	9.20	162	1,488
1948	69.5	6,962	50.00	8.87	139	1,235
1947	70.5	7,173	50.00	8.54	143	1,225
1946	71.5	3,308	50.00	8.22	66	544
1945	72.5	2,132	50.00	7.89	43	337
1944	73.5	1,900	50.00	7.58	38	288
1943	74.5	967	50.00	7.26	19	140
1942	75.5	1,457	50.00	6.95	29	202
1941	76.5	1,650	50.00	6.64	33	219

1940	77.5	1,327	50.00	6.33	27	168
1939	78.5	1,159	50.00	6.03	23	140
1938	79.5	1,160	50.00	5.73	23	133
1937	80.5	1,443	50.00	5.43	29	157
1936	81.5	1,075	50.00	5.13	21	110
1935	82.5	813	50.00	4.84	16	79
1934	83.5	742	50.00	4.55	15	68
1933	84.5	606	50.00	4.26	12	52
1932	85.5	671	50.00	3.97	13	53
1931	86.5	1,267	50.00	3.69	25	93
1930	87.5	1,482	50.00	3.41	30	101
1929	88.5	1,958	50.00	3.13	39	122
1928	89.5	1,554	50.00	2.85	31	89
1927	90.5	1,698	50.00	2.57	34	87
1926	91.5	1,419	50.00	2.30	28	65
1925	92.5	1,140	50.00	2.03	23	46
1924	93.5	596	50.00	1.76	12	21
1923	94.5	68	50.00	1.50	1	2
		########			222,990	8,181,227

AVERAGE SERVICE LIFE	50.00
AVERAGE REMAINING LIFE	36.69

Observed Life Table Results
UGI Gas
Account: 385 - Ind. Meas and Reg Eqpmt

Age	Exposures	Retiremen	Retiremen Ratio (%)	Survivor Ratio (%)	Cumulative Survivors
BAND		1917 - 2010			
0	6,756,668	5,376	0.0796	99.9204	1.0000
0.5	6,751,292	16,585	0.2457	99.7543	0.9992
1.5	6,362,545	23,689	0.3723	99.6277	0.9967
2.5	5,980,401	41,221	0.6893	99.3107	0.9930
3.5	5,498,821	59,821	1.0879	98.9121	0.9862
4.5	5,402,760	17,118	0.3168	99.6832	0.9755
5.5	5,385,642	44,198	0.8207	99.1793	0.9724
6.5	5,324,467	15,840	0.2975	99.7025	0.9644
7.5	5,308,627	56,865	1.0712	98.9288	0.9615
8.5	4,973,510	33,788	0.6794	99.3206	0.9512
9.5	4,815,473	11,483	0.2385	99.7615	0.9448
10.5	4,798,302	7,040	0.1467	99.8533	0.9425
11.5	4,730,150	20,426	0.4318	99.5682	0.9411
12.5	4,497,823	29,106	0.6471	99.3529	0.9371
13.5	4,379,581	3,025	0.0691	99.9309	0.9310
14.5	4,261,564	14,532	0.3410	99.6590	0.9304
15.5	3,608,710	2,122	0.0588	99.9412	0.9272
16.5	3,322,909	2,814	0.0847	99.9153	0.9266
17.5	3,104,355	3,148	0.1014	99.8986	0.9259
18.5	3,033,378	6,249	0.2060	99.7940	0.9249
19.5	2,905,415	14,121	0.4860	99.5140	0.9230
20.5	2,669,716	7,280	0.2727	99.7273	0.9185
21.5	2,458,460	7,306	0.2972	99.7028	0.9160
22.5	2,267,734	8,018	0.3535	99.6465	0.9133
23.5	1,976,096	10,577	0.5353	99.4647	0.9101
24.5	1,807,947	11,772	0.6511	99.3489	0.9052
25.5	1,717,589	1,397	0.0813	99.9187	0.8993
26.5	1,615,137	14,599	0.9039	99.0961	0.8986
27.5	1,553,288	1,265	0.0815	99.9185	0.8904
28.5	1,462,812	392	0.0268	99.9732	0.8897
29.5	1,230,330	3,823	0.3108	99.6892	0.8895
30.5	945,725	5	0.0005	99.9995	0.8867
31.5	671,778	4,518	0.6726	99.3274	0.8867
32.5	537,664	3,709	0.6898	99.3102	0.8808
33.5	533,956	0	0.0000	100.0000	0.8747
34.5	533,956	376	0.0703	99.9297	0.8747
35.5	531,654	0	0.0000	100.0000	0.8741
36.5	528,206	0	0.0000	100.0000	0.8741
37.5	525,771	0	0.0000	100.0000	0.8741
38.5	519,914	0	0.0000	100.0000	0.8741

39.5	445,427	0	0.0000	100.0000	0.8741
40.5	394,943	0	0.0000	100.0000	0.8741
41.5	338,315	0	0.0000	100.0000	0.8741
42.5	258,616	0	0.0000	100.0000	0.8741
43.5	180,389	0	0.0000	100.0000	0.8741
44.5	146,763	0	0.0000	100.0000	0.8741
45.5	123,944	250	0.2020	99.7980	0.8741
46.5	109,347	0	0.0000	100.0000	0.8723
47.5	87,410	1,405	1.6072	98.3928	0.8723
48.5	61,819	1,170	1.8921	98.1079	0.8583
49.5	38,615	1,347	3.4878	96.5122	0.8420
50.5	24,468	0	0.0000	100.0000	0.8127
51.5	7,717	0	0.0000	100.0000	0.8127
52.5	7,717	0	0.0000	100.0000	0.8127
53.5	7,717	0	0.0000	100.0000	0.8127
54.5	2,931	0	0.0000	100.0000	0.8127
55.5	692	0	0.0000	100.0000	0.8127
56.5	692	0	0.0000	100.0000	0.8127
57.5	692	0	0.0000	100.0000	0.8127
58.5	0	0	0.0000	100.0000	0.8127
59.5	0	0	0.0000	100.0000	0.8127
60.5	0	0	0.0000	100.0000	0.8127
61.5	0	0	0.0000	100.0000	0.8127
62.5	0	0	0.0000	100.0000	0.8127
63.5	0	0	0.0000	100.0000	0.8127
64.5	0	0	0.0000	100.0000	0.8127
65.5	0	0	0.0000	100.0000	0.8127
66.5	0	0	0.0000	100.0000	0.8127
67.5	0	0	0.0000	100.0000	0.8127
68.5	0	0	0.0000	100.0000	0.8127
69.5	0	0	0.0000	100.0000	0.8127
70.5	0	0	0.0000	100.0000	0.8127
71.5	0	0	0.0000	100.0000	0.8127
72.5	0	0	0.0000	100.0000	0.8127
73.5	0	0	0.0000	100.0000	0.8127
74.5	0	0	0.0000	100.0000	0.8127
75.5	0	0	0.0000	100.0000	0.8127
76.5	0	0	0.0000	100.0000	0.8127
77.5	0	0	0.0000	100.0000	0.8127
78.5	0	0	0.0000	100.0000	0.8127
79.5	0	0	0.0000	100.0000	0.8127
80.5	0	0	0.0000	100.0000	0.8127
81.5	0	0	0.0000	100.0000	0.8127
82.5	0	0	0.0000	100.0000	0.8127
83.5	0	0	0.0000	100.0000	0.8127
84.5	0	0	0.0000	100.0000	0.8127
85.5	0	0	0.0000	100.0000	0.8127

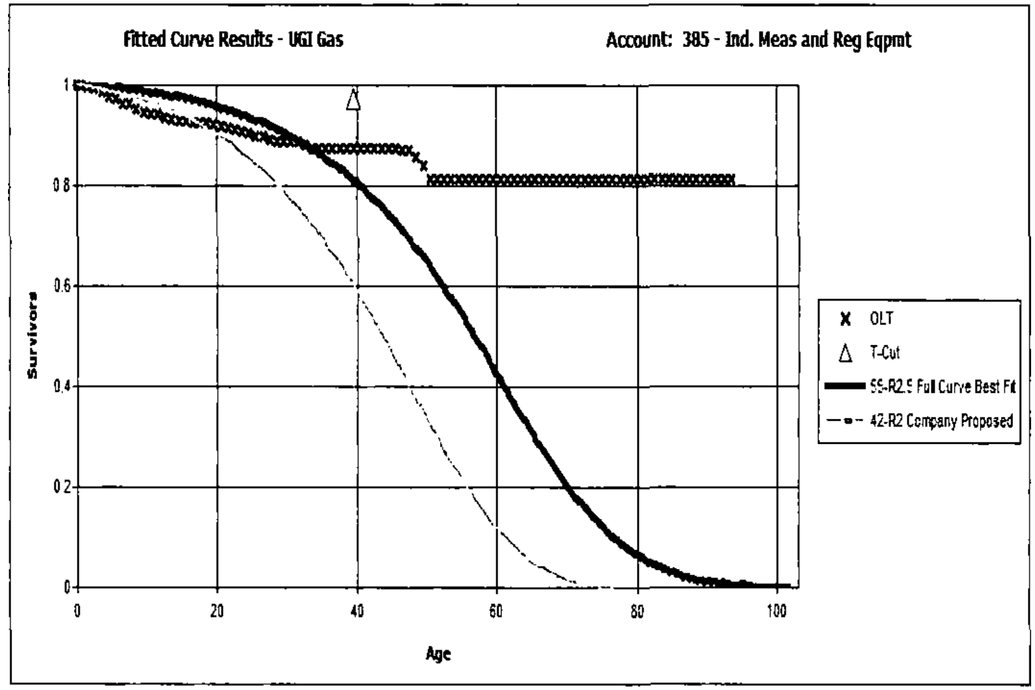
86.5	0	0	0.0000	100.0000	0.8127
87.5	0	0	0.0000	100.0000	0.8127
88.5	0	0	0.0000	100.0000	0.8127
89.5	0	0	0.0000	100.0000	0.8127
90.5	0	0	0.0000	100.0000	0.8127
91.5	0	0	0.0000	100.0000	0.8127
92.5	0	0	0.0000	100.0000	0.8127
93.5	0	0	0.0000	100.0000	0.8127

Best Fit Curve Results
UGI Gas
Account: 385 - Ind. Meas and Reg Eqpmt

Curve	Life	Sum of Squared Differences
BAND	**1917 - 2011**	
R2.5	55.0	410.756
R2	55.0	452.816
R3	52.0	664.238
S1.5	55.0	775.666
R1.5	55.0	878.529
S2	55.0	941.799
S1	55.0	959.706
L3	54.0	1,080.524
R4	47.0	1,163.366
L2	55.0	1,274.601
S3	50.0	1,327.523
S0.5	55.0	1,369.568
L4	48.0	1,410.450
S4	46.0	1,797.597
R1	55.0	1,816.528
R5	44.0	1,840.144
L1.5	55.0	1,876.913
L5	45.0	1,878.759
S5	44.0	2,198.581
S0	55.0	2,232.128
S6	42.0	2,499.893
SQ	40.0	3,035.668
L1	55.0	3,144.759
R0.5	55.0	3,606.887
S-0.5	55.0	3,779.070
L0.5	55.0	4,589.045
O1	55.0	6,137.141
L0	55.0	6,638.477
O2	55.0	8,984.316
O3	55.0	21,413.679
O4	55.0	37,948.866

Analytical Parameters

OLT Placement Band:	1917 - 2010
OLT Experience Band	1917 - 2011
Minimum Life Paramet	1
Maximum Life Parame	55
Life Increment Parame	1
Max Age (T-Cut):	39.5



Analytical Parameters

OLT Placement Band:	1917 - 2011
OLT Experience Band:	1917 - 2011
Minimum Life Parameter:	1
Maximum Life Parameter:	55
Life Increment Parameter:	1
Max Age (T-Cut):	41.0

UGI Gas 2017 GAs

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Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 55 R2.5

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	545,271	55.00	54.53	9,914	540,572
2016	1.5	573,993	55.00	53.58	10,436	559,209
2015	2.5	96,266	55.00	52.64	1,750	92,143
2014	3.5	216,494	55.00	51.71	3,936	203,538
2013	4.5	0	55.00	50.78	0	0
2012	5.5	13,018	55.00	49.85	237	11,799
2011	6.5	0	55.00	48.92	0	0
2010	7.5	0	55.00	48.01	0	0
2009	8.5	0	55.00	47.09	0	0
2008	9.5	122,226	55.00	46.18	2,222	102,626
2007	10.5	35,909	55.00	45.27	653	29,559
2006	11.5	0	55.00	44.37	0	0
2005	12.5	16,797	55.00	43.48	305	13,279
2004	13.5	0	55.00	42.59	0	0
2003	14.5	0	55.00	41.71	0	0
2002	15.5	122,626	55.00	40.83	2,230	91,031
2001	16.5	5,609	55.00	39.96	102	4,075
2000	17.5	60,194	55.00	39.09	1,094	42,784
1999	18.5	208,498	55.00	38.23	3,791	144,940
1998	19.5	87,601	55.00	37.38	1,593	59,540
1997	20.5	112,871	55.00	36.54	2,052	74,981
1996	21.5	625,742	55.00	35.70	11,377	406,148
1995	22.5	277,685	55.00	34.87	5,049	176,041
1994	23.5	210,867	55.00	34.04	3,834	130,525
1993	24.5	66,191	55.00	33.23	1,203	39,990
1992	25.5	118,567	55.00	32.42	2,156	69,893
1991	26.5	215,453	55.00	31.62	3,917	123,871
1990	27.5	197,943	55.00	30.83	3,599	110,953
1989	28.5	177,619	55.00	30.05	3,229	97,031
1988	29.5	274,026	55.00	29.27	4,982	145,835

1987	30.5	151,870	55.00	28.50	2,761	78,708
1986	31.5	75,546	55.00	27.75	1,374	38,112
1985	32.5	96,872	55.00	27.00	1,761	47,551
1984	33.5	45,158	55.00	26.26	821	21,560
1983	34.5	84,991	55.00	25.53	1,545	39,449
1982	35.5	220,339	55.00	24.81	4,006	99,385
1981	36.5	265,597	55.00	24.10	4,829	116,368
1980	37.5	258,104	55.00	23.40	4,693	109,798
1979	38.5	121,584	55.00	22.71	2,211	50,196
1978	39.5	0	55.00	22.03	0	0
1977	40.5	0	55.00	21.36	0	0
1976	41.5	1,781	55.00	20.70	32	670
1975	42.5	3,171	55.00	20.06	58	1,156
1974	43.5	2,227	55.00	19.42	40	786
1973	44.5	5,321	55.00	18.80	97	1,819
1972	45.5	67,234	55.00	18.20	1,222	22,245
1971	46.5	45,251	55.00	17.60	823	14,483
1970	47.5	50,382	55.00	17.02	916	15,594
1969	48.5	70,353	55.00	16.46	1,279	21,051
1968	49.5	68,484	55.00	15.91	1,245	19,805
1967	50.5	29,181	55.00	15.37	531	8,154
1966	51.5	19,621	55.00	14.85	357	5,297
1965	52.5	12,216	55.00	14.34	222	3,185
1964	53.5	18,492	55.00	13.85	336	4,657
1963	54.5	20,169	55.00	13.38	367	4,905
1962	55.5	18,168	55.00	12.92	330	4,267
1961	56.5	10,430	55.00	12.47	190	2,366
1960	57.5	13,478	55.00	12.05	245	2,952
1959	58.5	0	55.00	11.64	0	0
1958	59.5	0	55.00	11.24	0	0
1957	60.5	3,691	55.00	10.86	67	729
1956	61.5	1,699	55.00	10.49	31	324
1955	62.5	0	55.00	10.14	0	0
1954	63.5	0	55.00	9.80	0	0
1953	64.5	460	55.00	9.48	8	79
		6,163,336			112,061	4,006,016

AVERAGE SERVICE LIFE 55.00
AVERAGE REMAINING LIFE 35.75

UGI Gas 2017 GAs

386 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 50 S1

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	0	50.00	49.50	0	0
2016	1.5	0	50.00	48.50	0	0
2015	2.5	0	50.00	47.51	0	0
2014	3.5	0	50.00	46.53	0	0
2013	4.5	0	50.00	45.55	0	0
2012	5.5	0	50.00	44.59	0	0
2011	6.5	0	50.00	43.65	0	0
2010	7.5	0	50.00	42.71	0	0
2009	8.5	0	50.00	41.80	0	0
2008	9.5	0	50.00	40.89	0	0
2007	10.5	0	50.00	40.01	0	0
2006	11.5	0	50.00	39.14	0	0
2005	12.5	276,908	50.00	38.29	5,538	212,042
2004	13.5	19,261	50.00	37.45	385	14,427
2003	14.5	0	50.00	36.63	0	0
2002	15.5	0	50.00	35.83	0	0
2001	16.5	0	50.00	35.05	0	0
2000	17.5	0	50.00	34.28	0	0
1999	18.5	15,161	50.00	33.52	303	10,166
1998	19.5	0	50.00	32.79	0	0
1997	20.5	0	50.00	32.07	0	0
1996	21.5	0	50.00	31.36	0	0
1995	22.5	0	50.00	30.67	0	0
1994	23.5	0	50.00	29.99	0	0
1993	24.5	0	50.00	29.33	0	0
1992	25.5	0	50.00	28.68	0	0
1991	26.5	0	50.00	28.04	0	0
1990	27.5	0	50.00	27.42	0	0
1989	28.5	0	50.00	26.80	0	0
1988	29.5	0	50.00	26.21	0	0

1987	30.5	0	50.00	25.62	0	0
1986	31.5	0	50.00	25.04	0	0
1985	32.5	0	50.00	24.48	0	0
1984	33.5	0	50.00	23.92	0	0
1983	34.5	0	50.00	23.38	0	0
1982	35.5	0	50.00	22.85	0	0
1981	36.5	0	50.00	22.32	0	0
1980	37.5	0	50.00	21.81	0	0
1979	38.5	0	50.00	21.30	0	0
1978	39.5	0	50.00	20.80	0	0
1977	40.5	0	50.00	20.32	0	0
1976	41.5	0	50.00	19.84	0	0
1975	42.5	0	50.00	19.36	0	0
1974	43.5	0	50.00	18.90	0	0
1973	44.5	0	50.00	18.44	0	0
1972	45.5	16,781	50.00	17.99	336	6,039
1971	46.5	1,925	50.00	17.55	39	676
1970	47.5	585	50.00	17.11	12	200
1969	48.5	4,349	50.00	16.69	87	1,451
1968	49.5	821	50.00	16.26	16	267
1967	50.5	207	50.00	15.85	4	66
1966	51.5	1,969	50.00	15.43	39	608
		337,967			6,759	245,942

AVERAGE SERVICE LIFE 50.00
AVERAGE REMAINING LIFE 36.39

UGI Gas 2017 GAs

386.1 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 50 S1

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	0	50.00	49.50	0	0
2016	1.5	0	50.00	48.50	0	0
2015	2.5	1,658	50.00	47.51	33	1,575
2014	3.5	10,178	50.00	46.53	204	9,471
2013	4.5	22,348	50.00	45.55	447	20,361
2012	5.5	115,202	50.00	44.59	2,304	102,743
2011	6.5	0	50.00	43.65	0	0
2010	7.5	55	50.00	42.71	1	47
2009	8.5	0	50.00	41.80	0	0
2008	9.5	0	50.00	40.89	0	0
2007	10.5	0	50.00	40.01	0	0
2006	11.5	3,670	50.00	39.14	73	2,873
2005	12.5	3,317	50.00	38.29	66	2,540
2004	13.5	347	50.00	37.45	7	260
2003	14.5	0	50.00	36.63	0	0
2002	15.5	0	50.00	35.83	0	0
2001	16.5	0	50.00	35.05	0	0
2000	17.5	2,552	50.00	34.28	51	1,750
1999	18.5	13,041	50.00	33.52	261	8,744
1998	19.5	8,784	50.00	32.79	176	5,760
1997	20.5	8,544	50.00	32.07	171	5,480
1996	21.5	22,335	50.00	31.36	447	14,008
1995	22.5	22,679	50.00	30.67	454	13,910
1994	23.5	30,338	50.00	29.99	607	18,197
1993	24.5	45,456	50.00	29.33	909	26,661
1992	25.5	56,753	50.00	28.68	1,135	32,549
1991	26.5	30,826	50.00	28.04	617	17,287
1990	27.5	55,497	50.00	27.42	1,110	30,430
1989	28.5	52,802	50.00	26.80	1,056	28,307
1988	29.5	26,270	50.00	26.21	525	13,768

1987	30.5	25,831	50.00	25.62	517	13,235
1986	31.5	23,744	50.00	25.04	475	11,892
1985	32.5	25,258	50.00	24.48	505	12,365
1984	33.5	6,649	50.00	23.92	133	3,181
1983	34.5	6,768	50.00	23.38	135	3,165
1982	35.5	95,201	50.00	22.85	1,904	43,498
1981	36.5	121,509	50.00	22.32	2,430	54,244
1980	37.5	17,091	50.00	21.81	342	7,454
1979	38.5	5,236	50.00	21.30	105	2,231
1978	39.5	183	50.00	20.80	4	76
1977	40.5	1,422	50.00	20.32	28	578
1976	41.5	3,733	50.00	19.84	75	1,481
1975	42.5	502	50.00	19.36	10	194
1974	43.5	678	50.00	18.90	14	256
1973	44.5	5,741	50.00	18.44	115	2,118
1972	45.5	2,029	50.00	17.99	41	730
1971	46.5	31,925	50.00	17.55	638	11,206
1970	47.5	1,105	50.00	17.11	22	378
1969	48.5	2,743	50.00	16.69	55	915
1968	49.5	5,157	50.00	16.26	103	1,677
1967	50.5	7,811	50.00	15.85	156	2,475
1966	51.5	1,500	50.00	15.43	30	463
1965	52.5	611	50.00	15.03	12	184
1964	53.5	1,895	50.00	14.63	38	555
1963	54.5	1,519	50.00	14.24	30	433
1962	55.5	1,777	50.00	13.85	36	492
1961	56.5	5,466	50.00	13.46	109	1,472
1960	57.5	6,232	50.00	13.08	125	1,631
1959	58.5	739	50.00	12.71	15	188
1958	59.5	237	50.00	12.34	5	58
1957	60.5	546	50.00	11.97	11	131
1956	61.5	989	50.00	11.61	20	230
1955	62.5	2,275	50.00	11.26	46	512
1954	63.5	0	50.00	10.90	0	0
1953	64.5	0	50.00	10.56	0	0
1952	65.5	0	50.00	10.21	0	0
1951	66.5	0	50.00	9.87	0	0
1950	67.5	0	50.00	9.53	0	0
1949	68.5	0	50.00	9.20	0	0
1948	69.5	0	50.00	8.87	0	0
1947	70.5	0	50.00	8.54	0	0
1946	71.5	0	50.00	8.22	0	0
1945	72.5	0	50.00	7.89	0	0
1944	73.5	0	50.00	7.58	0	0
1943	74.5	0	50.00	7.26	0	0
1942	75.5	0	50.00	6.95	0	0
1941	76.5	0	50.00	6.64	0	0

1940	77.5	0	50.00	6.33	0	0
1939	78.5	0	50.00	6.03	0	0
1938	79.5	0	50.00	5.73	0	0
1937	80.5	0	50.00	5.43	0	0
1936	81.5	0	50.00	5.13	0	0
1935	82.5	0	50.00	4.84	0	0
1934	83.5	0	50.00	4.55	0	0
1933	84.5	0	50.00	4.26	0	0
1932	85.5	0	50.00	3.97	0	0
1931	86.5	0	50.00	3.69	0	0
1930	87.5	0	50.00	3.41	0	0
1929	88.5	141	50.00	3.13	3	9
		946,896			18,938	536,424

AVERAGE SERVICE LIFE 50.00
AVERAGE REMAINING LIFE 28.33

UGI Gas 2017 GAs

386.2 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 25 R3

			BG/VG Average			
Year	**Age**	**Surviving Investment**	**Service Life**	**Remaining Life**	**ASL Weights**	**RL Weights**
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	0	25.00	24.51	0	0
2016	1.5	0	25.00	23.53	0	0
2015	2.5	0	25.00	22.55	0	0
2014	3.5	0	25.00	21.59	0	0
2013	4.5	0	25.00	20.63	0	0
2012	5.5	0	25.00	19.68	0	0
2011	6.5	0	25.00	18.75	0	0
2010	7.5	0	25.00	17.82	0	0
2009	8.5	0	25.00	16.91	0	0
2008	9.5	0	25.00	16.02	0	0
2007	10.5	0	25.00	15.15	0	0
2006	11.5	0	25.00	14.29	0	0
2005	12.5	0	25.00	13.45	0	0
2004	13.5	0	25.00	12.63	0	0
2003	14.5	0	25.00	11.83	0	0
2002	15.5	0	25.00	11.05	0	0
2001	16.5	0	25.00	10.30	0	0
2000	17.5	0	25.00	9.57	0	0
1999	18.5	0	25.00	8.86	0	0
1998	19.5	0	25.00	8.18	0	0
1997	20.5	104	25.00	7.54	4	31
1996	21.5	0	25.00	6.92	0	0
1995	22.5	0	25.00	6.34	0	0
1994	23.5	335	25.00	5.80	13	78
1993	24.5	5,858	25.00	5.29	234	1,240
1992	25.5	3,051	25.00	4.82	122	588
1991	26.5	4,510	25.00	4.39	180	792
1990	27.5	10,556	25.00	4.00	422	1,688
1989	28.5	291	25.00	3.64	12	42

	24,705	988	4,460
AVERAGE SERVICE LIFE			25.00
AVERAGE REMAINING LIFE			4.51

Observed Life Table Results
UGI Gas
Account: 387 - Other Equipment

Age	Exposures	Retiremen	Retiremen Ratio (%)	Survivor Ratio (%)	Cumulative Survivors
BAND		1902 - 2011			
0	2,210,814	0	0.0000	100.0000	1.0000
0.5	2,200,824	3,829	0.1740	99.8260	1.0000
1.5	2,196,995	3,293	0.1499	99.8501	0.9983
2.5	2,151,202	1,626	0.0756	99.9244	0.9968
3.5	2,051,667	15,810	0.7706	99.2294	0.9960
4.5	1,998,553	2,191	0.1096	99.8904	0.9883
5.5	1,911,319	6,441	0.3370	99.6630	0.9873
6.5	1,834,471	968	0.0528	99.9472	0.9839
7.5	1,723,798	3,838	0.2227	99.7773	0.9834
8.5	1,497,946	1,451	0.0969	99.9031	0.9812
9.5	1,454,038	9,297	0.6394	99.3606	0.9803
10.5	1,328,702	6,169	0.4643	99.5357	0.9740
11.5	1,122,564	7,064	0.6293	99.3707	0.9695
12.5	995,844	10,911	1.0957	98.9043	0.9634
13.5	909,534	8,414	0.9251	99.0749	0.9528
14.5	816,624	9,498	1.1631	98.8369	0.9440
15.5	761,711	13,436	1.7639	98.2361	0.9330
16.5	678,285	8,698	1.2823	98.7177	0.9166
17.5	618,487	35,465	5.7342	94.2658	0.9048
18.5	557,726	5,562	0.9972	99.0028	0.8529
19.5	537,119	6,160	1.1469	98.8531	0.8444
20.5	504,944	7,096	1.4053	98.5947	0.8347
21.5	464,525	7,205	1.5511	98.4489	0.8230
22.5	441,351	8,464	1.9177	98.0823	0.8102
23.5	419,611	8,860	2.1116	97.8884	0.7947
24.5	387,164	5,231	1.3512	98.6488	0.7779
25.5	362,363	1,252	0.3454	99.6546	0.7674
26.5	348,042	2,364	0.6793	99.3207	0.7648
27.5	314,847	3,151	1.0008	98.9992	0.7596
28.5	309,940	5,737	1.8510	98.1490	0.7520
29.5	291,288	6,021	2.0672	97.9328	0.7380
30.5	275,104	4,506	1.6379	98.3621	0.7228
31.5	268,880	4,083	1.5184	98.4816	0.7109
32.5	262,879	2,225	0.8465	99.1535	0.7002
33.5	259,388	4,700	1.8121	98.1879	0.6942
34.5	250,393	1,431	0.5715	99.4285	0.6816
35.5	240,375	926	0.3854	99.6146	0.6778
36.5	230,968	616	0.2667	99.7333	0.6751
37.5	228,700	4,646	2.0314	97.9686	0.6733
38.5	224,054	576	0.2570	99.7430	0.6597

39.5	219,432	4,328	1.9723	98.0277	0.6580
40.5	204,129	1,188	0.5819	99.4181	0.6450
41.5	200,656	1,381	0.6882	99.3118	0.6412
42.5	197,693	959	0.4850	99.5150	0.6368
43.5	188,672	5,125	2.7163	97.2837	0.6337
44.5	178,683	170	0.0953	99.9047	0.6165
45.5	174,601	3,817	2.1863	97.8137	0.6159
46.5	169,032	8,461	5.0055	94.9945	0.6025
47.5	154,802	0	0.0000	100.0000	0.5723
48.5	153,762	579	0.3765	99.6235	0.5723
49.5	152,895	8	0.0052	99.9948	0.5702
50.5	150,927	57	0.0381	99.9619	0.5701
51.5	148,864	2,637	1.7712	98.2288	0.5699
52.5	130,442	541	0.4144	99.5856	0.5598
53.5	129,250	670	0.5184	99.4816	0.5575
54.5	125,448	1,049	0.8363	99.1637	0.5546
55.5	116,062	106	0.0912	99.9088	0.5500
56.5	115,354	1,664	1.4428	98.5572	0.5495
57.5	108,172	227	0.2097	99.7903	0.5415
58.5	77,819	2,908	3.7375	96.2625	0.5404
59.5	73,785	19,583	26.5400	73.4600	0.5202
60.5	52,834	47	0.0884	99.9116	0.3821
61.5	44,416	532	1.1976	98.8024	0.3818
62.5	21,697	286	1.3196	98.6804	0.3772
63.5	21,411	2,403	11.2232	88.7768	0.3723
64.5	18,552	0	0.0000	100.0000	0.3305
65.5	18,552	0	0.0000	100.0000	0.3305
66.5	18,552	0	0.0000	100.0000	0.3305
67.5	18,552	2,799	15.0854	84.9146	0.3305
68.5	15,754	204	1.2960	98.7040	0.2806
69.5	15,549	130	0.8386	99.1614	0.2770
70.5	15,419	3,071	19.9195	80.0805	0.2747
71.5	12,348	83	0.6749	99.3251	0.2200
72.5	12,264	0	0.0000	100.0000	0.2185
73.5	12,264	0	0.0000	100.0000	0.2185
74.5	12,264	0	0.0000	100.0000	0.2185
75.5	12,264	0	0.0000	100.0000	0.2185
76.5	12,264	0	0.0000	100.0000	0.2185
77.5	12,264	0	0.0000	100.0000	0.2185
78.5	12,264	0	0.0000	100.0000	0.2185
79.5	12,264	2,002	16.3249	83.6751	0.2185
80.5	10,262	114	1.1062	98.8938	0.1828
81.5	10,149	12	0.1186	99.8814	0.1808
82.5	10,137	0	0.0000	100.0000	0.1806
83.5	10,137	545	5.3789	94.6211	0.1806
84.5	9,591	343	3.5725	96.4275	0.1709
85.5	9,249	0	0.0000	100.0000	0.1647

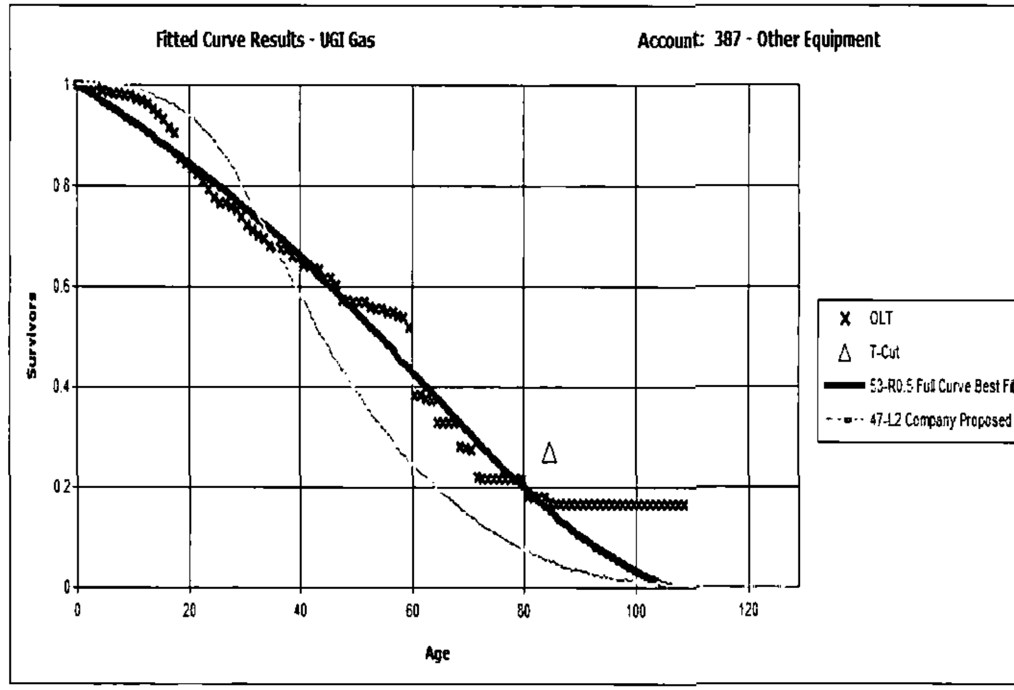
86.5	9,249	0	0.0000	100.0000	0.1647
87.5	408	0	0.0000	100.0000	0.1647
88.5	408	0	0.0000	100.0000	0.1647
89.5	266	0	0.0000	100.0000	0.1647
90.5	266	0	0.0000	100.0000	0.1647
91.5	266	0	0.0000	100.0000	0.1647
92.5	0	0	0.0000	100.0000	0.1647
93.5	0	0	0.0000	100.0000	0.1647
94.5	0	0	0.0000	100.0000	0.1647
95.5	0	0	0.0000	100.0000	0.1647
96.5	0	0	0.0000	100.0000	0.1647
97.5	0	0	0.0000	100.0000	0.1647
98.5	0	0	0.0000	100.0000	0.1647
99.5	0	0	0.0000	100.0000	0.1647
100.5	0	0	0.0000	100.0000	0.1647
101.5	0	0	0.0000	100.0000	0.1647
102.5	0	0	0.0000	100.0000	0.1647
103.5	0	0	0.0000	100.0000	0.1647
104.5	0	0	0.0000	100.0000	0.1647
105.5	0	0	0.0000	100.0000	0.1647
106.5	0	0	0.0000	100.0000	0.1647
107.5	0	0	0.0000	100.0000	0.1647
108.5	0	0	0.0000	100.0000	0.1647

Best Fit Curve Results
UGI Gas
Account: 387 - Other Equipment

Curve	Life	Sum of Squared Differences
BAND	**1902 - 2011**	
R0.5	53.0	1,108.163
S-0.5	53.0	1,181.147
S0	54.0	1,413.400
L0.5	56.0	1,496.196
R1	53.0	1,564.944
L1	56.0	1,765.242
L0	57.0	1,916.646
O1	52.0	2,223.299
S0.5	54.0	2,545.535
O2	59.0	2,577.357
L1.5	56.0	3,007.958
R1.5	54.0	3,146.593
S1	55.0	4,510.056
L2	56.0	5,210.713
O3	74.0	5,876.758
R2	55.0	5,912.238
S1.5	55.0	7,111.968
O4	98.0	7,545.093
R2.5	55.0	9,509.022
S2	56.0	10,516.526
L3	56.0	11,682.489
R3	56.0	14,229.626
S3	57.0	18,246.111
L4	57.0	21,527.742
R4	57.0	23,978.625
S4	57.0	29,134.696
L5	58.0	32,323.471
R5	57.0	36,507.871
S5	58.0	39,850.985
S6	58.0	49,416.002
SQ	60.0	68,241.916

Analytical Parameters

OLT Placement Band:	1902 - 2011
OLT Experience Band	1902 - 2011
Minimum Life Paramet	1
Maximum Life Parame	100
Life Increment Parame	1
Max Age (T-Cut):	84.5



Analytical Parameters

OLT Placement Band:	1902 - 2011
OLT Experience Band:	1902 - 2011
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	86.0

UGI Gas 2017 GAs

387 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 53 R0.5

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	280,515	53.00	52.69	5,293	278,874
2016	1.5	295,900	53.00	52.07	5,583	290,707
2015	2.5	0	53.00	51.45	0	0
2014	3.5	0	53.00	50.83	0	0
2013	4.5	0	53.00	50.22	0	0
2012	5.5	0	53.00	49.61	0	0
2011	6.5	14,794	53.00	48.99	279	13,676
2010	7.5	0	53.00	48.38	0	0
2009	8.5	41,619	53.00	47.77	785	37,516
2008	9.5	95,330	53.00	47.17	1,799	84,837
2007	10.5	36,043	53.00	46.56	680	31,664
2006	11.5	81,381	53.00	45.96	1,535	70,564
2005	12.5	66,622	53.00	45.35	1,257	57,008
2004	13.5	102,571	53.00	44.75	1,935	86,605
2003	14.5	205,009	53.00	44.15	3,868	170,773
2002	15.5	38,730	53.00	43.55	731	31,824
2001	16.5	104,615	53.00	42.95	1,974	84,779
2000	17.5	178,312	53.00	42.35	3,364	142,492
1999	18.5	105,629	53.00	41.76	1,993	83,222
1998	19.5	65,958	53.00	41.16	1,244	51,226
1997	20.5	73,320	53.00	40.57	1,383	56,123
1996	21.5	39,126	53.00	39.98	738	29,512
1995	22.5	59,921	53.00	39.39	1,131	44,530
1994	23.5	43,503	53.00	38.80	821	31,846
1993	24.5	20,301	53.00	38.21	383	14,637
1992	25.5	12,683	53.00	37.63	239	9,004
1991	26.5	21,827	53.00	37.05	412	15,257
1990	27.5	27,831	53.00	36.47	525	19,149
1989	28.5	13,270	53.00	35.89	250	8,986
1988	29.5	10,974	53.00	35.32	207	7,313

1987	30.5	19,384	53.00	34.74	366	12,707
1986	31.5	15,978	53.00	34.18	301	10,303
1985	32.5	10,594	53.00	33.61	200	6,719
1984	33.5	24,793	53.00	33.05	468	15,461
1983	34.5	1,400	53.00	32.49	26	858
1982	35.5	9,496	53.00	31.94	179	5,722
1981	36.5	7,940	53.00	31.39	150	4,702
1980	37.5	1,327	53.00	30.84	25	772
1979	38.5	574	53.00	30.30	11	328
1978	39.5	953	53.00	29.76	18	535
1977	40.5	1,825	53.00	29.22	34	1,006
1976	41.5	5,812	53.00	28.69	110	3,146
1975	42.5	6,099	53.00	28.16	115	3,241
1974	43.5	1,167	53.00	27.64	22	609
1973	44.5	0	53.00	27.12	0	0
1972	45.5	2,748	53.00	26.60	52	1,379
1971	46.5	7,288	53.00	26.09	138	3,588
1970	47.5	1,480	53.00	25.59	28	715
1969	48.5	997	53.00	25.09	19	472
1968	49.5	4,933	53.00	24.59	93	2,289
1967	50.5	2,876	53.00	24.10	54	1,307
1966	51.5	2,229	53.00	23.61	42	993
1965	52.5	876	53.00	23.13	17	382
1964	53.5	2,972	53.00	22.65	56	1,270
1963	54.5	505	53.00	22.17	10	211
1962	55.5	131	53.00	21.70	2	53
1961	56.5	820	53.00	21.23	15	329
1960	57.5	694	53.00	20.77	13	272
1959	58.5	5,212	53.00	20.31	98	1,997
1958	59.5	182	53.00	19.86	3	68
1957	60.5	423	53.00	19.41	8	155
1956	61.5	1,286	53.00	18.96	24	460
		2,178,778			41,109	1,834,174

AVERAGE SERVICE LIFE 53.00
AVERAGE REMAINING LIFE 44.62

UGI Gas 2017 GAs

387.1 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 25 O1

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	0	25.00	24.75	0	0
2016	1.5	0	25.00	24.25	0	0
2015	2.5	0	25.00	23.75	0	0
2014	3.5	0	25.00	23.25	0	0
2013	4.5	0	25.00	22.75	0	0
2012	5.5	0	25.00	22.25	0	0
2011	6.5	0	25.00	21.75	0	0
2010	7.5	0	25.00	21.25	0	0
2009	8.5	0	25.00	20.75	0	0
2008	9.5	0	25.00	20.25	0	0
2007	10.5	0	25.00	19.75	0	0
2006	11.5	0	25.00	19.25	0	0
2005	12.5	0	25.00	18.75	0	0
2004	13.5	0	25.00	18.25	0	0
2003	14.5	93,599	25.00	17.75	3,744	66,471
2002	15.5	7,564	25.00	17.25	303	5,221
2001	16.5	13,979	25.00	16.75	559	9,368
2000	17.5	0	25.00	16.25	0	0
1999	18.5	0	25.00	15.75	0	0
1998	19.5	10,727	25.00	15.25	429	6,546
1997	20.5	0	25.00	14.76	0	0
1996	21.5	0	25.00	14.26	0	0
1995	22.5	4,075	25.00	13.76	163	2,242
1994	23.5	0	25.00	13.26	0	0
1993	24.5	515	25.00	12.76	21	263
1992	25.5	3,540	25.00	12.26	142	1,736
1991	26.5	1,588	25.00	11.76	64	747
1990	27.5	11,535	25.00	11.26	461	5,194
1989	28.5	77,363	25.00	10.76	3,095	33,287
1988	29.5	167,324	25.00	10.26	6,693	68,650

1987	30.5	112,022	25.00	9.76	4,481	43,721
1986	31.5	113,889	25.00	9.26	4,556	42,174
		617,720			24,709	285,618

AVERAGE SERVICE LIFE 25.00
AVERAGE REMAINING LIFE 11.56

UGI Gas 2017 GAs

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Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 20 O1

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	239,294	20.00	19.75	11,965	236,345
2016	1.5	252,500	20.00	19.25	12,625	243,077
2015	2.5	279,924	20.00	18.75	13,996	262,481
2014	3.5	158,472	20.00	18.25	7,924	144,636
2013	4.5	49,177	20.00	17.75	2,459	43,655
2012	5.5	0	20.00	17.25	0	0
2011	6.5	0	20.00	16.75	0	0
2010	7.5	798,604	20.00	16.25	39,930	649,037
2009	8.5	371,655	20.00	15.75	18,583	292,761
2008	9.5	11,477	20.00	15.25	574	8,754
2007	10.5	101,500	20.00	14.75	5,075	74,881
2006	11.5	18,210	20.00	14.25	911	12,979
2005	12.5	52,939	20.00	13.76	2,647	36,409
2004	13.5	37,141	20.00	13.26	1,857	24,616
2003	14.5	88,750	20.00	12.76	4,437	56,602
2002	15.5	16,826	20.00	12.26	841	10,310
2001	16.5	57,957	20.00	11.76	2,898	34,067
2000	17.5	17,374	20.00	11.26	869	9,778
1999	18.5	437,984	20.00	10.76	21,899	235,559
1998	19.5	177,195	20.00	10.26	8,860	90,873
		3,166,979			158,349	2,466,820

AVERAGE SERVICE LIFE 20.00
AVERAGE REMAINING LIFE 15.58

UGI Gas 2017 GAs

391.1 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 5 O1

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	20,849	5.00	4.76	4,170	19,862
2016	1.5	22,000	5.00	4.26	4,400	18,765
2015	2.5	1,240,313	5.00	3.77	248,063	934,400
2014	3.5	1,035,648	5.00	3.27	207,130	677,184
2013	4.5	814,318	5.00	2.77	162,864	451,604
		3,133,127			626,625	2,101,814

AVERAGE SERVICE LIFE 5.00
AVERAGE REMAINING LIFE 3.35

UGI Gas 2017 GAs

392.1 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 7 L2

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	0	7.00	6.50	0	0
2016	1.5	0	7.00	5.56	0	0
2015	2.5	0	7.00	4.71	0	0
2014	3.5	0	7.00	3.99	0	0
2013	4.5	0	7.00	3.48	0	0
2012	5.5	0	7.00	3.13	0	0
2011	6.5	0	7.00	2.87	0	0
2010	7.5	0	7.00	2.63	0	0
2009	8.5	0	7.00	2.38	0	0
2008	9.5	0	7.00	2.14	0	0
2007	10.5	0	7.00	1.89	0	0
2006	11.5	0	7.00	1.66	0	0
2005	12.5	37,043	7.00	1.44	5,292	7,623
2004	13.5	0	7.00	1.24	0	0
2003	14.5	0	7.00	1.05	0	0
2002	15.5	3,600	7.00	0.87	514	447
		40,643			5,806	8,070

AVERAGE SERVICE LIFE	7.00
AVERAGE REMAINING LIFE	1.39

UGI Gas 2017 GAs

392.2 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 11 L3

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	379,080	11.00	10.50	34,462	361,810
2016	1.5	400,000	11.00	9.50	36,364	345,439
2015	2.5	0	11.00	8.51	0	0
2014	3.5	0	11.00	7.56	0	0
2013	4.5	0	11.00	6.65	0	0
2012	5.5	16,491	11.00	5.79	1,499	8,679
2011	6.5	0	11.00	5.02	0	0
2010	7.5	0	11.00	4.40	0	0
2009	8.5	0	11.00	3.93	0	0
2008	9.5	0	11.00	3.62	0	0
2007	10.5	0	11.00	3.41	0	0
2006	11.5	0	11.00	3.24	0	0
2005	12.5	0	11.00	3.06	0	0
2004	13.5	0	11.00	2.85	0	0
2003	14.5	0	11.00	2.60	0	0
2002	15.5	0	11.00	2.35	0	0
2001	16.5	0	11.00	2.09	0	0
2000	17.5	0	11.00	1.85	0	0
1999	18.5	0	11.00	1.62	0	0
1998	19.5	0	11.00	1.40	0	0
1997	20.5	0	11.00	1.19	0	0
1996	21.5	0	11.00	0.99	0	0
1995	22.5	0	11.00	0.81	0	0
1994	23.5	0	11.00	0.64	0	0
1993	24.5	0	11.00	0.51	0	0
1992	25.5	0	11.00	0.50	0	0
1991	26.5	0	11.00	0.50	0	0
1990	27.5	0	11.00	0.50	0	0
1989	28.5	0	11.00	0.50	0	0
1988	29.5	0	11.00	0.50	0	0

1987	30.5	0	11.00	0.50	0	0
1986	31.5	0	11.00	0.50	0	0
1985	32.5	0	11.00	0.50	0	0
1984	33.5	0	11.00	0.50	0	0
1983	34.5	0	11.00	0.50	0	0
1982	35.5	0	11.00	0.50	0	0
1981	36.5	0	11.00	0.50	0	0
1980	37.5	0	11.00	0.50	0	0
1979	38.5	0	11.00	0.50	0	0
1978	39.5	14,178	11.00	0.50	1,289	644
		809,748			73,613	716,572

AVERAGE SERVICE LIFE 11.00
AVERAGE REMAINING LIFE 9.73

UGI Gas 2017 GAs

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Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 20 O1

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	1,046,161	20.00	19.75	52,308	1,033,269
2016	1.5	1,103,895	20.00	19.25	55,195	1,062,699
2015	2.5	1,711,975	20.00	18.75	85,599	1,605,296
2014	3.5	465,207	20.00	18.25	23,260	424,591
2013	4.5	792,113	20.00	17.75	39,606	703,157
2012	5.5	368,654	20.00	17.25	18,433	318,039
2011	6.5	453,581	20.00	16.75	22,679	379,969
2010	7.5	162,965	20.00	16.25	8,148	132,444
2009	8.5	269,695	20.00	15.75	13,485	212,445
2008	9.5	251,797	20.00	15.25	12,590	192,053
2007	10.5	647,841	20.00	14.75	32,392	477,936
2006	11.5	582,434	20.00	14.25	29,122	415,127
2005	12.5	585,132	20.00	13.76	29,257	402,427
2004	13.5	376,497	20.00	13.26	18,825	249,529
2003	14.5	344,961	20.00	12.76	17,248	220,007
2002	15.5	160,394	20.00	12.26	8,020	98,287
2001	16.5	155,344	20.00	11.76	7,767	91,311
2000	17.5	129,059	20.00	11.26	6,453	72,636
1999	18.5	224,988	20.00	10.76	11,249	121,004
1998	19.5	125,969	20.00	10.26	6,298	64,602
		9,958,664			497,933	8,276,829

AVERAGE SERVICE LIFE	20.00
AVERAGE REMAINING LIFE	16.62

UGI Gas 2017 GAs

396 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 14 L2

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	0	14.00	13.50	0	0
2016	1.5	0	14.00	12.52	0	0
2015	2.5	0	14.00	11.57	0	0
2014	3.5	0	14.00	10.67	0	0
2013	4.5	15,374	14.00	9.81	1,098	10,778
2012	5.5	0	14.00	9.01	0	0
2011	6.5	0	14.00	8.29	0	0
2010	7.5	0	14.00	7.68	0	0
2009	8.5	64,652	14.00	7.17	4,618	33,092
2008	9.5	0	14.00	6.74	0	0
2007	10.5	37,931	14.00	6.39	2,709	17,315
2006	11.5	28,808	14.00	6.09	2,058	12,533
2005	12.5	14,736	14.00	5.82	1,053	6,131
2004	13.5	66,888	14.00	5.58	4,778	26,646
2003	14.5	47,179	14.00	5.34	3,370	17,987
2002	15.5	3,720	14.00	5.10	266	1,354
2001	16.5	30,318	14.00	4.85	2,166	10,511
2000	17.5	6,498	14.00	4.61	464	2,138
1999	18.5	21,410	14.00	4.35	1,529	6,659
1998	19.5	22,379	14.00	4.10	1,599	6,559
1997	20.5	35,225	14.00	3.85	2,516	9,698
1996	21.5	32,884	14.00	3.61	2,349	8,481
1995	22.5	71,703	14.00	3.37	5,122	17,277
1994	23.5	53,508	14.00	3.14	3,822	12,013
1993	24.5	20,463	14.00	2.92	1,462	4,269
1992	25.5	29,668	14.00	2.70	2,119	5,730
1991	26.5	8,108	14.00	2.49	579	1,444
1990	27.5	98,157	14.00	2.29	7,011	16,049
1989	28.5	83,291	14.00	2.09	5,949	12,431
1988	29.5	55,741	14.00	1.89	3,982	7,543

1987	30.5	20,059	14.00	1.70	1,433	2,441
1986	31.5	74,285	14.00	1.52	5,306	8,049
1985	32.5	92,626	14.00	1.33	6,616	8,818
1984	33.5	50,934	14.00	1.15	3,638	4,183
1983	34.5	1,255	14.00	0.97	90	87
1982	35.5	39,998	14.00	0.79	2,857	2,250
1981	36.5	56,108	14.00	0.61	4,008	2,447
1980	37.5	9,350	14.00	0.50	668	334
1979	38.5	7,705	14.00	0.50	550	275
1978	39.5	9,565	14.00	0.50	683	342
1977	40.5	36,335	14.00	0.50	2,595	1,298
1976	41.5	6,602	14.00	0.50	472	236
1975	42.5	12,337	14.00	0.50	881	441
1974	43.5	10,872	14.00	0.50	777	388
1973	44.5	3,084	14.00	0.50	220	110
1972	45.5	1,184	14.00	0.50	85	42
1971	46.5	4,288	14.00	0.50	306	153
1970	47.5	5,396	14.00	0.50	385	193
1969	48.5	1,225	14.00	0.50	87	44
1968	49.5	4,253	14.00	0.50	304	152
1967	50.5	2,769	14.00	0.50	198	99
1966	51.5	2,108	14.00	0.50	151	75
1965	52.5	6,056	14.00	0.50	433	216
1964	53.5	4,005	14.00	0.50	286	143
1963	54.5	4,062	14.00	0.50	290	145
1962	55.5	9,367	14.00	0.50	669	335
1961	56.5	2,981	14.00	0.50	213	106
1960	57.5	4,660	14.00	0.50	333	166
1959	58.5	3,128	14.00	0.50	223	112
1958	59.5	2,817	14.00	0.50	201	101
1957	60.5	1,282	14.00	0.50	92	46
1956	61.5	4,099	14.00	0.50	293	146
1955	62.5	1,110	14.00	0.50	79	40
1954	63.5	18,678	14.00	0.50	1,334	667
1953	64.5	801	14.00	0.50	57	29
1952	65.5	4,190	14.00	0.50	299	150
1951	66.5	2,128	14.00	0.50	152	76
1950	67.5	164	14.00	0.50	12	6
1949	68.5	0	14.00	0.50	0	0
1948	69.5	285	14.00	0.50	20	10
		1,370,791			97,914	281,584

AVERAGE SERVICE LIFE 14.00
AVERAGE REMAINING LIFE 2.88

UGI Gas 2017 GAs

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Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 10 O1

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	0	10.00	9.76	0	0
2016	1.5	0	10.00	9.26	0	0
2015	2.5	0	10.00	8.76	0	0
2014	3.5	0	10.00	8.26	0	0
2013	4.5	31,838	10.00	7.76	3,184	24,701
2012	5.5	82,938	10.00	7.26	8,294	60,204
2011	6.5	3,294	10.00	6.76	329	2,226
2010	7.5	0	10.00	6.26	0	0
2009	8.5	105,387	10.00	5.76	10,539	60,715
2008	9.5	283,428	10.00	5.26	28,343	149,147
		506,885			50,688	296,994

AVERAGE SERVICE LIFE 10.00
AVERAGE REMAINING LIFE 5.86

UGI Gas 2017 GAs

398 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 10 O1

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	130,309	10.00	9.76	13,031	127,137
2016	1.5	137,500	10.00	9.26	13,750	127,283
2015	2.5	39,300	10.00	8.76	3,930	34,416
2014	3.5	172,906	10.00	8.26	17,291	142,782
2013	4.5	51,778	10.00	7.76	5,178	40,171
2012	5.5	102,456	10.00	7.26	10,246	74,372
2011	6.5	96,716	10.00	6.76	9,672	65,376
2010	7.5	45,540	10.00	6.26	4,554	28,510
2009	8.5	63,823	10.00	5.76	6,382	36,770
2008	9.5	14,386	10.00	5.26	1,439	7,571
		854,715			85,471	684,387

AVERAGE SERVICE LIFE 10.00
AVERAGE REMAINING LIFE 8.01

UGI Gas 2017 GAs

391 Common -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 20 O1

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	0	20.00	19.75	0	0
2016	1.5	0	20.00	19.25	0	0
2015	2.5	0	20.00	18.75	0	0
2014	3.5	0	20.00	18.25	0	0
2013	4.5	0	20.00	17.75	0	0
2012	5.5	0	20.00	17.25	0	0
2011	6.5	0	20.00	16.75	0	0
2010	7.5	747,319	20.00	16.25	37,366	607,357
2009	8.5	4,753	20.00	15.75	238	3,744
2008	9.5	572	20.00	15.25	29	437
2007	10.5	878	20.00	14.75	44	648
2006	11.5	2,469	20.00	14.25	123	1,760
2005	12.5	39,966	20.00	13.76	1,998	27,487
2004	13.5	11,896	20.00	13.26	595	7,884
2003	14.5	7,183	20.00	12.76	359	4,581
2002	15.5	0	20.00	12.26	0	0
2001	16.5	25,355	20.00	11.76	1,268	14,904
		840,391			42,020	668,801

AVERAGE SERVICE LIFE 20.00
AVERAGE REMAINING LIFE 15.92

UGI Gas 2017 GAs

391.1 Common -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 5 O1

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	0	5.00	4.76	0	0
2016	1.5	0	5.00	4.26	0	0
2015	2.5	13,608	5.00	3.77	2,722	10,252
2014	3.5	15,125	5.00	3.27	3,025	9,890
2013	4.5	126,305	5.00	2.77	25,261	70,046
		155,038			31,008	90,188

AVERAGE SERVICE LIFE 5.00
AVERAGE REMAINING LIFE 2.91

UGI Gas 2017 GAs

392.1 Common -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 7 L2

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	0	7.00	6.50	0	0
2016	1.5	0	7.00	5.56	0	0
2015	2.5	0	7.00	4.71	0	0
2014	3.5	22,225	7.00	3.99	3,175	12,676
2013	4.5	0	7.00	3.48	0	0
2012	5.5	0	7.00	3.13	0	0
2011	6.5	0	7.00	2.87	0	0
2010	7.5	0	7.00	2.63	0	0
2009	8.5	0	7.00	2.38	0	0
2008	9.5	22,536	7.00	2.14	3,219	6,878
2007	10.5	0	7.00	1.89	0	0
2006	11.5	0	7.00	1.66	0	0
2005	12.5	0	7.00	1.44	0	0
2004	13.5	26,876	7.00	1.24	3,839	4,750
		71,637			10,234	24,304

AVERAGE SERVICE LIFE 7.00
AVERAGE REMAINING LIFE 2.37

UGI Gas 2017 GAs

391 IS -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 20 O1

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	0	20.00	19.75	0	0
2016	1.5	0	20.00	19.25	0	0
2015	2.5	0	20.00	18.75	0	0
2014	3.5	0	20.00	18.25	0	0
2013	4.5	0	20.00	17.75	0	0
2012	5.5	0	20.00	17.25	0	0
2011	6.5	0	20.00	16.75	0	0
2010	7.5	0	20.00	16.25	0	0
2009	8.5	0	20.00	15.75	0	0
2008	9.5	0	20.00	15.25	0	0
2007	10.5	1,760	20.00	14.75	88	1,298
2006	11.5	0	20.00	14.25	0	0
2005	12.5	0	20.00	13.76	0	0
2004	13.5	5,699	20.00	13.26	285	3,777
2003	14.5	22,684	20.00	12.76	1,134	14,467
2002	15.5	6,694	20.00	12.26	335	4,102
2001	16.5	3,769	20.00	11.76	188	2,216
2000	17.5	0	20.00	11.26	0	0
1999	18.5	6,159	20.00	10.76	308	3,312
1998	19.5	24,630	20.00	10.26	1,232	12,632
		71,395			3,570	41,804

AVERAGE SERVICE LIFE 20.00
AVERAGE REMAINING LIFE 11.71

UGI Gas 2017 GAs

391.1 IS -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 5 O1

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	0	5.00	4.76	0	0
2016	1.5	0	5.00	4.26	0	0
2015	2.5	1,226,704	5.00	3.77	245,341	924,148
2014	3.5	1,020,523	5.00	3.27	204,105	667,294
2013	4.5	621,616	5.00	2.77	124,323	344,736
		2,868,843			573,769	1,936,177

AVERAGE SERVICE LIFE 5.00
AVERAGE REMAINING LIFE 3.37

UGI Gas 2017 GAs

391.3 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 10 O1

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	5,970,510	10.00	9.76	597,051	5,825,188
2016	1.5	6,300,000	10.00	9.26	630,000	5,831,883
2015	2.5	979,405	10.00	8.76	97,940	857,700
2014	3.5	981,640	10.00	8.26	98,164	810,619
2013	4.5	431,237	10.00	7.76	43,124	334,567
2012	5.5	2,890,938	10.00	7.26	289,094	2,098,496
2011	6.5	24,265	10.00	6.76	2,427	16,402
2010	7.5	324,586	10.00	6.26	32,459	203,201
2009	8.5	775,538	10.00	5.76	77,554	446,802
2008	9.5	259,507	10.00	5.26	25,951	136,559
		18,937,625			1,893,762	16,561,417

AVERAGE SERVICE LIFE 10.00
AVERAGE REMAINING LIFE 8.75

UGI Gas 2017 GAs

391.4 IS -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 15 O1

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	88,186,648	15.00	14.75	5,879,110	86,743,454
2016	1.5	120,000	15.00	14.25	8,000	114,037
2015	2.5	0	15.00	13.75	0	0
2014	3.5	495,556	15.00	13.26	33,037	437,908
2013	4.5	527,926	15.00	12.76	35,195	448,921
2012	5.5	533,950	15.00	12.26	35,597	436,253
2011	6.5	457,199	15.00	11.76	30,480	358,312
2010	7.5	0	15.00	11.26	0	0
2009	8.5	0	15.00	10.76	0	0
2008	9.5	2,908,998	15.00	10.26	193,933	1,989,078
2007	10.5	3,042,652	15.00	9.76	202,843	1,979,112
2006	11.5	1,660,898	15.00	9.26	110,727	1,025,019
2005	12.5	867,789	15.00	8.76	57,853	506,651
		98,801,617			6,586,774	94,038,745

AVERAGE SERVICE LIFE	15.00
AVERAGE REMAINING LIFE	14.28

UGI Utilities, Inc., Gas Division
PA Docket # R-2015-2518438
Calculated Reserve

ACCOUNT		SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	REMAINING LIFE
(1)		(2)	(3)	(4)	(5)
DISTRIBUTION PLANT					
375	STRUCTURES AND IMPROVEMENTS	60 - L0.5	2,185,833	1,446,653	34.2
376.1	MAINS - PRIMARILY STEEL	76 - R2.5	231,294,934	78,311,541	53.6
376.2	MAINS - CAST IRON	82 - L0.5	2,733,094	788,879	44.8
376.3	MAINS - PLASTIC	68 - R3	515,422,589	112,315,208	55.9
376.5	MAINS - PRIMARILY WROUGHT IRON	70 - R1	294,940	254,942	12.3
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	61 - L0.5	34,124,579	5,149,506	54.9
378.1	MEASURING AND REGULATING STATION EQUIPMENT - SCADA	13 - S2	1,316,613	660,294	7.1
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	44 - R2.5	4,794,310	3,093,712	17.4
380	SERVICES	50 - S1	592,758,055	159,613,547	38.9
381	METERS	37 - S0.5	48,498,754	17,159,112	28.6
381.2	ELECTRONIC METERS	20 - S2	11,046,136	6,264,387	11.1
382	METER INSTALLATIONS	50 - S1	65,196,088	23,154,952	36.8
383	HOUSE REGULATORS	50 - S1	7,404,361	1,667,308	37.4
384	HOUSE REGULATOR INSTALLATIONS	50 - S1	11,149,494	4,220,552	36.7
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	55 - R2.5	6,163,336	3,586,364	35.8
386	OTHER PROPERTY ON CUSTOMERS PREMISES	50 - S1	337,967	131,585	36.9
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	50 - S1	946,896	583,957	28.3
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	25 - R3	24,705	23,592	4.5
386.3	OTHER PROPERTY ON CUSTOMER PREMISES - CNG REFUELING STATION			1,036	
387	OTHER EQUIPMENT	32 - L2	2,178,778	848,337	21.2
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	25 - SQ	1,490,664	1,446,389	11.6
TOTAL DISTRIBUTION PLANT			**1,539,362,126**	**420,721,853**	
GENERAL PLANT					
390.1	STRUCTURES AND IMPROVEMENTS	VARIOUS*	32,047,414	15,682,103	15.7
390.2	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	SQUARE	11,241	5,878	2.4
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	20 - SQ	2,255,193	998,122	15.6
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	5 - SQ	109,246	138,845	0.0
392.1	TRANSPORTATION EQUIPMENT - CARS	7 - L2.5	40,643	40,635	1.4
392.2	TRANSPORTATION EQUIPMENT - TRUCKS	11 - L3	809,748	89,061	9.7
392.4	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	14 - L4	12,549	12,549	0.0
394	TOOLS, SHOP AND GARAGE EQUIPMENT	20 - SQ	9,958,664	3,331,267	16.6
396	POWER OPERATED EQUIPMENT	14 - L2.5	1,370,792	1,315,394	2.4
397	COMMUNICATION EQUIPMENT	10 - SQ	506,885	416,447	5.9
398	MISCELLANEOUS EQUIPMENT	10 - SQ	854,715	339,529	8.0
TOTAL GENERAL PLANT			**47,977,090**	**22,369,830**	

UGI Utilities, Inc., Gas Division
PA Docket # R-2015-2518438
Calculated Reserve

ACCOUNT		SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	REMAINING LIFE
(1)		(2)	(3)	(4)	(5)
TOTAL DEPRECIABLE GAS PLANT			1,587,339,216	443,091,683	
COMMON PLANT					
390.2	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	SQUARE	159,895	139,250	1.5
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	20 - SQ	840,391	164,240	15.9
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	5 - SQ	155,038	112,023	2.3
392.1	TRANSPORTATION EQUIPMENT - CARS	7 - L2.5	71,637	61,742	2.4
TOTAL COMMON PLANT			1,226,961	477,255	
INFORMATION SERVICES (IS)					
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	20 - SQ	71,395	59,106	11.7
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	5 - SQ	2,868,843	1,746,659	3.4
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	10 - SQ	18,937,625	4,843,763	8.8
391.4	OFFICE FURNITURE & EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS **	15 - SQ	98,801,617	6,654,743	14.3
TOTAL INFORMATION SERVICES			117,739,242	13,304,271	
GRAND TOTAL			1,706,305,419	456,873,209	

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2015-2518438
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, James S. Garren, hereby state that the facts above set forth in my Direct Testimony, OCA St. No. 5, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: ______________________
James S. Garren

Consultant Address: Snavely King Majoros & Associates, Inc.
PO Box 727
Millersville, MD 21108

DATED: April 12, 2016

OCA St. No. 5-SR
6/2/16 [illegible]

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2015-2518438**
	:	
UGI Utilities, Inc. – Gas Division	:	

SURREBUTTAL TESTIMONY OF

JAMES S. GARREN

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

MAY 25, 2016

SURREBUTTAL TESTIMONY AND EXHIBITS OF JAMES S. GARREN

A. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is James S. Garren. I am an analyst with the economic consulting firm of Snavely King Majoros & Associates, Inc. ("Snavely King").

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I filed direct testimony on April 12, 2016.

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Pennsylvania Office of Consumer Advocate

Q. WHAT IS THE OBJECTIVE OF YOUR TESTIMONY?

A. The purpose of this surrebuttal testimony is to respond to UGI witness Wiedmayer, who has submitted rebuttal that responds to my direct testimony.

Q. WHAT ISSUES HAS MR. WIEDMAYER RAISED REGARDING YOUR DIRECT TESTIMONY?

A. Mr. Wiedmayer has raised several issues with my direct testimony. In the order that I intend to address them, they are:

- Switching from ELG to ASL remaining lives.
- Incorporation of future expectations.
- Curve fitting analysis.
- Curves used for amortization.

<u>**Switching from ELG to ASL remaining lives.**</u>

Q. WOULD YOU LIKE TO ADDRESS MR. WIEDMAYER'S STATEMENTS REGARDING ELG REMAINING LIFE CALCULATIONS?

A. Yes. Mr. Wiedmayer defends the use of the Equal Life Group (ELG) method on three primary bases. First, that the Company's Annual Depreciation Report ("ADR") fulfills the need for frequent updating of lives necessary for ELG to maintain an accurate depiction of remaining lives. The Company's ADRs serve to update the Company's remaining lives for changes to the Company's plant in service, but the problem with ELG remaining life calculations isn't its inherent errors, but its sensitivity, meaning that it magnifies errors in average service life projections. This is why ELG necessitates *annual* service life studies to ensure that it does not over or under collect depreciation expense. Given that UGI – Gas only performs *service life* studies once every five years at best, ELG is an inappropriate way to calculate UGI's remaining lives.

I do appreciate that the use of the ELG remaining lives method has been used by other utilities in Pennsylvania. That said, I have not conducted a study of the practices of all fifty states but I am not aware of another jurisdiction in the country, nor the FERC, that continues to rely on ELG remaining life calculations for the very reasons that I have pointed out. Accordingly, such a method should not be relied on in this case to set rates and the Company should convert back to using Average Service Life ("ASL") remaining life.

Incorporation of future expectations.

Q. PLEASE DESCRIBE THE ISSUES RAISED BY MR. WIEDMAYER REGARDING THE COMPANY'S FUTURE EXPECTATIONS FOR PLANT IN SERVICE.

A. Mr. Wiedmayer criticizes my approach on the basis that I have not incorporated expectations regarding the Company's future plans. Mr. Wiedmayer asserts that I have failed to incorporate a judgmental component to my proposals for average service lives. Specifically, regarding the Long-Term Infrastructure Investment Program ("LTIIP"), Mr. Wiedmayer states that the Company plans to retire all cast iron mains by March 1, 2027, that this is his recommendation for all accounts, and that this is important information to consider when proposing an average service life to be used for cast iron mains.[1]

In order to illustrate, Mr. Wiedmayer provides a life analysis of Account 376.2 with an experience band of 1960-2027, which presumably incorporates forecasted retirements from 2011-2027. A graph showing the results of this analysis for Account 367.2 are

[1] UGI Gas – Statement No. 5-R (Wiedmayer), p. 24, lines 6-22.

shown in Figure 2 in his rebuttal testimony. This figure purports to show the results of curve fitting analysis for the experience band 1960-2027, which suggests that the best fit is a 64-R1 Iowa curve.

Q. WAS THIS ANALYSIS PROVIDED IN CONNECTION WITH MR. WIEDMAYER'S DIRECT TESTIMONY?

A. No. In fact, Mr. Wiedmayer provided no analysis or commentary regarding the LTIIP whatsoever in his direct testimony. In Book 7 of UGI's filing, which contains the Company's 2016 depreciation study, at page III-4, in the section entitled "Judgment," Mr. Wiedmayer outlines some limited expectations regarding average service life on the Company's largest plant accounts, including Account 376.1 – Mains, Primary Steel. During the process of completing my exhibits and testimony, I reviewed each of these explanations and did not find that any of these explanations significantly modified the historical expectations provided by UGI's depreciation data.

If Mr. Wiedmayer expects the LTIIP to have as profound an effect as he suggests in his Rebuttal testimony, that analysis, or at least the narrative explanation of these impacts, should have been presented in his Direct testimony, where they could have been adequately evaluated by the Commission and intervenors. When asked specifically in OCA Set VI-90 to identify and explain the impacts of any Company programs that might affect plant lives, Company witness Hans Bell replied with four programs: LTIIP, Annual Asset Optimization Plan ("AAOP"), Distribution Integrity Management Plan ("DIMP"), and Transmission Integrity Management Plan ("TIMP"). No explanation or discussion whatsoever of the impact of these programs was provided.

Although in his Rebuttal testimony Mr. Wiedmayer places great importance on the LTIIP for the service life expectations of Account 376.2 as indicated by his analysis of apparently forecasted retirement data, in his depreciation study, Mr. Wiedmayer does not discuss Account 376.2 at all, indicating no reason for diverging from his historical life analysis.

Q. SHOULD MR. WIEDMAYER'S ANALYSIS OF THE 1960-2027 EXPERIENCE BAND BE GIVEN CREDENCE IN DETERMINING THE APPROPRIATE AVERAGE SERVICE LIFE OF ACCOUNT 376.2?

A. No. The primary reason that this analysis should not be considered is that Mr. Wiedmayer does not attempt to provide the information that would be necessary to evaluate its veracity. He provides no information regarding how the underlying data was derived, and makes no effort to describe where the data comes from. It seems likely that most of the data from 2016-2027 were the result of some sort of forecasting. However, none of this information or analysis was provided prior to Mr. Wiedmayer's Rebuttal testimony. In response to OCA Set XX-4 regarding his rebuttal, Mr. Wiedmayer explains that this data was produced by essentially assuming a final retirement date of 2027, and dividing the remaining plant balance over the next ten years, using an R1 curve to disperse the retirements.[2]

Q. HOW SHOULD THE COMPANY HANDLE THE EARLY PREMATURE RETIREMENT AND REPLACEMENT OF CAST IRON MAINS?

A. Once plans and timelines for the LTIIP have received final approval from the Commission, the Company should, in its subsequent rate case, explicitly request accelerated depreciation for Account 376.2 – Mains, Cast Iron, in order to recover the remaining depreciation on a timeline that reflects the shortened expected service lives. The Company would then propose a straight-line amortization period that would reflect the early retirement date, while mitigating the rate shock that can result from these kinds of large, one time retirements of an entire class of plant. This would also provide transparency to regulators and to consumers.

Curve fitting analysis.

Q. DOES YOUR LIFE ANALYSIS AGREE WITH THE LIFE ANALYSIS CONDUCTED BY MR. WIEDMAYER?

A. Yes. Despite Mr. Wiedmayer's criticisms of my analysis, the table below clearly shows that my proposals are substantially in line with Mr. Wiedmayer's own life analysis. The Table below shows UGI's proposals and the best-fitting curves from Mr. Wiedmayer's life analysis provided in response to OCA Set VI-49.

[2] Wiedmayer response to OCA Set XX-4.

Table 1
UGI Proposed lives and curves v. Wiedmayer's best fit survivor curves

	ACCOUNT	UGI Proposed Survivor Curve	Wiedmayer Best Fit Survivor Curve	OCA Proposed Survivor Curve
	(1)	(2)	(3)	(4)
DISTRIBUTION PLANT				
375	STRUCTURES AND IMPROVEMENTS	55-S0.5	63.1-L0.5	60-L0.5
376.1	MAINS - PRIMARILY STEEL	72-R2.5	87.3-L2	76-R2.5
376.2	MAINS - CAST IRON	70-R1	82.1-L0.5	82-L0.5
378	MEAS. AND REG. STATION EQUIPMENT – GENERAL	50S0.5	61.9-L0	61-L0.5
379	MEAS. AND REG. STATION EQUIPMENT - CITY GATE	40-R3	64.1-L1	44-R2.5
380	SERVICES	47-R2	54-L1	50-S1
381	METERS	36-R1.5	36-R1	37-S0.5
385	IND. MEAS. AND REG. STATION EQUIPMENT	47-R2	144.6-O1	55-R2.5
387	OTHER EQUIPMENT	32-L2	45.8-L0	32-L2
GENERAL PLANT				
392.1	TRANSPORTATION EQUIPMENT – CARS	7-L2.5	6.3-S2	7-L2.5
392.2	TRANSPORTATION EQUIPMENT – TRUCKS	11-L3	10.4-L3	11-L3
392.4	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	14-L4	13.6-L3	14-L4
396	POWER OPERATED EQUIPMENT	14-L2.5	18.5-O4	14-L2.5

As we can see, my proposals are actually conservative, relative to what Mr. Wiedmayer's analysis shows. This is because, particularly in the case of Account 385 – Industrial Measuring and Regulating Station Equipment, the SCIAS life analysis limits the maximum average service life by the maximum service life found in the industry.

Q. ARE THE MAXIMUM LIVES INDICATED BY YOUR PROPOSED LIVES AND CURVES UNREASONABLE?

A. No. In Mr. Wiedmayer's Rebuttal testimony, he states that my service life and Iowa curve selection for Account 378 are unreasonable because they result in 15% of plant in service remaining in service at 120 years, and a maximum life of 247 years.[3] What Mr. Wiedmayer is saying here is true. However, it is not unreasonable. As of right now, for Account 378 you can see in my Exhibit JSG-3 for this account, plant in service at the age of the oldest retirement, which is at age 87, are still at 91% of their original plant. Given that fact, it is not unreasonable to expect that 15% of these exposures will remain in another 38 years.

It is also possible that future retirement experience will show a greater rate of retirements at older ages than the current data suggests is likely. In that case, a future life analysis will predict a higher modal curve. This is why it is necessary to conduct life analyses every few years, to bring our forecasts in line with the most recent data. However, for now, there is no reason to suggest that 15% of the plant in service for Account 378 will not remain in plant in service at 125 years.

Moreover, it is important to keep in perspective the impact that these "long tails" of surviving plant have on the calculated remaining life of an account. For instance, right now, I am proposing a 61-L0.5 life and curve for Account 378, while Mr. Wiedmayer is proposing a 50-S0.5 curve for the same account. My 61-L0.5 curve results in a remaining life of 54.9, calculated on an ASL basis. Exhibit JSG-SR 2 shows a generation arrangement for a 61-S0.5 curve, or the combination of my recommended average service life and Mr. Wiedmayer's preferred curve shape. This shows that the

[3] UGI Gas Statement No. 5-R (Wiedmayer), p. 39, lines 9-13.

remaining life for a 61-S0.5 curve is 55.4 years, or 0.5 years *longer* than the remaining life that I have proposed, despite only having a maximum life of 122 years.

Q. DOES MR. WIEDMAYER TAKE ISSUE WITH YOUR T-CUTS?

A. Yes. Again referring to Account 378, Mr. Wiedmayer states that I have included too much of the observed life table in my curve fitting analysis. He indicates that the exposures beyond Age 60.5 are "less than $40,000", which represents a fairly small sample size, relative to the $20,238,567 of assets at age 0.[4]

Mr. Wiedmayer truncated his data in the graph for this account in his depreciation study at Age 57.5, and indicates that my truncation of the data at Age 78.5 is inappropriate.[5] Mr. Wiedmayer suggests that because the exposures at Age 60 are small relative to exposures at Age 0, they should be disregarded. This is misleading because all amounts shown in our life analysis are recorded at original cost. That means that the "less than $40,000" amount that Mr. Wiedmayer dismisses is actually $16,855 dollars at Age 78.5, where I have made my truncation of the data. That is $16,855 dollars in 1938 dollars. If we were to represent the dollar values of plant in service shown in the OLT at their present values, the decline in value of the exposures from Age 0 to Age 78.5 would appear substantially less steep.

Moreover, the decision to truncate the longest lived assets in each account unnecessarily biases Mr. Wiedmayer's analysis towards shorter lives and higher modal curves without any objective basis.

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[4] UGI Gas Statement No. 5-R (Wiedmayer), p. 41, lines 12-17.
[5] UGI Gas Exhibit C (Future), p. VI-24.

Curves used for amortization.

Q. WHAT DOES MR. WIEDMAYER STATE REGARDING THE CURVES THAT YOU USED FOR AMORTIZATION ACCOUNTS?

A. Mr. Wiedmayer points out that the depreciation expense for amortization accounts in General, Common, and IS plant calculated in Exhibit JSG-2 to my testimony is incorrect. I had initially recalculated remaining lives for these accounts in order to convert their remaining lives to an ASL calculation from ELG. However, as Mr. Wiedmayer points out, in the process, I utilized O1 curves in place of SQ curves. O1 curves are very similar to SQ, in that they are straight lines, as should be utilized for an amortization account. However, whereas an O1 curve reflects a typical average service life, a SQ curve actually terminates at the "average service life." This difference results in the discrepancy that Mr. Wiedmayer has pointed out. In the attached Exhibit JSG SR-1 I have corrected this discrepancy, resulting in an adjustment to my initial recommended depreciation expense of $748,513.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2015-2518438**
	:	
UGI Utilities, Inc. – Gas Division	:	

EXHIBITS ACCOMPANYING THE

SURREBUTTAL TESTIMONY OF

JAMES S. GARREN

ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

MAY 25, 2016

1

UGI Utilities, Inc., Gas Division
PA Docket # R-2015-2518438
Calculation of Depreciation Rates and Accruals

ACCOUNT		SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	REMAINING LIFE	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
DISTRIBUTION PLANT								
375	STRUCTURES AND IMPROVEMENTS	60 - L0.5	2,185,833	1,446,653	739,180	34.2	0.99%	21,645
376.1	MAINS - PRIMARILY STEEL	76 - R2.5	231,294,934	78,311,541	152,983,393	53.6	1.24%	2,856,833
376.2	MAINS - CAST IRON	82 - L0.5	2,733,094	788,879	1,944,215	44.8	1.59%	43,398
376.3	MAINS - PLASTIC	68 - R3	515,422,589	112,315,208	403,107,381	55.9	1.40%	7,207,355
376.5	MAINS - PRIMARILY WROUGHT IRON	70 - R1	294,940	254,942	39,998	12.3	1.10%	3,241
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	61 - L0.5	34,124,579	5,149,506	28,975,073	54.9	1.55%	527,971
378.1	MEASURING AND REGULATING STATION EQUIPMENT - SCADA	13 - S2	1,316,613	660,294	656,319	7.1	7.06%	92,963
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	44 - R2.5	4,794,310	3,093,712	1,700,598	17.4	2.03%	97,511
380	SERVICES	50 - S1	592,758,055	159,613,547	433,144,508	38.9	1.88%	11,131,959
381	METERS	37 - S0.5	48,498,754	17,159,112	31,339,642	28.6	2.26%	1,096,559
381.2	ELECTRONIC METERS	20 - S2	11,046,136	6,264,387	4,781,749	11.1	3.92%	432,737
382	METER INSTALLATIONS	50 - S1	65,196,088	23,154,952	42,041,136	36.8	1.75%	1,143,354
383	HOUSE REGULATORS	50 - S1	7,404,361	1,667,308	5,737,053	37.4	2.07%	153,274
384	HOUSE REGULATOR INSTALLATIONS	50 - S1	11,149,494	4,220,552	6,928,942	36.7	1.69%	188,851
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	55 - R2.5	6,163,336	3,586,364	2,576,972	35.8	1.17%	72,083
386	OTHER PROPERTY ON CUSTOMERS PREMISES	50 - S1	337,967	131,585	206,382	36.9	1.65%	5,591
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	50 - S1	946,896	583,957	362,939	28.3	1.35%	12,825
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	25 - R3	24,705	23,592	1,113	4.5	1.00%	247
386.3	OTHER PROPERTY ON CUSTOMER PREMISES - CNG REFUELING STATION			1,036	(1,036)			0
387	OTHER EQUIPMENT	32 - L2	2,178,778	848,337	1,330,441	21.2	2.88%	62,727
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	25 - SQ	1,490,664	1,446,389	44,275	11.6	0.26%	3,830
TOTAL DISTRIBUTION PLANT			**1,539,362,126**	**420,721,853**	**1,118,640,273**		1.63%	**25,154,955**
GENERAL PLANT								
390.1	STRUCTURES AND IMPROVEMENTS	VARIOUS*	32,047,414	15,682,103	16,365,311		3.25%	1,042,799
390.2	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	SQUARE	11,241	5,878	5,363		19.71%	2,216
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	20 - SQ	2,255,193	998,122	1,257,071	15.6	3.58%	80,685
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	5 - SQ	109,246	138,845	(29,599)		0.00%	0
392.1	TRANSPORTATION EQUIPMENT - CARS	7 - L2.5	40,643	40,635	8	1.4	0.01%	6
392.2	TRANSPORTATION EQUIPMENT - TRUCKS	11 - L3	809,748	89,061	720,687	9.7	9.15%	74,069
392.4	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS	14 - L4	12,549	12,549	0		0.00%	0
394	TOOLS, SHOP AND GARAGE EQUIPMENT	20 - SQ	9,958,664	3,331,267	6,627,397	13.2	5.03%	500,559
396	POWER OPERATED EQUIPMENT	14 - L2.5	1,370,792	1,315,394	55,398	2.4	1.70%	23,276
397	COMMUNICATION EQUIPMENT	10 - SQ	506,885	416,447	90,438	1.7	10.50%	53,199
398	MISCELLANEOUS EQUIPMENT	10 - SQ	854,715	339,529	515,186	1.7	35.46%	303,051
TOTAL GENERAL PLANT			**47,977,090**	**22,369,830**	**25,607,260**		4.34%	**2,079,859**
TOTAL DEPRECIABLE GAS PLANT			**1,587,339,216**	**443,091,683**	**1,144,247,533**		1.72%	**27,234,814**
NONDEPRECIABLE PLANT								
302.1	FRANCHISES AND CONSENTS - PERPETUAL		20,149					
302.2	FRANCHISES AND CONSENTS - LIMITED TERM		8,107					
304.1	LAND AND LAND RIGHTS - LAND		375,198					
304.2	LAND AND LAND RIGHTS - LAND RIGHTS		6,454					
374.1	LAND AND LAND RIGHTS - LAND		232,579					
374.2	LAND AND LAND RIGHTS - LAND RIGHTS		2,040,764					
389.1	LAND AND LAND RIGHTS - LAND		1,491,454					
389.2	LAND AND LAND RIGHTS - LAND RIGHTS		1,313					
TOTAL NONDEPRECIABLE PLANT			**4,176,018**					
			1,591,515,234					

UGI Utilities, Inc., Gas Division
PA Docket # R-2015-2518438
Calculation of Depreciation Rates and Accruals

ACCOUNT (1)		SURVIVOR CURVE (2)	ORIGINAL COST (3)	BOOK RESERVE (4)	FUTURE ACCRUALS (5)	REMAINING LIFE (6)	CALCULATED ANNUAL ACCRUAL RATE (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)
COMMON PLANT								
301	ORGANIZATION (NONDEPRECIABLE)		138,964					
390.2	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	SQUARE	159,895	139,250	20,645		8.61%	13,764
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	20 - SQ	840,391	164,240	676,151	11.8	6.81%	57,204
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	5 - SQ	155,038	112,023	43,015	0.8	36.03%	55,864
392.1	TRANSPORTATION EQUIPMENT - CARS	7 - L2.5	71,637	61,742	9,895	2.4	5.83%	4,175
TOTAL COMMON PLANT			**1,365,925**	**477,255**	**749,706**		**1068.00%**	**131,007**
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISION - 15.36%			**209,806**	**73,306**	**115,155**			**20,123**
INFORMATION SERVICES (IS)								
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	20 - SQ	71,395	59,106	12,289	3.4	5.05%	3,604
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	5 - SQ	2,868,843	1,746,659	1,122,184	1.7	22.88%	656,248
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEAF	10 - SQ	18,937,625	4,843,763	14,093,862	7.5	9.95%	1,884,206
391.4	OFFICE FURNITURE & EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS '	15 - SQ	98,801,617	6,654,743	92,146,874	13.5	6.89%	6,805,530
TOTAL INFORMATION SERVICES			**120,679,480**	**13,304,271**	**107,375,209**		7.75%	**9,349,588**
TOTAL INFORMATION SERVICES ALLOCATED TO GAS DIVISION - 48.83%			**58,927,790**	**6,496,476**	**52,431,315**			**4,565,404**
390.1	STRUCTURES AND IMPROVEMENTS	100 - R1	2,097,073	1,176,645	920,428		3.59%	75,268
TOTAL READING SERVICE CENTER ALLOCATED TO OTHER DIVISIONS - 51.74%			**1,085,026**	**608,796**	**476,229**			**38,944**
TOTAL OTHER UTILITY PLANT ALLOCATED TO GAS DIVISION			**58,052,570**	**5,960,986**	**52,070,241**		7.83%	**4,546,583**
TOTAL PLANT IN SERVICE			**1,649,567,804**	**449,052,669**	**1,196,317,774**		1.93%	**31,781,397**
ENVIRONMENTAL EXPENDITURES FOR SITE REMEDIATION - ACCOUNT 305				(316,923)				
AMORTIZATION OF NEGATIVE NET SALVAGE								*4,995,504*
GRAND TOTAL			**1,649,567,804**	**448,735,746**	**1,196,317,774**		2.23%	**36,776,901**

* SURVIVOR CURVES FOR ACCOUNT 390.1 ARE INTERIM SURVIVOR CURVES. INDIVIDUAL BUILDINGS ARE LIFE SPANNED.
** ASSETS IN ACCOUNTS 391.3 AND 391.4 ARE INDIVIDUALLY DEPRECIATED BASED ON THE SERVICE LIVES SHOWN IN THIS REPORT. ALSO, UGI PLANS TO REPLACE THEIR CUSTOMER INFORMATION SYSTEM (CIS) IN ACCOUNT 391.3 IN 2017. UGI PLANS TO AMORTIZE THE UNRECOVERED COSTS RELATED TO CIS PROJECTS OVER THEIR ESTIMATED REMAINING LIVES. CIS IS EXPECTED TO BE RETIRED IN SEPTEMBER 2017.

UGI Gas 2017 GAs

378 -

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2017

Survivor Curve .. IOWA: 61 S-0.5

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2017	0.5	5,026,329	61.00	60.63	82,399	4,995,814
2016	1.5	5,292,010	61.00	59.90	86,754	5,196,941
2015	2.5	3,737,198	61.00	59.19	61,266	3,626,543
2014	3.5	1,371,741	61.00	58.50	22,488	1,315,464
2013	4.5	843,404	61.00	57.81	13,826	799,333
2012	5.5	2,242,144	61.00	57.14	36,756	2,100,174
2011	6.5	1,576,390	61.00	56.47	25,842	1,459,406
2010	7.5	544,137	61.00	55.82	8,920	497,907
2009	8.5	532,133	61.00	55.17	8,723	481,273
2008	9.5	1,425,436	61.00	54.53	23,368	1,274,259
2007	10.5	717,596	61.00	53.90	11,764	634,054
2006	11.5	838,987	61.00	53.27	13,754	732,717
2005	12.5	853,737	61.00	52.66	13,996	736,951
2004	13.5	1,133,299	61.00	52.04	18,579	966,902
2003	14.5	2,107,236	61.00	51.44	34,545	1,776,923
2002	15.5	248,321	61.00	50.84	4,071	206,956
2001	16.5	403,354	61.00	50.24	6,612	332,233
2000	17.5	624,906	61.00	49.66	10,244	508,692
1999	18.5	140,135	61.00	49.07	2,297	112,734
1998	19.5	459,690	61.00	48.49	7,536	365,443
1997	20.5	274,061	61.00	47.92	4,493	215,296
1996	21.5	830,135	61.00	47.35	13,609	644,391
1995	22.5	368,758	61.00	46.79	6,045	282,835
1994	23.5	155,209	61.00	46.23	2,544	117,619
1993	24.5	78,676	61.00	45.67	1,290	58,904
1992	25.5	255,435	61.00	45.12	4,187	188,931
1991	26.5	177,216	61.00	44.57	2,905	129,485
1990	27.5	165,553	61.00	44.03	2,714	119,486
1989	28.5	295,715	61.00	43.49	4,848	210,808
1988	29.5	135,543	61.00	42.95	2,222	95,432

1987	30.5	127,308	61.00	42.41	2,087	88,520
1986	31.5	168,829	61.00	41.88	2,768	115,923
1985	32.5	153,701	61.00	41.36	2,520	104,208
1984	33.5	68,803	61.00	40.83	1,128	46,057
1983	34.5	30,308	61.00	40.31	497	20,030
1982	35.5	138,857	61.00	39.79	2,276	90,587
1981	36.5	144,184	61.00	39.28	2,364	92,845
1980	37.5	81,553	61.00	38.77	1,337	51,830
1979	38.5	25,352	61.00	38.26	416	15,901
1978	39.5	26,485	61.00	37.75	434	16,391
1977	40.5	30,177	61.00	37.25	495	18,426
1976	41.5	49,583	61.00	36.75	813	29,868
1975	42.5	37,882	61.00	36.25	621	22,510
1974	43.5	39,812	61.00	35.75	653	23,332
1973	44.5	7,138	61.00	35.25	117	4,125
1972	45.5	29,434	61.00	34.76	483	16,774
1971	46.5	88,617	61.00	34.27	1,453	49,789
1970	47.5	15,273	61.00	33.78	250	8,459
1969	48.5	6,697	61.00	33.30	110	3,656
1968	49.5	102	61.00	32.81	2	55
		34,124,579			559,419	31,003,189

AVERAGE SERVICE LIFE 61.00

AVERAGE REMAINING LIFE 55.42

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2015-2518438
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, James S. Garren, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA St. No. 5-SR, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: ______________________
James S. Garren

Consultant Address: Snavely King Majoros & Associates, Inc.
PO Box 727
Millersville, MD 21108

DATED: May 25, 2016