COMMONWEALTH OF PENNSYLVANIA

OFFICE OF CONSUMER ADVOCATE
555 Walnut Street, 5th Floor, Forum Place
Harrisburg, Pennsylvania 17101-1923
(717) 783-5048
800-684-6560

@pa_oca
/pennoca

FAX (717) 783-7152
consumer@paoca.org

July 7, 2021

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission
v.
UGI Utilities, Inc. – Electric Division
Docket No. R-2021-3023618

Dear Secretary Chiavetta:

Consistent with Section 5.412a of the Commission's regulations, 52 Pa. Code Section 5.412a, which requires the electronic submission of pre-served testimony, enclosed for electronic filing please find the following testimony and exhibits on behalf of the Office of Consumer Advocate ("OCA") in the above-referenced proceeding. Please note that the documents listed below were admitted into the record pursuant to the Order Granting Joint Stipulation For Admission of Evidence entered on June 29, 2021.

Office of Consumer Advocate's Direct Testimony

OCA Statement 1 -- Direct Testimony of Lafayette K. Morgan (Revised Public Version)

OCA Statement 2 -- Direct Testimony of Aaron L. Rothschild

OCA Statement 3 -- Direct Testimony of Jerome D. Mierzwa

OCA Statement 4 -- Direct Testimony of Roger D. Colton

OCA Statement 5 -- Direct Testimony of Morgan N. DeAngelo

Office of Consumer Advocate's Rebuttal Testimony

OCA Statement 3R -- Rebuttal Testimony of Jerome D. Mierzwa

Office of Consumer Advocate's Surrebuttal Testimony

OCA Statement 1SR -- Surrebuttal Testimony of Lafayette K. Morgan (Public Version)

OCA Statement 2SR -- Surrebuttal Testimony of Aaron L. Rothschild

OCA Statement 3SR -- Surrebuttal Testimony of Jerome D. Mierzwa

OCA Statement 4SR -- Surrebuttal Testimony of Roger D. Colton

OCA Statement 5SR -- Surrebuttal Testimony of Morgan N. DeAngelo

The following confidential testimony and exhibits will be e-mailed directly to Secretary Rosemary Chiavetta:

OCA Statement 1 -- Direct Testimony of Lafayette K. Morgan (Revised **CONFIDENTIAL** Version)

OCA Statement 1SR -- Surrebuttal Testimony of Lafayette K. Morgan (**CONFIDENTIAL** Version)

The OCA's submission also addresses the requirements of the Commission's January 10, 2013 Implementation Order at Docket M-2012-2331973, which requires electronic access to pre-served testimony.

All parties and the presiding officer have been served previously with the testimony and exhibits and copies have been served per the attached Certificate of Service.

Respectfully submitted,

/s/ Phillip D. Demanchick
Phillip D. Demanchick
Assistant Consumer Advocate
PA Attorney I.D. # 324761
E-Mail: PDemanchick@paoca.org

Enclosures:
cc: The Honorable Steven K. Haas **(email only)**
Certificate of Service
*312873

CERTIFICATE OF SERVICE

Re:	Pennsylvania Public Utility Commission	:	
		:	
	v.	:	Docket No. R-2021-3023618
		:	
	UGI Utilities, Inc. – Electric Division	:	

I hereby certify that I have this day served a true copy of the following document, the Office of Consumer Advocate's Letter Re: Pre-Served Testimony, upon parties of record in this proceeding in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant), in the manner and upon the persons listed below:

Dated this 7th day of July 2021.

SERVICE BY E-MAIL ONLY

Scott B. Granger, Esquire
Bureau of Investigation & Enforcement
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

Steven C. Gray, Esquire
Office of Small Business Advocate
555 Walnut Street
1st Floor, Forum Place
Harrisburg, PA 17109-1923

Kent Murphy, Esquire
Michael S. Swerling, Esquire
UGI Corporation
460 North Gulph Road
King of Prussia, PA 19406

Devin T. Ryan, Esquire
Garrett P. Lent, Esquire
Post & Schell, P.C.
17 North Second Street, 12th Floor
Harrisburg, PA 17101-1601

David B. MacGregor, Esquire
Post & Schell, P.C.
Four Penn Center
1600 John F. Kennedy Boulevard
Philadelphia, PA 19103-2808

Joseph L. Vullo, Esquire
Commission on Economic Opportunity
Burke Vullo Reilly Roberts
1460 Wyoming Avenue
Forty Fort, PA 18704

James M. Van Nostrand, Esquire
Keyes & Fox LLP
320 Fort Duquesne Blvd., #15K
Pittsburgh, PA 15222

Scott F. Dunbar, Esquire
Keys & Fox LLP
1580 Lincoln Street, Suite 1105
Denver, CO 80203

Deanne M. O'Dell, Esquire
Sarah C. Stoner, Esquire
Eckert Seamans Cherin & Mellott, LLC
213 Market Street, 8th Floor
Harrisburg, PA 17101

Cody T. Murphey, Esquire
Eckert Seamans Cherin & Mellott, LLC
919 E Main Street
Suite 1300
Richmond, VA 23219

John W. Sweet, Esquire
Ria M. Pereira, Esquire
Pennsylvania Utility Law Project
118 Locust Street
Harrisburg, PA 17101

Brandi Brace
114 Hartman Road
Hunlock Creek, PA 18621

/s/ Phillip D. Demanchick

Phillip D. Demanchick
Assistant Consumer Advocate
PA Attorney I.D. # 324761
E-Mail: PDemanchick@paoca.org

Darryl A. Lawrence
Senior Assistant Consumer Advocate
PA Attorney I.D. # 93682
E-Mail: DLawrence@paoca.org

Counsel for:
Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923
Phone: (717) 783-5048
Fax: (717) 783-7152

Dated: July 7, 2021

*312872

OCA Statement No. 1 REVISED

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
	)	
v.	**)**	**Docket No. R-2021-3023618**
	)	
UGI Utilities, Inc. – Electric Division	**)**	

DIRECT TESTIMONY

OF

LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

PUBLIC VERSION

May 3, 2021

EXETER

ASSOCIATES, INC.

10480 Little Patuxent Parkway, Suite 300

Columbia, Maryland 21044

TABLE OF CONTENTS

INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lafayette K. Morgan, Jr. My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland, 21044. I am a Public Utilities Consultant working with Exeter Associates, Inc. (Exeter). Exeter is a consulting firm specializing in issues pertaining to public utilities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND QUALIFICATIONS.

A. I received a Master of Business Administration degree from The George Washington University. The major area of concentration for this degree was Finance. I received a Bachelor of Business Administration degree with concentration in Accounting from North Carolina Central University. I was previously a CPA licensed in the state of North Carolina, however, in 2009, I elected to place my license in an inactive status as I focused on start-up activities for other business interests.

Q. WOULD YOU PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE?

A. From May 1984 until June 1990, I was employed by the North Carolina Utilities Commission - Public Staff in Raleigh, North Carolina. I was responsible for analyzing testimony, exhibits, and other data presented by parties before the North Carolina Utilities Commission. I had the additional responsibility of performing the examination of books and records of utilities involved in rate proceedings and summarizing the results into testimony and exhibits for presentation before that Commission. I was also involved in numerous special projects, including participating in compliance and prudence audits of a major utility and conducting research on several issues affecting natural gas and electric utilities.

From June 1990 until July 1993, I was employed by Potomac Electric Power Company (Pepco) in Washington, D.C. At Pepco, I was involved in the preparation of the cost of service, rate base and ratemaking adjustments supporting the company's requests for revenue increases in the State of Maryland and the District of Columbia.

From July 1993 through 2010, I was employed by Exeter. as a Senior Regulatory Analyst. During that period, I was involved in the analysis of the operations of public utilities, with emphasis on utility rate regulation. I reviewed and analyzed utility rate filings, focusing primarily on revenue requirements determination. This work involved natural gas, water, electric, and telephone companies.

In 2010, I left Exeter to focus on start-up activities for other ongoing business interests. In late 2014, I returned to Exeter continuing to work in a similar capacity as prior to my hiatus.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON UTILITY RATES?

A. Yes. I have previously presented testimony and affidavits on numerous occasions before the North Carolina Utilities Commission, the Pennsylvania Public Utility Commission, the Virginia Corporation Commission, the Louisiana Public Service Commission, the Georgia Public Service Commission, the Maine Public Utilities Commission, the Kentucky Public Service Commission, the Public Utilities Commission of Rhode Island, the Vermont Public Service Board, the Illinois Commerce Commission, the West Virginia Public Service Commission, the Maryland Public Service Commission, the Corporation Commission of Oklahoma, Kansas Corporation Commission, the Philadelphia Water, Sewer and Storm Water Rate Board, the Colorado Public Utilities Commission, the Public Service Commission of South Carolina, and the Federal Energy Regulatory Commission (FERC). My resume is attached hereto as Appendix A.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am presenting testimony on behalf of the Office of Consumer Advocate (OCA).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Exeter has been retained by the OCA to assist in the evaluation of the general rate filing submitted by UGI Utilities, Inc. - Electric Division (UGI Electric or the Company). The purpose of my testimony in this proceeding is two-fold. First, from a policy perspective, I provide my opinion on the reasonableness of increasing utility rates at this time, in light of the impact of the COVID-19 pandemic on the ratepayers and the residents of Pennsylvania. I discuss whether it is reasonable to grant UGI Electric a rate increase at this time given the economic and social data that suggest that increasing utility rates at this time will place an additional burden on families and ratepayers who are struggling to get their lives back to normal. Second, despite my conclusion from a policy perspective, I have been asked by the OCA to present my findings with respect to UGI Electric's revenue requirements and its proposed rate increase. I calculate the Company's rate base, pro forma operating income under present rates, and overall revenue deficiency based upon my recommended adjustments to the Company's claims. My findings are based upon incorporating the recommendations and findings of other OCA witnesses who are also presenting testimony in this proceeding.

Q. PLEASE IDENTIFY THE OCA'S OTHER EXPERT WITNESSES WHO ARE PRESENTING TESTIMONY IN THIS PROCEEDING.

A. The OCA is sponsoring the testimony of four other witnesses who will provide testimony in this proceeding. In OCA Statement 2, Mr. Aaron Rothschild discusses some of the pandemic's effects on capital markets and the uncertainties. He also provides the OCA's cost of capital recommendations which I have used in my determination of the Company's revenue requirement for the FPFTY. In OCA Statement 3, Mr. Jerome Mierzwa discusses the Company's cost-of-service study, allocation of any rate increase among the customer classes, and issues associated with the design of residential rates. In OCA Statement 4, Mr. Roger Colton addresses the effectiveness of UGI Electric's current CAP program as well as the plight of UGI Electric's low-income customers during this challenging time. Finally, in OCA Statement 5, Ms. Morgan N. DeAngelo discusses the impact of the COVID-19 pandemic on the health and economy of the Commonwealth and, in particular, UGI Electric's ratepayers.

Q. IN CONNECTION WITH THIS CASE, HAVE YOU PERFORMED AN EXAMINATION AND REVIEW OF THE COMPANY'S TESTIMONY AND EXHIBITS?

A. Yes. I have reviewed UGI Electric's testimony, exhibits and its rate filing. I have also reviewed the Company's responses to the OCA, the Bureau of Investigation & Enforcement (I&E) and the Office of Small Business Advocate's (OSBA) interrogatories.

Q. WHAT TIME PERIOD HAVE YOU USED IN MAKING YOUR DETERMINATION OF UGI ELECTRIC'S REVENUE REQUIREMENTS ON THE AS-FILED COST OF SERVICE?

A. I used the Fully Projected Future Test Year (FPFTY) ending September 30, 2022, as filed by UGI Electric, as the basis for determining its rate year revenue requirements.

Q. HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR TESTIMONY?

A. Yes. I have prepared Schedules LKM-1 through LKM-17. Schedule LKM-1 provides a summary of revenues and expenses under present and proposed rates. Schedule LKM-2 summarizes my adjustments to UGI Electric's FPFTY. Schedule LKM-3 provides a summary of my adjustments to rate year revenues and expenses and the resulting operating income. My adjustments to UGI Electric's claimed revenues and operating expenses are presented on Schedules LKM-4 through LKM-17.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. First, I provide a summary of the Company's filing and my findings and recommendations. Next, I explain my reservations about the reasonableness of the Company's cost of service and why I believe it is not representative of the operations during the FPFTY. Then, in the remainder of my testimony, I document and explain each of the adjustments to the as-filed rate base and operating income that I have made to arrive at the rate year revenue requirement shown on Schedule LKM-1. My discussion of these adjustments is organized into sections corresponding to the issue being addressed. These sections are set forth in the Table of Contents for this testimony.

SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE THE RATE RELIEF REQUESTED BY UGI ELECTRIC IN ITS FILING.

A. On February 8, 2021, UGI Electric filed this rate increase request to raise annual jurisdictional revenues by $8.7 million based on the FPFTY year ending September 30, 2022. This increase would raise total revenues (distribution and generation charges) by approximately 10.0%. The Company is also seeking an overall rate of return on rate base of 7.57 percent.

UGI Electric states the principal reason for its request for rate relief is that current rates do not provide a reasonable opportunity for the Company to earn a fair rate of return on its investment, although it has taken reasonable efforts since its last base rate case to control its expenses. However, UGI Electric states that because of the ongoing COVID-19 Pandemic, it has implemented several measures to assist customers impacted by the economic effects of the COVID-19 Pandemic, and without the requested rate relief, its returns on investment will continue to decline.

Q. PLEASE SUMMARIZE YOUR CONCERNS, FINDINGS AND RECOMMENDATIONS.

Based on my review of the Company's filing, I have concerns about whether the projected data and assumptions contained in the Company's filing provide a fair or reasonable projection of the Company's cost of service during the rate effective period. Given the uncertainty in the US economy as a result of the COVID-19 pandemic, I am concerned about whether the forecasted/budgeted data can be relied upon as representative of normal operations. One of the principles of ratemaking is that the test years should be representative of normal operations. The 2020 disruption of the economy and the lingering effects of the pandemic on the economy and the lives of citizens of the Commonwealth will naturally affect the reliability of the forecasts for the FPFTY. The filing of the rate case is ill-timed because there are many customers who are still struggling economically and are unable to make ends meet and need assistance to meet their utility obligations. As evidence, in March 2021, the national unemployment rate was 6.0 percent while Pennsylvania's unemployment rate was 7.0 percent. Therefore, as the Commission decides the issues in this proceeding, it should carefully consider the impacts of the COVID-19 Pandemic on UGI Electric's customers when reviewing the Company's request because, although there are signs of economic recovery, the state of the economy is not robust.

Despite my concerns about the reasonableness of the underlying forecasted data for the cost of service, I have determined the revenue requirement based on the FPFTY cost of service as filed by the Company.

As shown on Schedule LKM-1, if the Commission determines that a rate increase would be just and reasonable at this time, I have determined that the Company's proposed revenue should be reduced to reflect an increase of no more than **$4.479 million** for the FPFTY ending September 30, 2022. This represents a decrease of $ **4.230 million** from UGI Electric's requested increase of $8.709 million. This is the amount by which revenues exceed those required to generate an overall rate of return of 6.32 percent after accounting for the OCA's adjustments to UGI Electric's claimed rate base and operating income. The overall return of 6.32 percent, which reflects a return on equity of 8.30 percent, represents Mr. Rothschild's findings regarding the Company's overall rate of return. In comparison, the Company is seeking an overall return of 7.57 percent and a return on equity of 10.75 percent.

THE REASONABLENESS OF UGI ELECTRIC'S FPFTY COST OF SERVICE

Q. HOW HAS UGI ELECTRIC DERIVED ITS COST OF SERVICE FOR THE FPFTY?

A. From a revenue requirements perspective, the cost of service is composed of the rate base and the components of the net operating income (i.e., revenues, operation and maintenance expenses, depreciation and amortization expense, and taxes). According to the Company, the cost of service for the FPFTY ending September 30, 2022, includes rate base claims, operating expenses claims, and certain pro forma adjustments derived from UGI Electric's operating and capital budgets for the 12 months ending September 30, 2022.

Q. PLEASE EXPLAIN UGI ELECTRIC'S BUDGETING PROCESS.

A. According to the Company,

> Preparation of the UGI Electric Operating Budget for the subsequent fiscal year begins during the spring, i.e., the budget for the October 1, 2020 through September 30, 2021 fiscal year was prepared in the spring of 2020. The revenue portion of the budget is a joint effort between the Marketing, Operations, and Rates Departments. The Marketing and Operations Departments provide customer growth and attrition information by customer class along with specific large commercial and industrial sales and revenue budget projections…
>
> …The number of customers by customer class is determined using a wide range of factors, including trends in usage, the level of applications and inquiries for service from existing customers, new construction, and shifts in type of residence and customer mix. Usage per customer is developed by reviewing the long-term usage trends and current and anticipated levels of operation. The budgeted number of customers and usage per customer are combined to produce monthly budgeted sales. The revenue budget is calculated by applying tariff rates for each customer class to budgeted sales, plus an adjustment for unbilled revenue...
>
> Concurrently, the expense portion of the Operating Budget is prepared. Operating and maintenance expenses are developed by each functional manager based upon review of trends, monthly expenditure patterns, and new or changed programs. Employee levels are reviewed, and appropriate staffing levels are set for the upcoming fiscal year…
>
> The UGI Electric Capital Budget is prepared in conjunction with the Operating Budget. With the passage of Act 11 of 2012, UGI Electric has also instituted a process for establishing an Operating Budget and Capital Budget for an additional fiscal year in the future, i.e., the FPFTY. This process is the same as outlined above; however, the starting point for the additional year is the FTY budget. The FTY revenue budget is based on normalized weather conditions, per

> customer usage trends, and projections concerning growth in numbers of customers. Similarly, FTY budget expense amounts are adjusted for salary and personnel increases, known program changes and expense needs…

Q. WHEN WERE THE FPFTY AND FTY BUDGETS PREPARED?

A. According to Company witness Anzaldo, the budget for the October 1, 2020 through September 30, 2021 fiscal year (the FTY) was prepared in the spring of 2020 and as explained above, the FPFTY was prepared at the same time.

Q. WHY IS THE BUDGET PREPARATION DATE IMPORTANT?

A. The budget preparation date is critical because the events, circumstances and related data from that period affects the judgement and decision making while preparing the budget. For example, during April and May 2020, there were very dramatic changes in the US economy. In April 2020, sales of existing homes dropped by 17.8 percent. The National Association of Home Builders (NAHB) Housing Market Index (HMI) [1] dropped from 72 to 30 and 37 for April and May, respectively. Unemployment surged in April to 14.7 percent from 4.4 percent in March. While these data points began to recover in June 2020, the disruption, volatility and uncertainty during that period would naturally influence the decision-making. It is doubtful that one could accurately project customer growth with the volatility in the housing market and business closures.

Another reason to have concerns over the Company's budget is related to the spike in unemployment and the moratorium placed on utility service disconnection and late payment fees. These factors had the effect of increasing uncollectible expense and reducing revenues from late payment fees.

Q. DO YOU BELIEVE THE BUDGET USED FOR THE FTY AND FPFTY COST OF SERVICE IS REASONABLE?

A. No. As I have explained, the Commission cannot rely on the Company's FPFTY data as filed. The data presented in the testimony of OCA witness DeAngelo provides further evidence that the economic activity during this period has been less than robust. However, it is critical to recognize the Federal government's efforts at injecting economic stimuli because the effect on the overall economy remains to be seen. Hence, the assumptions and available data from a year ago could lead to different conclusions if the same analysis were performed today. While this is true for any forecast from year to year, the differences are exacerbated by the unprecedented nature of the effect of the COVID-19 pandemic.

To put it into context, one has to consider the size of each of the COVID relief bills that were signed into law. The Coronavirus Aid, Relief, and Economic Security Act, also known as the CARES Act, was a $2.2 trillion economic stimulus bill passed by Congress and signed into law on March 27, 2020. According to a story in the Los Angeles Times, the CARES Act was the largest stimulus package to ever be passed into law. The $2.2 trillion equated to 9 percent of GDP.

On December 27, 2020, an additional $900 billion in COVID relief was provided as part of the Consolidated Appropriations Act of 2021 which was signed into law.

Then in March 2021, President Joe Biden signed into law the American Rescue Plan Act of 2021, which contained a $1.9 trillion COVID-relief package. These stimulus packages support one conclusion, that the economy is not yet stable as we recover from the COVID-19 pandemic. Hence, now may not be the right time to place an additional cost on to ratepayers.

OCA ADJUSTMENTS TO UGI ELECTRIC'S TEST YEAR

Q. IF THE COMMISSION ACCEPTS UGI ELECTRIC'S COST OF SERVICE FOR RATEMAKING IN THIS PROCEEDING, WHAT DO YOU RECOMMEND?

A. As stated above, the Commission cannot rely on the Company's projections and data regarding its test year revenue requirement. As a matter of prudence, however, I have examined the FPFTY data presented by the Company as the basis for future rates and made adjustments where I found costs to be inappropriate for inclusion, uncertain and unreasonable. I discuss each of those adjustments in the following section of my testimony.

Electric Vehicle Program

Q. PLEASE EXPLAIN THE COMPANY'S ELECTRIC VEHICLE CHARGING INITIATIVE.

A. The Company has identified a need for electric vehicle (EV) charging stations in its service area and plans to install and own three Company-owned DC Fast Charge ("DCFC") charging stations. According to the Company, the installation of the EV Charging stations will support and promote the growth of EVs in its service territory by promoting electric vehicle charging infrastructure build-out and expanded access to EV charging infrastructure. The Company is also seeking approval to modify its service extension provisions in its tariff to specifically provide for Company investment related to the installation of make ready infrastructure associated with Level 2 or DCFC charging stations not owned by the Company. This investment may include, (1) transformers or transformer upgrades, (2) electric distribution service drop, (3) separate utility service meter for the charging station, (4) new electric service panel, and (5) associated conduit and conductor and ancillary equipment necessary to connect the EV charging stations to the electric grid.

In the cost of service, UGI Electric included $300,000 in capital costs in rate base for all the charging stations and make-ready infrastructure. The Company claims that its EV charging initiative is consistent with Duquesne Light Company ("DLC") and PECO Energy Company ("PECO") programs that were approved by the Commission at Dockets R-2018-3000124 and R-2018-3000164, respectively.

Q. HAS THE COMPANY MADE ANY REVISIONS TO ITS TARIFF TO ACCOMMODATE ITS EV CHARGING PROPOSAL?

A. Yes. The Company has added a new Rate EV-C (Electric Vehicle – Company Owned Charging), which sets forth the terms and conditions of its ownership of the EV Charging Stations and a fee structure for any charging use. The Company has also added Rule 5-l and 5-m to its tariff which modifies its service line extension regulations to provide make-ready infrastructure to any qualified electric vehicle charging stations:

> 5-l Service to Electric Vehicle Supply Equipment. Where Company provides service to Qualified Electric Vehicle Charging Stations ("Qualified EV Charging Stations") which will be accessible to the public for charging access, the Company shall provide all required investment without contribution and will design and install the required infrastructure facilities necessary for operation of such Qualified EV Charging Stations (including any new conductor replacement, transformers, services, and meters; inclusive of any make ready work). Such facilities shall be provided at no required contribution to the customer as part of an EV infrastructure which will end September 30, 2026.
>
> 5-m Qualified EV Charging Stations shall be defined as one (1) to four (4) DC Fast Charge ("DCFC") stations of 50kW or greater which are (a) configured to support SAE/CCS and Tesla plug configurations at a minimum and are located directly along a major highway and in a commercial retail office, hotel or shopping location having parking accommodations for not less than 100 vehicles, (b) located in a commercial gasoline retail service station, or (c) located in another location where the Company, in its sole discretion, anticipates that adequate public availability

and access is being provided. Installation locations may also be inclusive of one or more adjacent Level 2 charging stations.

Q. IS UGI ELECTRIC'S EV CHARGING INITIATIVE CONSISTENT WITH THE DLC AND PECO EV CHARGING PROGRAMS?

A. The programs are consistent to the extent that they all seek to establish and expand the EV charging stations. But, there is a fundamental difference in UGI Electric's proposal and the other two companies. The difference is that UGI Electric intends to own the charging stations whereas with DLC and PECO, the utility ownership of the charging station is limited. For DLC and PECO, rather, the focus of the utility investment of the charging station is primarily limited to the "make ready infrastructure." In other words, the investment to make the facilities ready to install the charging stations. The charging stations, however, are owned by third parties.[2]

Q. WHAT IS YOUR CONCERN WITH RESPECT TO THE COMPANY'S PROPOSAL FOR EV CHARGING STATIONS?

A. My concern relates to the Company's ownership of the charging stations. The Company's ownership of the EV charging station, as any other third party, results in allowing a regulated utility to enter into an unregulated competitive market with all the risk being borne by captive ratepayers. Therefore, I believe these costs should not be included in the cost of service.

Q. WHAT ADJUSTMENT HAVE YOU MADE RELATED TO THE EV CHARGING STATIONS?

A. I have adjusted the plant-related investment to remove the capital costs of $300,000 from the Company's plant in service claim. I have also made an adjustment of $34,000 to decrease depreciation expense to remove the depreciation expense related to the

Company owned EV charging stations. These adjustments are presented on Schedule LKM-4.

Q. WHAT DO YOU RECOMMEND REGARDING THE COMPANY'S TARIFF CHANGES?

A. As I recommend the Company not be allowed to own the charging stations, the Company's Rate EV-C should not be adopted by the Commission. Regarding the modifications to the Company's service line extension rules, I recommend that they not be adopted by this Commission. As Company witness Taylor states, the Company's current tariff already allows the Company to own, install, and maintain everything up to the electric service panel.[3] It should be the responsibility of the electric charging owner to purchase and maintain all necessary equipment to connect the charging station to the electric service panel.

<u>Asset Data Collection</u>

Q. WHAT IS THE COMPANY'S ASSET DATA COLLECTION PROJECT?

A. The Asset Data Collection (ADC) is one of the elements of UGI Corporation's Enterprise Asset Management project, which is part of its improvement to its information technology program referred to as UNITE. The ADC project will focus on the identification, standardization, and capture of asset data information across UGI. According to the Company the project will begin in **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and should be completed by the end of the FPFTY.

Q. WHAT IS YOUR CONCERN WITH RESPECT TO THE PROJECT?

A. I have two concerns with respect to this project. First, the project has been included in rate base even though it has not yet been approved by the Company's Board of Directors. Second, the date on which the project will be used and useful and in-service is unclear.

Q. WHAT EVIDENCE DO YOU HAVE THAT THE PROJECT HAS NOT BEEN APPROVED BY THE BOARD OF DIRECTORS?

A. The Company's response to OCA-III-8, indicates that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The responses to more recent OCA data requests indicate that is still the case.

Q. WHY DO YOU CLAIM THAT THE DATE THAT THE PROJECT WILL BECOME USED AND USEFUL AND IN-SERVICE IS NOT CLEAR?

A. First, in Mr. Brown's testimony he states the project will begin in early 2021. However, the Company now indicates that the project will begin in **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** It is reasonable to presume that if the project begins later than it was planned, the end date of the project would also have to move forward because of the time it would take to complete the project. Moreover, the Company claims, in the response to OCA-VIII-2, that it has **[BEGIN CONFIDENTIAL] "**[redacted] **[END CONFIDENTIAL]** While an explanation of the refinement was not provided, the increased costs suggests that the project's scope has widened, which may require more time to complete.

Next, the roadmap in the Business Case, provided in the response to OCA-VIII-8, shows **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** as stated by the Company. More importantly the Business Case states**: [BEGIN CONFIDENTIAL] "**[redacted] **[END CONFIDENTIAL]** Here the Company itself is indicating the possibility that the date of completion could change.

Finally, the Business Case states **[END CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Considering that the Electric Division is allocated **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the cost of the project, it appears that the Company's scheduling is being designed to allow the costs to be included in this proceeding. In other words, one would expect most of the allocable cost of the project would be gas related, and Company has stated that part of the project will be completed **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** This clearly brings into question whether the electric costs being included in the cost of service represents used and useful plant in service or plant that is completed.

Q. WHAT IS YOUR RECOMMENDATION FOR THESE PROJECT COSTS?

A. I am recommending an adjustment that removes the cost of this project from the cost of service. I present this adjustment on Schedule LKM-5. This adjustment reduces rate base by $1.432 million and depreciation expense by $65,000.

Battery Storage Project

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED BATTERY STORAGE PROJECT.

A. According to the Company's filing, UGI Electric is planning to install and interconnect a utility-owned, small-scale, 1.25 MWh energy storage battery into the primary distribution system. The rationale for this project is to use the battery storage technology as a targeted option to enhance resiliency and service in parts of the distribution system that has experienced reliability issues. OCA witness Mierzwa discusses this issue in more detail in his testimony.

Q. WHAT ADJUSTMENT ARE HAVE YOU MADE TO THE COST OF THE BATTERY STORAGE PROJECT?

A. Based on the discussion and recommendation in Mr. Mierzwa's testimony, I have made an adjustment to remove the cost of the project from the cost of service. On Schedule LKM-6, I present this adjustment, which reduces rate base by $1.5 million and depreciation expense by $90,000.

Materials and Supplies

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO MATERIALS AND SUPPLIES.

A. The Materials and Supplies balance included in UGI Electric's rate base is based upon the 13-month average balance as of September 2020. I requested and received more recent actual monthly data from the Company through February 2021. Given that the test year used for ratemaking is the FPFTY, it is appropriate to use the most recent data in the cost of service. Therefore, the Materials and Supplies balance should be adjusted.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO THE MATERIALS AND SUPPLIES BALANCE?

A. On Schedule LKM-7, I present my adjustment to Materials and Supplies to reflect the 13-month average balance as of February 2021. The resulting average of $1,446,000 was compared to the Company's claim of $1,309,000. This results in an adjustment, which increases rate base by $137,000.

Customer Deposits

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO CUSTOMER DEPOSITS.

A. This adjustment is similar to the adjustment I recommended for Materials and Supplies. The Customer Deposits balance included in UGI Electric's rate base is based upon the 13-month average balance as of September 2020. I requested and received more recent monthly data from the Company through February 2021. Given that the test year used for ratemaking is the FPFTY, it is appropriate to use the most recent data in the cost of service. Therefore, the Customer Deposits balance should be adjusted.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO THE CUSTOMER DEPOSITS?

A. On Schedule LKM-8, I present my adjustment, which updates the Customer Deposits balance to reflect the 13-month average balance as of February 2021. The resulting average of $1,094,000 was compared to the Company's claim of $1,197,000. This results in an adjustment, which decreases rate base by $103,000.

Allowance for Cash Working Capital

Q. HOW DO YOU DEFINE CASH WORKING CAPITAL?

A. For ratemaking purposes, cash working capital is the investment that a utility needs to have on hand to fund its day-to-day operations. Positive cash working capital represents funds provided by investors that should be included in rate base so that the utility earns a return on it. Negative cash working capital represents funds supplied by ratepayers that should be recognized as a rate base offset to reflect funds advanced for operations by ratepayers.

Q. HOW DID THE COMPANY REFLECT CASH WORKING CAPITAL IN ITS FILING?

A. The Company's cash working capital allowance is calculated based upon the results of a lead/lag study. A lead/lag study is an in-depth analysis that measures the difference between the lapse of time when a company receives revenue for the provision of service and the lapse of time when a company pays for the costs of providing service. This difference is expressed as a number of days and is used to calculate the level of investor-supplied funds advanced for operations, or the funds advanced by customers for operations.

Q. WHAT CHANGES HAVE YOU MADE TO THE ALLOWANCE FOR CASH WORKING CAPITAL?

A. I have made an adjustment to cash working capital to reduce rate base by $79,000 on Schedule LKM-9. This adjustment is the result of reflecting the adjustments I have recommended be made to O&M expenses and taxes in the lead/lag study. The operating expenses (O&M expenses and taxes) are the bases on which the lead/lag working capital is calculated. Therefore, when deriving the allowance for cash working capital, any adjustment made to operating expenses or taxes in the cost of service should also be incorporated in the lead/lag study.

In addition, I have adjusted the total prepaid expenses component of the lead/lag study to reflect the most recent month actual balances that were provided by UGI Electric. In UGI Electric's presentation of the prepaid expenses, the Company used the HTY monthly balances for FPFTY balances. However, since more recent data is available, they should be used.

Payroll Expense

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PAYROLL EXPENSE.

A. The Company's FPFTY payroll expense was calculated to annualize budgeted payroll expense to reflect the number of employees at the end of the FPFTY and reflect a 3.0 percent salary and wage increase for both Union and Non-Exempt employees forecasted to be effective on April 1, 2022 and Exempt employees forecasted to be effective on December 1, 2021. The Company's adjusted payroll expense also includes the addition of six new electric positions for FY 2021. However, in the response to IE-RE-32-D, the Company explained that FPFTY salaries and wages included two temporary employees in addition to the permanent employees.

I am recommending an adjustment to payroll expense to reflect two changes. First, I remove the effect of the two temporary employees and then I have reduced the pay rate increase applied to the Non-Exempt and Exempt employees from 3.0 percent to 2.5 percent.

Q. WHY HAVE YOU REMOVED THE TEMPORARY EMPLOYEES?

A. I have removed the temporary employees in order to reflect only the permanent employees, as the word "temporary" implies these employees are not expected to work for the Company indefinitely. Since the rates from a general rate case are to be reflective of normal ongoing costs, I have removed the temporary employees from my calculation of the annualized payroll.

Q. WHY HAVE YOU REDUCED THE PAY RATE INCREASES FOR THE NON-EXEMPT AND EXEMPT EMPLOYEES?

A. I have reduced the pay rate increase for the Non-Exempt and Exempt because the information supplied by the Company to support the pay increase refers to the Union contract. The Union contract governs only the Union pay, not the Non-Exempt and Exempt pay. The Non-Exempt and Exempt pay rate increases are discretionary. Therefore, I have used the 2.5 percent that has historically been granted.

Q. PLEASE SUMMARIZE YOUR PAYROLL ADJUSTMENT.

A. As explained above, the combination of removing the two temporary employees and reflecting the 2.5 percent pay rate increase for the Non-Exempt and Exempt employees results in a decrease to payroll expenses of $124,000. This adjustment is presented on Schedule LKM-10.

<u>Incentive Compensation</u>

Q. WHAT ADJUSTMENT HAVE YOU MADE TO INCENTIVE COMPENSATION EXPENSE?

A. As part of UGI Electric's overall compensation, the Company offers a Stock Option and a Restricted Stock Awards Compensation plans. The plans are designed to give qualified employees and Board members **[BEGIN CONFIDENTIAL]** [redacted] **[END**

CONFIDENTIAL] However, these plans are based entirely on earnings goals and shared value goals.

The adjustment I am recommending is to remove these costs because they are earnings driven and are tied to increasing share value. These types of goals are targeted towards increasing shareholder value or benefitting shareholders. Therefore, these costs are not properly recoverable from ratepayers for several reasons. First, if the financial targets are set properly, achieving the necessary performance should be self-supporting. This means that the measures that achieve additional cost savings, increase revenue, or otherwise improve financial results should generate the necessary income to make the incentive plan payments. Second, these payments are not targeted to ratepayer benefits such as meeting quality of service, operational efficiency, or conservation goals. Finally, the incentive to improve financial performance is not necessarily consistent with the interests of UGI Electric's ratepayers, but, instead, is more aligned with shareholders' interests. Therefore, it is appropriate for shareholders, not ratepayers, to bear theses costs.

Q. WHAT IS THE EFFECT OF YOUR ADJUSTMENT TO ELIMINATE INCENTIVE COMPENSATION PAYMENTS?

A. As shown on Schedule LKM-11, my adjustment reduces the FPFTY O&M expenses by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

<u>Postretirement Benefits Expense</u>

Q. WHAT ADJUSTMENT HAVE YOU MADE TO THE POSTRETIREMENT BENEFITS EXPENSE?

A. In the cost of service, as filed, the Company used the best estimate it had at the time the case was prepared for the postretirement benefits expense. During the discovery period, the Company provided more recent updates to the postretirement benefits expense. I have used the updated estimates to derive my adjustment.

On Schedule LKM-12, I present this adjustment which reduces O&M expense by **[BEGIN CONFIDENTIAL]** [redacted] **[BEGIN CONFIDENTIAL]**.

Rate Case Expense

Q. WHAT ADJUSTMENT HAVE YOU MADE TO RATE CASE EXPENSE?

A. UGI Electric's rate case expense claim is based upon an estimated $839,000 in cost that has been normalized over a two-year period. I reviewed the rate case expense claim after considering the costs incurred by the Company in its last electric rate case (which was fully litigated). **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** I then normalize my adjusted amount over a three-year period to derive my normalized rate case expense of $250,000.

In determining the normalization period, I review the average period between rate cases for the Company as shown below. That analysis shows that the average period between rate cases is 7 years. Therefore, the Company's 2-year normalization period is too short. Therefore, I have used the 3-year normalization period, which is consistent with the Commission's decision in UGI-Electric's last litigated proceeding. Below is their previous filing history:

UGI-Electric Rate Case Filings
R-2021-3023618 – Filed February 8, 2021
R-2017-2640058 – Filed January 26, 2018
R-00953534 – File January 26, 1996
R-00932862 – Filed November 1, 1993
R-00922195 – Filed June 12, 1992

When compared to the Company's claim, the resulting adjustment is $166,000, as shown on Schedule LKM-13.

Uncollectible Expense

Q. WHAT ADJUSTMENT DO YOU RECOMMEND RELATED TO UNCOLLECTIBLE EXPENSE?

A. As part of its claim for uncollectible expense, the Company included its normalization of the COVID-Related Uncollectible Regulatory Asset that it had accumulated. The regulatory asset was normalized over a two-year period to derive an annual expense claim of $507,000.

The adjustment I am recommending is to use a five-year period to normalize the claim related to the COVID-related Regulatory Asset. This results in an adjustment of $304,000. This adjustment is presented on Schedule LKM-14.

Q. DOES THE COMPANY PROPOSE TO CONTINUE TRACKING INCREMENTAL UNCOLLECTIBLE EXPENSE IN FUTURE YEARS?

A. Yes. Company witness Ressler states:

> The Company proposes to continue to recognize and record as a regulatory asset any incremental uncollectible accounts expense in excess of $1,347,000 after the implementation of its revised rates. UGI Electric further proposes to seek recovery of these excess costs, which will be tracked as a regulatory asset, in a future rate proceeding.

Q. SHOULD THE COMPANY BE PERMITTED TO CONTINUE TRACKING INCREMENTAL UNCOLLECTIBLE EXPENSE AFTER THE CONCLUSION OF THIS RATE CASE?

A. No. I infer, from the Company's request for higher rates, that it believes that its customer base can absorb higher utility costs. Therefore, the Commission does not need to provide an additional layer of protection for the Company. I recommend that the

Company stop the deferral as of September 1, 2021. The Company can recover its uncollectibles in its next rate case as it has done historically.

COVID-Related Regulatory Asset

Q. WHAT IS THE COVID-RELATED REGULATORY ASSET?

A. In response to Governor Wolf's declaration of a state of emergency throughout the Commonwealth as a result of the COVID-19 pandemic, the Commission issued two directives. One, was in Docket No. M-2020-3019244 where the Commission declared a moratorium on the termination of utility services. The other directive was the Commission's Secretarial Letter dated May 13, 2020, that directed public utilities to account for prudently incurred incremental extraordinary, nonrecurring expenses related to COVID-19, and indicated that utilities were authorized to create regulatory assets for incremental COVID-related expenses. It also directed utilities to track any incremental uncollectibles resulting from the COVID-19 Pandemic that is not currently embedded in existing base rates. The COVID-related regulatory asset that the Company is now seeking to recover is both the accumulation of costs and uncollectibles pursuant to the Commission's directives.

Q. PLEASE SUMMARIZE THE COMPONENTS OF THE COMPANY'S COVID-RELATED REGULATORY ASSET.

A. UGI Electric's claim for the COVID-related regulatory asset includes:

- Lost Late Fees and other Miscellaneous Fees
- Incremental Salaries and Benefits
- Other Incremental Cost (e.g., PPEs, Vehicle Rentals, etc.)

Q. DO YOU AGREE WITH ANY OF THE COMPONENTS OF THE COMPANY'S REGULATORY ASSET RELATED TO THE COVID-19 PANDEMIC?

A. No. I do not. The Company explains in the response I&E-RE-65, that these COVID-19 costs were not deferred and that they were included in the Company's 2020 HTY Administrative and General Expenses. The Company is seeking Commission approval for recovery, or reimbursement, of these costs as part of this proceeding.

Q. PLEASE EXPLAIN THE REASON FOR YOUR ADJUSTMENT?

A. Based on my review of these costs, they do not appear to be incremental nor does the magnitude of these costs appear to be large enough to impact the financial viability of the Company. Clearly, the Company had determined that they would absorb those cost. Moreover, the Commission did not guarantee recovery of any of cost that may have been deferred. Therefore, as shown on Schedule LKM-15, I am recommending an adjustment that removes these costs from the cost of service. This adjustment reduces O&M expenses of $220,000.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO FUTURE DEFERRALS TO THE COVID-RELATED REGULATORY ASSET?

A. I recommend that the Commission direct the Company to cease the deferral of costs into the COVID-related regulatory asset account effective September 1, 2021.

<u>Interest Synchronization</u>

Q. PLEASE EXPLAIN YOUR INTEREST SYNCHRONIZATION ADJUSTMENT.

A. To determine the tax deductible interest for ratemaking, I have multiplied the OCA's recommended rate base by the weighted cost of debt included in the capital structure recommended by OCA witness Rothschild. This procedure synchronizes the interest deduction for tax purposes with the interest component of the return on rate base to be recovered from ratepayers. As shown at the bottom of Schedule LKM-17, this adjustment decreases the interest deduction by $68,000 compared to the interest deduction recognized by UGI Electric. This increases state and federal income taxes by $7,000 and $13,000, respectively.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**Docket No. R-2021-3023618**
UGI Electric Utilities, Inc. - Electric Division	)	

SCHEDULES ACCOMPANYING THE DIRECT TESTIMONY

OF

LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

May 3, 2021

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

UGI Utilities, Inc. - Electric Division

Summary of Operating Income
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Company Amounts at Present Rates	OCA Adjustments	Amounts After OCA Adjustments	Pro Forma Change in Revenues	Amounts After Change in Revenues
	Operating Revenues					
1	Customer & Distribution Revenue	$ 34,215	$ -	$ 34,215	$ -	$ 34,215
2	Revenue - Cost of Purchased Power	51,820	-	51,820	-	51,820
3	Other Revenue	1,030	-	1,030	-	1,030
4	Revenue Increase	-	-	-	**4,479**	4,479
5	Total Operating Revenues	$ 87,065	$ -	$ 87,065	**$ 4,479**	$ 91,544
6						
7	Operating Revenue Deductions					
8	Other Power Supply Expenses	$ 41,179	$ -	$ 41,179	$ -	$ 41,179
9	Operating & Maintenance Expense	28,515	(1,080)	27,435	**70**	27,505
10	Depreciation & Amortization Expense	7,114	(189)	6,925	-	6,925
11	Taxes Other Than Income Taxes	5,929	(51)	5,878	**281**	6,159
12	Total Operating Revenue Deductions	$ 82,737	$ (1,320)	$ 81,417	**$ 351**	$ 81,768
13						
14	Operating Income Before Income Taxes	4,328	1,320	5,648	**4,128**	9,776
15						
16	Income Taxes	56	403	459	**1,193**	1,652
17						
18	Net Operating Income	$ 4,272	$ 917	$ 5,189	**$ 2,935**	$ 8,125
19						
20	Rate Base	$ 131,831		$ 128,555		$ 128,555
21						
22	Return On Rate Base	3.24%		4.04%		6.32%

UGI Utilities, Inc. - Electric Division

Summary of Revenue Increase at OCA Rate of Return
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description		Amount		Source
1	Adjusted Rate Base		$	128,555	Schedule LKM-2, Page 2
2	Required Rate of Return			6.320%	
3					
4	Net Operating Income Required		$	8,125	
5	Net Operating Income at Present Rates			**5,189**	Schedule LKM-1, Page 1
6					
7	Income Deficiency/(Surplus)		**$**	**2,936**	
8	Revenue Multiplier			1.525733	
9					
10	Required Change in Company Revenue		**$**	**4,479**	
11					
12	Proposed Revenue Change		$	4,479	
13	Less: Uncollectibles	1.5570%		**70**	
14	Revenues After Uncollectibles			4,409	
15	Gross Receipts Tax	6.2700%		**281**	
16					
17	Income Before State Taxes		$	4,128	
18	State Income Tax Effect Tax Rate	9.9900%			
19	Less: State Income Tax			**412**	
20					
21	Income Before Federal Taxes		$	3,716	
22	Federal Income Tax	21.0000%		**780**	
23					
24	Net Income Surplus/(Deficiency)		$	2,935	

UGI Utilities, Inc. - Electric Division

Summary of Rate Base
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount per Company Filing	OCA Rate Base Adjustments	Amount After OCA Adjustments
1	Utility Plant	$ 226,945	$ (3,334)	$ 223,611
2	Accumulated Depreciation	(74,795)	102	(74,693)
3	Net Plant in Service	$ 152,150	$ (3,232)	$ 148,918
4				
5	Working Capital	$ 7,657	$ (79)	$ 7,578
6	Accumulated Deferred Income Taxes	(28,088)	-	(28,088)
7	Customer Deposits	(1,197)	(103)	(1,300)
8	Materials & Supplies	1,309	137	1,446
9				
10	Total Rate Base	$ 131,831	$ (3,276)	$ 128,555

UGI Utilities, Inc. - Electric Division

Summary of Rate Base Adjustments
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.		Source	Amount
1	Rate Base per Company Filing	Schedule LKM-2, Page 1	$ 131,831
2			
3			
4	OCA Adjustments:		
5	Remove EV Charging Stations	Schedule LKM-4	$ (300)
6	Remove EAM Costs	Schedule LKM-5	(1,432)
7	Remove Battery Storage Cost	Schedule LKM-6	(1,500)
8	Update Materials& Supplies	Schedule LKM-7	137
9	Update Customer Deposits	Schedule LKM-8	(103)
10	Cash Working Capital	Schedule LKM-9	(79)
11			
12	Total Ratemaking Adjustments		$ (3,276)
13			
14	Adjusted Rate Base per OCA		$ 128,555

UGI Utilities, Inc. - Electric Division

Summary of Adjustments to Income Before Income Taxes
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.		Amount	Source
1	Operating Income per Company	$ 4,272	Schedule LKM-1
2			
3	OCA Adjustments:		
4	Annualize Payroll	$ 88	
5	Remove Stock Based Incentive Compensation	176	
6	Annualize OPEB	13	
7	Normalize Rate Case Expense	118	
8	Normalize Uncollectibles	216	
9	Normalize Incremental COVID-Related Expenses	156	
10	Adjustment to Annualize Payroll Taxes	36	
11	Remove EV Charging Station	24	
12	Remove EAM Cost	46	
13	Remove Battery Storage Cost	64	
14	Interest Synchronization	(20)	
15	Total OCA Adjustments	917	
16			
17	Total OCA Adjustments	$ 5,189	

UGI Utilities, Inc. - Electric Division

Summary of Adjustments to Income Before Income Taxes
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.		Operating Revenues	O&M Expenses	Depreciation & Amortization	Taxes Other Than Income	Income Taxes	Operating Income Before Income Taxes
1	Amount per Company	$ 87,065	$ 69,694	$ 7,114	$ 5,929	$ 56	$ 4,272
2							
3	OCA Adjustments:						
4	Annualize Payroll	$ -	$ (124)	$ -	$ -	$ 36	$ 88
5	Remove Stock Based Incentive Compensation	-	[redacted]	-	-	[redacted]	[redacted]
6	Annualize OPEB	-	[redacted]	-	-	[redacted]	[redacted]
7	Normalize Rate Case Expense	-	[redacted]	-	-	[redacted]	[redacted]
8	Normalize Uncollectibles	-	(304)	-	-	88	216
9	Normalize Incremental COVID-Related Expenses		(220)		-	64	156
10	Adjustment to Annualize Payroll Taxes		-	-	(51)	15	36
11	Remove EV Charging Station	-	-	(34)	-	10	24
12	Remove EAM Cost	-	-	(65)	-	19	46
13	Remove Battery Storage Cost	-	-	(90)	-	26	64
14	Interest Synchronization	-	-	-	-	20	(20)
15							
16	Total OCA Adjustments	$ -	$ (1,080)	$ (189)	$ (51)	$ 403	$ 917
17							
18	Total Adjusted Income Before Income Taxes	$ 87,065	$ 68,614	$ 6,925	$ 5,878	$ 459	$ 5,189

UGI Utilities, Inc. - Electric Division

Adjustment to Remove EV Charging Stations
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	**Rate Base**	
2	EV Charging Station Capital Costs	$ 300 [1/]
3		
4	Accumulated Depreciation	-
5		
6	Adjustment to Rate Base	$ (300)
7		
8	**Depreciation Expense**	
9	EV Charging Station Capital Costs	$ 300 [1/]
10		
11	Depreciation Rate	11.35%
12		
13	Adjustment to Depreciation Expenses	$ (34)

Notes:
[1/] UGI Filing Book VI, Schedule C, Page II-3.

UGI Utilities, Inc. - Electric Division

Adjustment to Remove Battery Storage Equipment
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	**Rate Base**	
2	Battery Storage Equipment	$ 1,500 [1/]
3		
4	Accumulated Depreciation	
5		
6	Adjustment to Rate Base	$ (1,500)
7		
8	**Depreciation Expense**	
9	Battery Storage Equipment	$ 1,500 [1/]
10		
11	Depreciation Rate	6.01% [1/]
12		
13	Adjustment to Depreciation Expenses	$ (90)

Notes:
[1/] UGI Filing Book VI, Schedule C, Page II-3.

UGI Utilities, Inc. - Electric Division

Adjustment to 13-Month Average Materials & Supplies
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount	
1	13-Month Average Materials & Supplies per OCA	$ 1,446	1/
2			
3	13-Month Average Materials & Supplies per UGI	1,309	2/
4			
5			
6	Adjustment to Rate Base	$ 137	

Notes:
1/ Schedule LKM-6, Page 2.
2/ UGI Gas Exhibit A, Schedule C-8.

UGI Utilities, Inc. - Electric Division

Calculation of 13-Month Average Materials & Supplies Balances
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description		Amount [1/]
1	February, 2020	$	1,412
2	March		1,400
3	April		1,520
4	May		1,300
5	June		1,255
6	July		1,210
7	August		1,258
8	September		1,217
9	October		1,351 [2/]
10	November		1,750 [2/]
11	December		1,745 [2/]
12	January, 2021		1,693 [2/]
13	February		1,690 [2/]
14			
15	13-Month Average Materials & Supplies	$	1,446

Notes:
1/ UGI Gas Exhibit A, Schedule C-8.
2/ Response to OCA-III-19.

UGI Utilities, Inc. - Electric Division

Adjustment to 13-Month Average Customer Deposits
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	13-Month Average Customer Deposits per OCA	$ 1,094 [1/]
2		
3	13-Month Average Customer Deposits per UGI	1,197 [2/]
4		
5	Adjustment to Rate Base	$ (103)
6		

Notes:
1/ Schedule LKM 7, Page 2.
2/ UGI Gas Exhibit A, Schedule C-7.

UGI Utilities, Inc. - Electric Division

Calculation of 13-Month Average Customer Deposits Balances
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description		Amount [1/]
1	February, 2020	$	1,188
2	March		1,165
3	April		1,154
4	May		1,140
5	June		1,120
6	July		1,102
7	August		1,082
8	September		1,070
9	October		1,068
10	November		1,069 [2/]
11	December		1,041 [2/]
12	January, 2021		1,021 [2/]
13	February		1,005 [2/]
14			
15	13-Month Average Customer Deposits	$	1,094

Notes:
1/ UGI Gas Exhibit A, Schedule C-7.
2/ Response to OCA-III-17.

UGI Utilities, Inc. - Electric Division

Adjustment to Cash Working Capital
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No	Description	Amount per OCA	Amount per UGI	OCA Adjustment
1	Working Capital for O & M Expense	$ 5,661	$ 5,755	$ (94)
2	Interest Payments	(228)	(234)	6
3	Tax Payment Lag Calculations	174	175	(1)
4	Prepaid Expenses	1,972	1,962	10
5	Total Cash Working Capital Requirements	$ 7,579	$ 7,658	$ (79)

UGI Utilities, Inc. - Electric Division
Combined Operations
Summary of Working Capital
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No	Description	Test Year Expenses	OCA Adjustments	Test Year Expenses	Factor	Number of (Lead) / Lag Days	Totals
	WORKING CAPITAL REQUIREMENT						
1	Revenue Lag Days						59.98
2							
3	Expense Lag Days						
4	Payroll	$ 5,911	$ (124)	$ 5,787	12.00	$ 69,446	
5	Purchased Power Costs	41,179	-	41,179	30.63	1,261,313	
6	Other Expenses	20,752	(652)	20,100	30.70	617,070	
7							
8	Total	$ 67,842	$ (776)	$ 67,066		$ 1,947,829	
9							
10	O & M Expense Lag Days						29.04
11							
12	Net (Lead) Lag Days						30.94
13	Operating Expenses Per Day						$ 183
14							
15	Working Capital for O & M Expense						$ 5,661
16							
17	Interest Payments						(228)
18							
19	Tax Payment Lag Calculations						174
20							
21	Prepaid Expenses						1,972
22							
23	Total Working Capital Requirement						$ 7,579

UGI Utilities, Inc. - Electric Division

Calculation of Interest Payments
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No	Description	# of Days	# of Days	Total
1	Measure of Value at September 30, 2020			$ 128,555
2				
3	Long-term Debt Ratio			48.80%
4				
5	Embedded Cost of Long-term Debt			4.25%
6				
7	Pro forma Interest Expense			$ 2,666
8				
9	Daily Amount	365		$ 7
10				
11	Days to mid-point of interest payments		91.25	
12				
13	Less: Revenue Lag Days		59.98	
14				
15	Interest Payment lag days			(31.3)
16				
17	Total Interest for Working Capital			$ (228)

UGI Utilities, Inc. - Electric Division

Calculation of Prepaid Expenses
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	TOTAL	Insurance	PUC Assessment	Gross Receipts Tax	Subscriptions	Miscellaneous	Maintenance & Services	
1	February, 2020	$ 738	$ 179	$ 91	$ -	$ 51	$ 187	$ 230	1/
2	March	4,312	133	68	3,595	46	60	410	1/
3	April	3,400	114	46	2,777	41	65	357	1/
4	May	3,001	76	23	2,451	36	58	357	1/
5	June	3,008	70	-	2,439	30	41	428	1/
6	July	2,060	483	-	1,102	25	38	412	1/
7	August	1,733	436	-	769	20	36	472	1/
8	September	1,838	389	217	724	16	45	447	1/
9	October	1,419	343	193	331	24	56	472	1/
10	November	1,067	299	169	-	85	53	461	2/
11	December	958	255	145	-	80	52	426	2/
12	January, 2021	1,056	222	121	-	89	24	600	2/
13	February	1,047	177	96	-	79	13	682	2/
14	TOTAL	$ 25,637	3,176	1,169	14,188	622	728	5,754	
15									
16	13-Montth Average		$ 244	$ 90	$ 1,091	$ 48	$ 56	$ 443	
17	Rate Base Amount	$ 1,972							

Notes:
1/ Attachment OCA-II-7.
2/ Attachment OCA-II-6.

UGI Utilities, Inc. - Electric Division

Adjustment to Annualize Payroll
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount Per Company
1	OCA Annual Payroll Expense	$ 5,751
2	Annualizing Adjustment	50
3	Annualized Payroll per OCA	5,801
4	Annualized Payroll per UGI	5,911
5		
6	Adjustment to Payroll	$ (110)
7		
8	Adjustment to Remove Potential Double Count of Payroll Increase on New employees	(14)
9		
10	Adjustment to O&M Expense	$ (124)

UGI Utilities, Inc. - Electric Division

Calculation of FPFTY Payroll Based on Removing 2 Temporary Employees
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount Per Company
1	Total FPFTY Budgeted Unadjusted Payroll	$ 5,854
2	Number of FPFTY Employees per Company	83
3		
4	Payroll per Employee	$ 71
5	Most Recent average Number of Employees	81
6		
7	Annual Payroll Based on Most Recent Average Employee	$ 5,751

UGI Utilities, Inc. - Electric Division

Calculation of FPFTY Payroll Increase
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line #	Description	Union Increase At 6-1	Non-Exempt	Exempt	Pro Forma Total Payroll
1	Budgeted Payroll For TY 9-30-22	$ 1,428	$ 1,289	$ 3,034	$ 5,751
2					
3	**Annualize for Wage Increase to 9-30-22**				
4	Percent Increase	3.00%	2.50%	2.50%	
5	Union Increase At 4-1 Annualization Factor	50%			
6	Non-Exempt Annualization Factor		50%		
7	Exempt Annualization Factor			17%	
8	Increase for wage rate changes	21	16	13	$ 50
13					
14	Pro Forma Salaries & Wages for TY	$ 1,450	$ 1,305	$ 3,046	
15					
16	Pro Forma Adjustment to S&W				$ 50

UGI Utilities, Inc. - Electric Division

Adjustment to Normalize Uncollectibles Expense
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount	
1	**COVID-Related Uncollectible Regulatory Asset**		
2	Regulatory Asset balance as of 9/30/20	$ 1,013	
3			
4	Normalization Period	5	
5			
6	Normalized COVID-Related Uncollectible Regulatory Asset per OCA	$ 203	
7			
8	Normalized COVID-Related Uncollectible Regulatory Asset per Company	507	
9			
10	Adjustment to Normalized COVID-Related Uncollectible Regulatory Asset		(304)
11			
12	Adjustment to Uncollectible Expense		$ (304)

UGI Utilities, Inc. - Electric Division

Adjustment to Normalize Incremental COVID-Related Expenses
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount	Total
1	Normalization of Incremental COVID Expenses per Company		$ 220
2			
3	Adjustment to O&M Expenses		$ (220)

UGI Utilities, Inc. - Electric Division

Adjustment to Annualize Payroll Taxes
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount Per Company	
1	Adjustment to Payroll	$ (124)	1/
2	Adjustment to incentive Compensation	(248)	
3			
4	Total Adjustment to Labor Costs	$ (372)	
5	Payroll Tax Rate	7.65%	
6			
7	Annualized Payroll Taxes to Reflect OCA Decrease in Payroll	$ (28)	
8			
9	Correct FICA Tax Rate	(11)	2/
10			
11	Correct Payroll Unemployment Tax Rate	(12)	3/
12			
13	Adjustment to Payroll Taxes	$ (51)	

Notes:
1/ Response IE-RE-15.
2/ Response IE-RE-17.

UGI Utilities, Inc. - Electric Division

Interest Synchronization Adjustment
For the Rate Year Ending September 30, 2022

Line No.	Description		Amount	
1	Company Rate Base	$	128,555	1/
2	Weighted Cost of Debt		2.070%	
3				
4	Adjusted Interest Deduction	$	2,661	
5	Interest Deduction Per Company		2,729	2/
6				
7	Adjustment to Synchronize Interest Expense	$	(68)	
8	Effective State Income Tax Rate		9.99%	
9				
10	Adjustment to State Income Taxes	$	7	
11				
12	Federal Income Tax Base	$	(61)	
13	Federal Income Tax Rate		21.00%	
14				
15	Adjustment to Federal Income Taxes	$	13	

Notes:
1/ Schedule LKM-2, Page 1.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**Docket No. R-2021-3023618**
UGI Electric Utilities, Inc. - Electric Division	)	

Appendix A

LAFAYETTE K. MORGAN, JR.

Mr. Morgan is an independent regulatory consultant focusing in the area of the analysis of the operations of public utilities with particular emphasis on rate regulation. He has reviewed and analyzed utility rate filings, focusing primarily on revenue requirements determination, accounting and regulatory policy and cost recovery mechanisms. This work has included natural gas, water, electric, and telephone utilities.

Education and Qualifications

B.B.A. (Accounting) – North Carolina Central University, 1983

M.B.A. (Finance) – The George Washington University, 1993

C.P.A. – Licensed in the State of North Carolina (Inactive status)

Previous Employment

1993-2010	Senior Regulatory Analyst Exeter Associates, Inc. Columbia, MD
1990-1993	Senior Financial Analyst Potomac Electric Power Company Washington, D.C.
1984-1990	Staff Accountant North Carolina Utilities Commission – Public Staff Raleigh, NC

Professional Experience

As a Staff Accountant with the North Carolina Utilities Commission – Public Staff, Mr. Morgan was responsible for analyzing testimony, exhibits, and other data presented by parties before the Commission. In addition, he performed examinations of the books and records of utilities involved in rate proceedings and summarized the results into testimony and exhibits for presentation before the Commission. Mr. Morgan also participated in several policy proceedings and audits involving regulated utilities.

As a Senior Financial Analyst with Potomac Electric Power Company, Mr. Morgan was a lead analyst and was involved in the preparation of the cost of service, rate base, and ratemaking adjustments supporting the Company's request for revenue increases in its retail jurisdictions.

As a Senior Regulatory Analyst with Exeter Associates, Inc., Mr. Morgan has been involved in the analysis of the operations of public utilities with particular emphasis on rate regulation. He has reviewed and analyzed utility rate filings, focusing primarily on revenue requirements determination, accounting and regulatory policy and cost recovery mechanisms. This work included natural gas, water, electric, and telephone utilities.

Expert Testimony

of Lafayette K. Morgan, Jr.

Kings Grant Water Company (North Carolina Utilities Commission, Docket No. W-250, Sub 5), 1984. Presented testimony on rate base, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

Northwood Water Company (North Carolina Utilities Commission, Docket No. W-690, Sub 1), 1985. Presented testimony on rate base, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

Emerald Village Water System (North Carolina Utilities Commission, Docket No. W-184, Sub 3), 1985. Presented testimony on rate base, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

General Telephone Company of the South (North Carolina Utilities Commission, Docket No. P-19, Sub 207), July 1986. Presented testimony on the level of cash working capital allowance on behalf of the North Carolina Utilities Commission – Public Staff.

Heins Telephone Company (North Carolina Utilities Commission, Docket No. P-26, Sub 93), November 1986. Presented testimony on rate base, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

Carolina Power and Light Company (North Carolina Utilities Commission, Docket No. E-2, Sub 537), March 1988. Presented testimony on rate base, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

Public Service Company of North Carolina, Inc. (North Carolina Utilities Commission, Docket No. G-5, Sub 246), August 1989. Presented testimony on rate base, cash working capital allowance, cost of service, and revenue and expense adjustments on behalf of the North Carolina Utilities Commission – Public Staff.

Conestoga Telephone and Telegraph Company (Pennsylvania Public Utility Commission, Docket No. I-00920015), September 1993. Presented testimony on cost of service on behalf of the Pennsylvania Office of Consumer Advocate.

Louisiana Power and Light Company (Louisiana Public Service Commission, Docket No. U-20925), February 1995. Presented testimony on rate base and working capital issues on behalf of the Louisiana Public Service Commission Staff.

South Central Bell Telephone Company – Louisiana (Louisiana Public Service Commission, Docket No. U-17949, Subdocket E), June 1995. Presented testimony on rate base and working capital issues on behalf of the Louisiana Public Service Commission Staff.

Expert Testimony

of Lafayette K. Morgan, Jr.

Apollo Gas Company (Pennsylvania Public Utility Commission, Docket No. R-00953378), August 1995. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Carnegie Natural Gas Company (Pennsylvania Public Utility Commission, Docket No. R-00953379), August 1995. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Tennessee Gas Pipeline Company (Federal Energy Regulatory Commission, Docket No. RP95-112), September 1995. Presented testimony rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Virginia-American Water Company (Virginia State Corporation Commission, Case No. PUE-950003), March 1996. Presented testimony on rate base and cost of service issues on behalf of the City of Alexandria.

GTE North, Inc. Interconnection Arbitration (Pennsylvania Public Utility Commission, Docket No. A-310125F0002), September 1996. Presented testimony on the determination of the appropriate resale discount on behalf of the Pennsylvania Office of Consumer Advocate.

United Cities Gas Company (Georgia Public Service Commission, Docket No. 6691-U), October 1996. Presented testimony on rate base and cost of service issues on behalf of the Office of Governor, Consumer Utility Counsel Division.

GTE North, Inc. (Pennsylvania Public Utility Commission, Docket Nos. R-00963666 and R-00963666C001), February 1997. Presented testimony on the determination of the appropriate resale discount on behalf of the Pennsylvania Office of Consumer Advocate.

Consumers Maine Water Company (Maine Public Utilities Commission, Docket No. 96-739), May 1997. Presented testimony on rate base, cost of service, and rate of return issues on behalf of the Maine Office of the Public Advocate.

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission, Docket No. R-00973944), July 1997. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Pennsylvania-American Water Company – Wastewater Operations (Pennsylvania Public Utility Commission, Docket No. R-00973973), July 1997. Presented testimony on rate base, cost of service, depreciation, and rate design issues on behalf of the Pennsylvania Office of Consumer Advocate.

Expert Testimony

of Lafayette K. Morgan, Jr.

Jackson Purchase Electric Cooperative Corporation (Kentucky Public Service Commission, Case No. 97-224), December 1997. Presented testimony on rate base and cost of service issues on behalf of the Kentucky Office of the Attorney General.

Henderson Union Electric Cooperative Corporation (Kentucky Public Service Commission, Case No. 97-220), January 1998. Presented testimony on the return of patronage capital on behalf of the Kentucky Office of the Attorney General.

Green River Electric Corporation (Kentucky Public Service Commission, Case No. 97-219), January 1998. Presented testimony on the return of patronage capital on behalf of the Kentucky Office of the Attorney General.

Western Kentucky Gas Company (Kentucky Public Service Commission, Case No. 99-070), November 1999. Presented testimony on rate base and cost of service issues on behalf of the Kentucky Office of the Attorney General.

American Broadband, Inc. (Rhode Island Public Utilities Commission, Docket No. 2000-C-3), June 2000. Presented report and testimony on the Company's financing plan on behalf of the Rhode Island Division of Public Utilities and Carriers.

PPL Utilities (Pennsylvania Public Utility Commission, Docket No. R-00005277), October 2000. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

T.W. Phillips Oil and Gas Company (Pennsylvania Public Utility Commission, Docket No. R-00005459), October 2000. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Pike County Light & Power Company (Pennsylvania Public Utility Commission, Docket No. P-00011872), May 2001. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Vermont Gas Systems, Inc. (Vermont Public Service Board, Docket No. 6495), June 2001. Presented testimony on rate base and cost of service issues on behalf of the Vermont Public Service Department.

Community Service Telephone Company (Maine Public Utilities Commission, Docket No. 2001-249), July 2001. Presented joint testimony on rate base and cost of service issues on behalf of the Maine Office of the Public Advocate.

Expert Testimony

of Lafayette K. Morgan, Jr.

West Virginia-American Water Company (Public Service Commission of West Virginia, Docket No. 01-0326-W-42-T), August 2001. Presented testimony on rate base and cost of service issues on behalf of the Consumer Advocate Division.

Philadelphia Suburban Water Company (Pennsylvania Public Utility Commission, Docket No. R-00016750) February 2002. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Illinois-American Water Company (Illinois Commerce Commission, Docket No. 02-0690) January 2003. Presented testimony on cost of service issues on behalf of Citizens Utility Board.

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission, Docket No. R-00027983), February 2003. Presented testimony addressing surcharge mechanism to recover security costs on behalf of the Pennsylvania Office of Consumer Advocate.

FairPoint New England Telephone Companies (Maine Public Utilities Commission, Docket Nos. 2002-747, 2003-34, 2003-35, 2003-36, and 2003-37), June 2003. Presented testimony on rate base and cost of service issues on behalf of the Maine Office of the Consumer Advocate.

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission, Docket No. R-00038304), August 2003. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

PPL Electric Utilities Corporation (Pennsylvania Public Utility Commission, Docket No. R-00049255), June 2004. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Entergy Louisiana, Inc. (Louisiana Public Service Commission, Docket No. U-20925 RRF 2004), August 2004. Presented testimony on rate base and cost of service issues on behalf of the Louisiana Public Service Commission Staff.

Vectren Energy Delivery of Indiana (Indiana Utility Regulatory Commission, Cause No. 42598), September 2004. Presented testimony on O&M expense issues on behalf of the Indiana Office of Utility Consumer Counselor.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission, Docket No. R-00049656), December 2004. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Expert Testimony

of Lafayette K. Morgan, Jr.

Block Island Power Company (Rhode Island Public Utilities Commission, Docket No. 3655), April 2005. Presented testimony on cash working capital on behalf of the Rhode Island Division of Public Utilities & Carriers.

Verizon New England, Inc. (Maine Public Utilities Commission, Docket No. 2005-155), September 2005. Presented joint testimony with Thomas S. Catlin on rate base and cost of service issues on behalf of the Maine Office of the Public Advocate.

T.W. Phillips Oil and Gas Company (Pennsylvania Public Utility Commission, Docket No. R-00051178), May 2006. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Duquesne Light Company (Pennsylvania Public Utility Commission, Docket No. R-00061346), July 2006. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

National Fuel Gas Distribution Company (Pennsylvania Public Utility Commission, Docket No. R-00061493), September 2006. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Southern Indiana Gas & Electric Co. (Indiana Utility Regulatory Commission, Cause No. 43112), January 2007. Presented testimony on rate base and cost of service issues on behalf of the Indiana Office of Utility Consumer Counsel.

PPL Electric Utilities (Pennsylvania Public Utility Commission, Docket No. R-00072155), July 2007. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Aqua Pennsylvania, Inc. (Pennsylvania Public Utility Commission, Docket No. R-00072711), February 2008. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Equitable Gas Company (Pennsylvania Public Utility Commission, Docket No. R-2008-2029325), October 2008. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

The Narragansett Bay Commission (Rhode Island Public Utilities Commission, Docket No. 4026), April 2009. Presented testimony on rate base and cost of service issues on behalf of the Rhode Island Division of Public Utilities and Carriers.

Expert Testimony

of Lafayette K. Morgan, Jr.

Maryland-American Water Company (Maryland Public Service Commission, Case No. 9187), July 2009. Presented testimony on rate base and cost of service issues on behalf of the Maryland Office of People's Counsel.

Monongahela Power Company & The Potomac Edison Company, both d/b/a Allegheny Power Company (West Virginia Public Service Commission, Case No. 09-1352-E-42T), February 2010. Presented testimony on rate base and cost of service issues on behalf of the West Virginia Consumer Advocate Division.

PPL Electric Utilities (Pennsylvania Public Utility Commission, Docket No. R-2010-2161694), June 2010. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Pawtucket Water Supply Board (Rhode Island Public Utilities Commission, Docket No. 4550), June 2015. Presented testimony on revenue requirements issues on behalf of the Rhode Island Division of Public Utilities and Carriers.

Columbia Gas of Pennsylvania (Pennsylvania Public Utility Commission, Docket No. R-2015-2468056), June 2015. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Indianapolis Power and Light Company (Indiana Utility Regulatory Commission, Cause No. 44576/44602), July 2015. Presented testimony on revenue requirements issues on behalf of the Indiana Office of Utility Consumer Counselor.

Public Service Company of Oklahoma (Corporation Commission of Oklahoma, Cause No. PUD 201500208), October 2015. Presented testimony on revenue requirements and environmental compliance rider issues on behalf of the United States Department of Defense and the Federal Executive Agencies.

Northern Indiana Public Service Company (Indiana Utility Regulatory Commission, Cause No. 44688), January 2016. Presented testimony on the company's electric division operating revenues, operating expenses and income taxes issues on behalf of the Indiana Office of Utility Consumer Counselor.

Philadelphia Water Department (Philadelphia Water, Sewer And Storm Water Rate Board, FY2017-2018 Rate Proceeding), March 2016. Presented testimony on revenue requirements issues on behalf of the Public Advocate.

Columbia Gas of Maryland (Public Service Commission of Maryland, Case No. 9417), June 2016. Presented testimony on rate base and cost of service issues on behalf of the Office of People's Counsel.

Expert Testimony

of Lafayette K. Morgan, Jr.

Chesapeake Utilities Corporation (Delaware Public Service Commission, PSC Docket No. 15-1734), August 2016. Presented testimony on rate base and cost of service issues on behalf of the Staff of the Delaware Public Service Commission.

Kent County Water Authority (Public Service Commission of Rhode Island, Docket No. 4611), September 2016. Presented testimony on rate base and cost of service issues on behalf of the Division of Public Utilities and Carriers.

Northern Utilities, Inc. (Maine Public Utilities Commission, Docket No. 2017-00065), August 2017. Assisted the Maine Office of Public Advocate (OPA) with Northern Utilities application for an increase in rates. Mr. Morgan provided testimony, on behalf of the OPA, on accounting issues including test year revenue requirements, the utility's request to renew and modify its alternative rate plan, and its Targeted Infrastructure Replacement Adjustment.

Indiana Michigan Power Company (Indiana Utility Regulatory Commission, Cause No. 44967), November 2017. Presented testimony on rate base, operating revenues and operating expenses issues on behalf of the Indiana Office of Utility Consumer Counselor.

Emera Maine (Maine Public Utilities Commission, Docket No. 2017-00198), December 2017. Assisted the Maine Office of Public Advocate (OPA) with Emera Maine's application for an increase in rates. Mr. Morgan provided testimony, on behalf of the OPA, on accounting issues including test year revenue requirements, the utility's request to reflect the changes brought about by the Tax Change and Jobs Act of 2017.

UGI-Electric (Pennsylvania Public Utility Commission, Docket No. R-2017-2640058), April 2018. Assisted the Pennsylvania Office of Consumer Advocate (OCA) with UGI-Electric's application for an increase in rates. Mr. Morgan provided testimony, on behalf of the OCA, on accounting issues including test year revenue requirements, the utility's request to reflect the changes brought about by the Tax Change and Jobs Act of 2017.

Philadelphia Water Department (Philadelphia Water, Sewer And Storm Water Rate Board, FY2019-2020 Rate Proceeding), April 2018. Presented testimony on revenue requirements and the Department's three-year rate plan issues on behalf of the Public Advocate.

Westar Energy, Inc. (Westar Energy) and Kansas Gas and Electric Company (KGE), (Kansas State Corporation Commission, Docket No. 18-WSEE-328-RTS), May 2018. Presented testimony on revenue requirements on behalf on behalf of the Federal Executive Agencies.

Expert Testimony

of Lafayette K. Morgan, Jr.

Duquesne Light Company (Pennsylvania Public Utility Commission, Docket No. R-2018-3000124), June 2018. Assisted the Pennsylvania Office of Consumer Advocate (OCA) with UGI-Electric's application for an increase in rates. Presented testimony, on behalf of the OCA, on accounting issues including test year revenue requirements, the utility's request to reflect the changes brought about by the Tax Change and Jobs Act of 2017.

Bangor Natural Gas Company (Maine Public Utilities Commission, Docket No. 2018-00007), June 2018. Assisted the Maine Office of Public Advocate (OPA) Presented testimony, on behalf of the OPA, on the changes brought about by the Tax Change and Jobs Act of 2017.

SUEZ Water Pennsylvania, Inc. (Pennsylvania Public Utility Commission, R-2018-3000834), July 2018. Assisted the Pennsylvania Office of Consumer Advocate (OCA) with SUEZ Water's application for an increase in rates. Presented testimony, on behalf of the OCA, on accounting issues including Rate Base, Operating Income, Inclusion of Costs Related to Expansion Territories and the utility's request to reflect the changes brought about by the Tax Change and Jobs Act of 2017.

Woonsocket Water Division (Public Service Commission of Rhode Island, Docket No. 4879), January 2019. Presented testimony on cost of service issues on behalf of the Division of Public Utilities and Carriers.

Central Maine Power Company (Maine Public Utilities Commission, Docket No. 2018-00194), January 2019. Assisted the Maine Office of Public Advocate (OPA) with Central Maine Power's application for an increase in rates. Mr. Morgan provided testimony, on behalf of the OPA, on accounting issues including test year revenue requirements, the utility's request to reflect the changes brought about by the Tax Change and Jobs Act of 2017.

Newport Water Department (Public Service Commission of Rhode Island, Docket No. 4933), July 2019. Presented testimony on cost of service issues on behalf of the Division of Public Utilities and Carriers.

UGI-Gas (Pennsylvania Public Utility Commission, Docket No. R-2018-3006814), April 2019. Assisted the Pennsylvania Office of Consumer Advocate (OCA) with UGI-Gas' application for an increase in rates. Mr. Morgan provided testimony, on behalf of the OCA, on accounting issues including Rate Base and Net Operating Income.

Columbia Gas of Maryland (Public Service Commission of Maryland, Case No. 9609), August 2019. Presented testimony on rate base and cost of service issues on behalf of the Office of People's Counsel.

Expert Testimony

of Lafayette K. Morgan, Jr.

Public Service Company of Colorado (Colorado Public Utility Commission, Proceeding No. 19AL-0268E), September 2019. Mr. Morgan provided testimony, on behalf of the Department of Energy and the Federal Executive Agencies, on accounting issues including test year revenue requirements, Rate Base and Net Operating Income.

Northern Utilities, Inc. (Maine Public Utilities Commission, Docket No. 2019-00092), September 2019. Assisted the Maine Office of Public Advocate (OPA) with Northern Utilities application for an increase in rates. Mr. Morgan provided testimony, on behalf of the OPA, on accounting issues including test year revenue requirements and the utility's request to institute a Capital Investment Recovery Mechanism.

Citizens' Electric Company of Lewisburg (Pennsylvania Public Utility Commission, Docket No. R-2019-3008212), October 2019. Provided testimony on Plant in Service, Construction Work in Progress, Materials and Supplies, Customer Deposits, Depreciation Expense, Growth Factor, and The Tax Cuts and Jobs Act. Mr. Morgan provided testimony, on behalf of the Pennsylvania Office of Consumer Advocate (OCA).

Valley Energy, Inc. (Pennsylvania Public Utility Commission, Docket No. R-2019-3008209), October 2019. Provided testimony on Plant in Service, Construction Work in Progress, Materials and Supplies, Customer Deposits, Depreciation Expense, Growth Factor, and The Tax Cuts and Jobs Act. Mr. Morgan provided testimony, on behalf of the Pennsylvania Office of Consumer Advocate (OCA).

Wellsboro Electric Company (Pennsylvania Public Utility Commission, Docket No. R-2019-3008208), October 2019. Provided testimony on Plant in Service, Construction Work in Progress, Materials and Supplies, Customer Deposits, Depreciation Expense, Growth Factor, and The Tax Cuts and Jobs Act. Mr. Morgan provided testimony, on behalf of the Pennsylvania Office of Consumer Advocate (OCA).

Blue Granite Water Company (Public Service Commission of South Carolina, (Docket No. 2019-290-WS), January 2020. Assisted the South Carolina Department of Consumer Affairs. Presented testimony on accounting policy issues including test year revenue requirements.

UGI-Gas (Pennsylvania Public Utility Commission, Docket No. R-2019-3015162), May 2020. Assisted the Pennsylvania Office of Consumer Advocate (OCA) with UGI-Gas' application for an increase in rates. Mr. Morgan provided testimony, on behalf of the OCA, on accounting issues including Rate Base and Net Operating Income.

Columbia Gas of Maryland (Public Service Commission of Maryland, Case No. 9644), July 2020. Presented testimony on rate base and cost of service issues on behalf of the Office of People's Counsel.

Expert Testimony

of Lafayette K. Morgan, Jr.

PECO Energy Company - Gas Division (Pennsylvania Public Utility Commission, Docket No. R-2020-3018929), December 2020. Assisted the Pennsylvania Office of Consumer Advocate (OCA) with PECO-Gas' application for an increase in rates. Mr. Morgan provided testimony, on behalf of the OCA, on accounting issues including Rate Base and Net Operating Income.

Philadelphia Water Department (Philadelphia Water, Sewer And Storm Water Rate Board, Fiscal Years 2022 - 2023 Rates Proceeding), March 2021. Presented testimony on revenue requirements and the Department's three-year rate plan issues on behalf of the Public Advocate.

Versant Maine (Maine Public Utilities Commission, Docket No. 2020-00316), April 2021. Assisted the Maine Office of Public Advocate (OPA) with Emera Maine's application for an increase in rates. Mr. Morgan provided testimony, on behalf of the OPA, on accounting issues including test year revenue requirements.

Special Projects

Developed a Uniform System of Accounts and Financial Data Collection Template for five countries participating in the National Association of Regulatory Utility Commissioners (NARUC)/East Africa Regional Energy Regulatory Partnership. Also conducted training seminars and participated as a panel member addressing issues in the utility industry from the perspective of the regulator. This work was conducted by NARUC) and the United States Agency for International Development (USAID).

Other Projects

Texas Gas Transmission Corporation (Federal Energy Regulatory Commission, Docket No. RP93-106). Technical analysis and participation in settlement negotiations on cost of service, invested capital, and revenue deficiency on behalf of the Indiana Office of Utility Consumer Counselor.

Natural Gas Pipeline Company of America (Federal Energy Regulatory Commission, Docket No. RP93-36). Technical analysis and participation in settlement negotiations on cost of service, invested capital, and revenue deficiency on behalf of the Indiana Office of Utility Consumer Counselor.

Texas Gas Transmission Company (Federal Energy Regulatory Commission, Docket No. RP94-423). Technical analysis and participation in settlement negotiations on cost of service, invested capital, and revenue deficiency on behalf of the Indiana Office of Utility Consumer Counselor.

Lafourche Telephone Company (Louisiana Public Service Commission, Docket No. U-21181). Analysis and investigation of earnings and appropriate rate of return on behalf of the Louisiana Public Service Commission Staff.

Natural Gas Pipeline Company of America (Federal Energy Regulatory Commission, Docket No. RP95-326). Technical analysis and participation in settlement negotiations on cost of service, invested capital, and revenue deficiency on behalf of the Indiana Office of Utility Consumer Counselor.

Pymatuning Independent Telephone Company (Pennsylvania Public Utility Commission, Docket No. R-00953502). Technical analysis and development of settlement position in the Company’s rate case on behalf of the Pennsylvania Office of Consumer Advocate.

Illinois Bell Telephone Company (Illinois Commerce Commission, Docket No. 96-0172). Technical analysis of the Company’s annual rate filing pursuant to its Price Cap Plan on behalf of Citizens Utility Board.

Illinois Bell Telephone Company (Illinois Commerce Commission, Docket No. 97-0157). Technical analysis of the Company's annual rate filing pursuant to its Price Cap Plan on behalf of Citizens Utility Board.

TDS Telecom (Pennsylvania Public Utility Commission, Docket Nos. R-00973892 and R-00973893). Technical analysis regarding rate base, cost of service, rate design, and rate of return, and assistance in settlement negotiations in the Company's rate case and alternative regulatory filing on behalf of the Pennsylvania Office of Consumer Advocate.

Appalachian Power Company (Virginia State Corporation Commission, Case No. PUE 960301). Technical analysis regarding rate base and cost of service and assistance in settlement negotiations in the Company's rate case and alternative regulatory filing on behalf of the Virginia Office of the Attorney General.

Central Maine Power Company (Maine Public Utilities Commission, Docket No. 97-580). Technical analysis regarding attrition and accounting issues in the Company's Transmission and Distribution unbundling proceeding on behalf of the Maine Public Utilities Commission Staff.

Illinois Bell Telephone Company (Illinois Commerce Commission, Docket No. 98-0259). Technical Analysis of the Company's annual rate filing pursuant to its Price Cap Plan on behalf of Citizens Utility Board.

Maine Public Service Company (Maine Public Utilities Commission, Docket No. 98-577). Technical analysis regarding attrition and accounting issues in the Company's Transmission and Distribution unbundling proceeding on behalf of the Maine Public Utilities Commission Staff.

Bangor Hydro-Electric Company (Maine Public Utilities Commission, Docket No. 97-596). Technical analysis regarding attrition and accounting issues in the Company's Transmission and Distribution unbundling proceeding on behalf of the Maine Public Utilities Commission Staff.

TDS Telecom (Maine Public Utilities Commission, Docket Nos. 98-894, 98-895, 98-904, 98-906, 98-911, and 98-912). Technical analysis regarding accounting issues and access rate changes on behalf of the Maine Office of the Public Advocate.

Mid-Maine Telecom (Maine Public Utilities Commission, Docket No. 2000-810). Technical analysis regarding accounting issues and access rate changes on behalf of the Maine Office of the Public Advocate.

Unitel, Inc. (Maine Public Utilities Commission, Docket No. 2000-813). Technical analysis regarding accounting issues and access rate changes on behalf of the Maine Office of the Public Advocate.

Hydraulics International, Inc. (Armed Services Board of Contract Appeals, ASBCA No. 51285). Technical analysis and support relating to the Economic Adjustment Clause claim on behalf of the Air Force Materiel Command.

Tidewater Telecom and Lincolnville Telephone Company (Maine Public Utilities Commission, Docket Nos. 2002-100 and 2002-99). Technical analysis regarding accounting issues and access rate changes on behalf of the Maine Office of the Public Advocate.

TDS Telecom (Vermont Public Service Board, Docket No. 6576). Technical analysis regarding rate base, cost of service, and depreciation expense on behalf of the Vermont Department of Public Service.

CenterPoint Energy-Entex (Louisiana Public Service Commission, Docket No. U-26720, Subdocket A). Technical analysis regarding rate base and cost of service on behalf of the Louisiana Public Service Commission Staff.

CenterPoint Energy-Arkla (Louisiana Public Service Commission, Docket No. U-27676). Technical analysis regarding rate base and cost of service on behalf of the Louisiana Public Service Commission Staff.

Provided technical analysis and support on behalf of the Louisiana Public Service Commission Staff relating to CLECO Power LLC Rate Stabilization Plan.

Provided technical analysis and support on behalf of the Louisiana Public Service Commission Staff relating to CLECO Power LLC post-Katrina power purchases.

Provided technical analysis and support on behalf of the Louisiana Public Service Commission Staff relating to Entergy Louisiana LLC recovery of storm damage costs.

Westar Energy, Inc. (Westar Energy) and Kansas Gas and Electric Company (KGE), (Kansas State Corporation Commission, Docket No. 17-WSEE-147-RTS). Technical analysis regarding rate base and cost of service on behalf of the Federal Executive Agencies.

Westar Energy, Inc. (Westar Energy) and Kansas Gas and Electric Company (KGE), (Kansas State Corporation Commission, Docket No. 17-WSEE-147-RTS). Technical analysis regarding rate base and cost of service on behalf of the Federal Executive Agencies.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3023618
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Lafayette K. Morgan Jr., hereby state that the facts above set forth in my Revised Direct Testimony, Revised OCA Statement 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).

DATED: May 7, 2021
*308296

Signature: Lafayette Morgan Jr.
Lafayette K. Morgan Jr.

Consultant Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044-3575

OCA STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2021-3023618
UGI Utilities, Inc. - Electric Division	:	

DIRECT TESTIMONY
OF
AARON L. ROTHSCHILD

COST OF CAPITAL

ON BEHALF OF
THE OFFICE OF CONSUMER ADVOCATE

May 3, 2021

Contents

I. STATEMENT OF QUALIFICATIONS

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

A. My name is Aaron L. Rothschild. My title is President, and my business address is 15 Lake Road, Ridgefield, CT.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am President of Rothschild Financial Consulting ("RFC").

Q. PLEASE STATE YOUR EDUCATIONAL ACHIEVEMENTS AND PROFESSIONAL DESIGNATIONS.

A. I have a B.A. degree in mathematics from Clark University (1994) and an M.B.A. from Vanderbilt University (1996).

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE.

A. I performed financial analysis in the telecom industry in the United States and Asia Pacific from 1996 to 2001, investment banking consulting in New York, complex systems science research regarding the power sector at an independent research institute, and I have prepared rate of return testimonies since 2002. My experience includes providing expert witness services to the California Public Advocates Office to evaluate the financial health, basic operation, wildfire cost recovery, and organizational culture/governance of gas and electric utilities,[1] as well as evaluating bankruptcy restructuring plans for Pacific Gas and Electric. On October 16, 2020, the California Public Utility Commission adopted my

[1] The California Public Utility Commission's PG&E Safety Culture Investigation 15-08-019.

recommendation for the creation of a financial team to ensure Southern California Edison's proposed issuance of securitized bonds reduce, to the maximum extent possible, the rates that consumers will pay on a present value basis compared to traditional utility financing mechanisms.[2] See Appendix A for my resume.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION, OR OTHER STATE COMMISSIONS? IF SO, WHICH COMMISSIONS?

A. Yes. My expert witness experience includes testifying in over 50 cost of capital proceedings before the following state commissions: California, Colorado, Connecticut, Delaware, Florida, New Jersey, Maryland, North Dakota, Pennsylvania, South Carolina, and Vermont. See Appendix B for the list of dockets for each of my testimonies.

Q. ON WHOSE BEHALF ARE YOU PROVIDING THIS TESTIMONY?

A. The Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide my recommendations to the Pennsylvania Public Utility Commission ("PA PUC" or "Commission") regarding the appropriate cost of equity, capital structure and overall cost of capital for UGI Utilities, Inc. - Electric Division ("UGI Electric" or "Company").

My testimony addresses the cost of capital portion of the revenue requirement for UGI Electric. The cost of capital determination consists of:

[2] Application 20-07-008.

1. **Cost of equity/appropriate authorized return on equity (ROE)**: As discussed in detail later in my testimony, I calculate UGI Electric's current market-based cost of equity.
2. **Capital Structure:** I recommend using the capital structure proposed by UGI Electric for its Fully Projected Future Test Year ("FPFTY") ended Sept. 30, 2022.
3. **Cost of Debt:** I evaluate the reasonableness of UGI Electric's embedded cost of debt calculations.

Q. HAVE YOU CONSIDERED THE ABILITY OF ELECTRIC UTILITY COMPANIES TO RAISE CAPITAL IN THE CURRENT FINANCIAL MARKETS?

A. Yes. It is in the best interest of Pennsylvania consumers for UGI Electric to have access to the capital needed to provide safe and reliable service in the short and long term.

II. INTRODUCTION AND SUMMARY OF CONCLUSIONS

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I provide a summary of my recommendations, an overview of cost of equity concepts, and how current capital markets relate to my cost of equity calculations. Second, I provide my capital structure and cost of debt recommendations. Third, I provide an overview of current capital markets. Fourth, I provide a detailed explanation of how I calculate my cost of equity recommendation.

Q. PLEASE PROVIDE A SUMMARY OF YOUR RECOMMENDATIONS.

A. My cost of capital recommendations for UGI Electric's electric distribution operations are summarized below and the midpoint of my recommendations are presented in Table 1 below.

I recommend[3] the following:

- an overall cost of capital/rate of return of between 5.97% and 6.68%, with a midpoint of 6.32%;
- a DCF market-based cost of equity range between 7.61% and 8.99%, with an average DCF result of 8.30%;
- a capital structure containing 51.20% common equity, 48.80% long-term debt and 0.00% preferred equity; and
- a debt cost rate of 4.25%.

TABLE 1: ALR RECOMMENDED RANGE MIDPOINT
Docket No. R-2021-3023618

	Capital Structure Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	48.80%	4.25%	2.07%
Short-Term Debt	0.00%	0.00%	0.00%
Preferred Equity	0.00%	0.00%	0.00%
Common Equity	51.20%	8.30%	4.25%
Rate of Return			6.32%

Exhibit ALR-1, page 1

[3] Exhibit ALR-1, page 1.

Q. PLEASE PROVIDE THE ANNUAL REVENUE IMPACT OF YOUR COST OF EQUITY RECOMMENDATIONS.

A. I calculated the annual revenue impact on UGI Electric by applying my cost of capital recommendations to the amount of rate base requested by the Company in this case and grossing up for state and federal income taxes.

Using my recommended capital structure (51.20% common equity ratio) and cost of debt (4.25%), application of my range of cost of equity recommendations to the Company's requested rate base of $131.8 million results in an annual revenue reduction of between about $1.7 million and $3.0 million.

TABLE 2: ANNUAL REVENUE IMPACT VS. REQUESTED
($ million)

Recommended Common Equity Ratio:	**51.20%**		
Recommended DCF ROE - Unadjusted:	7.91%	8.60%	9.29%
Recommended DCF ROE - Adjusted for Capital Structure:	7.61%	8.30%	8.99%
Cost of Debt			
4.25%	($3.0)	($2.4)	($1.7)

Inputs:

Requested Rate Base [1]	$	131.8
Federal income tax rate		21.00%
State income tax rate		9.99%
Uncollectable Expense		1.03%

[1] Witness Anzaldo's Direct Testimony, Schedule A-1

Q. PLEASE PROVIDE A SUMMARY OF HOW YOUR COST OF EQUITY RECOMMENDATION COMPARES TO RETURN EXPECTATIONS OF MAJOR FINANCIAL INSTITUTIONS.

A. My cost of equity recommendation of 8.30% (7.61% - 8.99% based on DCF results after adjusting for UGI Electric's requested capital structure) is on the upper half of the range of the expectations published by major banks and brokerage houses (5.5 to 8.5%) shown in Table 3 on page 6, which should give the Commission confidence that if my recommendation is used as the starting point to set rates, it will still enable UGI Electric to raise the capital needed to provide safe and reliable service.

TABLE 3: U.S. EQUITY RETURN EXPECTATIONS AMONG MAJOR FINANCIAL INSTITUTIONS	
Duff & Phelps (December 2020) [1]	**8.0%**
Horizon Actuarial Services, LLC Survey (July 2020) [2]	**5.5 - 8.5%**
50% Percentile: 7.2%	
J.P. Morgan Asset Management - Equity Long-Term Returns (March 2020) [3]	**7.2%**
Charles Schwab - Long-Term Market Returns (March 2020) [4]	**7.1%**

Dates above indicate latest market-data used in analysis.

Sources:

[1] Duff & Phelps Recommended U.S. Equity Risk Premium Decreased from 6.0% to 5.5%, Effective December 9, 2020

[2] Horizon Actuarial Services, LLC, Survey of Capital Market Assumptions Survey, July 2020. Participants Include: Bank of New York Mellon, BlackRock, Franklin Templeton, Goldman Sachs Asset Management J.P. Morgan Asset Management, Merrill Lynch Global Institutional Consulting, Morgan Stanley Wealth Management, Royal Bank of Canada, SunTrust, UBS, The Vanguard Group.

[3] J.P. Morgan Asset Management - LTCMA Market-to-Market: COVID-19 - New Cycle, New Starting Point, April 30, 2020.

[4] Charles Schwab - Why Market Returns May Be Lower and Global Diversification More Important in the Future, June 23, 2020.

I provide the data shown in Table 3 above to show that major financial institutions are telling their clients to expect lower returns on their investments than the cost of equity I am proposing. The return expectations published by all these financial institutions are based on their own financial models and are for the overall stock market. My cost of equity recommendation is for a regulated utility company. It is unlikely that investors would expect to earn a higher return on equity for a cost of service regulated utility company than for the overall stock market.

Q. PLEASE COMPARE YOUR COST OF CAPITAL RECOMMENDATIONS TO UGI ELECTRIC'S REQUESTED COST OF CAPITAL.

A. Mr. Moul and I recommend a different cost of equity for UGI Electric because we have fundamentally different analytical approaches. I focus on using market data (e.g., stock prices, bond yields, stock option prices) to measure investors' expectations as much as possible. On the other hand, Mr. Moul relies almost exclusively on non-market data, including economists' interest rate forecasts even when market data is available. He increases his DCF result from 9.40% to 10.84% by implementing his so-called leverage adjustment. As discussed below, this adjustment is inappropriate and should be rejected. In UGI's last rate case (Docket No. R-2017-2640058) the Commission found Mr. Moul's leverage adjustment to not be reasonable and it was denied.[4]

I do not agree with Mr. Moul on the appropriate cost of equity for UGI Electric for many reasons. The reasons I have come to different conclusions include: (1) Mr. Moul's use of non-market data such as interest rate forecasts; (2) the growth rates applied in the Constant Growth DCF model; (3) the implementation of the CAPM; (4) the inclusion of a non-market-based model, the Expected Earnings Analysis; (5) adding a leverage adjustment to his DCF and CAPM results; and (6) adding a size premium adjustment to his CAPM result.

As shown in Table 6 below, Mr. Moul and I recommend the same cost of debt (4.25%) and capital structure. Our cost of equity recommendations are different, however. My 8.30% cost of equity recommendation results in a 6.32% overall rate of return. Mr. Moul's 10.75% cost of equity recommendation results in an overall rate of return of 7.58%.

TABLE 6: RECOMMENDATION COMPARISON - ROTHSCHILD AND MOUL

	Cost of Equity	Cost of Debt	Common Equity %	Debt %	Rate of Return
Rothschild [1]	8.30%	4.25%	51.20%	48.80%	6.32%
Moul [2]	10.75%	4.25%	51.20%	48.80%	7.58%

[1] Exhibit ALR-1, page 1
[2] Mr. Moul's Direct Testimony, Schedule 1.

[4] Docket No. R-2017-2640058, Opinion and Order, Page 93

Q. YOU STATED THAT A MARKET-BASED COST OF EQUITY BETWEEN 7.61% AND 8.99% SHOULD SERVE AS A STARTING POINT FOR THE COMMISSION'S RATE OF RETURN ANALYSIS. PLEASE EXPLAIN.

A. My cost of equity determination is market-based. In other words, the cost of equity is the return investors expect to earn when they purchase the equity (or stock) of a company. This makes sense because investor-owned utility companies ("IOUs") raise money from investors. This, however, is one factor in the Commission's determination of a fair rate of return, which must account for and balance both investor expectations and consumer interests.[5] As recently stated by the PA PUC:

> Indeed, in our opinion, the applicable legal standards that require the Commission to balance between the interests of the utility's customers, investors, and the public interest, require the Commission, by necessary implication, to weigh evidence or unique considerations related to changes in service, market forces, and the economy. Thus, it is our responsibility under the applicable legal and constitutional standards to weigh evidence and unique considerations related to the COVID-19 pandemic in setting just and reasonable rates, and our continued use of traditional ratemaking methodologies permit our consideration of important ratemaking principles, like gradualism and rate affordability, in relation to this pandemic. Moreover, the traditional ratemaking methodologies permit consideration of evidence presented regarding the risks, uncertainties, and impact of the COVID-19 global pandemic in determining various components of a utility's cost of service, or revenue requirement. As explained further below, such components include, for example, a fair rate of return, projected expenses, and projected capital spending.[6]

Q. WHAT CONSUMER INTERESTS SHOULD BE CONSIDERED WHEN BALANCING INVESTOR EXPECTATIONS?

A. My testimony focuses on investor expectations when determining a market-based return on equity. While I do not focus specifically on consumer interests, however, a more-

[5] Federal Power Commission v. Hope Natural Gas Company 320 U.S. 591, 603 (1944).
[6] Docket No. R-2020-3018835, Opinion and Order, Page 48.

detailed analysis of consumer interests and concerns can be found in the testimonies of other OCA witnesses.

Q. DO SOME RATE OF RETURN WITNESSES USE A DIFFERENT DEFINITION FOR THE COST OF EQUITY?

A. All rate of return witnesses that I am aware of define the cost of equity as market-based somewhere in their testimony. However, many witnesses implicitly define the cost of equity, at least in part, as a hybrid of accounting returns (return on book equity) and return expectations of "expert forecasters" such as economists and equity analysts. Some even use their personal market speculations to calculate the cost of equity. This mischaracterization of the cost of equity is unfortunate because it makes it more challenging for a commission to make an informed decision.

Q. IS YOUR MARKET-BASED COST OF EQUITY RECOMMENDATION BASED ON YOUR OPINION OR YOUR OWN FORECASTS OF FUTURE STOCK PRICE RETURNS?

A. No. I do not pretend to have a capital market crystal ball. Capital markets are unpredictable and as explained above, it is investor expectations that matter since they are the ones providing the capital. Therefore, I provide an expert evaluation of investors' return expectations as indicated by the market prices of stocks, bonds, and stock options. This is an important topic that I will revisit throughout my testimony.

I do use Value Line and Zacks forecasts to estimate the market-based cost of equity in my DCF analyses. However, I do not use them mechanically and I go to great lengths to distill the sustainable growth component to ensure it is in line with investors' long-term expectations. My CAPM is based completely on investors' expectations as indicated by market prices.

Q. WHY DON'T YOU BASE YOUR COST OF EQUITY RECOMMENDATION ON YOUR PERSONAL STOCK MARKET FORECASTS?

A. I do not base my cost of equity recommendation for UGI Electric on my opinion of the future because I do not know what stock prices will be in the future. Capital markets are extremely difficult, if not impossible, to forecast because current stock and bond prices already reflect the forecasts of millions of investors who stand to make a lot of money if their forecasts are even slightly more accurate than the market consensus.

Q. PLEASE SUMMARIZE HOW YOU DETERMINED YOUR COST OF EQUITY RECOMMENDATIONS FOR UGI ELECTRIC'S ELECTRIC DISTRIBUTION OPERATIONS (7.61% - 8.99%).

A. To arrive at my recommendations, I applied the Discounted Cash Flow ("DCF") Model, including a Constant Growth and a Non-Constant Growth method to a proxy group of 22 publicly traded electric utility companies ("RFC Electric Proxy Group") using data available through March 31, 2021. As a check on the reasonableness of the DCF indicated results, I also used a Capital Asset Pricing Model ("CAPM") analysis. As discussed below, I review capital market data in general and the model results of leading financial institutions as an additional check on the reasonableness of my model results.

Q. ARE YOUR COST OF EQUITY MODELS BASED ON ESTABLISHED METHODOLOGIES?

A. The purpose of my testimony is to provide the Commission with an independent analysis. However, I do not reinvent the wheel. It is mostly a question of which established methodologies and theories to use. There are countless established methodologies and theories used by investors, scholars, and rate of return witnesses. Further, finance does not stand still. For example, Wall Street traders have been increasingly using machine learning to make investment decisions and the use of quantum computing is likely the next new tool.

The Constant Growth DCF model I chose to use is the same one chosen by major financial institutions. J.P. Morgan Chase uses the sustainable growth form of the DCF method, as I do, in its 2019 Long-Term Capital Market Assumptions publication.[7] *Principles of Corporate Finance*, a leading financial textbook used in business schools and investment banks around the world, recommends using the very same method I use to calculate the cost of equity for regulated energy utility companies.[8] As discussed in Section V. Capital Asset Pricing Model on page 52, my CAPM is based on methodologies used by Value Line, the Chicago Board of Options Exchange (CBOE), and published in peer-reviewed academic journals (e.g., The Review of Financial Studies). My CAPM method has also been recognized by other commissions. On April 9, 2020, the Public Service Commission of South Carolina stated the following:

> Amongst the three witnesses, Consumer Affairs Rothschild's approach was unique in that he included the use of both historical and forward-looking,

[7] 23rd Annual Edition, Long-Term Capital Market Assumptions - Time-tested projections to build stronger portfolios, pp. 62-63.
[8] Brealey, Myers, and Allen (2017), Principles of Corporate Finance, 12th Edition, McGraw-Hill Irwin, New York, page 86-87.

market-based data in his analysis. Based on the testimony and facts presented, the Commission therefore adopts the recommended ROE of 7.46% proposed by witness Rothschild.[9]

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR COST OF EQUITY MODELS.

A. I have determined the cost of equity for the average company in my RFC Electric Proxy Group to be between 5.98% and 8.29%.[10] As shown in Table 4 below, the high-end results of my cost of equity models, including eight variations of the CAPM, range between 6.10% and 9.29%, with an upper quartile at 8.29%. The low-end results of my cost of equity models range between 5.97% and 9.08%, with a lower quartile at 5.98%.

TABLE 4: COST OF EQUITY MODEL RESULTS		
DCF	**Low**	**High**
Constant Growth	7.91%	7.96%
Non-Constant Growth	9.08%	9.29%
CAPM		
Spot (Mar. 31, 2021)		
Risk Free Rate - 3-Month T Bill	5.98%	6.10%
Risk Free Rate - 30-Yr T Bond	6.89%	6.98%
3-Mo. Weighted Average (Jan. to Mar. 2021)		
Risk Free Rate - 3-Month T Bill	5.97%	6.15%
Risk Free Rate - 30-Yr T Bond	6.88%	7.02%
Outer Quartile Range	**5.98%**	**8.29%**
Midpoint of Range	**7.13%**	

Exhibit ALR-2

My recommended cost of equity of 8.30%[11] for UGI Electric is in line with the Commission's stated preference for the DCF model. As shown in Table 4 above, the results of my constant growth DCF model range between 7.91% and 7.96%, just under 8.00%. The results of my non-constant growth DCF model range between 9.08% and 9.29%. The

[9] Order Ruling on Application for Adjustment in Rates, Docket No. 2019-290-WS, Order No. 2020-306, April 9, 2020, page 43.
[10] Exhibit ALR-2.
[11] Exhibit ALR-1, page 1

average of my four DCF results is 8.60%, which after adjusting for UGI Electric's requested capital structure results in my 8.30% recommendation.

Q. WHY ARE YOU RECOMMENDING A COST OF EQUITY OF 8.30% FOR UGI ELECTRIC WHEN THE AVERAGE OF YOUR FOUR DCF RESULTS IS 8.60%?

A. As discussed below, UGI Electric is requesting a capital structure with a common equity ratio (51.20%) that is significantly higher than the average common equity ratio (43.6%) of the electric utility companies in my proxy group. Therefore, the cost of equity model results based on the companies in my proxy group must be adjusted to reflect UGI Electric's requested capital structure. A higher common equity ratio means less debt, a lower chance of financial stress (financial risk), and therefore a lower cost of equity.[12] On the other hand, a lower common equity ratio means more debt, a higher chance of financial stress (financial risk), and therefore a higher cost of equity. Based on a regression analysis of dozens of utility companies, I found a 0.04% reduction in the DCF cost of equity results for every 1% increase in the common equity ratio.

Q. WHAT DOES CAPITAL MARKET DATA INDICATE REGARDING HOW THE COVID PANDEMIC HAS AND IS INFLUENCING THE COST OF EQUITY?

A. Market data shows that in the early stages of the COVID pandemic, capital market risks increased but have since declined to approximately pre-pandemic levels, as elaborated upon below.

[12] I found a 0.04% reduction in the DCF cost of equity results for every 1% increase in the common equity ratio.

Q. PLEASE EXPLAIN WHAT MARKET DATA SHOWS REGARDING HOW INVESTORS PERCEPTION OF ELECTRIC UTILITY EQUITY RISK WAS IMPACTED BY THE COVID PANDEMIC.

A. As shown in Chart 1 below, investors' forward beta expectations of electric utility companies[13] were about 0.8 in pre-pandemic market conditions in the winter of 2019-2020, spiked to over 1.0 during the spring 2020 initial phase of the pandemic, and since early February 2021 have ranged between 0.53 and 0.62. These lower electric utility betas indicate that the cost of equity for electric utility stocks has decreased since the initial outbreak of the pandemic and points to a lower cost of equity than before the pandemic.

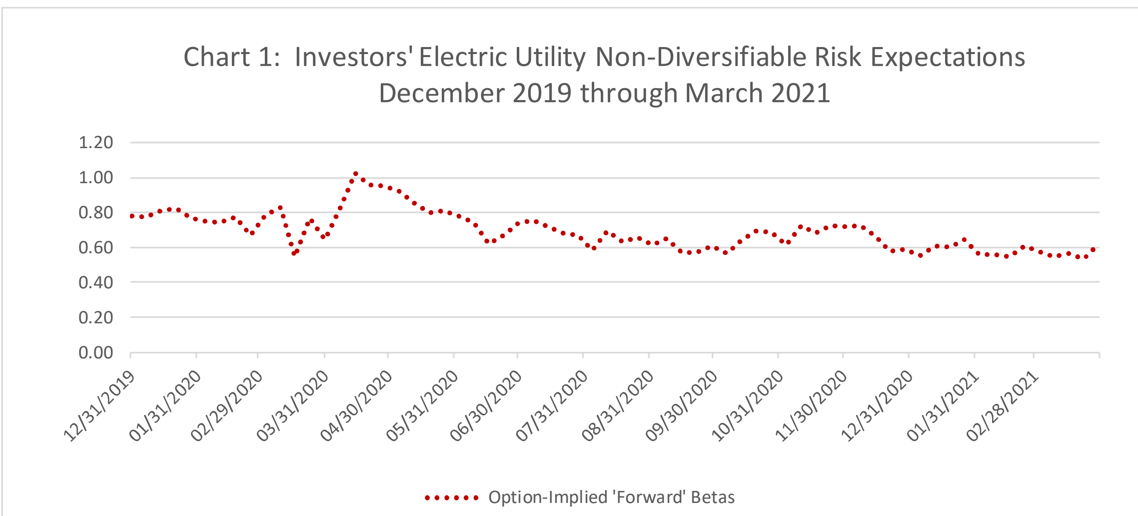


Table 5 on page 15 shows a summary of how COVID-19 has impacted financial markets between December 31, 2019 and March 31, 2021. Line 1 of Table 5 shows how the overall stock market (S&P 500) sharply declined during the initial spread of COVID-19, but has fully recovered and is regularly reaching new highs. Line 2 shows that interest rates initially declined (30-year U.S. Treasury yields fell from 2.39% to 1.28%) but have

[13] 22 electric utility companies in RFC Electric Proxy Group. See Section V.B. of this testimony for a list of companies in the proxy group and how I chose these companies.

come back to slightly above (2.41%) pre-pandemic levels. As shown on line 3, in March through September 2020, investors were demanding an increased credit spread to invest in riskier corporate bonds (125 basis point increase from December 2019 and April 2020), but have since come down to pre-pandemic levels. Line 4 shows that investors' volatility expectations as measured by the VIX Index increased significantly from 13.78 in December 2019 to 75.91 in March 2020 but have since come back down considerably to 19.4 in March 2021. Line 5 shows that stock option prices indicate that the equity risk premium, which also peaked in March and April 2020, have since come down but remain somewhat elevated when compared to pre-pandemic levels. Lastly, as shown on line 6 of Table 5 and Chart 1 on page 14, option-implied betas, which also peaked in March and April 2020, have since decreased to levels below those before the pandemic (0.62 in March 2021 vs. 0.78 in December 2019), indicating that investors expect electric utility stock price movements to be less correlated with the overall market than before the pandemic and therefore to be less risky relative to the market.

TABLE 5: COST OF EQUITY IN TODAY'S FINANCIAL MARKET - SUMMARY
MEASURING COVID-19'S IMPACT ON THE COST OF EQUITY

	31-Dec-19	19-Feb-20	17-Mar-20	30-Apr-20	30-Jun-20	30-Sep-20	31-Dec-20	31-Mar-21	
	Pre-Crisis	COVID-19 Crisis							Dec '19 - Mar '21 Delta
		Mkt Peak	Trough	"Recovery"					
1. Stock Prices (S&P 500)	$3,230.78	$3,386.15	$2,529.19	$2,912.43	$3,100.29	$3,363.00	$3,756.07	$3,972.89	$742.11
Growth Since 12/31/19		*4.8%*	*-21.7%*	*-9.9%*	*-4.0%*	*4.1%*	*16.3%*	*23.0%*	
2. Interest Rates (30-Yr) [1]	2.39%	2.01%	1.63%	1.28%	1.41%	1.46%	1.65%	2.41%	0.02%
3. Credit Spreads (Baa vs. 10-Yr) [2]	1.98%	2.05%	3.49%	3.23%	2.93%	2.75%	2.18%	2.03%	0.05%
4. Volatility Expectations (30-Day) [3]	13.78	14.38	75.91	34.15	30.43	26.37	22.75	19.40	5.62
5. Market Risk Premium [4]	4.56%	4.99%	10.71%	10.01%	9.14%	10.21%	8.42%	7.27%	2.71%
6. RFC Electric Proxy Group - Fwd. Beta (6-Mo.) [5]	0.78	0.77	0.54	0.95	0.74	0.61	0.59	0.62	-0.16

[1] 30-year U.S. Treasury Yield
www.treasury.gov
[2] Baa rated corporate bond yield - 10-year U.S. Treasury Yield
https://fred.stlouisfed.org/series/BAA
https://fred.stlouisfed.org/series/GS10
[3] VIX Index - 30 days
[4] Annualized option-implied market risk premium vs. 30-year Treasury RFR - weighted across all traded expirations as of last Tuesday before date, assuming 50.0% cumulative probability (median)
[5] Option-implied beta - 6-month, as of last Tuesday before date
Exhibit ALR-4

Q. PLEASE DEFINE YOUR ANALYTICAL APPROACH?

A. My cost of equity ("COE") recommendation is my opinion of the return investors require to provide equity capital to UGI Electric based on current capital markets. My recommendation is consistent with the following legal standards set by the United States Supreme Court for a fair rate of return:

> The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[14]

And

> …sufficient to…support its credit and…raise the money necessary for the proper discharge of its public duties.[15]

Because the cost of equity is not a published figure like a bond yield, some interpretation is required to determine the appropriate market price. My cost of equity recommendation is based on my computation of what the market indicates investors require (return on investment) to provide capital to companies with comparable risk to UGI Electric.

As explained below, I use current market prices (e.g., stocks, bonds, options), which measures investors' expectations directly, instead of relying solely on historical data and analyst forecasts.

[14] Federal Power Commission v. Hope Natural Gas Company 320 U.S. 591, 603 (1944).
[15] Bluefield Water Works & Improvement Company v. Public Service Commission of the State of West Virginia 262 U.S. 679, 692-693 (1923).

III. CAPITAL STRUCTURE AND COST OF DEBT

Q. WHAT IS UGI ELECTRIC'S REQUESTED CAPITAL STRUCTURE RATIO?

A. UGI Electric has requested a capital structure consisting of 48.80% long-term debt, 0.00% preferred stock, and 51.20% common equity.[16]

Q. IS UGI ELECTRIC'S REQUESTED CAPITAL STRUCTURE CONSISTENT WITH THE CAPITAL STRUCTURE RATIOS USED BY OTHER ELECTRIC UTILITY COMPANIES?

A. No. UGI Electric's requested capital structure contains a significantly higher equity ratio than the average common equity ratio used by other electric utility companies in the country; the average common equity ratio the 22 companies in the RFC Electric Proxy Group is 43.6%.[17]

Q. IS UGI ELECTRIC'S REQUESTED CAPITAL STRUCTURE CONSISTENT WITH THE CAPITAL STRUCTURE RATIOS USED BY ITS PARENT UGI CORP?

A. No. UGI Electric's requested capital structure contains significantly higher common equity ratio (51.20%) than the current common equity ratio of its parent UGI Corp. (43.0%).[18]

[16] Mr. Moul's Direct Testimony, Schedule 1.
[17] Exhibit ALR-5, page 5.
[18] UGI Corp.'s Value Line company report, February 26, 2021.

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND BE USED FOR UGI ELECTRIC'S OVERALL COST OF CAPITAL?

A. I recommend using UGI Electric's requested capital structure that comprises 51.20% common equity, 48.80% long-term debt, and 0.00% preferred equity because it is my understanding that the Commission has a preference for using the actual capital structure used by the utility.

IV. COST OF EQUITY IN TODAY'S FINANCIAL MARKETS

Q. HOW DOES YOUR COST OF EQUITY RECOMMENDATION RELATE TO THE CURRENT FINANCIAL MARKET?

A. Capital market uncertainty due to the COVID-19 pandemic has fundamentally changed capital markets. It has increased uncertainty and as a result stock prices have been volatile. In the first half of March 2020, stock prices crashed, but by mid-August, the S&P 500 had already fully recovered, reaching a new high on January 8, 2021. The unemployment rate increased to nearly 15% in April 2020 but has fallen to under 7%[19] as of December 2020. In the first and second quarters of 2020 real gross domestic product fell sharply. In response, the Federal Reserve has cut short-term Treasury yields to 0% and Congress has passed multiple stimulus packages worth trillions of dollars.

During a financial crisis, many investors panic and sell shares in companies without regard for their economics. Others are forced to sell because of margin calls. Many unnerved investors purchase the safest (least risky) securities they can find, including

[19] Federal Reserve estimates that unemployment rate for lowest paid workers is likely above 20%.

treasury bonds and utility stocks, in a "flight-to-safety" response. All these developments can impact the cost of equity.

Q. HOW HAS THE RECENT FINANCIAL CRISIS IMPACTED THE COST OF EQUITY FOR ELECTRIC UTILITY COMPANIES?

A. Electric utility stocks have been impacted along with the overall market. As shown in Chart 2 on page 22, the stocks in my RFC Electric Proxy Group have underperformed the overall market since the pre-pandemic S&P-500 peak reached on February 19, 2020. The RFC Electric Proxy Group is down -3.66% between December 31, 2019 and March 31, 2021 while the S&P 500 is up 22.97% over the same time period.

Q. PLEASE DISCUSS SOME CURRENT MARKET DEVELOPMENTS THAT IMPACT THE COST OF EQUITY.

A. Below I will discuss in more depth the data presented in Table 5 on page 15. It is important to consider the results of my cost of equity models (DCF and CAPM) in the context of current financial market conditions as follows:

1. **Stock prices crashed and fully recovered.** The S&P 500, Dow Jones Industrial Average, and other stock indices fell faster in the second half of March 2020 than during the 2007-2008 financial crisis, the crash of 1987, or the Great Depression. As of March 23, 2020, the S&P 500 had fallen approximately 34% from its all-time high reached on February 19, 2020. On August 8, 2020, the S&P 500 set a new high which represents the fastest recovery (126 trading days) from a bear market. Electric utility stocks initially fell slightly less than the overall market (about 33% off their peak versus 34% for the overall market). As of the end of March 31, 2021, electric utility stock prices have significantly lagged the overall market.

2. **Low interest rates and a steep yield curve.** As short-term Treasury yields reach 0%, long-term rates have dropped sharply as well. The difference between long-term and short-term yields, referred to as the yield curve, has increased. A steep yield curve (where long-term yields are significantly higher than short-term yields) indicates investors expect the economy to improve.

3. **Credit spreads increased sharply, declined, and remain elevated.** The spread between the yield investors demand to purchase U.S. Corporate bonds and U.S. Treasury bonds (see Chart 6 on page 25) increased significantly in the initial phases of the COVID-19 pandemic, but never got as high as it did during the financial crisis of 2007-2008. As of the end of March 31, 2021, the yield spread between Baa credit-rated corporate bonds is about 2.75%. It reached a high of over 4.0% in March 2020.

4. Investors' stock price volatility expectations have fallen from highs reached during initial phases of the pandemic. In March 2020, the Market Volatility Index ("VIX") reached levels not seen since the financial crisis of 2007-2008, and even set all-time records. Volatility expectations remain higher than before COVID-19 but have declined significantly since peaks reached in March 2020.

5. Market Risk Premiums. As discussed in the CAPM section below, stock option data indicates that the premium investors require to invest in stock has likely increased because volatility expectations have increased since the spread of the coronavirus.

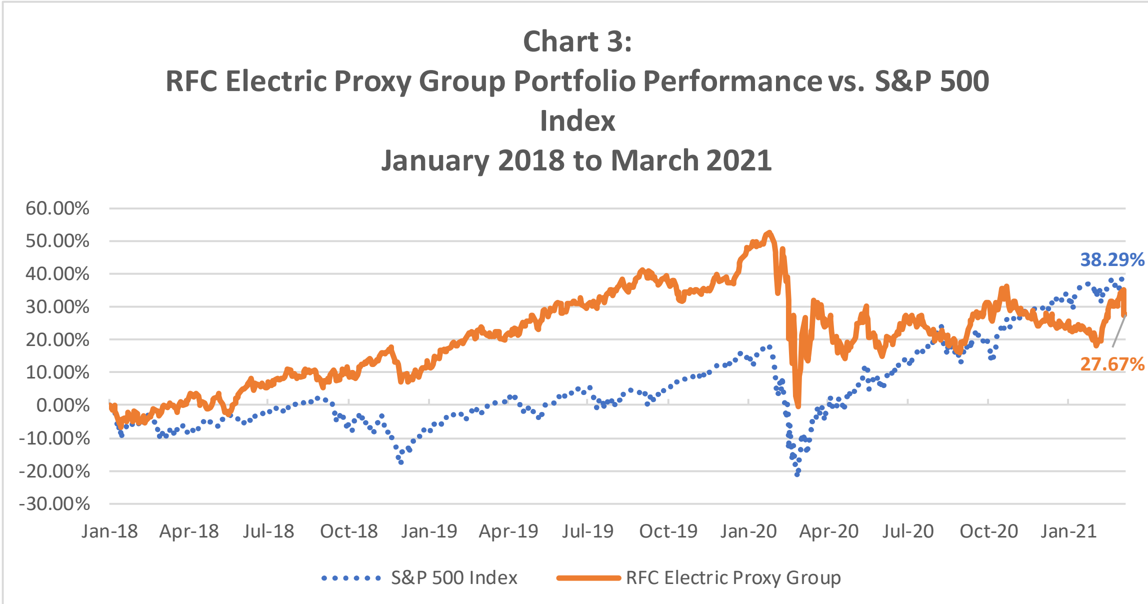
6. RFC Electric Proxy Group Forward 6-month Betas have decreased. As discussed in depth in the CAPM section below, stock option data indicates that investors expect electric utility stock price movements to be less correlated to the overall market. This development indicates that the cost of equity for electric utility companies has been impacted less than the overall market.

A. Stock Price Trends

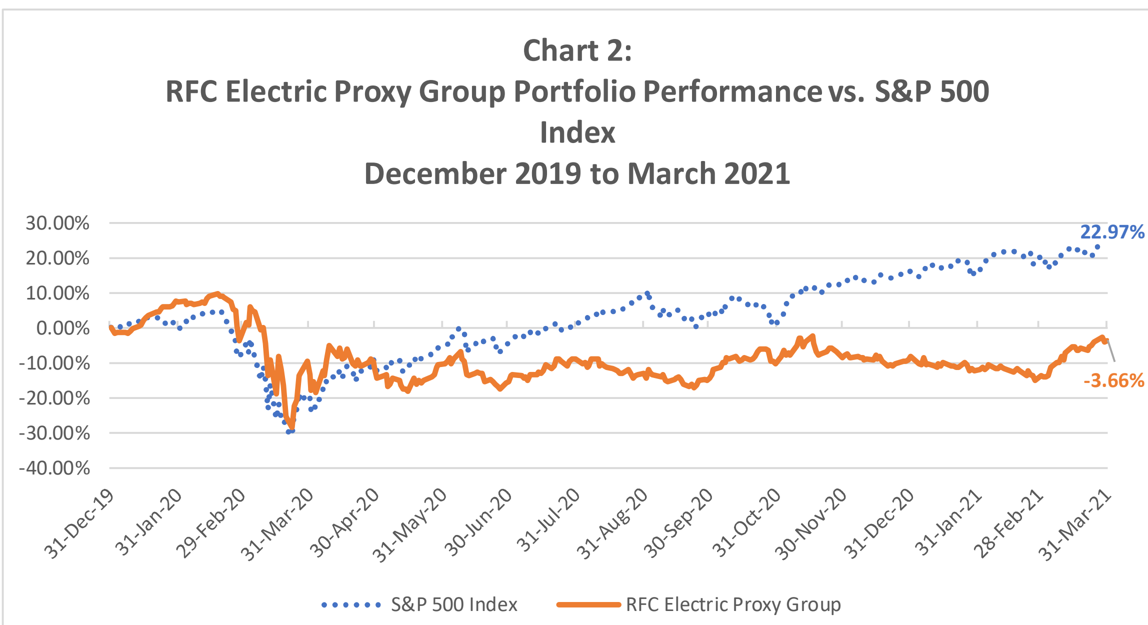
Q. WHAT, IF ANYTHING, DOES STOCK MARKET DATA INDICATE WITH REGARD TO THE COST OF EQUITY?

A. As stock prices have increased significantly in recent years, the price-to-earnings (P/E) ratios have increased as well. This indicates that the cost of equity may be decreasing along with the higher stock prices because investors are paying a higher price for the same earnings. For example, an investor paying $100 for a share of a stock with $10 per year of earnings will earn a 10% annual return, assuming no growth. If this stock goes up to $200 per share the annual earnings decrease to 5%. As shown in Chart 3 on page 22, until the recent COVID-19-related crash, stock prices for the S&P 500 and the RFC Electric Proxy Group increased significantly in the more than three years since UGI Electric filed its last rate case on January 26, 2018.[20] At their peaks, the RFC Electric Proxy Group had increased about 22% while the S&P 500 had increased about 35%. After the significant losses due to COVID-19, the RFC Electric Proxy Group is down about 1% as of March 31, 2021. In comparison, the S&P 500 is nearly 52% higher than it was as of January 26, 2018.

[20] Docket No. R-2017-2640058.



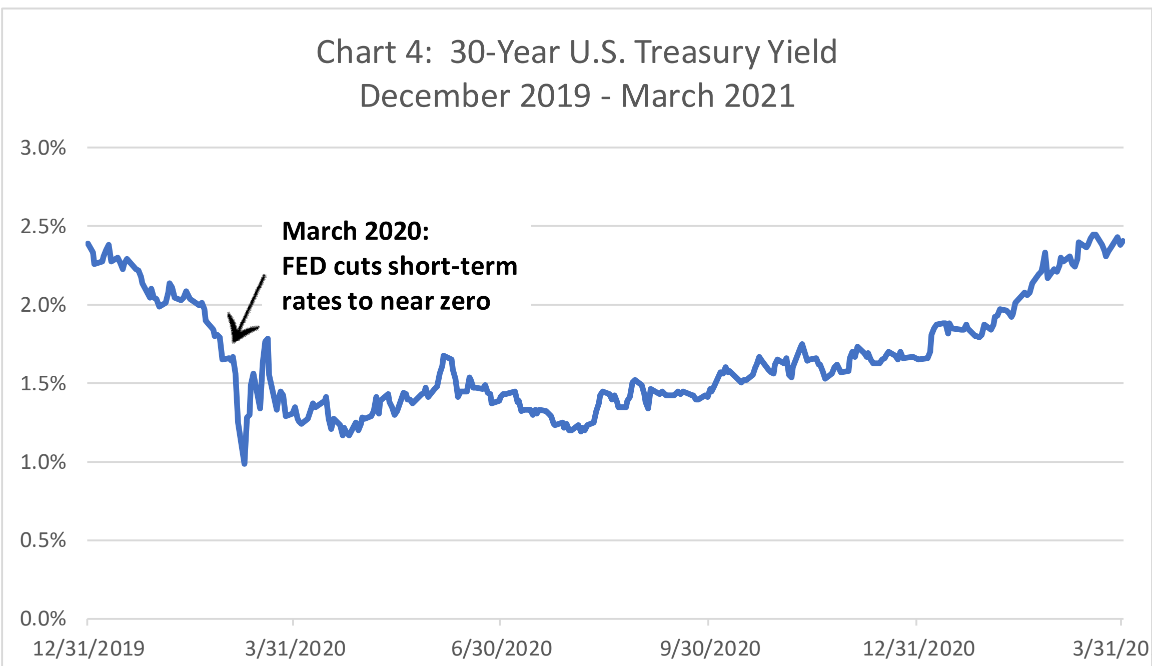
Focusing on the drop in stock prices since the market's peak on February 19, 2020 as of March 31, 2021, the RFC Electric Proxy Group was down over -3.66% compared to a gain of 22.97% for the overall market, as shown in Chart 2 below.



B. Interest Rates

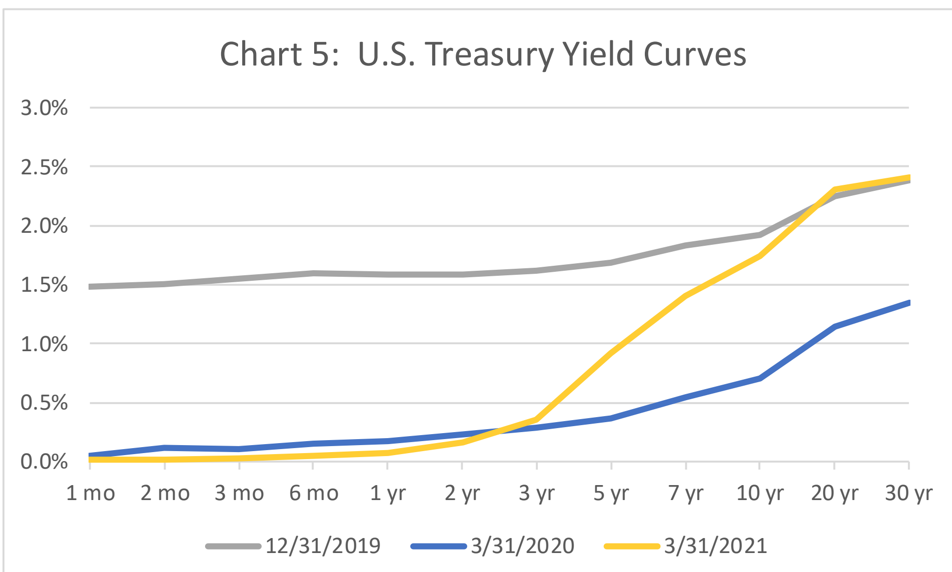
Q. PLEASE DISCUSS THE CURRENT INTEREST RATE ENVIRONMENT AND WHAT IT INDICATES REGARDING THE COST OF EQUITY.

A. There are two significant interest rate developments occurring in response to COVID-19. First, interest rates have fallen significantly. Short-term interest rates are near 0%. Starting in early March 2020, as shown on Chart 4 below, yields on 30-year U.S. Treasuries have fallen from about 2.30% at the beginning of 2020 to about 1.70% in December 2020. Federal Reserve officials pledged to support economic recovery by holding rates near zero for at least three years.[21] Lower interest rates indicate a lower cost of equity for electric utility companies because many bond investors sell bonds and purchase utility stocks as interest rates decline.



[21] Fed Says Virus Poses Considerable Risks, Maintains Low-Rates Pledges, WSJ, November 5, 2020.

The second development, as shown in Chart 5 below, is that the yield curve[22] has steepened significantly as a result of the Coronavirus-induced financial crisis.[23] Before the crisis, the yield on the 1-month Treasury bill was about 1.5%, increasing to less than 2.5% for the 30-year Treasury bond, which is less than a double. On the other hand, as of April 30, 2020, the yield curve increased from nearly 0% for the 1-month Treasury bill to 1.28% for the 30-year U.S Treasury bond. A steep yield curve indicates investors expect economic conditions to improve because, with expected profitable investment opportunities, they require a significant premium in order to commit their money for long periods of time. On the other hand, when the yield curve is "flat" they do not require a premium to commit their money for long periods of time because they do not expect as many opportunities.



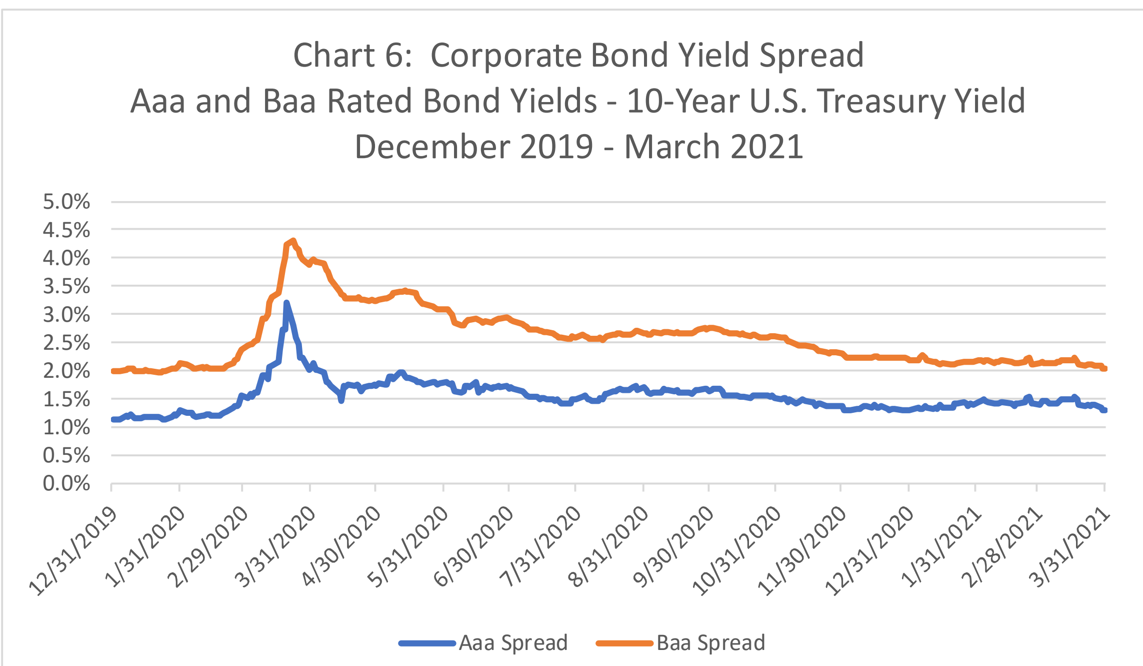
[22] The difference between short-and long-term interest rates is the slope of the yield curve. As this difference increases, the yield curve becomes steeper.

[23] The yield curve was even steeper for years (2009-2017) after the financial crisis of 2007-2008. It was relatively flat (short-term rates were about the same as long-term rates) for most of 2019 and early 2020 before the COVID-19 pandemic.

C. Increasing Credit Spreads

Q. WHAT DOES AN INCREASING CREDIT SPREAD MEAN FOR THE COST OF EQUITY?

A. As shown in Chart 6 below, the yield spread between Corporate bonds and Treasury bonds increased significantly as the Coronavirus has spread throughout the world. The interest rate spread between Baa Corp bonds and 10-year U.S. Treasuries peaked at over 4% mid-March. This chart clearly shows that yield spreads have declined since their peak. As of March 31, 2021, the yield spread between Baa Corp bonds and 10-year U.S. Treasuries is 2.75%, nearly 200 basis points lower than the peak reached in March 2020 and about 77 basis points higher than before the pandemic. A declining yield spread indicates that investors' appetite for risk has increased since mid-March 2020. As investors' appetite for risk increases, the cost of equity tends to decline.



D. Volatility Expectations

Q. PLEASE DISCUSS CURRENT STOCK PRICE VOLATILITY EXPECTATIONS AND WHAT THEY INDICATE REGARDING THE COST OF EQUITY.

A. Volatility, uncertainty, and risk are synonymous. There are two primary types of volatility: "realized volatility" and "implied volatility." The former is based on historical returns which may or may not represent future volatility. For example, the current high volatility in the markets will most likely decrease after the spread of the Coronavirus is contained and people return to work. On the other hand, implied volatility is calculated from options data, which indicates investors' future expectations for volatility. As discussed below, the "term structure" of volatility indicates investors' volatility expectations over different forward-looking time periods (e.g., 1-month, 1-year).

Q. PLEASE EXPLAIN THE TERM STRUCTURE OF VOLATILITY.

A. Investors can expect volatility to increase or decrease in the future. During a crisis, investors often expect volatility to decrease in coming months or years. In other words, investors expect the current capital market hurricane to pass and the winds to die down. In general (i.e., in "normal" financial markets), investors expect higher volatility for longer time horizons. For example, investors generally expect the chance stock prices will increase or decrease by 10% in 1 year (on an annual basis) to be greater than the chance of a 10% move over the next 30 days (on an annual basis). This makes sense because there is more uncertainty regarding economic and stock market changes the further in the future you look out.

However, during the peak of implied volatility (to date) in mid-March 2020, shortly after the World Health Organization declared COVID-19 a pandemic, the data indicated that investors expected stock price volatility to decrease over time (see Chart 9 on page 29). This implies that investors expected the riskiness of equity investments to decrease over time. As shown in Chart 7 below, before the COVID-19 outbreak, investors expected volatility to increase from less than 15% annually at the 1-month time frame to about 20% annually at the 24-month time frame. Post COVID-19 outbreak, investors expected volatility to decrease from over 70% at the 1-month time frame to about 38% at the 24-month time frame.

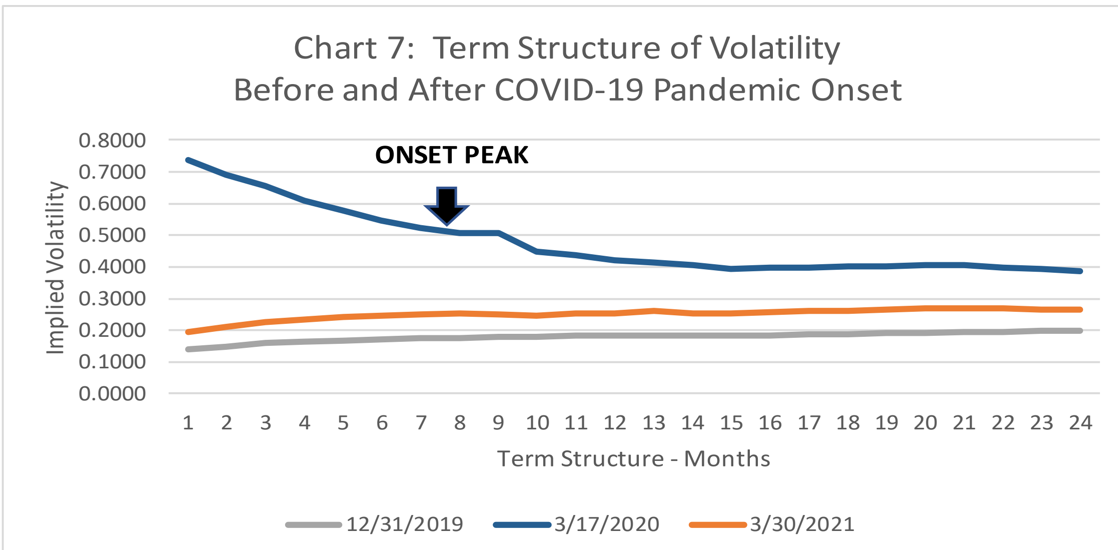


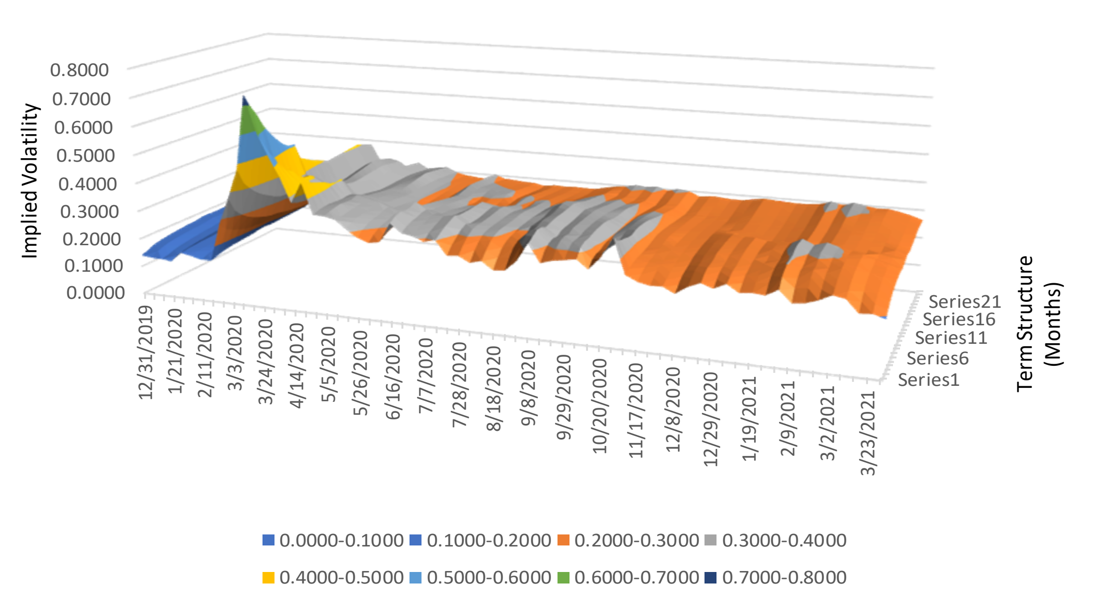
Chart 7: Term Structure of Volatility
Before and After COVID-19 Pandemic Onset

Chart 8[24] on page 28 provides a 3-dimensional surface to show how the term-structure of volatility has evolved since before the COVID-19 outbreak and how it has changed during the outbreak. One can see that on January 7th, the term structure of volatility is almost flat, increasing slightly from 1-month to the 24-month time frame. In mid-March 2020, the implied volatility increased over every time period in comparison to January 7th, but one can see that investors expected a declining term structure of volatility. By the end of July 2020, the implied volatility for all time periods had decreased, and the

[24] The X axis shows the implied volatility. The Y axis shows the data. The Z axis shows market expectation of future implied volatility of different time frames. Series1 = 1 month and Series31 = 31 months.

declining term structure moved to a more typical structure in which investors expected higher volatility over longer time periods.

Chart 8: VIX Volatility Term Structure Surface

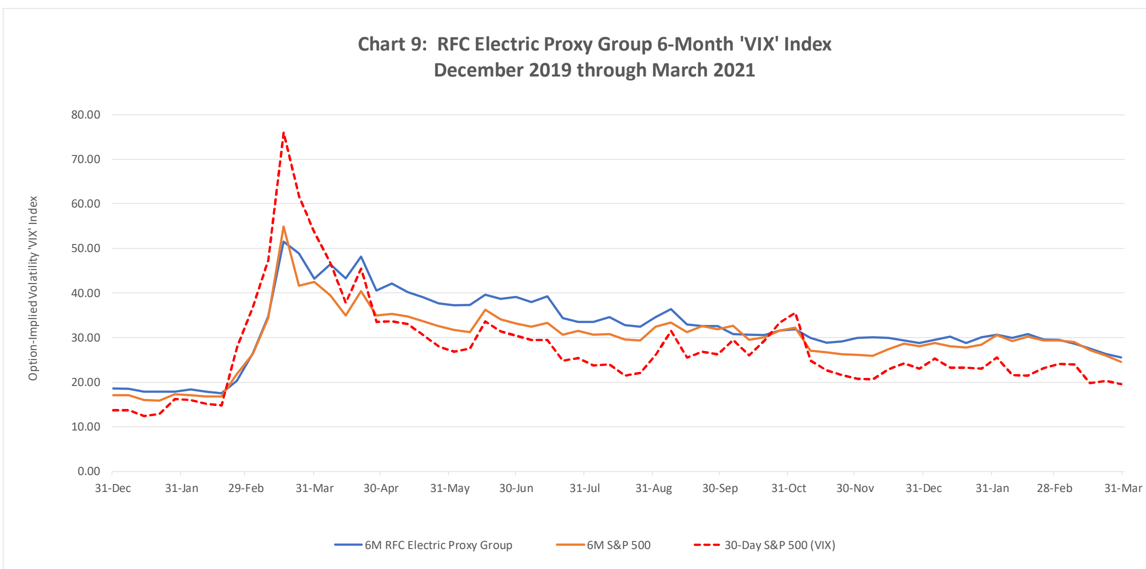


A declining term structure of volatility is important data to consider in determining the appropriate cost of equity for UGI Electric because it shows that investors expected risk to decline during the peak (so far) of the pandemic's impact on financial markets. Lower risk means a lower cost of equity. Investors market volatility expectations turned out to be correct. Investors expected implied volatility to decline, and it did.

Q. HOW HAVE VOLATILITY EXPECTATIONS FOR ELECTRIC UTILITY COMPANIES COMPARED TO VOLATILITY EXPECTATIONS FOR THE S&P 500?

A. The dashed red line and the solid orange line in Chart 9 on page 29 show investors' stock price volatility expectations for the overall market (S&P 500) increased significantly as COVID-19 infections spread to the U.S. and continued to grow exponentially around the world. The dashed red line and solid orange line show volatility expectations over the next 30 days and 6 months, respectively. In the middle of February 2020, investors expected an annualized change of about 13.00% over the next 30 days. In mid-March 2020, investors' volatility expectations peaked at over 80.00%. As of March 31, 2021, investors expected an annualized change of about 25.00%. The blue line in Chart 9 shows that investors' volatility expectations for my RFC Electric Proxy Group, as indicated by their stock option prices, increased along with the market, but to a significantly lesser degree in mid-March 2020.

Investors' volatility expectations for electric utility companies were higher than the overall market for the most part from April to December 2020.



But note that the implied volatility of electric utility companies is higher than the S&P 500 even before the COVID-19 outbreak. The implied volatility for individual stocks and small groups of stocks is almost always higher than the overall market because of the effects of diversification. Therefore, the relative volatilities do not indicate that electric utility companies were or are riskier than the S&P 500 before or after the breakout of COVID-19 and in fact further accentuate the difference between the expected volatilities at the peak of the COVID-19 outbreak. As discussed below, changes in implied volatility do not paint the full cost of equity picture. We must consider implied covariance, or how correlated investors expect the volatility of returns for electric utility companies and the overall market (e.g., S&P 500) to be.

Q. HOW IS COVID-19 IMPACTING FINANCIAL MARKETS AND THE COST OF EQUITY FOR ELECTRIC UTILITY COMPANIES?

A. The spread of COVID-19 caused a financial crisis. However, financial data indicates that the current capital market upheaval has not significantly impacted the cost of equity for electric utility companies. Investors know that electric utility companies provide an essential service that will be used and paid for even during a financial crisis.

Although stock and bond prices remain more volatile than before COVID-19, market data shows that investors' volatility expectations have declined for both the overall market and electric utility companies since mid-March 2020. Investors' volatility expectations are important, but as explained in my CAPM section on page 52, investors' expectations regarding the co-variance between electric utility stocks and the overall market are more relevant to cost of equity than volatility expectations alone. Option-implied betas indicate that investors expect electric utility stock price movements to be less correlated with the overall market than before the pandemic. As explained below, I use stock option data to calculate an "option-implied beta" which is a measurement to determine what investors' expectations are regarding the covariance between the expected returns for the RFC Electric Proxy Group and for the S&P 500. In December 2019, the average option-implied beta for my RFC Electric Proxy Group was approximately 0.77.

As of September 30, 2020, the average option-implied beta of these 22 companies was 0.62. In other words, investors expect electric utility stocks to move only a little more than a half a percent for every percent the market moves. Before the pandemic, investors expected that electric utility stocks would move about 0.77% for every 1.0% move. Declining electric utility option-implied betas indicates that investors understand that electric utility companies provide an essential service that will be relatively unimpacted by the overall economy. This also indicates that the cost of equity for electric utility companies has not increased and possibly even declined since before the pandemic.

Every financial crisis is unique, and this one is no exception. But it seems that, as has been the case during financial crises in the past, investors do not require a higher cost of equity for electric utility companies despite the current market turbulence.

V. COST OF EQUITY CALCULATION

A. <u>Overview</u>

Q. PLEASE PROVIDE YOUR DEFINITION OF THE COST OF CAPITAL.

A. The cost of capital is the return investors require to provide capital to UGI Electric based on current capital markets. The spread of COVID-19 has made it more challenging to determine the current cost of capital because it has drastically increased the speed and intensity of capital market change. In order to measure the cost of equity accurately during rapid change, it is critical to use current market data. Because of the current financial crisis, it is particularly important to consider model results in the context of extreme financial turbulence. In order to do this, it is critical to consider how model results change over time throughout this crisis.

As discussed above, my cost of equity ("COE") recommendation is my opinion of the return investors require to provide equity capital to UGI Electric based on current capital markets. My recommendation is consistent with the following legal standards set by the United States Supreme Court for a fair rate of return: "[t]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks"[25] and "sufficient to… support its credit and… raise the money necessary for the proper discharge of its public duties."[26]

Because the cost of equity is not a published figure like a bond yield, some interpretation is required to determine the appropriate market price. My cost of equity recommendation is based on my computation of what the market indicates investors require (return on investment) to provide capital to companies with comparable risk to UGI Electric.

As explained below, I use current market prices (e.g., stocks, bonds, options), which measures investors' expectations directly, instead of relying solely on historical data and analyst forecasts.

A cost of equity based on market prices (market-based) is superior to a cost of equity based on historical data (non-market-based) for two reasons:

1. The cost of equity that UGI Electric has to pay investors is based on capital markets. Interest rates remain at historical low levels after a persistent

[25] Federal Power Commission v. Hope Natural Gas Company 320 U.S. 591, 603 (1944).
[26] Bluefield Water Works & Improvement Company v. Public Service Commission of the State of West Virginia 262 U.S. 679, 692-693 (1923).

downtrend since the early 1980s. It is possible interest rates will increase, but if the marketplace expected interest rates to change, then that would already be part of current prices.

2. Capital markets are unpredictable. Regarding capital markets' unpredictability, investment guru Warren Buffet recently gave the following advice to investors: "[t]hey should not listen to a lot of the jabbering about what the market is going to do tomorrow, or next week or next month because nobody knows."[27]

Current capital markets are our best source of investors' expectations regarding future capital markets. Current market prices of stocks and bonds reflect investors' forecasts for long-term interest rates and capital markets in general. If, indeed, investors in the aggregate should be expecting an increase in interest rates, adding a separate factor for this on top of what is already indicated in market prices would amount to a double-count.

Q. HOW DID YOU ARRIVE AT YOUR COST OF EQUITY RECOMMENDATIONS?

A. To arrive at my recommendations, I applied the Discounted Cash Flow Model ("DCF"), including a Constant Growth and a Non-Constant Growth method and a Capital Asset Pricing Model ("CAPM") analysis to a group of similar companies (RFC Electric Proxy Group) using data available through March 31, 2021 as discussed below.

[27] PBS News Hour, June 26, 2017, Part 1 – America should stand for more than just wealth, says Warren Buffett.

B. Proxy Group Selection

Q. PLEASE EXPLAIN HOW YOU SELECTED THE COMPANIES IN YOUR COMPARABLE PROXY GROUP?

A. I selected 22 publicly traded electric utility companies to include in my comparable proxy group, referred to as the RFC Electric Proxy Group, based on the following criteria:

Criteria 1: The company is categorized by Value Line as an electric utility;

Criteria 2: The company has at least 80% of its assets dedicated to regulated operations;[28]

Criteria 3: The company pays dividends and has not cut the size of its dividend in the past 6 months;

Criteria 4: The company is not involved in any significant merger and acquisition ("M&A") activity; and

Criteria 5: The company is not being impacted by extraordinary events that could significantly impact its risk characteristics.

Table 7 on page 35 shows all 36 electric utility companies covered by Value Line plus two companies (MDU Resources, NiSource) included in the EEI Index, along with why 16 of these companies were excluded from my proxy group. Table 8 on page 36 shows the 22 companies that make up the RFC Electric Proxy Group.

[28] The Edison Electric Institute (EEI) classifies electric utilities as regulated if greater than 80% of its assets are regulated. In EEI's 2020 Industry Financial Highlights

TABLE 7: RFC ELECTRIC PROXY GROUP SELECTION CRITERIA

No.	Company Name	Ticker	Criteria 1 Value Line Electric Utility	Criteria 2 Over 80% Regulated Assets	Criteria 3 No Dividend Cuts	Criteria 4 No Signficant M&A	Criteria 5 No Extraudinary Events
1	AMEREN	AEE	Yes	Yes	Yes	Yes	Yes
2	AMERICANELEC.PWR.	AEP	Yes	Yes	Yes	Yes	Yes
3	AVISTACORP.	AVA	Yes	Yes	Yes	Yes	Yes
4	BLACKHILLSCORP.	BKH	Yes	Yes	Yes	Yes	Yes
5	CMSENERGYCORP.	CMS	Yes	Yes	Yes	Yes	Yes
6	CON.EDISON	ED	Yes	Yes	Yes	Yes	Yes
7	EDISONINTERNAT'L	EIX	Yes	Yes	Yes	Yes	Yes
8	EVERSOURCEENERGY	ES	Yes	Yes	Yes	Yes	Yes
9	ENTERGYCORP.	ETR	Yes	Yes	Yes	Yes	Yes
10	EVERGY, INC.	EVRG	Yes	Yes	Yes	Yes	Yes
11	FORTIS, INC.	FTS.TO	Yes	Yes	Yes	Yes	Yes
12	IDACORP,INC.	IDA	Yes	Yes	Yes	Yes	Yes
13	ALLIANTENERGY	LNT	Yes	Yes	Yes	Yes	Yes
14	MGEENERGYINC.	MGEE	Yes	Yes	Yes	Yes	Yes
15	NORTHWESTERN	NWE	Yes	Yes	Yes	Yes	Yes
16	OGEENERGYCORP.	OGE	Yes	Yes	Yes	Yes	Yes
17	OTTERTAILCORP.	OTTR	Yes	Yes	Yes	Yes	Yes
18	PINNACLEWEST	PNW	Yes	Yes	Yes	Yes	Yes
19	PORTLANDGENERAL	POR	Yes	Yes	Yes	Yes	Yes
20	SOUTHERNCOMPANY	SO	Yes	Yes	Yes	Yes	Yes
21	WECENERGYGROUP	WEC	Yes	Yes	Yes	Yes	Yes
22	XCELENERGY	XEL	Yes	Yes	Yes	Yes	Yes
23	PPLCORPORATION	PPL	Yes	Yes	Yes	**No**	Yes
24	CENTERPOINTEN'RGY	CNP	Yes	Yes	YES	**No**	YES
25	DOMINIONENERGY	D	Yes	Yes	**No**	**No**	YES
26	DUKEENERGY	DUK	Yes	Yes	Yes	**No**	YES
27	FIRSTENERGY	FE	Yes	Yes	YES	YES	**No**
28	PNMRESOURCES	PNM	Yes	Yes	**No**	YES	YES
29	AVANGRID,INC.	AGR	Yes	**No**	**No**	YES	YES
30	ALLETE	ALE	Yes	**No**	YES	YES	YES
31	DTEENERGYCO.	DTE	Yes	**No**	YES	YES	YES
32	EXELONCORP.	EXC	Yes	**No**	YES	YES	YES
33	HAWAIIANELECTRIC	HE	Yes	**No**	YES	YES	YES
34	NEXTERAENERGY	NEE	Yes	**No**	YES	YES	YES
35	P.S.ENTERPRISEGP.	PEG	Yes	**No**	YES	YES	YES
36	SEMPRAENERGY	SRE	Yes	**No**	YES	YES	YES
37	MDU RESOURCES	MDU	**No**	**No**	YES	YES	YES
38	NISOURCE	NI	**No**	Yes	YES	YES	YES

Source: 2020 Industry Financial Highlights, EEI, February 10, 2021, VI. Dividend Summary, page 3.

Categories: R = Regulated (80% or more of total assets are regulated)
MR = Mostly Regulated (Less than 80% of total assets are regulated)
Based on assets at 12/31/2019.

TABLE 8: RFC ELECTRIC PROXY GROUP COMPOSITION			
No.	**Company Name**	**Ticker**	**Market Cap in $ Billions As of 3/31/2021**
1	AMEREN	AEE	20.61
2	AMERICANELEC.PWR.	AEP	42.06
3	AVISTACORP.	AVA	3.28
4	BLACKHILLSCORP.	BKH	4.19
5	CMSENERGYCORP.	CMS	17.69
6	CON.EDISON	ED	25.05
7	EDISONINTERNAT'L	EIX	22.18
8	EVERSOURCEENERGY	ES	29.69
9	ENTERGYCORP.	ETR	19.94
10	EVERGY, INC.	EVRG	13.51
11	FORTIS, INC.	FTS.TO	25.45
12	IDACORP,INC.	IDA	5.04
13	ALLIANTENERGY	LNT	13.53
14	MGEENERGYINC.	MGEE	2.58
15	NORTHWESTERN	NWE	3.30
16	OGEENERGYCORP.	OGE	6.47
17	OTTERTAILCORP.	OTTR	1.92
18	PINNACLEWEST	PNW	9.16
19	PORTLANDGENERAL	POR	4.25
20	SOUTHERNCOMPANY	SO	65.66
21	WECENERGYGROUP	WEC	29.52
22	XCELENERGY	XEL	34.95

Source: Value Line, Yahoo Finance

Q. MR. MOUL USES A DIFFERENT PROXY GROUP TO CALCULATE HIS COST OF EQUITY RECOMMENDATION FOR UGI ELECTRIC. WHY IS IT MORE APPROPRIATE TO USE YOUR PROXY GROUP TO CALCUALTE UGI ELECTRIC'S COST OF EQUITY THAN THE ONE USED BY MR. MOUL?

A. My proxy group is more appropriate to use to calculate UGI Electric's cost of equity because most of the companies (7 of 9) in Mr. Moul's proxy group are being impacted by developments that put them in a different risk category than UGI Electric. As detailed above, I selected the 22 companies in the RFC Electric Proxy Group based on five criteria. I chose to include companies that are not involved in major merger activity and have a minimum of 80% of assets dedicated to regulated operations because mergers and unregulated operations are risk factors not faced by UGI Electric. For example, Mr. Moul includes PPL Corporation in his proxy group despite its ongoing sale of its United Kingdom operations. He also includes First Energy in his proxy group despite its ongoing fraud investigation. Moreover, AVANGRID, Exelon Corp, NextEra Energy, and Public Service Enterprise Group all have less than 80% of assets dedicated to regulated operations and therefore should not be used to calculate UGI Electric's cost of equity because they are risker than UGI Electric. Please refer to Table 7 on page 35 for details on why I excluded 7 of the 9 companies in Mr. Moul's proxy group when I selected the companies to include in my proxy group.

C. Discounted Cash Flow

Q. HOW DID YOU ARRIVE AT YOUR DCF-BASED COST OF EQUITY RECOMMENDATION?

A. I used both the constant growth form of the Discounted Cash Flow ("DCF") method, which determines growth based on the sustainable retention growth procedure, and a non-constant DCF method. My constant growth form DCF analysis indicates a cost of equity range of between 7.91% and 7.96% for the RFC Electric Proxy Group.[29] The results of my non-

[29] See Exhibit ALR-3, page 1.

constant DCF method indicates a cost of equity of between 9.08% and 9.29% for the RFC Electric Proxy Group.[30]

Q. WHAT IS THE DISCOUNTED CASH FLOW METHOD?

A. The DCF method, is an approach to determining the cost of equity. The method recognizes that investors purchase common stock to receive future cash payments. These payments come from: (a) current and future dividends, and (b) proceeds from selling stock. A rational investor will buy stock to receive dividends and to ultimately sell the stock to another investor at a gain. The price the new owner is willing to pay for stock is related to that buyer's expectation of future flow of dividends and the future expected selling price. The value of the stock is the discounted value of all future dividends until the stock is sold plus the value of proceeds from the sale of the stock.

Q. HAVE INVESTORS ALWAYS USED THE DCF METHOD?

A. While investors who buy stock have always done so for future cash flow, the DCF approach first appeared in the 1937 Harvard Ph.D. thesis of John Burr Williams titled *The Theory of Investment Value*. Author Peter L. Bernstein once stated that "Williams' model for valuing a security calls for the investor to make a long-run projection of a company's future dividend payments…"[31] The Williams DCF model separately discounts each and every future expected cash flow. Dividends and proceeds from the sale of stock are the expected cash flows. Its accuracy is therefore unaffected by non-constant growth rates. Myron Gordon and Eli Shapiro, who helped to make this method widely used, referred to

[30] See Exhibit ALR-3, page 2 and Exhibit ALR-3, page 3.
[31] P. BERNSTEIN, *Capital Ideas: The Improbable Origins of Modern Wall Street* (The Free Press, © 1992).

Williams' work in their paper published in 1956 "Equipment Analysis: The Required Rate of Profit."

D. Constant Growth Form of the DCF Model

Q. YOU STATE YOU USED THE CONSTANT GROWTH FORM OF THE DCF MODEL. WHAT IS THE CONSTANT GROWTH FORM OF THE DCF MODEL?

A. The constant growth form of the DCF model is a form of the DCF method that can be used in determining the cost of equity when investors can reasonably expect that the growth of retained earnings and dividends will be constant.

Retained earnings are funds that a company keeps in its treasury, so that they are available for future needs, such as operating expenses, capital expenditures, debt payments, and new investments. These retained earnings show investors whether the company is growing which, in turn, is a measure of the future indicator of dividends and the value of a company's stock.

Q. DESCRIBE HOW THE CONSTANT GROWTH MODEL WORKS.

A. The constant growth model is described by this equation $k = D/P + g$, where: [32]

k= cost of equity;
D=Dividend; and
P=Market price of stock at time of the analysis.

and where:

g=the growth rate, where $g = br + sv$;
b=the earnings retention rate;
r=return on common equity investment (referred to below as "book equity");
v=the fraction of funds raised by the sale of stock that increases the book value of the existing shareholders' common equity; and

[32] M. GORDON, *Cost of Capital to a Public Utility*, at 32-33 (MSU Public Utility Studies 1974).

s=the rate of continuous new stock financing.

The constant growth model is therefore correctly recognized to be:

k=D/P + (br +sv).

The cost of equity demanded by investors is the sum of two factors. The first factor is the dividend yield. The second factor is growth (dividends and stock price). The logical relationship among these factors is as follows: the dividend yield is calculated based on current dividend payments while growth indicates what dividends and stock price will be in the future.

Q. WHAT OTHER FACTORS IMPACT HOW ONE USES THE CONSTANT GROWTH FORM OF THE DCF MODEL?

A. Sufficient care must be taken to be sure that the growth rate "g" is representative of the constant sustainable growth. To obtain an accurate constant growth DCF result, the mathematical relationship between earnings, dividends, book value and stock price must be respected.

Suppose one is faced with a situation where Value Line forecasts of growth are being used as a source for inputs and Value Line projects different growth rates for earnings per share and dividends per share. Under such conditions, the earnings per share growth rate does not provide a reasonable proxy for earnings per share growth, and dividends per share and stock price growth as well. Consider the following:

1. It is the lower dividend growth rate that makes it possible for more earnings to be retained, which in turn makes the earnings per share growth rate higher than it would be if dividends had in fact been modeled by Value Line to keep pace with earnings per share growth.

2. A dividend growth rate that is lower than both the earnings per share growth rate and the stock price growth rate means that the dividend yield will be going down. However, the constant growth form of the DCF model has no mechanism to account for the lower dividend yield investors would get if the Value Line projections were correct.

Using an earnings per share growth rate in the constant growth form of the DCF model will therefore result in an overstatement of the cost of equity whenever the earnings per share growth rate that has been modeled is derived along with an expectation of a lower dividend growth rate. This is because, under these conditions, the dividend yield portion of the constant growth form of the equation will be overstated.

The basic difference between the use of an analysts' earnings per share growth rate in the constant growth DCF formula and using the "br" (**b** (the earnings retention rate) X **r** (rate of return on common equity investment)) approach is that the "br" form, if properly applied, eliminates the mathematical error caused by an inconsistency between the expectations for earnings per share growth and dividends per share growth. Because it eliminates that error, the results of a properly applied "br" approach will be superior to the answer obtained from other approaches to the constant growth form of the DCF model. This is not to say that even a properly applied "br" approach will be perfect. The self-correcting nature of a properly applied "br" to forecasted differences in earnings per share and dividends per share growth rates helps mitigate the resultant error but should not be viewed as the perfect way to quantify the impact of expected non-constant growth rates.

Q. ARE YOU AWARE OF CLAIMS ALLEGING THAT THE "BR" APPROACH TO THE CONSTANT GROWTH DCF MODEL IS FLAWED BECAUSE IT RELIES

ON THE VALUE OF THE FUTURE EXPECTED RETURN ON BOOK EQUITY "R" TO ESTIMATE WHAT THE EARNED RETURN ON EQUITY SHOULD BE?

A. Yes. One common criticism is that it is not reasonable for the DCF to indicate a cost of equity (market return) that is different (lower or higher) than the expected return on book equity (accounting). There are multiple reasons why this concern is unfounded:

1. The constant growth form of the equation using "br" is:

   $$k= D/P + (br + sv).$$

   In this equation, "k" is the variable for the cost of equity, and "r" is the future expected return on equity. The cost of equity, "k," is not the same variable as the future expected earned return on equity, "r." In fact, there often is a large difference between the two.

2. The correct value to use for "r" is the return on book equity expected by investors as of the time the stock price and dividend data is used to quantify the D/P term in the equation. Therefore, even if future events occur that may change what investors expect for "r," the computation of the cost of equity "k" remains correct as of the time the computation was made.

3. The ability of a commission's ROE decision to influence future cash flow expectations is not unique to the retention growth DCF approach. The five-year analysts' earnings per share growth rate is a computation that is directly influenced by what earnings per share will be in five years. Allowed ROE's impact earning – higher allowed returns lead to higher earnings growth because the higher allowed returns the more earnings that are available for reinvestment.

Q. CAN CHANGES IN THE ACTUAL EARNED RETURNS IMPACT GROWTH ABOVE AND BEYOND WHATEVER GROWTH RESULTS FROM EARNINGS RETENTION?

A. Yes, but large short-term changes in earnings per share caused by a perceived change in the future expected earned returns are unsustainable. The new perceived earned return on book equity should be part of the computation, but the one-time growth spurt to get there is no more indicative of the sustainable growth required in the constant growth DCF formula than the temporary negative growth that occurs when a company has a bad year.

Q. HOW HAVE YOU IMPLEMENTED THE CONSTANT GROWTH FORM OF THE DCF MODEL IN THIS CASE?

A. I have applied the constant growth form of the DCF model by staying true to the mathematically derived "k=D/P + (br + sv)" form of the DCF model. I have also taken care to fully allocate all future expected earnings to either future cash flow in the form of dividends ("D") or to retained earnings (the retention rate, "b"). This extra accuracy is obtained only when the retention rate "b" is derived from the values used for "D" and "r," rather than independently.

Q. PLEASE EXPLAIN HOW YOU OBTAINED THE VALUES YOU USED IN THE CONSTANT GROWTH FORM OF THE DCF METHOD.

A. The DCF model generally calls for the use of the dividend expected over the next year. A reasonable way to estimate next year's dividend rate is to increase the quarterly dividend rate by ½ of the current actual quarterly dividend rate. This is a good approximation of the rate that would be obtained if the full prior year's dividend were escalated by the entire growth rate.[33]

I obtained the stock price—"P"—used in my DCF analysis from the closing prices of the stocks on March 31, 2021. I also obtained an average stock price for the 12 months ending March 31, 2021 by averaging the high and low stock prices for the year.

I based the value of the future expected return on equity— "r" —on the average return on book equity expected by Value Line, adjusted in consideration of recent returns. I also made a computation that was based on a review of both the earned return on equity consistent with analysts' consensus earnings growth rate expectations and on the actual earned returns on equity. For a stable industry such as utility companies, investors will typically look at actual earned returns on equity as one meaningful input into what can be expected for future earned returns on book equity. See Exhibit ALR-3, page 1.

This return on book equity expectation used in the DCF method to compute growth must *not* be confused with the cost of equity. Since the stock prices for the comparative companies are substantially higher than their book value, the return investors expect to receive on their market price investment is considerably less than the anticipated return on book value. If the market price is low relative to book value, the cost of equity will be

[33] For example, assume a company paid a dividend of $0.50 in the first quarter a year ago, and has a dividend growth rate of 4 % per year. This dividend growth rate equals (1.04)^4-1=0.00985 % per quarter. Thus, the dividend is $0.5049 in the second quarter, $0.5099 in the third quarter, and $0.5149 in the fourth quarter. If that 4 % per annum growth continues into the following year, then the dividend would be $0.5199 in the 1st quarter, $0.5251 in the 2nd quarter, $0.5303 in the 3rd quarter, and $0.5355 in the 4th quarter. Thus, the total dividends for the following year equal $2.111 (0.5199 + 0.5251 + 0.5303 + 0.5355). I computed the dividend yield by taking the current quarter (the $0.5149 in the 4th quarter in this example) and multiplying it by 4 to get an annual rate of $2.06. I then escalated this $2.06 by ½ the 4 % growth rate, which means it is increased by 2 %. $2.06 x 1.02= $2.101, which is within one cent of the $2.111 obtained in the example.

higher than the future expected return on book equity, and if the market price is high, then the return on book equity will be less than the cost of equity.

In addition to growing through the retention of earnings, utility companies also grow by selling new common stock. Selling new common stock increases a company's growth. I quantified this growth caused by the sale of new common stock by multiplying the amount that the actual market-to-book ratio exceeds 1.0, by the compound annual growth rate of stock that Value Line forecasts. The results of that computation are shown on line 4 of Exhibit ALR-3, page 1.

Pure financial theory prefers concentrating on the results from the most current price because investors cannot purchase stock at historical prices. There is a legitimate concern, however, about the potential distortion of using just a single price. I present DCF results based on the most recent stock pricing data (March 31, 2021) as well as the average of the high and low stock price over the past 12 months to obtain a range of reasonable values. As shown in Exhibit ALR-3, page 1, the DCF result based on the average of the high and low stock price for the year ending March 31, 2021 is 7.91%. The DCF result based on the stock price as of March 31, 2021 is 7.96%. Exhibit ALR-3, page 1, shows more of the specifics of how I implemented the constant growth form of the DCF model for the RFC Electric Proxy Group.

Q. PLEASE EXPLAIN HOW YOU DETERMINED WHAT VALUE TO USE FOR "R" WHEN COMPUTING GROWTH IN YOUR CONSTANT GROWTH FORM OF THE DCF MODEL.

A. The inputs I considered are shown in Footnote [C] of Exhibit ALR-3, page 1. The value of "r" that is appropriate to use in the DCF formula is the value anticipated by investors to be maintained on average in the future. This Exhibit shows that the average future return on equity forecasted by Value Line for the RFC Electric Proxy Group between 2021 and 2023-25 is 10.30%. The same footnote also shows that the future expected return on equity derived from the Zacks consensus forecast is 9.72%, and that the actual returns on equity earned by the RFC Electric Proxy Group on average were 9.74% in 2018, 10.32% in 2019, and 9.52% in 2020. Based on the combination of the forecasted return on equity derived from the Zacks consensus, the recent historical actual earned returns, and Value Line's forecast, I made the DCF growth computation using a 10.00%[34] value of "r".

Q. WHAT COST OF EQUITY IS INDICATED BY THE CONSTANT GROWTH FORM OF THE DCF METHOD THAT YOU RELY ON FOR YOUR RECOMMENDATION?

A. The result of my DCF analysis using the Constant Growth form of the DCF indicates a cost of equity range of between 7.91% and 7.96% for the RFC Electric Proxy Group.[35] Since these DCF findings use analysts' forecasts to derive sustainable growth (in part) and on analysts' forecasts of dividend growth and book value growth in the non-constant form of the DCF method, the results should be considered as conservatively high. This is because, as previously mentioned above, analysts' forecasts of such growth have been notoriously overstated.

My results are not as influenced by over-optimistic analysts' forecasts as would have been the case had I merely used analysts' five-year earnings growth rate forecasts as a proxy for long-term growth. This is because the DCF methods I use compute sustainable

[34] I used 10.00% in consideration of historical returns, allowed returns, and Value Line projected returns for the RFC Electric Proxy Group.

[35] Exhibit ALR-3, page 1.

growth rates, rather than growth rates that can exaggerate the growth rate due to assuming that a relatively short-term forecast (five-years) will remain indefinitely.

E. Non-Constant Growth Form of the DCF Model

Q. PLEASE EXPLAIN HOW YOU IMPLEMENTED THE NON-CONSTANT GROWTH FORM OF THE DCF MODEL.

A. The non-constant growth form of the DCF model determines the return on investment expected by investors based on an estimate of each separate annual cash flow the investor expects to receive. For the purpose of this computation, I have incorporated Value Line's detailed annual forecasts to arrive at the specific non-constant growth expectations that an investor who trusts Value Line would expect. This implementation is shown on Exhibit ALR-3, page 2 and Exhibit ALR-3, page 3. In the first stage, cash flow entry is the cash outflow an investor would experience when buying a share of stock at the market price. The subsequent years of cash flow are equal to the dividends per share that Value Line forecasts. For the intermediate years of the forecast period in which Value Line does not provide a specific dividend, the annual dividends were obtained by estimating that dividend growth would persist at a compound annual rate. The cash flow at the end of the forecast period consists of both the last year's dividend forecast by Value Line, and the proceeds from the sale of the stock. The stock price used to determine the proceeds from selling the stock was obtained by estimating that the stock price would grow at the same rate at which Value Line forecasts book value to grow.

Q. WHY DID YOU USE BOOK VALUE GROWTH TO PROVIDE THE ESTIMATE OF THE FUTURE STOCK PRICE?

A. For any given earned return on book equity, earnings are directly proportional to the book value. Furthermore, book value growth is the net result after the company produces earnings, pays a dividend and also, perhaps, either sells new common stock at market price or repurchases its own common stock at market price.

Once these cash flows are entered into an Excel spreadsheet, the compound annual return an investor would achieve as a result of making this investment was obtained by using the Internal Rate of Return (IRR) function built into the spreadsheet. As shown on Exhibit ALR-3, page 2 and Exhibit ALR-3, page 3, this multi-stage DCF model produced an average indicated cost of equity of 9.08% based on the year-end stock price, and 9.29% based on average prices for the year ending March 31, 2021 for the RFC Electric Proxy Group.

Q. YOUR NON-CONSTANT GROWTH DCF MODEL USES ANNUAL EXPECTED CASH FLOWS. SINCE DIVIDENDS ARE PAID QUARTERLY RATHER THAN ANNUALLY, HOW DOES THIS SIMPLIFICATION IMPACT YOUR RESULTS?

A. I used the annual model because it is easier to input the data and for observers to visualize what is happening. By modeling cash flows to be annual rather than when they are actually expected to occur causes a small overstatement of the cost of equity.

Q. WHY IS IT A SMALL OVERSTATEMENT OF THE COST OF EQUITY IF YOU HAVE MODELED DIVIDENDS TO BE RECEIVED SOME MONTHS AFTER INVESTORS ACTUALLY EXPECT TO RECEIVE THEM?

A. The process of changing from an annual model to a quarterly model would require two changes, not just one. A quarterly model would show dividends being paid sooner and would also show earnings being available sooner. A company that receives its earnings sooner, rather than at the end of the year, has the opportunity to compound them. Since revenues, and therefore earnings, are essentially received every day, a company that is supposed to earn an annual rate of 9.00% on equity would have to earn only 8.62% if the return were compounded daily.[36] This reduction from 9.00% to 8.62% would then be partially offset by the impact of the quarterly dividend payment to bring the result of switching from the simplifying annual model closer to, but still a bit below 9.00%.

Q. BY USING CASH FLOW EXPECTATIONS AS THE VALUATION PARAMETER, DOES THE NON-CONSTANT DCF MODEL STILL RELY ON EARNINGS?

A. Yes. It relies on an expectation of future cash flows. Future cash flows come from dividends during the time the stock is owned and capital gains from the sale of the stock once it is sold. Since earnings impact both dividends and stock price, the non-constant DCF model still relies on earnings.

Every dollar of earnings is used for the benefit of stockholders, either in the form of a dividend payment, or earnings reinvested for future growth in earnings and/or dividends. Earnings paid out as a dividend have a different value to investors than earnings retained in the business. Recognizing this difference and properly considering it in the

[36] (1+.0862/365)^365=1.09=9.00 %.

quantification process is a major strength of the DCF model and is why the non-constant DCF model as I have set forth is an improvement over either the price-to-earnings ratio (P/E ratio) or dividend/price (D/P) methods. Comparing the P/E ratios and the dividend yield (D/P) are helpful as a rule of thumb, but they must be used with caution because, among other reasons, two companies with the same dividend yield can have a different cost of equity if they have different retention rates. A DCF model is more reliable than these rules of thumb because it can account for different retention rates, among other factors.

Q. WHY IS THERE A DIFFERENCE TO INVESTORS IN THE VALUE OF EARNINGS PAID OUT AS A DIVIDEND COMPARED TO THE VALUE OF EARNINGS RETAINED IN THE BUSINESS?

A. The return on earnings retained in the business depends upon the opportunities available to that company. If a regulated utility reinvests earnings in needed "used and useful" utility assets, then those reinvested earnings have the potential to earn at whatever return is consistent with ratemaking procedures allowed and the skill of management in prudently operating the system.

When an investor receives a dividend, he can either reinvest it in the same or another company or use it for other things, such as paying down debt or paying living expenses. Although an investor could theoretically use the proceeds from any dividend payments to simply buy more stock in the same company, when an investor increases her investment in a company by purchasing more stock, the transaction occurs at market price. However, when the same investor sees her investment in a company increase because earnings are retained rather than paid as a dividend, the reinvestment occurs at book value. Stated within the context of the DCF terminology: earnings retained in the business earn at the future expected return on book equity "r," and dividends used to purchase new stock earn at the rate "k." When the market price exceeds book value (that is, the market-to-book ratio exceeds 1.0), retained earnings are worth more than earnings paid out as a dividend because "r" will be higher than "k." Conversely, when the market price is below book value, "k" will be higher than "r," meaning that earnings paid out as a dividend earn a higher rate than retained earnings.

Q. IF RETAINED EARNINGS WERE MORE VALUABLE WHEN THE MARKET-TO-BOOK RATIO IS ABOVE 1.0, WHY WOULD A COMPANY WITH A MARKET-TO-BOOK RATIO ABOVE 1.0 PAY A DIVIDEND RATHER THAN RETAIN ALL OF THE EARNINGS?

A. Retained earnings are more valuable than dividends only if there are sufficient opportunities to profitably reinvest those earnings. Regulated utility companies are allowed to earn the cost of capital only on assets that are used and useful in providing utility service. Investing in assets that are not needed may not produce any return at all. For unregulated companies, opportunities to reinvest funds are limited by the demands of the business. For example, how many new computer chips can Intel profitably develop at the same time?

Q. UNDER THE NON-CONSTANT DCF MODEL, IS IT NECESSARY FOR EARNINGS AND DIVIDENDS TO GROW AT A CONSTANT RATE FOR THE MODEL TO BE ABLE TO ACCURATELY DETERMINE THE COST OF EQUITY?

A. No, because the non-constant form of the DCF model separately discounts each and every future expected cash flow, it does *not* rely on any assumptions of constant growth. The dividend yield can be different from period to period, and growth can bounce around in any imaginable pattern without harming the accuracy of the answer obtained from quantifying those expectations. When the non-constant DCF model is correctly used, the answer obtained is as accurate as the estimates of future cash flow.

Q. WHAT COST OF EQUITY DOES YOUR NON-CONSTANT GROWTH DCF METHOD INDICATE?

A. My non-constant growth DCF method indicates a cost of equity of between 9.08% and 9.29%.[37]

F. Capital Asset Pricing Model

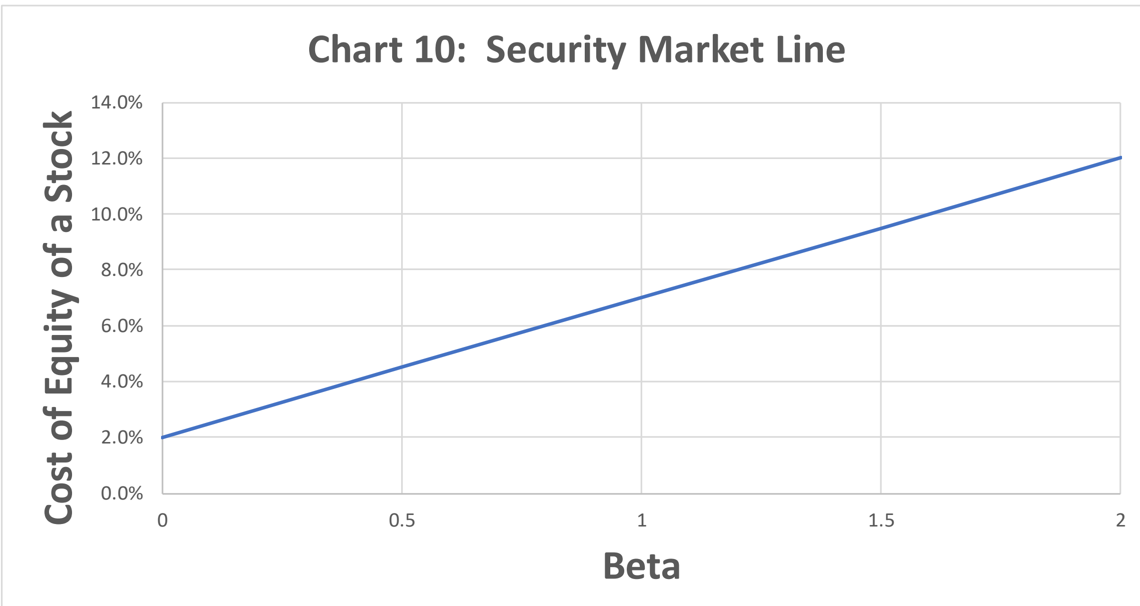
Q. PLEASE DESCRIBE THE CAPM.

A. CAPM stands for "Capital Asset Pricing Model." The CAPM relates return to risk; specifically, it relates the expected return on an investment in a security to the risk of investing in that security. The riskier the investment, the greater the expected return (*i.e.,* the cost of equity) investors require to make for that investment.

Investors in a firm's equity face two types of risks: (1) firm-specific risk and (2) market risk (financial analysts refer to this market risk as systematic risk). Firm-specific risk refers to risks unique to the firm such as management performance and losing market share to a new competitor. Investors can reduce firm-specific risk by purchasing stocks as part of a diverse portfolio of companies if they construct the portfolio to cause the firm-specific risk of individual companies to balance out. Market-related risk refers to potential

[37] Exhibit ALR-3, page 2 and Exhibit ALR-3, page 3.

impacts from the overall market such as a recession or interest rate changes. This risk cannot be removed by diversification, so the investor must bear it no matter what. Because the investor has no option but to bear market risk, the investor's cost of equity will reflect that risk. The CAPM predicts that for a given equity security, the cost of equity has a positive linear relationship to how sensitive the stock's returns are to movements in the overall market (e.g., S&P 500). A security's market sensitivity is measured by its **Beta.**[38] As shown in Chart 10 below, the higher the beta of a stock, the higher the company's cost of equity—the return required by the investor to invest in the stock.



Here is the standard CAPM formula:

K = Rf + βí * (Rm – Rf)

Where:

K is the cost of equity;
Rf is the risk-free interest rate;
Rm is the expected return on the overall market (e.g., S&P 500);

[38] The covariation of the return on an individual security with the return on the market portfolio.

[Rm – Rf] is the premium investors expect to earn above the risk-free rate for investing in the overall market ("equity risk premium" or "market risk premium"); and

βí (Beta) is a measure of non-diversifiable, or systematic, risk.

Q. PLEASE EXPLAIN HOW YOU IMPLEMENTED THE CAPM.

A. First, I determined appropriate values or ranges for each of the three model inputs: (a) Risk-Free Rate, (b) Beta, and (c) Equity Risk Premium. Second, I used the equation above to calculate the cost of equity implied by the model. Below I will explain how I calculated the three model inputs and summarize the CAPM cost of equity numbers resulting from those inputs. Table 9 and Table 10 on page 72 show the results of my CAPM.

Risk-Free Rate

Q. WHAT RISK-FREE RATE DID YOU USE IN YOUR CAPM?

A. It is generally preferable to use the market yield on short-term U.S. Treasury yields as the risk-free rate because these bonds have a beta close to zero. *Principles of Corporate Finance* states "The CAPM… calls for a short-term interest rate."[39] I chose to use a risk-free rate based on both long- and short-term Treasury yields, however, because, as indicated by the steepness of the yield curve,[40] investors with a longer investment horizon would likely use a higher risk-free rate as an opportunity cost for their investment decisions. My short-term risk-free rate is based on the yield of 3-month U.S. Treasury bills and my long-term risk-free rate is based on the yield of 30-year U.S. Treasury bonds. In line with my Spot and Weighted Average CAPM approaches, I use both spot values as

[39] Brealey, Myers, and Allen (2017), Principles of Corporate Finance, 12th Edition, McGraw-Hill Irwin, New York, page 228.

[40] The yield curve on U.S. Treasury bonds relates the yield to its time to maturity. We say the current yield curve is steep because the difference in yield between short-term (near 0%) and long-term (over 1%) bonds is large in percentage terms.

of March 31, 2021 and weighted averages over the three months ending on that date for these two yields.

As outlined in Exhibit ALR-4, page 2, my spot and weighted average short-term risk-free rates are 0.03% and 0.04%, respectively. My spot and weighted average long-term risk-free rates are 2.41% and 2.20%, respectively.

U.S. government bonds are reasonable to use as a risk-free rate because they have a negligible risk of default. The value of short-term U.S. Treasury bills has a relatively low exposure to swings in the overall market. The value of long-term U.S. Treasury bonds is relatively more exposed to the market and therefore must be used with caution. I considered using a risk-free rate based on subtracting the historical spread between long-term and short-term U.S. Treasury bills from current long-term yields, as recommended by some financial textbooks.[41] I did not use this method because in the current capital markets, this method results in an unreasonably low risk-free rate (under 0%).

Regarding my weighted average risk-free rates, it is worth noting that any form of averaging or weighting approach applied to the last eight months of historical yield data would not have any significant effect on my CAPM results.

Q. WHAT IS YOUR RESPONSE TO ANALYSTS WHO CLAIM THAT THE CAPM MUST BE IMPLEMENTED WITH A LONG-TERM INTEREST RATE (E.G.,

[41] Brealey, Myers, and Allen (2017), Principles of Corporate Finance, 12th Edition, McGraw-Hill Irwin, New York, page 228.

YIELD ON 30-YEAR TREASURY BOND) AS AN ESTIMATE OF THE RISK-FREE RATE COMPONENT OF THE CAPM?

A. When looking for a security to calculate an estimate of the risk-free rate, it could be argued that it is appropriate to find one with a term or maturity that best matches the life of the asset being financed. In that sense, the 30-year Treasury bond yield can be argued to be ideal for this specific application. However, it is equally important to find a security that has a beta coefficient with the overall market as close to zero as possible, because by the very definition of the risk-free rate in the CAPM model, its movements should have no correlation to the movements of the market. And this is where the problem with the 30-year Treasury bond yield arises, as it has an established non-zero beta. The 3-month Treasury bill yield has a considerably lower beta, and therefore is superior in that respect to the 30-year Treasury bond yield. Neither one is a perfect fit on both fronts, which is why I have chosen to consider both as proxies for the risk-free rate to establish a range for my CAPM results.

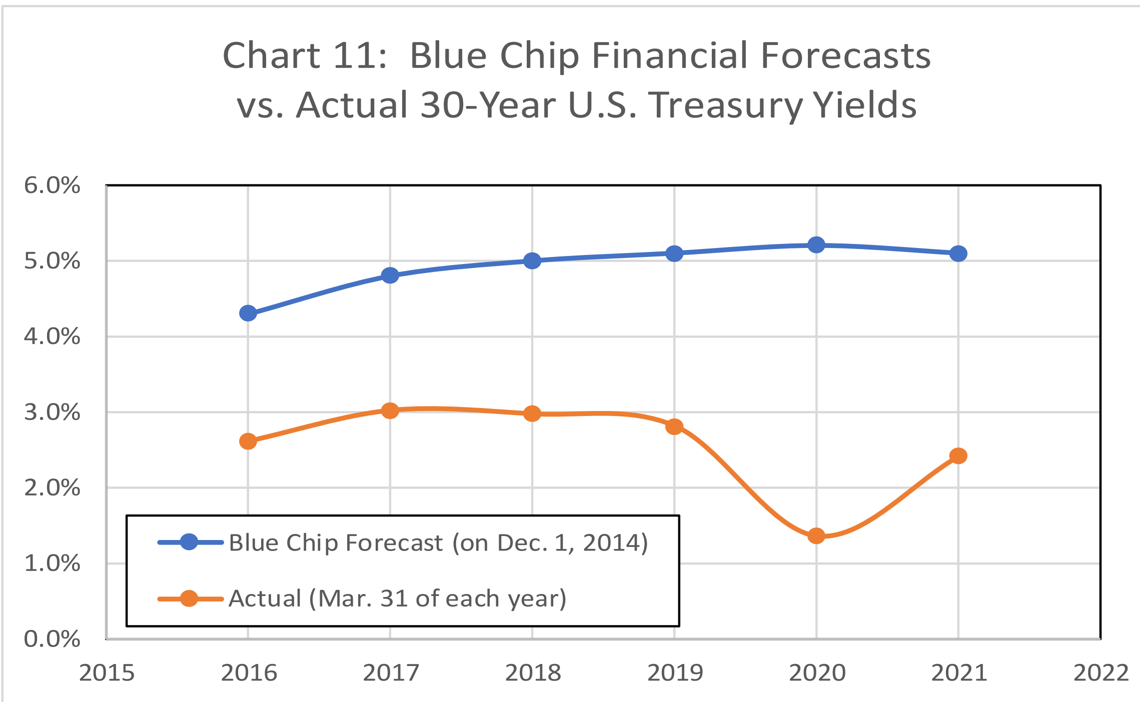
Q. HOW DO YOU RESPOND TO ANALYSTS WHO CLAIM THAT THE RISK-FREE RATE SHOULD BE BASED ON INTEREST RATE FORECASTS FROM FIRMS SUCH AS BLUE CHIP FINANCIAL?

A. It is important to recognize that current long-term Treasury bond yields represent a direct observation of investor expectations and there is no need to use "expert" forecasts such as Blue Chip to determine the appropriate risk-free rate to use in a CAPM analysis or any other cost of equity calculations.

Many economists and forecasters will continue to be quoted in the press prognosticating on possible developments that are truly unpredictable. The Nobel Laureate Economist Daniel Kahneman stated the following regarding forecasting:

> It is wise to take admissions of uncertainty seriously, but declarations of high confidence mainly tell you that an individual has constructed a coherent story in his mind, not necessarily that the story is true.[42]

As Chart 11 below shows, Blue Chip Financial forecasted in 2014 that 30-Year U.S. Treasury bonds would be over 5% by 2018 while in fact they turned out to be under 2%.



The time covered in Chart 11 above was chosen to provide a concrete example. Blue Chip's interest rate forecasts have been persistently inaccurate for decades. A recent paper published by the Congressional Budget Office determined Blue Chip consensus

[42] Daniel Kahneman, *Thinking Fast and Slow* (New York: Farrar, Straus and Giroux, 2011): 212.

forecasts exhibited "significant positive bias" between 1984 and 2012 and "have become more biased and less accurate over time."[43]

Beta

Q. WHAT BETA DID YOU USE IN YOUR CAPM?

A. Since the cost of equity should be based on investor expectations, I chose to use two betas. My "forward beta" is based on forward-looking investor expectations of non-diversifiable risk. My "hybrid beta" is based on both forward-looking investor expectations and historical return data.

Most published betas are based exclusively on historical return data. For example, Value Line publishes a 5-year historical beta for each of the companies it covers. However, it is also possible to calculate betas based on investors' expectations of the probability distribution of future returns. This probability distribution of future returns expected by investors can be calculated based on the market prices of stock options.

Q. WHAT IS A STOCK OPTION?

A. A stock option is the right to buy or sell a stock at a specific price for a specified amount of time. A call option is the right to buy a stock at a specified exercise or strike price on or before a maturity date. A put option is the right to sell a stock at a specified exercise or strike price on or before a maturity date. For example, a call option to purchase Apple Computer stock for $230 on January 17, 2020 allows the owner the option (not the obligation) to buy Apple stock for $230 on that date. At the end of July 2019, Apple stock was trading at about $215 per share. Why would anyone pay for the right to buy a stock

[43] Did Treasury Debt Markets Anticipate the Persistent Decline in Long-Term Interest Rates?, Congressional Budget Office, Edward N. Gamber, page 2. This paper can be found at: https://www.cbo.gov/system/files/115th-congress-2017-2018/workingpaper/53153-interestrateswp.pdf

higher than the current price? Investors who purchased those call options thought there was a chance Apple stock would be trading higher than $230 on January 17, 2020, and those options gave those investors the right to buy Apple stock for $230 and profit by selling it at the market price on that date, if it was higher. The price of Apple's stock was $317.98 at the close of trading on January 17, 2020. Therefore, the investor who purchased this call option for $635 on July 31, 2019 earned a profit of $8,163[44] at expiry on January 17, 2020. On the other hand, the investor who purchased an Apple put option with the same expiration date and strike price on July 31, 2019 would have lost the price of the option ($2,248) and gained nothing on the expiration date because the right to sell Apple stock for $230 when the price is over $300 is worthless.

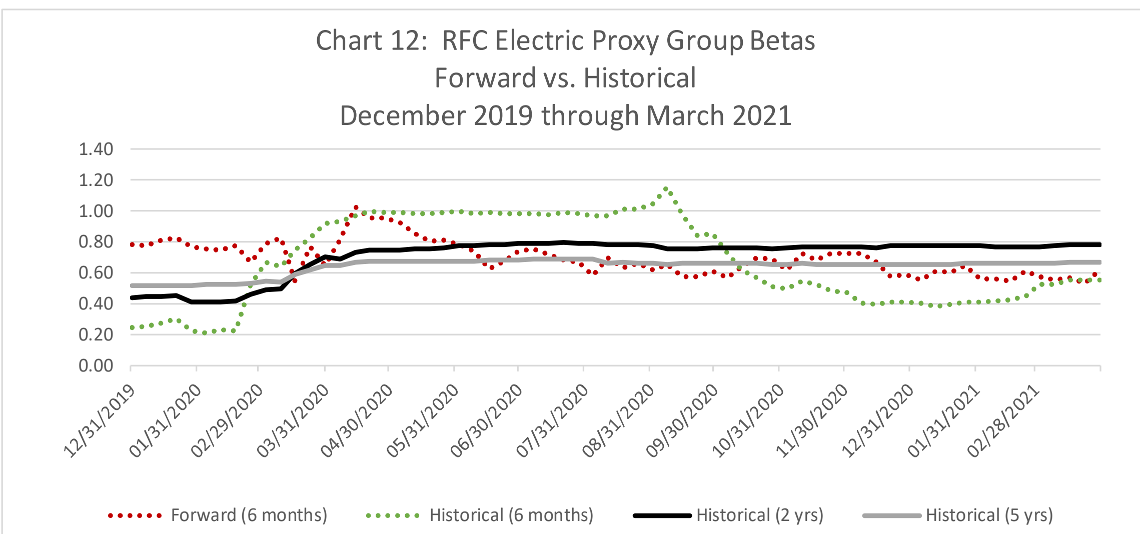
The market prices of put options and call options provide information regarding the probability distribution of future stock prices expected by investors. Using established techniques, I am able to use price data for stock options of my RFC Electric Proxy Group companies and the S&P 500 Index to determine investors' return expectations, including the relationship (covariance) between the return expectations for individual RFC Electric Proxy Group companies and those for the overall market (S&P 500). This covariance between the expected returns for my RFC Electric Proxy Group and for the S&P 500 indicates what investors expect betas will be in the future. I refer to betas based on option price calculations as "option-implied betas."

[44] $8,163 profit from exercising call option ($31,798 from selling at $317.98 market price - $23,000 cost to purchase at $230) - $635 ($6.35 X 100) option purchase price. Note: Each call option is the right to purchase 100 shares.

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE BETAS USED IN YOUR CAPM.

A. Traditionally, the betas used in CAPM calculations are calculated from historical returns. This approach has strengths and weaknesses. An alternative way to calculate betas is to incorporate investors' return expectations by calculating option-implied betas as explained in the previous paragraph. As discussed below, I have chosen to use both historical and option-implied betas in my CAPM analysis. I chose to use option-implied betas in my CAPM analysis because, among other reasons, studies have found that betas calculated based on investor expectations (option-implied) provide information regarding future perceived risks and expectations.[45]

As shown in Chart 12 below, stock option prices indicate that investors likely expect lower betas for the RFC Electric Proxy Group in the future.



See Exhibit ALR-4, page 3 for data used in creating Chart 12 above.

I used the following two betas in my CAPM analysis:

[45] Bo-Young Chang & Peter Christoffersen & Kris Jacobs & Gregory Vainberg. (2011) Option-Implied Measures of Equity Risk, *Review of Finance* 16: 385-428.

1. **Hybrid Beta:** 50% Option-Implied Beta (6 months) + 25% Historical Beta (6 months) + 15% Historical Beta (2 years) + 10% Historical Beta (5 years).
2. **Forward Beta:** 100% Option-Implied Beta (6 months).

Q. PLEASE EXPLAIN HOW YOU CALCULATED HISTORICAL BETAS.

A. I calculate historical betas following the methodology used by Value Line. Specifically, I use the following guidelines:

1. Returns for each security are regressed against returns for the overall market in the following form:

   $$\mathrm{Ln}\,(p^{I}_{t} / p^{I}_{t-1}) = a_{I} + B_{I} * \mathrm{Ln}\,(p^{m}_{t} / p^{m}_{t-1})$$

   Where:

   - p^{I}_{t} is the price of the security I at time t
   - p^{I}_{t-1} is the price of the security I one week before time t
   - p^{m}_{t} and p^{m}_{t-1} are the corresponding values of the market index
   - B_I is the regression estimate of Beta for the security against the market index
2. The natural log of the price ratio is used as an approximation of each return and no adjustment is made for dividends paid during the week.
3. Weekly returns are calculated weekly on Tuesdays to minimize the effect of holidays as much as possible.
4. Betas calculated using the regression method above are adjusted as per Blume (1971)[46] using the following formula:

   $$\text{Adjusted } B_{I} = 0.35 + 0.67 * \text{Calculated } B_{I}$$

[46] M. Blume, On the Assessment of Risk, The Journal of Finance, Vol. XXVI, March 1971.

The only significant difference between my beta calculations and Value Line's calculations is that, whereas Value Line uses the NYSE Composite Index as the market index, I use the S&P 500 Index. S&P 500 Index has a much larger number of options traded, making the calculation of option-implied betas more reliable, and I wanted to make my historical betas as comparable as possible to my option-implied betas. Value Line only calculates betas every three months and always uses a five year period for the return regression in their company reports,[47] whereas I use the same consistent methodology to calculate betas every week during the most recent three complete months (January through March 2021) and calculate historical betas for periods of six months, two years, and five years, as shown in Chart 12 on page 60.

Q. PLEASE EXPLAIN HOW YOU CALCULATED OPTION-IMPLIED BETAS.

A. Calculating option-implied betas of a company requires (1) obtaining stock option data for that company and a market index, (2) filtering the stock option data, (3) calculating the option-implied volatility for the company and for the index, (4) calculating the option-implied skewness for the company and for the index, and (5) calculating option-implied betas for the company based on implied volatility and skewness for the company and for the index. There are various ways one could choose to perform the steps above, but I chose to filter stock option data and calculate option-implied volatility[48] and skewness[49] following exactly the same methodology used by the Chicago Board of Options Exchange

[47] They offer betas calculated over different time periods on their website, including 3 years and 10 years.
[48] CBOE Volatility Index White Paper, 2018. Cover page says "proprietary information." The author has had access to this document in the public domain for at least 3 years.
[49] The CBOE SKEW Index, 2010. Cover page says "proprietary information." The author has had access to this document in the public domain for at least 3 years.

(CBOE) in the calculation of their widely-used VIX (or Volatility Index) and SKEW Index, respectively.

I start my process with publicly available trading information for all the options for a given security (company or index) for a complete trading day. I then filter the option data as described by the CBOE using the following guidelines:

1. Use the mid-quote or mark (average of bid and ask) as the option price.
2. Use only out-of-the-money call and put options.
   - Determine the "moneyness" threshold where absolute difference between call and put prices is smallest (using CBOE "Forward Index Price" formula).
   - Include "at-the-money" call and put options and use average of call and put prices as price for "blended" option.
3. Exclude all zero bids.
4. Exclude remaining (more out-of-the-money) options when two sequential zero bids are found.

I then apply the series of formulas clearly described in both of the CBOE's white papers to the remaining options to calculate Option-Implied Volatility and Option-Implied Skewness. In the words of the CBOE, each of its two indices is "an amalgam of the information reflected in the prices of all of the selected options." To be clear, Implied Volatility is not exactly the same as the VIX Index and Implied Skewness is not exactly the same as the SKEW Index, but both indices are directly based on their corresponding statistical value.

Option-Implied Volatility reflects investors' expectations regarding future stock price movements. Option-Implied Skewness reflects investors' expectations regarding how implied volatility changes for strike prices that are closer and further to the current value of the underlying stock price.

The CBOE calculates Times to Expiration by the minute—as do I. The Time to Expiration of traded options cannot be changed and varies from day to day. For the sake of consistency, the CBOE calculates the VIX and SKEW indices on a "30-day" basis by interpolating for two sets of options with Times to Expiration closest to the 30-day mark. I prefer to focus on as long of a time horizon as possible for forecasting purposes. Option Times to Expiration vary significantly for various stocks but can relatively consistently be found to go out to 6 months (180 days) for utility companies. Therefore, for the sake of consistency, I have chosen to interpolate to calculate 6-month volatility and skewness where possible. Occasionally, Times to Expiration for a given stock do not go out to 180 days. If the greatest Time to Expiration available is 171 days (95%) or greater, I use the volatility and skewness for that group of options as a proxy for the 180-day volatility and skewness, respectively.

Finally, once I have calculated the option-implied volatility and skewness for each company and index using the methodology described above, I calculate option-implied betas using the following formula developed by Christoffersen, Chang, Jacobs and Vainberg (2011): [50]

$$\beta_i = \left(\frac{SKEW_i}{SKEW_m}\right)^{1/3} \left(\frac{VAR_i}{VAR_m}\right)^{1/2}$$

[50] Bo-Young Chang & Peter Christoffersen & Kris Jacobs & Gregory Vainberg. (2011) Option-Implied Measures of Equity Risk, *Review of Finance* 16: 385-428.

Where:

β_i: $option - implied\ beta\ of\ security\ (e.g. stock, fund)$;
$SKEW_i$: $skewness\ of\ security$;
$SKEW_m$: $skewness\ of\ overall\ market\ (S\&P\ 500)$;
VAR_i: $variance\ of\ company$;
VAR_m: $variance\ of\ overall\ market\ (S\&P\ 500)$.

Q. YOU CALCULATE YOUR OPTION-IMPLIED BETAS BASED ON A SIX-MONTH HORIZON. WOULD IT NOT BE BETTER TO USE A LONGER FORECASTING HORIZON?

A. The methodology I use to calculate my option-implied betas "allows for the computation of a complete term structure of beta for each company so long as the options data are available,"[51] so there is nothing inherent in the methodology that limits it to a certain time horizon.

For many applications, including cost of capital, one could argue that the longer the time horizon for the option-implied betas, the better. However, the limitation on the forecasting horizon is always set by the longest expiration period of the options currently traded in the market. Some companies trade options with expiration periods up to two years or more into the future. As evidenced by the exhaustive option data in my working papers, the maximum expiration period for the options of the companies in my RFC Electric Proxy Group is between six and twenty-seven months. Only 12 of the 9 companies trade options with expiration periods of eight months or more, so for consistency across companies in my proxy group, I chose to use six months for the time horizon of my option-implied betas.

[51] Peter Christoffersen, Kris Jacobs, and Gregory Vainberg, "Forward-Looking Betas", April 25, 2008, Page 24.

Simply because it may be better to use longer time horizons in place of or in addition to a six-month horizon, it does not mean that a six-month option-implied beta is of no relevance or cannot be used. That would be tantamount to saying you cannot use a one-year Value Line Earnings Per Share estimate, or that the minimum relevant forecast is two or three years. In fact, for purposes of option-implied betas, it would be difficult to say if a time horizon of one year, for instance, is necessarily always better than a time horizon of six months. An option-implied forward-looking beta, even with a time horizon of less than six months, is still a useful tool in interpreting the current expectations of investors at any given time.

A final strong argument in support of using six-month option-implied betas in a cost of capital calculation looking years into the future is that, as expanded upon on page 67, the authors of the paper on which I based my option-implied betas concluded that their predictive powers are not limited to six months into the future. In fact, they conclude that six-month option-implied betas have stronger predictive power than six-month, one-year, or five-year historical betas when attempting to forecast betas one or two years into the future.

Q. WHY DIDN'T YOU USE LONG-TERM EQUITY ANTICIPATION SECURITIES (LEAPS), WHICH ARE OPTIONS CONTRACTS WITH AN EXPIRATION DATE OF TYPICALLY MORE THAN ONE YEAR?

A. It is not possible to use LEAPS to calculate option-implied betas for all utility companies because these contracts are not traded for many of them. Only 12 of the 9 companies in my RFC Electric Proxy Group trade options with expiration periods of eight months or more. For consistency across companies in my proxy group, I chose to use six months for the time horizon of my option-implied betas. As explained above, option-implied betas calculated from options contracts with expiration periods less than one year, in my case six months, are still a useful tool in interpreting investors' current expectations and are superior to the historical betas. As a further note, I use LEAPS in my CAPM when the data is available. The risk premium portion of my CAPM is based on options contracts with expiration periods exceeding one year, and as far out as 32 Months.

Q. HOW DID YOU DECIDE ON THE RELATIVE WEIGHTS YOU ALLOCATE TO EACH COMPONENT OF YOUR HYBRID BETAS? IS THERE ANY ACADEMIC SUPPORT FOR YOUR APPROACH?

A. I am not aware of any academic study specifically focused on the optimal relative weight of historical betas to predict future betas. However, the authors of the paper I relied upon for guidance on the calculation of my option-implied betas did attempt to quantify the predictive power of six-month option-implied ("forward-looking") betas as well as that of six-month ("180-day"), one-year, and five-year historical betas by back-testing historical predictions with actual *expost* results, or "realized" betas, for the 30 companies in the Dow Jones Index. In addition to using each of the betas above independently, they also measured the predictive power of a "mixed" beta consisting of a simple average of the six-month option-implied beta and the six-month historical beta.

Their conclusions for predicting six-month future betas are as follows:

> The forward-looking beta outperforms the other methods ten times, and the same is true for the 180-day historical beta. The mixed beta is the best performer in seven cases, and the 1-year historical beta in three cases. The 5-year historical beta is always outperformed by at least one other method,

> and it often ranks last. The 180-day historical beta clearly dominates the two other historical methods.[52]

Their conclusions for predicting one-year and two-year future betas are as follows:

> Somewhat unexpectedly, the performance of the forward-looking beta compared to that of the 180-day historical beta is much better [for the one-year prediction] than [for the six-month prediction], and this conclusion carries over to [the two-year prediction]. The mixed beta also perform [sic] well. It is perhaps not surprising that the performance of the 180-day historical beta [for the one- and two-year predictions] is poorer than [for the six-month prediction], because the horizons used in the construction of realized betas are no longer equal to 180 days. What is harder to explain is why the correlation between realized beta and forward-looking beta is in many cases higher [for the one- and two-year predictions] than [for the six-month prediction]. Finally, it is also interesting that the 1-year and 5-year historical betas do not perform well [for the one-and two-year predictions]. In summary, [for the one-year prediction] either the forward-looking beta or the mixed beta is the best performer in nineteen out of thirty cases. [For the two-year prediction], this the case twenty-two times out of thirty.[53]

Their conclusions strongly support the use of six-month historical betas, six-month option-implied betas, and/or an average of the two as predictors of future betas six months, one year, or two years into the future. They also seem to indicate that historical betas lose predictive power the longer the period that is used.

I decided on the composition of my hybrid betas primarily based on the conclusions of the authors above. A mixed or hybrid beta made up of 50% historical betas and 50% forward-looking option-implied betas seemed to be the best way to go. Though the predictive power of longer-term historical betas seems to be quite reduced, it is not zero, so in an effort to preserve the effect of longer-term market trends in my hybrid betas, I chose to further subdivide the historical component into 50% (25% of the hybrid) for the

[52] Peter Christoffersen, Kris Jacobs, and Gregory Vainberg, "Forward-Looking Betas", April 25, 2008, Page 16.
[53] Peter Christoffersen, Kris Jacobs, and Gregory Vainberg, "Forward-Looking Betas", April 25, 2008, Page 17.

stronger predicting six-month historical betas, 30% (15% of the hybrid) for the two-year historical betas, and 20% (10% of the hybrid) for the five-year historical betas.

Market Risk Premium

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE EQUITY RISK PREMIUM USED IN YOUR CAPM.

A. Traditionally, the risk premium used in CAPM calculations is calculated from historical returns and/or equity analyst projections. The former approach is historically accurate but does not take into account investors' expectations for future market risks and returns. The latter approach is based on analyst projections, which are not market-based and do not reflect current investor expectations. A superior market-based way to calculate the equity risk premium is to use option-implied return expectations, which is the approach I have used.

My equity risk premium is the expected return on the S&P 500 minus the risk-free rate. I calculate an expected return on the S&P 500 by using stock options traded on this index. To begin with, I use exactly the same methodology used by the CBOE to filter stock option data and calculate option-implied volatility and skewness,[54] as described in detail in the Beta section on page 62. The volatility and skewness calculated in this way describe a probability function representing the possible trajectories for the S&P 500 implied by the options market. The resulting skewed probability function can be closely approximated by a log-normal function using established statistical formulas, which then make it straightforward to calculate the expected growth for the S&P 500 for any given cumulative probability. A cumulative probability of 50% represents the median of the probability

[54] As used in the calculation of their widely-used VIX (or Volatility Index) and SKEW Index, respectively.

distribution, or the option-implied market consensus, which is how I arrive at my calculation of expected market growth.

Once the option-implied growth rate of the S&P 500 has been estimated as described above, I add the dividend yield and subtract the risk-free rate in order to arrive at the market risk premium, as laid out in Exhibit ALR-4, page 4 and Exhibit ALR-4, page 6. In line with my Spot and Weighted Average CAPM approaches, I use both spot values as of March 31, 2021 and weighted averages over the three months ending on that date for option-implied growth, dividend yields, and short- and long-term risk-free rates in these calculations to arrive at a total of four values for the market risk premium. The market risk premium I use in my Weighted Average CAPM analysis with short- and long-term risk-free rates is 10.29% and 8.14%, respectively. The market risk premium I use in my Spot CAPM analysis with short- and long-term risk-free rates is 9.62% and 7.24%, respectively.

Q. DID YOU TAKE INTO CONSIDERATION THE DIFFERENCE IN VOLATILITIES ACROSS EXPIRATION PERIODS IN THE OPTIONS TRADED ON THE S&P 500?

A. Yes. The volatility implied by the options market changes over time as investors' perception of risk changes. For example, during a crisis, implied volatility generally increases as investors expect that stock market prices have a greater chance of large swings compared to times when there is no crisis. As discussed earlier, investors also often have different volatility expectations over different time periods. For example, on any given day, investors might expect volatility to be relatively high over the next 30 days and to decrease over the next year or longer. The same holds true for skewness, even though it is less intuitive to understand changes in skewness than in volatility. Because of these changes across option expiration periods, I take a weighted average of the entire term structure of the option-implied volatility and skewness, which for the S&P 500 typically goes out to 26 to 35 months, interpolating where necessary, and giving the most weight to the option expiration period of 12 months.

Q. WHICH CUMULATIVE PROBABILITY DID YOU USE TO ESTIMATE THE OPTION-IMPLIED GROWTH OF THE S&P 500 IN THE CALCULATION OF YOUR MARKET RISK PREMIUM AND WHY?

A. I used a cumulative probability of 50.0% in the calculation of my option-implied growth for the S&P 500, which results in a value of 8.20% as of March 31, 2021 and a value of 8.85% for the weighted average of the three months ending on that date. As stated above, a cumulative probability of 50% represents the median of the probability distribution, or in this case the option-implied market consensus, which is why I have chosen to use this level.

As a matter of fact, using the same probability distribution derived from the options market described above, one can also calculate the cumulative probability implied by a given cost of capital. For instance, using the same risk-free rates and betas in my Weighted Average CAPM analysis, a rate of return on equity of 10.75% implies an average market risk premium of 15.9%, an average overall market return of 17.0%, average growth for the S&P 500 of 15.5%, and a cumulative probability of 65.5%. In other words, to achieve the required growth of 15.5%, reality would have to exceed 65.5% of the scenarios investors see as plausible for the market in aggregate, considerably more than the median market consensus at 50%. To put this into perspective, it is important to note that values on the tails of the probability function get increasingly separated, requiring an ever-increasing growth rate for every additional percentage in the cumulative probability, and making it impossible to ever arrive at 100%.

Using exactly the same methodology, the midpoint of my recommended cost of equity range for UGI Electric (8.30%) implies an average market risk premium of 11.8%, an average overall market return of 12.9%, average growth for the S&P 500 of 11.4%, and a cumulative probability of 55.6%.

CAPM Results

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR CAPM.

A. Table 9 and Table 10 below show the results of my Weighted Average CAPM and Spot CAPM Analyses, respectively.

Weighted Average CAPM

TABLE 9: CAPITAL ASSET PRICING MODEL (CAPM) - INDICATED COST OF EQUITY
WEIGHTED - All Inputs Weighted From January 2021 to March 2021

	3-Month Treasury Bill		30-Year Treasury Bond	
	Hybrid Beta	Forward Beta	Hybrid Beta	Forward Beta
Risk-Free Rate	0.04%	0.04%	2.20%	2.20%
Beta	0.59	0.58	0.59	0.58
Risk Premium	10.29%	10.29%	8.14%	8.14%
CAPM	6.15%	5.97%	7.02%	6.88%

Source: Exhibit ALR-4, page 1

Spot CAPM

TABLE 10: CAPITAL ASSET PRICING MODEL (CAPM) - INDICATED COST OF EQUITY (SPOT)
SPOT - All Inputs Based on Last Available Data as of March 31, 2021

	3-Month Treasury Bill		30-Year Treasury Bond	
	Hybrid Beta	Forward Beta	Hybrid Beta	Forward Beta
Risk-Free Rate	0.03%	0.03%	2.41%	2.41%
Beta	0.63	0.62	0.63	0.62
Risk Premium	9.62%	9.62%	7.24%	7.24%
CAPM	6.10%	5.98%	6.98%	6.89%

Source: Exhibit ALR-4, page 5

VI. ADDITIONAL COMMENTS ON MR. MOUL'S TESTIMONY

Q. PLEASE SUMMARIZE THE TESTIMONY OF MR. MOUL.

A. Mr. Moul has recommended that the Company be allowed a return on equity of 10.75%, a cost of debt of 4.25% and an overall cost of capital of 7.57%.[55] He arrived at his recommendation based upon his own versions of the Discounted Cash Flow ("DCF") model, Risk Premium analysis, Capital Asset Pricing Model ("CAPM") and the Comparable Earnings approach. Mr. Moul testified that, "At any point in time, a single method can provide an incomplete measure of the cost of equity depending upon extraneous factors that may influence market sentiment."[56] Mr. Moul adds a leverage adjustment to his DCF result, a credit quality adjustment to his Risk Premium approach and the size adjustment to his CAPM method. Mr. Moul applied his four cost of equity

[55] Mr. Moul's Direct Testimony, Schedule 1
[56] Mr. Moul's Direct Testimony, page 6, lines 4-6.

methods to his "Electric Group" of 9 electric utility companies. The results of Mr. Moul's four cost of equity methods are shown on Table 11 below.

TABLE 11: MR. MOUL'S COST OF EQUITY RESULTS

METHOD	Electric Group	Leverage Adjustment	Size Adjustment	Adjusted Commmon Equity Cost
DCF	9.40%	1.44%	0.00%	10.84%
RP	10.25%	0.00%	0.00%	10.25%
CAPM [1]	13.84%	0.00%	1.02%	14.86%
CE	13.20%	0.00%	0.00%	13.20%

Source: Mr. Moul's Direct Testimony, Schedule 1, page 2 of 2.

[1] CAPM Electric Group result includes a leverage adjustment built into the beta coefficient.

Q. WHAT IS YOUR OVERALL REACTION TO MR. MOUL'S TESTIMONY?

A. Mr. Moul's DCF result is 9.40% before adding 1.44% for a "leverage adjustment."[57] Mr. Moul's DCF result is unreasonably above the market-based cost of equity before including his inappropriate adjustments. Below I will explain why Mr. Moul's adjustments are inappropriate and the flaws in Mr. Moul's DCF method.

A. <u>DCF Method</u>

Q. DOES MR. MOUL CONSIDER THE DCF METHOD HIS PRIMARY METHOD FOR DETERMINING THE COST OF EQUITY?

A. No. He claims that the DCF method has limitations.[58]

Q. WHAT FORMULA DOES MR. MOUL USE IN HIS DCF ANALYSIS?

A. Dividend Yield (D/P) + Growth Rate (g) + leverage Adjustment (lev).[59]

[57] Mr. Moul's Direct Testimony, page 29, lines 13-14.
[58] Mr. Moul's Direct Testimony, page 19, lines 14-19.
[59] Mr. Moul's Direct Testimony, page 29, line 14.

Q. DOES MR. MOUL PROPERLY APPLY THE SIMPLIFIED OR CONSTANT DCF METHOD?

A. No. Mr. Moul adds a growth component to a dividend yield even though his growth analysis gives earnings per share growth forecasts by analysts the greatest emphasis.[60] It is only a DCF method if the dividend yield is computed properly, and the growth rate used is derived from a careful study of what future sustainable growth in cash flow is anticipated by investors.

Q. HOW DID MR. MOUL CALCULATE HIS GROWTH RATE FOR HIS DCF METHOD?

A. On page 22, lines 13-14 of Mr. Moul's testimony he says "…IBES/First Call, Zacks, and Value Line, provide the best indication of investor expectations."[61] Mr. Moul states, "DCF growth rates should not be established by a mathematical formulation, and I have not done so. In my opinion, a growth rate of 5.25% is a reasonable estimate of investor-expected growth of the Electric Group."[62] Below are the five-year projected earnings per share rates by the four investment research firms he chose:

IBES/First Call: 4.33%

Zacks: 4.80%

Value Line: 5.39%

Mr. Moul's 5.25% growth rate is higher than the average of I/B/ES and Zacks' growth forecasts. The average of Value Line's earnings forecasts for the nine companies in Mr. Moul's Electric Group is 5.39%, but this includes a 10% growth rate for NextEra

[60] Mr. Moul's Direct Testimony, Schedule 9.
[61] Mr. Moul's Direct Testimony, page 25, lines 2-3.
[62] Mr. Moul's Direct Testimony, page 25, lines 6-8.

Energy. If investors consider NextEra Energy's growth rates to be an outlier and not representative of Electric Group's growth prospects, Mr. Moul's DCF result of 9.40% significantly overstates UGI Electric's cost of equity.

Q. IS MR. MOUL'S METHODOLOGY TO DETERMINE THE GROWTH RATE TO USE IN HIS DCF MODEL APPROPRIATE?

A. No. Mr. Moul mentions the "b x r" method on pages 20-21 of his direct testimony but he does not use it. As stated above, Mr. Moul uses analyst five-year earnings per share growth without attempting to reconcile the retention rate used for computing growth with the retention rate he used to compute the dividend yield. This is analogous to failing to reconcile the money you are taking out of your checking account with your future balance, i.e., the basic balancing of a checkbook.

Q. CAN YOU PLEASE SUMMARIZE WHY A FUTURE ORIENTED "B X R" METHOD IS SUPERIOR TO A FIVE-YEAR EARNINGS PER SHARE GROWTH RATE FORECAST IN PROVIDING A LONG-TERM SUSTAINABLE GROWTH RATE?

A. Yes. The primary cause of sustainable earnings growth is the retention of earnings. A company can create higher future earnings by retaining a portion of the prior year's earnings in the business and purchasing new business assets with those retained earnings. There are many factors that can cause short-term swings in earnings growth rates, but the long-term sustainable growth is caused by retaining earnings and reinvesting those earnings. Factors that cause short-term swings include anything that causes a company to earn a return on book equity at a rate different from the long-term sustainable rate.

Assume, for example, that a particular utility company is regulated so that it is provided with a reasonable opportunity to earn 9.0% on its equity. If the company should experience an event such as the loss of several key customers, or unfavorable weather conditions which cause it to earn only 6.0% on equity in a given year, the drop of 9% earned return on equity to a 6% earned return on equity would be concurrent with a very large drop in earnings per share. In fact, if a company did not issue any new shares of stock during the year, a drop from a 9% earned return on book equity to a 6% earned return on book equity would result in a 33.3% decline in earnings per share over the period.[63] However, such a drop in earnings would not be any indication of what is a long-term sustainable earnings per share growth rate. If the drop were caused by weather conditions, the drop in earnings would be immediately offset once normal weather conditions return. If the drop were from the loss of some key customers, the company would replace the lost earnings by filing for a rate increase to bring revenues up to the level required for the company to be given a reasonable opportunity to recover its cost of equity.

For the above reasons, changes in earnings per share growth rates that are caused by non-recurring changes in the earned return on book equity are inconsistent with long term sustainable growth, but changes in earnings per share because of the reinvestment of additional assets is a cause of sustainable earnings growth. The "b x r" term in the DCF equation computes sustainable growth because it measures only the growth which a company can expect to achieve when its earned return on book equity "r" remains in equilibrium. If analysts have sufficient data to be able to forecast varying values of "r" in

[63] By definition, earned return on equity is earnings divided by book value. Therefore, whatever level of earnings is required to produce earnings of 6% of book would have to be 33.3% lower than the level of earnings required to produce a return on book equity of 9%.

future years, then a complex, or multi-stage DCF method must be used to accurately quantify the effect. Averaging growth rates over sub-periods, such as averaging growth over the first five years with a growth rate expected over the subsequent period, will not provide an appropriate representation of the cash flows expected by investors in the future and, therefore, will not provide an acceptable method of quantifying the cost of equity using the DCF method. The choices are either a constant growth DCF, in which one "b x r" derived growth rate should be used, or a complex DCF method in which the cash flow anticipated in each future year is separately estimated. Mr. Moul has done neither.

Q. WHY ARE ANALYSTS FIVE-YEAR CONSENSUS GROWTH RATES NOT INDICATIVE OF LONG-TERM SUSTAINABLE GROWTH RATES?

A. Analysts' five-year earnings per share growth rates are earnings per share growth rates that measure earnings growth from the most currently completed fiscal year to projected earnings five years into the future. These growth rates are not indicative of future sustainable growth rates in part because the sources of cash flow to an investor are dividends and stock price appreciation. While both stock price and dividends are impacted in the long-run by the level of earnings a company is capable of achieving, earnings growth over a period as short as five years is rarely in synchronization with the cash flow growth from increases in dividends and stock prices. For example, if a company experiences a year in which investors perceive that earnings temporarily dipped below normal trend levels, stock prices generally do not decline at the same percentage that earnings decline, and dividends are usually not cut just because of a temporary decline in a company's earnings. Unless both the stock price and dividends mirror every down swing in earnings, they cannot be expected to recover at the same growth rate that earnings recover.

Therefore, growth rates such as five-year projected growth in earnings per share are not indicative of long-term sustainable growth rates in cash flow. As a result, they are inapplicable for direct use in the simplified DCF method.

Q. IS THE USE OF FIVE-YEAR EARNINGS PER SHARE GROWTH RATES IN THE DCF MODEL ALSO IMPROPER?

A. A raw, unadjusted, five-year earnings per share growth rate is usually a poor proxy for either short-term or long-term cash flow that an investor expects to receive. When implementing the DCF method, the time value of money is considered by equating the current stock price of a company to present value of the future cash flows that an investor expects to receive over the entire time that he or she owns the stock. The discount rate required to make the future cash flow stream, on a net present value basis, equal to the current stock price is the cost of equity. The only two sources of cash flow to an investor are dividends and the net proceeds from the sale of stock at whatever time in the future the investor finally sells. Therefore, the DCF method is discounting future cash follows that investors expect to receive from dividends and from the eventual sale of the stock. Five-year earnings growth rate forecasts are especially poor indicators of cash flow growth even over the five years being measured by the five-year earnings per share growth rate number.

Q. WHY IS A FIVE-YEAR EARNINGS PER SHARE GROWTH RATE A POOR INDICATOR OF THE FIVE-YEAR CASH FLOW EXPECTATIONS FROM DIVIDENDS?

A. The board of directors changes dividend rates based upon long-term earnings expectations combined with the capital needs of a company. Most companies do not cut the dividend simply because a company has a year in which earnings were below sustainable trends, and similarly they do not increase dividends simply because earnings for one year happened to be above long-term sustainable trends. Therefore, over any given five-year period, earnings growth is frequently very different from dividend growth. In order for earnings growth to equal dividend growth, at a minimum, earnings per share in the first year of the five-year earnings growth rate period would have to be exactly on the long-term earnings trend line expected by investors. Since earnings in most years are above or below the trend line, the earnings per share growth rate over most five-year periods is different from what is expected for earnings growth.

Q. WHY IS THE FIVE-YEAR EARNINGS PER SHARE GROWTH RATE A POOR INDICATION OF FUTURE STOCK PRICE GROWTH?

A. If a company happens to experience a year in which earnings decline below what investors believe are consistent with the long-term trend, then the stock price does not drop anywhere near as much as earnings drop. Similarly, if a company happens to experience a year in which earnings are higher than the investor-perceived long-term sustainable trend, then the stock price will not increase as much as earnings. In other words, the P/E (price/earnings) ratio of a company will increase after a year in which investors believe earnings are below sustainable levels, and the P/E ratio will decline in a year in which investors believe earnings are higher than expected. Since it is stock price that is one of the important cash flow sources to an investor, a five-year earnings growth rate is a poor indicator of cash flow both because it is a poor indicator of stock price growth over the five years being examined and is equally a poor predictor of dividend growth over the period.

Q. ARE YOU SAYING THAT ANALYSTS' CONSENSUS EARNINGS PER SHARE GROWTH RATES ARE USELESS AS AN AID TO PROJECTING THE FUTURE?

A. No. Analysts' EPS growth rates are, however, very dangerous if used in a simplified DCF without proper interpretation. While they are not useful if used in their "raw" form, they can be useful in computing estimates of what earned return on equity investors expect will be sustained in the future, and as such, are useful in developing long-term sustainable growth rates.

Q. BESIDES GROWTH RATE, ARE THERE ANY OTHER DCF ANALYSIS INPUTS THAT MR. MOUL HAS ESTIMATED INCORRECTLY?

A. Yes. Mr. Moul made an unjustifiable "leverage adjustment."

Q. PLEASE DESCRIBE THE LEVERAGE ADJUSTMENT PROPOSED BY MR. MOUL IN THIS PROCEEDING.

A. Mr. Moul has proposed a leverage adjustment addition to his DCF derived cost of equity, stating "In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes), the market-derived cost rate must be adjusted to account for the difference in financial risk."[64] He then goes on to say: "Because the ratesetting process uses ratios calculated from a firm's book value capitalization, further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the equity."[65] Because of this alleged higher financial risk, Mr. Moul recommends adding 1.44%[66] to the DCF derived cost of equity.

[64] Mr. Moul's Direct Testimony, page 26, lines 5-7.
[65] Mr. Moul's Direct Testimony, page 26, lines 18-21.
[66] Mr. Moul's Direct Testimony, page 29, line 14.

Q. JUST BECAUSE THE MARKET VALUE CAPITAL STRUCTURE CONTAINS A HIGHER PERCENTAGE OF COMMON EQUITY THAN BOOK VALUE CAPITAL STRUCTURE, DOES THIS MEAN THE MARKET VALUE CAPITAL STRUCTURE HAS LOWER FINANCIAL RISK THAN THE BOOK VALUE CAPTIAL STRUCTURE?

A. No. Market value capital structure and book value capital structure are two completely different ways of measuring the same thing. Concluding that a market value capital structure is lower in risk because it contains more equity than the book value based capital structure for the same company is as inconsistent and illogical as claiming that a person who weighs 150 pounds could lose weight simply by stepping on a scale that measures weight in kilos instead of pounds. Financial risk is determined by a company's ability to meet its cash flow obligations. The most common and perhaps most important single measure of financial risk is the pretax interest coverage ratio. The interest coverage ratio is computed by dividing the sum of interest expense and pre-tax income by interest expense. This number is useful because it gives bondholders a sense of how far earnings would have to decline before a company would not be able to meet its interest payments. For example, if a company has an interest coverage ratio of 3.0, this means that at its current earnings rate, its earnings available for both payment of interest and pre-tax earnings, is three times as much as is needed to make its interest payments.

Q. DOES A DECLINE IN MARKET PRICE LOWER THE COVERAGE RATIO?

A. Lowering of the market value does not directly cause a change in the coverage ratio computation. Therefore, changing from a market value orientation to a book value orientation does no more to change a company's financial risk than the weight of a person was influenced by switching to a scale calibrated in kilos instead of pounds.

Q. DO INVESTORS UNDERSTAND THAT AS PART OF THE REGULATORY PROCESS ALLOWED RETURNS ARE APPLIED TO BOOK VALUE?

A. Yes, they do. This is a process that has been going on for decades and it is hard to argue that investors are not aware of this. By recommending this leverage adjustment, Mr. Moul is implying that investors forget this after each rate case. Evaluating the cost of equity based on a comparative group is like taking a snapshot of their expectations. After this snapshot is taken, it is then applied to the individual company so even if the allowed return affected the expectation of the investors in the comparative group it would be after the snapshot was taken.

Q. DOES MR. MOUL'S LEVERAGE ADJUSTMENT GO AGAINST ORIGNAL COST RATEMAKING?

A. Yes. Mr. Moul claims, "The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different than indicated by the market price (P)."[67] In other words, Mr. Moul is saying that as a consequence of original cost ratemaking an upward adjustment is needed. When a company has a market to book value above 1, and is thus over earning, applying the correct rate of return to the book value could have downward pressure on the stock price. No matter what logic is applied to the reason for adding a value to the rate of return, the leverage adjustment distorts the natural market dynamic between a regulated utility's stock price and its allowed rate of return.

[67] Mr. Moul's Direct Testimony, page 26, lines 11-13.

B. Risk Premium Method

Q. PLEASE EXPLAIN MR. MOUL'S VERSION OF THE RISK PREMIUM METHODS, AS PRESENTED IN HIS DIRECT TESTIMONY.

A. Mr. Moul calculates an equity risk premium of large company stocks over long-term corporate bonds based on historical data between 1926-2019 and presents the results in three categories based on the relative level of interest rates.

Category Equity Risk Premium:

Low Interest Rate 6.70%

Average Across All Interest Rates 5.69%

High Interest Rates 4.69%[68]

Q. PLEASE COMMENT ON MR. MOUL'S RISK PREMIUM METHOD.

A. Mr. Moul's equity risk premium is flawed for two reasons. First, Mr. Moul uses a bond yield of 3.5%[69] in his analysis based on a projected yield of A-rated public utility bonds instead of using the actual current market yields (2.77% - 2.95% for the six months)[70]. As discussed throughout my testimony, the cost of equity should be based on investors' expectations as indicated by market data and not on "expert forecasts". Economists have been forecasting interest rates will raise for decades, but they have not. Consumers should not be charged rates based on such completely unreliable forecasts. See Chart 11 on page 57 for data demonstrating how inaccurate these forecasts have been. Second, Mr. Moul's

[68] Mr. Moul's Direct Testimony, page 32, lines 16-17.
[69] Ibid. page 30, line10-12.
[70] Ibid. lines 16-18

claim there is an inverse relationship between the common equity risk premium and interest rates is based on a flawed analysis that mismatches historical equity returns and expected bond yields. See Schedule 12, page 2 of 2 of Mr. Moul's Direct Testimony.

C. CAPM Method

Q. PLEASE SUMMARIZE MR. MOUL'S CAPM METHOD.

A. Mr. Moul explains that, "To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return."[71] He uses a risk free rate of 2.00% based on interest rate forecasts and recent trends in long term Treasury yields.[72] His market premium portion of his CAPM analysis (10.96%) is based on the forecasted S&P 500 returns. He adds a "small size adjustment" of 1.02% to account for the relatively small size of UGI Electric relative to the companies in the Electric Group.[73]

Q. DO YOU AGREE WITH THE RESULTS OF MR. MOUL'S CAPM ANALYSIS?

A. No, I do not agree with results of Mr. Moul's CAPM analysis because I believe that they significantly and inaccurately overstate the Company's cost of equity.

The arithmetic average return that Mr. Moul uses overstates the historical risk premium by nearly 200 basis points. The 2021 SBBI Yearbook shows that investors actually earned a compounded annual return of 10.3%[74] between 1926 and 2020. The

[71] Mr. Moul's Direct Testimony, page 33, lines 16-20.
[72] Ibid. page 36, lines 17-24.
[73] Ibid. page 38, line 8.
[74] Ibbotson SBBI® 2021 Classic Yearbook, page 2-23.

arithmetic mean return of 12.2%[75] is possibly valuable to stockbrokers and fund managers attempting to predict future bonuses, but not for calculating the cost of equity. A Dow Jones Newswire article stated, "Some financial advisers rely too heavily on a formula known as the arithmetic average, which can be misleading when investing for the long term. Financial advisors who use this formula may be overstating your potential profit and leading you to take risks you might otherwise avoid…"[76] His prospective risk premium calculation is based on a DCF analysis that is not based on sustainable growth. His DCF analysis for the S&P 500 has a growth component of an astounding 12.47%.[77]

Q. IS MR. MOUL'S ADDER FOR A SMALL SIZE EFFECT AN APPROPRIATE PART OF A CAPM ANALYSIS?

A. No. Mr. Moul's premium adder for the relatively small size of UGI Electric is unjustifiable. A proper analysis of the data from Ibbotson SBBI/Morningstar shows that size is a diversifiable risk and therefore does not impact the cost of equity. Professor Aswath Damodaran said the following regarding the supposed "small cap premium": Even if you believe that small cap companies are more exposed to market risk than large cap ones, this is an extremely sloppy and lazy way of dealing with that risk, since risk ultimately has to come from something fundamental (and size is not a fundamental factor).[78]

[75] Ibid.
[76] Kaja Whitehouse, To Financial Advisors and Fuzzy Math, Dow Jones Newswires October 8, 2003.
[77] Mr. Moul's Direct Testimony, Schedule 13, page 2 of 3.
[78] Aswath Damodaran, Equity Risk Premiums (ERP): Determinates, Estimation and Implications – The 2014 Edition (paper updated, March 2015) page 42.

D. Comparable Earnings Method

Q. PLEASE EXPLAIN THE COMPARABLE EARNINGS METHOD PRESENTED BY MR. MOUL.

A. Mr. Moul selected a group of non-regulated companies that he believes to be of comparable risk to the Electric Group. After selecting the companies, he presents the historic and Value Line expected return on book equity. See Schedule 14, page 2 of 3 of Mr. Moul's direct testimony. The final column of numbers on this table is the "Projected 2023-25." However, what he labels as the projected 2023-25 return is actually the return on book equity that Value Line forecasts, not the return that Value Line projects investors will receive on their investment as a result of purchasing the common stock at current prices. According to Mr. Moul's Schedule 14, the total return expected by Value Line on the book equity of these industrial companies is between a 6.50% and a high of 71.5%, for an average of 21.8% (13.2% excluding companies with values > 20%).

Q. IS THIS METHOD VALID?

A. No. Mr. Moul has attempted to determine the cost of equity that would be demanded by investors on the market price of a company comparable to UGI Electric by comparing it to the historic and projected returns on book equity of a selection of industrial companies. Leaving aside the problems with actually being able to select companies that are comparable, the overriding problem with Mr. Moul's comparable earnings analysis is that it did not address the cost of equity at all. It simply considered the returns on book equity that were achieved and are expected to be achieved by Value Line in the next 3 to 5 years. The earned return on book equity is an entirely different concept from the cost of equity.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF MR. MOUL'S TESTIMONY.

A. Mr. Moul recommends that the Company be allowed a return on equity of 10.75%. Mr. Moul's DCF result of 10.84% is high because he adds a leverage adjustment that misrepresents the basics of evaluating a company's cost of equity. Without his leverage adjustment and credit quality addition his DCF result is 9.40%. Mr. Moul's Risk Premium method was developed based upon an improper mathematical approach to quantifying historic actual returns. Mr. Moul's CAPM approach relies on invalid implementations of the DCF method to quantify the projected cost of equity, an improper inflation of the "beta" because of a high market-to-book ratio, and he adds the invalid "size premium." The incorrect claim that investors demand a higher cost of equity to invest in a small company (referred to as "size premium") is manufactured by an incorrect use of data. Mr. Moul's Comparable Earnings method is not really an equity costing method at all, as no consideration was given to investor's reactions to the earned returns on book equity.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.

A. In line with the Commission's stated preference for the DCF model and based on the range of the DCF results presented in my testimony, I conclude that the cost of equity allowed for UGI Electric's electric distribution operations should be between 7.61% and 8.99% (recommended at the DCF midpoint of 8.30%).[79] Based on my recommended common equity ratio of 51.20%, which is in line with the Commission's stated preference for using the actual capital structure used by the utility, that results in an overall cost of capital of between 5.97% and 6.68% (recommended at 6.32%).

My cost of equity recommendation of 8.30% (7.61% to 8.99%) satisfies the requirements of *Hope* and *Bluefield* and should serve as the starting point for the Commission's determination of a fair rate of return.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APPENDIX A: RESUME OF AARON L. ROTHSCHILD

SUMMARY

Financial professional providing expert rate of return testimony in utility (water, electric and gas) rate case proceedings, applied mathematics research for utility industry as an affiliate of the New England Complex Systems Institute, and industry experience includes Head of Business Analysis for a major US telecom firm in Asia Pacific.

EXPERIENCE

Rothschild Financial Consulting, Ridgefield, CT **November 2001- present**
Independent consulting firm specializing in utility sector
President

- Providing technical and expert witness services to the California Public Advocates Office to evaluate the financial health, basic operation, wildfire cost recovery and organizational culture/governance of gas and electric utilities (I.15-08-019), including evaluating alternatives to PG&E.
- Provide financial testimony (e.g., rate of return and M&A) to state governments in utility rate cases, including the 2020 California energy cost of capital proceedings.
- Present at utility regulation conferences (NARUC/NASUCA and MARC) regarding rate of return, power purchase agreements, complex systems science, and subsidy auctions.

360 Networks, Hong Kong **January 2001 - October 2001**
Pioneer of the fiber optic telecommunications industry
Senior Manager

- Business development and investment evaluation
- Negotiated landing rights and formed local partnerships in Korea, Japan, Singapore, and Hong Kong for $1 billion undersea cable project
- Structured fiber optic bandwidth swapping agreement with Enron and Global Crossing
- Established relationships with Hong Kong based Investment Bankers to communicate Asia Pacific objectives and accomplishments to Wall Street

Dantis, Chicago, IL **July 2000- December 2000**
Start-up managed data-hosting services provider
Director

- Built capital raise valuation models and negotiated with potential investors
- Team raised $100M from venture capital firm through valuation negotiations and internal strategic analysis

MFS, MCI-WorldCom, Chicago, Hong Kong, Tokyo **September 1996- July 2000**
American Telecommunications Company
Head of Business Analysis for Japan operations

- Managed staff of 5 business development analysts
- Raised $80M internally for Japanese national fiber network expansion plan by conducting an investment evaluation and presenting findings to CEO of international operations in London, UK
- Built financial model for local fiber optic investment evaluation that was used by business development offices in Oak Brook, IL and Sydney, Australia

EDUCATION

Vanderbilt University, Nashville, TN **1994-1996**
MBA, Finance
- Completed business plan for Nextlink Communications in support of their national fiber optic network expansion, including identifying opportunities from passage of Telecom Act of 1996
- Developed analytical framework to evaluate predictability of rare events
- Provided financial and accounting analysis to Chicago's consumer advocate, the Citizens Utility Board (CUB) as a summer intern

Clark University, Worchester, MA **1990 - 1994**
BA, Mathematics

APPENDIX B: TESTIFYING EXPERIENCE OF AARON L. ROTHSCHILD

Filed Rate of Return Testimonies:

California
- Pacific Gas and Electric Company, Application 21-01-004, Securitization, February 2021
- Pacific Gas and Electric Company, Application 20-04-023, Securitization, October 2020
- Southern California Edison, Application 20-07-008, Securitization, September 2020
- San Diego Gas & Electric Company, Application 19-04-017, Rate of Return, August 2019
- Southern California Gas Company, Application 19-04-016, Rate of Return, August 2019
- Pacific Gas and Electric Company, Application 19-04-015, Rate of Return, August 2019
- Southern California Edison, Application 19-04-014, Rate of Return, August 2019
- Liberty Utilities, Application A.18-05-006, Rate of Return, August 2018
- San Gabriel Water Company, Application 18-05-005, Rate of Return, August 2018
- Suburban Water Company, Application 18-05-004, Rate of Return, August 2018
- Great Oaks Water Company, Application 18-05-001, Rate of Return, August 2018
- California Water Service Company, Application 17-04-006, Rate of Return, August 2017
- California American Water Company, Application 17-04-003, Rate of Return, August 2017
- Golden State Water Company, Application 17-04-002, Rate of Return, August 2017
- San Jose Water Company, Application 17-04-001, Rate of Return, August 2017

Colorado
- Public Service Company of Colorado, Docket No. 11AL-947E, Rate of Return, March 2012

Connecticut
- Eversource and United Illuminating, Docket No. 17-12-03RE11, Rate of Return / Interim Rate Reduction, April 2021
- United Water Connecticut, Docket No. 07-05-44, Rate of Return, November 2008
- Valley Water Systems, Docket No. 06-10-07, Rate of Return, May 2007

Delaware
- Tidewater Utilities, Inc., PSC Docket No. 11-397, Rate of Return, April 2012
- Delmarva Power & Light, PSC Docket No. 09-414, Rate of Return, February 2010
- Delmarva Power & Light, PSC Docket No. 09-276T, Rate of Return, February 2010

Florida
- Florida Power & Light (FPL), Docket No. 070001-EI, October 2007
- Florida Power Corp., Docket No. 060001 Fuel Clause, September 2007

New Jersey
- Aqua New Jersey, Inc., BPU Docket No. WR11120859, Rate of Return, April 2012

Maryland
- Delmarva Power & Light, Case No. 9317, Rate of Return, June 2013
- Columbia Gas of Maryland, Case No. 9316, Rate of Return, May 2013
- Potomac Electric Power Company, Case No. 9286, Rate of Return, March 2012

– Delmarva Power & Light, Case No. 9285, Rate of Return, March 2012

North Dakota

– Montana-Dakota Utilities Co., Case No. PU-20-379, Rate of Return, January 2021
– Otter Tail Power Company, Case No. PU-17-398, Rate of Return, May 2018
– Montana-Dakota Utilities Co., Case No. PU-15-90, Rate of Return, August 2015
– Northern States Power, Case No. PU-400-04-578, Rate of Return, March 2005

Pennsylvania

– Pennsylvania American Water Company, Docket No. P-2021-3022426, Rate of Return, February 2021
– Audubon Water Company, Docket No. R-2020-3020919, Rate of Return, November 2020
– Pennsylvania American Water Company, Docket No. R-2020-3019369 and R-2020-3019371, Rate of Return, September 2020
– Twin Lakes Utilities, Inc., Docket No. R-2019-3010958, Rate of Return, October 2019
– City of Lancaster Sewer Fund, Docket No. R-2019-3010955, Rate of Return, October 2019
– Community Utilities of Pennsylvania Inc. Wastewater Division, Docket No. R-2019-3008948, Rate of Return, July 2019
– Community Utilities of Pennsylvania Inc. Water Division, Docket No. R-2019-3008947, Rate of Return, July 2019
– Newtown Artesian Water Company, Docket No. R-20019-3006904, Rate of Return, May 2019
– Hidden Valley Utility Services, L.P. – Wastewater Division, Docket No. R-2018-3001307, Rate of Return, September 2018
– Hidden Valley Utility Services, L.P. – Water Division, Docket No. R-2018-3001306, Rate of Return, September 2018
– The York Water Company, Docket No. R-2018-3000019, Rate of Return, August 2018
– SUEZ PA Pennsylvania, Inc., Docket No. R-2018-000834, Rate of Return, July 2018
– UGI Utilities, Inc. – Electric Division, Docket No. R-2017-2640058, Rate of Return, April 2018
– Wellsboro Electric Company, Docket No. R-2016-2531551, Rate of Return, December 2016
– Citizens' Electric Company of Lewisburg, PA, Docket No. R-2016-2531550, Rate of Return, December 2016
– Columbia Gas of Pennsylvania, Inc., Docket No. R-2016-2529660, Rate of Return, June 2016
– Columbia Gas of Pennsylvania, Inc., Docket No. R-2015-2468056, Rate of Return, June 2015
– Pike County Light & Power Company, Docket No. R-2013-2397353 (gas), Rate of Return, April 2014
– Pike County Light & Power Company, Docket No. R-2013-2397237 (electric), Rate of Return, April 2014
– Columbia Water Company, Docket No. R-2013-2360798, Rate of Return, August 2013
– Peoples TWP LLC, Docket No. R-2013-2355886, Rate of Return, July 2013
– City of Dubois – Bureau of Water, Docket No. R-2013-2350509, Rate of Return, July 2013
– City of Lancaster – Sewer Fund, Docket No. R-2012-2310366, Rate of Return, December 2012
– Wellsboro Electric Company, Docket No. R-2010-2172665, Rate of Return, September 2010
– Citizens' Electric Company of Lewisburg, PA, Docket No. R-2010-2172662, Rate of Return, September 2010
– T.W. Phillips Gas and Oil Company, Docket No. R-2010-2167797, Rate of Return, August 2010

- York Water Company, Docket No. R-2010-2157140, Rate of Return, August 2010
- Joint Application of The Peoples Natural Gas Company, Dominion Resources, Inc. and Peoples Hope Gas Company LLC, Docket No. A-2008-2063737, Financial Analysis, December 2008
- York Water Company, Docket No. R-2008-2023067, Rate of Return, August 2008

South Carolina

- Dominion Energy South Carolina, Inc., Docket No. 2020-125-E, Rate of Return, November 2020
- Palmetto Utilities, Inc., Docket No. 2019-281-S, Rate of Return, May 2020
- Palmetto Utilities, Inc., Docket No. 2019-281-S, Accounting, May 2020
- Blue Granite Water Company, Docket No. 2019-290-WS, Rate of Return, January 2020

Vermont

- Central Vermont Public Service Corp., Docket No. 7321, Rate of Return, September 2007

OVERALL COST OF CAPITAL
UGI Utilities, Inc. - Electric Division

	Ratios		Cost Rate		Weighted Cost Rate
					[E]
Long-Term Debt	48.80%	[A]	4.25%	[B]	2.07%
Short-Term Debt	0.00%	[C]	0.00%	[C]	0.00%
Preferred Equity	0.00%	[C]	0.00%	[C]	0.00%
Common Equity	51.20%	[A]	8.30%	[D]	4.25%
	100.00%				**6.32%**

RECOMMENDED RANGES

		Low		High
Proxy Group DCF Cost of Equity Range		7.91%		9.29%
Proxy Group DCF Cost of Equity			8.60%	
Based on RFC Capital Structure Recommendation				
Capital Structure Risk Adjustment	[F]		-0.30%	
Adjusted Recommended Cost of Equity Range		**7.61%**		**8.99%**
Company Specific DCF Cost of Equity Recommendation			**8.30%**	
Cost of Capital Range		5.97%		6.68%
Based on Mr. Moul's Capital Structure Recommendation				
Capital Structure Risk Adjustment	[F]		-0.30%	
Adjusted Recommended Cost of Equity Range		**7.61%**		**8.99%**
Company Specific Cost of Equity Recommendation			**8.30%**	
Cost of Capital Range		5.97%		6.68%
Comprehensive Cost of Capital Range				
Cost of Debt Range		4.25%		4.25%
Common Equity Ratio Range		51.20%		43.58%
Comprehensive Cost of Capital Range		5.97%		6.32%

Sources:
[A] Recommendation based on Parent capital structure
[B] RFC Cost of Debt Recommendation
[C] Recommendation based on authorized capital structure and cost rates
[D] Company Specific Cost of Equity Recommendation based on RFC Capital Structure Recommendation
[E] Ratios times Cost Rate
[F] Based on estimate of 0.04% change in Cost of Equity for each 1% difference in Common Equity Ratio compared to the Proxy Group (Exhibit ALR-1, page 1 vs. Exhibit ALR-5, page 4).

COST OF EQUITY SUMMARY

RFC Electric Proxy Group (22 Companies)

		Low		High
DCF				
Constant Growth	[A]	7.91%		7.96%
Non-Constant Growth	[B]	9.08%		9.29%
CAPM				
3-Mo. Weighted Average (Jan. to Mar. 2021)				
3-Month Treasury Bill Risk-Free Rate	[C]	5.97%		6.15%
30-Year Treasury Bond Risk-Free Rate	[C]	6.88%		7.02%
Spot (Mar. 31, 2021)				
3-Month Treasury Bill Risk-Free Rate	[D]	5.98%		6.10%
30-Year Treasury Bond Risk-Free Rate	[D]	6.89%		6.98%
Average		**7.12%**		**7.25%**
Outer Quartile Range		**5.98%**		**8.29%**
Proxy Group Cost of Equity			**7.13%**	

Sources:
[A] Exhibit ALR-3, page 1
[B] Exhibit ALR-3, page 2 and Exhibit ALR-3, page 3
[C] Exhibit ALR-4, page 1
[D] Exhibit ALR-4, page 5

CONSTANT GROWTH DISCOUNTED CASH FLOW (DCF) - INDICATED COST OF EQUITY
RFC Electric Proxy Group (22 Companies)

			Based on Average Market Price For Year Ending 3/31/2021	Based On Market Price As Of 3/31/2021
1	Dividend Yield On Market Price	[A]	3.61%	3.42%
2	Retention Rate:			
	a) Market-to-Book Ratio	[A]	1.92	1.98
	b) Dividend Yield on Book	[B]	6.93%	6.77%
	c) Expected Return on Equity	[C]	10.00%	10.00%
	d) Retention Rate	[D]	30.66%	32.28%
3	Reinvestment Growth	[E]	3.07%	3.23%
4	New Financing Growth	[F]	1.16%	1.23%
5	Total Estimate of Investor Anticipated Growth	[G]	4.23%	4.46%
6	Increment to Dividend Yield for Growth to Next Year	[H]	0.08%	0.08%
7	**Indicated Cost of Equity**	**[I]**	**7.91%**	**7.96%**

Sources:

[A] Exhibit ALR-5, page 1

[B] Line 1 x Line 2a

[C] Some of the considerations for determining Future Expected Return on Equity:

	Median	Mean	From
Value Line Expectation	**10.25%**	**10.30%**	Exhibit ALR-5, page 2
Return on Equity to Achieve Zacks Growth	9.34%	9.72%	Exhibit ALR-5, page 3
Average Historical Growth	10.28%	9.86%	
Earned Return on Equity in 2020	10.10%	9.52%	Exhibit ALR-5, page 2
Earned Return on Equity in 2019	10.45%	10.32%	Exhibit ALR-5, page 2
Earned Return on Equity in 2018	10.30%	9.74%	Exhibit ALR-5, page 2

[D] 1 - Line 2b / Line 2c

[E] Line 2c x Line 2d

			From
[F] S x V = (Ext. Fin Rate) x (Line 2a - 1)	Ext. Fin. Rate =	1.26%	Exhibit ALR-3, page 4

S = rate of continuous new stock financing

V = fraction of funds raised by sale of stock that increases the book value of existing shareholders' common equity

[G] Line 3 + Line 4

[H] Line 1 x one-half of Line 5

[I] Line 1 + Line 5 + Line 6

NON-CONSTANT GROWTH DISCOUNTED CASH FLOW (DCF) - INDICATED COST OF EQUITY

(BASED ON VALUE LINE FORECASTS AND CLOSING STOCK PRICE)

RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
		Forecasted Dividends per Share					Growth	Book Value		Closing Stock Price		Cash Flow From Buying and Selling Stock (At Closing Price)					
		2021	2022	2022	2023	2024	2021-24	3/31/21	3/31/24	3/31/2021	3/31/2024		2021	2022	2023	2024	IRR / DCF
		[A]	[A]	[B]	[B]	[A]	[B]	[C]	[C]	[D]	[E]	[F]	[F]	[F]	[F]	[F]	[G]
AMEREN	AEE	$2.20	NA	$2.41	$2.64	$2.90	9.65%	$35.83	$45.21	$81.36	$102.65		($79.71)	$2.41	$2.64	$103.38	11.09%
AMERICANELEC.PWR.	AEP	$3.00	NA	$3.23	$3.48	$3.75	7.72%	$41.94	$53.14	$84.70	$107.33		($82.45)	$3.23	$3.48	$108.27	12.13%
AVISTACORP.	AVA	$1.68	NA	$1.75	$1.82	$1.90	4.19%	$29.50	$31.77	$47.75	$51.42		($46.49)	$1.75	$1.82	$51.89	6.28%
BLACKHILLSCORP.	BKH	$2.31	NA	$2.45	$2.59	$2.75	5.98%	$41.15	$46.07	$66.77	$74.75		($65.04)	$2.45	$2.59	$75.44	7.62%
CMSENERGYCORP.	CMS	$1.74	NA	$1.91	$2.10	$2.30	9.75%	$19.44	$26.06	$61.22	$82.07		($59.92)	$1.91	$2.10	$82.65	13.45%
CON.EDISON	ED	$3.10	NA	$3.23	$3.36	$3.50	4.13%	$55.88	$62.33	$74.80	$83.44		($72.48)	$3.23	$3.36	$84.31	8.17%
EDISONINTERNAT'L	EIX	$2.68	NA	$2.78	$2.89	$3.00	3.83%	$37.25	$41.97	$58.60	$66.03		($56.59)	$2.78	$2.89	$66.78	8.97%
EVERSOURCEENERGY	ES	$2.40	NA	$2.59	$2.78	$3.00	7.72%	$43.41	$51.36	$86.59	$102.44		($84.79)	$2.59	$2.78	$103.19	8.83%
ENTERGYCORP.	ETR	$3.86	NA	$4.15	$4.46	$4.80	7.54%	$55.28	$65.92	$99.47	$118.60		($96.58)	$4.15	$4.46	$119.80	10.35%
EVERGY,INC.	EVRG	$2.17	NA	$2.32	$2.48	$2.65	6.89%	$38.81	$44.18	$59.53	$67.77		($57.90)	$2.32	$2.48	$68.43	8.44%
FORTIS INC.	FTS.TO	$2.08	NA	$2.25	$2.44	$2.65	8.41%	$36.94	$43.50	$54.53	$64.22		($52.97)	$2.25	$2.44	$64.88	9.89%
IDACORP,INC.	IDA	$2.89	NA	$3.08	$3.28	$3.50	6.59%	$51.16	$57.20	$99.97	$111.76		($97.80)	$3.08	$3.28	$112.64	6.96%
ALLIANTENERGY	LNT	$1.61	NA	$1.75	$1.89	$2.05	8.39%	$23.16	$28.53	$54.16	$66.73		($52.95)	$1.75	$1.89	$67.24	10.51%
MGEENERGYINC.	MGEE	$1.52	NA	$1.64	$1.76	$1.90	7.72%	$27.86	$32.66	$71.39	$83.69		($70.25)	$1.64	$1.76	$84.16	7.79%
NORTHWESTERN	NWE	$2.48	NA	$2.57	$2.66	$2.75	3.50%	$41.43	$44.70	$65.20	$70.35		($63.34)	$2.57	$2.66	$71.04	6.63%
OGEENERGYCORP.	OGE	$1.64	NA	$1.74	$1.84	$1.95	5.94%	$18.26	$21.11	$32.36	$37.41		($31.13)	$1.74	$1.84	$37.89	10.54%
OTTERTAILCORP.	OTTR	$1.56	NA	$1.68	$1.81	$1.95	7.72%	$21.21	$25.24	$46.17	$54.94		($45.00)	$1.68	$1.81	$55.43	9.72%
PINNACLEWEST	PNW	$3.42	NA	$3.62	$3.83	$4.05	5.80%	$50.50	$56.65	$81.35	$91.26		($78.79)	$3.62	$3.83	$92.28	8.52%
PORTLANDGENERAL	POR	$1.68	NA	$1.78	$1.89	$2.00	5.98%	$29.19	$32.21	$47.47	$52.39		($46.21)	$1.78	$1.89	$52.89	7.22%
SOUTHERNCOMPANY	SO	$2.62	NA	$2.72	$2.83	$2.94	3.92%	$26.73	$31.14	$62.16	$72.42		($60.20)	$2.72	$2.83	$73.16	9.74%
WECENERGYGROUP	WEC	$2.71	NA	$2.94	$3.18	$3.45	8.38%	$33.48	$39.23	$93.59	$109.67		($91.56)	$2.94	$3.18	$110.53	8.66%
XCELENERGY	XEL	$1.82	NA	$1.92	$2.03	$2.15	5.71%	$27.58	$32.11	$66.51	$77.46		($65.15)	$1.92	$2.03	$78.00	8.17%
Maximum		$3.86	$0.00	$4.15	$4.46	$4.80	9.75%	$55.88	$65.92	$99.97	$118.60	$0.00	($31.13)	$4.15	$4.46	$119.80	13.45%
Minimum		$1.52	$0.00	$1.64	$1.76	$1.90	3.50%	$18.26	$21.11	$32.36	$37.41	$0.00	($97.80)	$1.64	$1.76	$37.89	6.28%
Median		$2.26	#NUM!	$2.43	$2.62	$2.75	6.74%	$36.38	$42.73	$65.86	$76.11	#NUM!	($64.19)	$2.43	$2.62	$76.72	8.74%
Average		$2.33	#DIV/0!	$2.48	$2.64	$2.81	6.61%	$35.73	$41.47	$67.98	$79.49	#DIV/0!	($66.24)	$2.48	$2.64	$80.19	**9.08%**

Sources:

[A] Value Line: Most current data available at time of schedule preparation. 2024 data is VL forecast for 2023-25.

[B] Straight line interpolation based on Value Line data, assuming constant dividend growth for 2021-24.

[C] Straight line interpolation based on Value Line data, assuming constant book value growth for 2021-24.

[D] EOD Data: Market Data as of March 31, 2021.

[E] Stock Price projected assuming constant Market to Book Ratio (Exhibit ALR-5, page 1) and using VL projected Book Value.

[F] Cash Flow from purchasing stock on April 1, 2021, receiving dividends through 2024, and selling on March 31, 2024.
Negative number in 2021 reflects cash outflow required to purchase stock.
Cash flow sources are 1) dividends and 2) proceeds of stock sale.
3 of 4 dividends assumed received in 2021 and 1 of 4 in 2024 based on purchase and sale date.

[G] Total return on equity to investor who purchased, held, and sold stock as described above,
assuming Value Line projections of Dividends and Book Value are correct and
assuming Stock Price grows at same rate as Book Value.

DCF result is an Internal Rate of Return computation made using the "IRR" function built into Microsoft Excel
based on projected cash flows from 2021 to 2024.

NON-CONSTANT GROWTH DISCOUNTED CASH FLOW (DCF) - INDICATED COST OF EQUITY

(BASED ON VALUE LINE FORECASTS AND LTM AVERAGE STOCK PRICE)

RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
		Forecasted Dividends per Share					Growth	LTM Avg. Book Value		LTM Avg. Stock Price		Cash Flow From Buying and Selling Stock (At LTM Average Price)					
		2021	2022	2022	2023	2024	2021-24	2021	2024	3/31/21	3/31/24		2021	2022	2023	2024	IRR / DCF
		[A]	[A]	[B]	[B]	[A]	[B]	[C]	[C]	[D]	[E]	[F]	[F]	[F]	[F]	[F]	[G]
AMEREN	AEE	$2.20	NA	$2.41	$2.64	$2.90	9.65%	$34.60	$43.65	$76.40	$96.39		($74.75)	$2.41	$2.64	$97.11	11.30%
AMERICANELEC.PWR.	AEP	$3.00	NA	$3.23	$3.48	$3.75	7.72%	$41.04	$52.00	$82.71	$104.80		($80.46)	$3.23	$3.48	$105.74	12.23%
AVISTACORP.	AVA	$1.68	NA	$1.75	$1.82	$1.90	4.19%	$29.25	$31.49	$40.70	$43.83		($39.44)	$1.75	$1.82	$44.30	6.95%
BLACKHILLSCORP.	BKH	$2.31	NA	$2.45	$2.59	$2.75	5.98%	$40.06	$44.85	$61.39	$68.73		($59.65)	$2.45	$2.59	$69.41	7.96%
CMSENERGYCORP.	CMS	$1.74	NA	$1.91	$2.10	$2.30	9.75%	$18.73	$25.11	$60.17	$80.66		($58.86)	$1.91	$2.10	$81.23	13.50%
CON.EDISON	ED	$3.10	NA	$3.23	$3.36	$3.50	4.13%	$55.16	$61.53	$77.78	$86.76		($75.46)	$3.23	$3.36	$87.64	7.99%
EDISONINTERNAT'L	EIX	$2.68	NA	$2.78	$2.89	$3.00	3.83%	$36.99	$41.68	$57.50	$64.79		($55.49)	$2.78	$2.89	$65.54	9.07%
EVERSOURCEENERGY	ES	$2.40	NA	$2.59	$2.78	$3.00	7.72%	$41.43	$49.02	$85.14	$100.72		($83.34)	$2.59	$2.78	$101.47	8.88%
ENTERGYCORP.	ETR	$3.86	NA	$4.15	$4.46	$4.80	7.54%	$53.71	$64.05	$98.08	$116.95		($95.19)	$4.15	$4.46	$118.15	10.42%
EVERGY,INC.	EVRG	$2.17	NA	$2.32	$2.48	$2.65	6.89%	$38.40	$43.71	$57.02	$64.91		($55.39)	$2.32	$2.48	$65.57	8.63%
FORTIS INC.	FTS.TO	$2.08	NA	$2.25	$2.44	$2.65	8.41%	$36.72	$43.25	$52.72	$62.08		($51.16)	$2.25	$2.44	$62.74	10.04%
IDACORP,INC.	IDA	$2.89	NA	$3.08	$3.28	$3.50	6.59%	$50.25	$56.18	$90.94	$101.66		($88.77)	$3.08	$3.28	$102.54	7.28%
ALLIANTENERGY	LNT	$1.61	NA	$1.75	$1.89	$2.05	8.39%	$22.39	$27.58	$50.86	$62.66		($49.65)	$1.75	$1.89	$63.17	10.73%
MGEENERGYINC.	MGEE	$1.52	NA	$1.64	$1.76	$1.90	7.72%	$26.65	$31.25	$65.37	$76.63		($64.23)	$1.64	$1.76	$77.11	8.01%
NORTHWESTERN	NWE	$2.48	NA	$2.57	$2.66	$2.75	3.50%	$41.01	$44.25	$56.85	$61.34		($54.99)	$2.57	$2.66	$62.03	7.25%
OGEENERGYCORP.	OGE	$1.64	NA	$1.74	$1.84	$1.95	5.94%	$19.16	$22.15	$30.81	$35.61		($29.58)	$1.74	$1.84	$36.10	10.84%
OTTERTAILCORP.	OTTR	$1.56	NA	$1.68	$1.81	$1.95	7.72%	$20.53	$24.43	$41.79	$49.73		($40.62)	$1.68	$1.81	$50.21	10.12%
PINNACLEWEST	PNW	$3.42	NA	$3.62	$3.83	$4.05	5.80%	$49.63	$55.67	$79.59	$89.28		($77.02)	$3.62	$3.83	$90.30	8.63%
PORTLANDGENERAL	POR	$1.68	NA	$1.78	$1.89	$2.00	5.98%	$29.08	$32.10	$42.69	$47.12		($41.43)	$1.78	$1.89	$47.62	7.67%
SOUTHERNCOMPANY	SO	$2.62	NA	$2.72	$2.83	$2.94	3.92%	$26.47	$30.84	$57.10	$66.52		($55.13)	$2.72	$2.83	$67.26	10.15%
WECENERGYGROUP	WEC	$2.71	NA	$2.94	$3.18	$3.45	8.38%	$32.91	$38.56	$93.70	$109.79		($91.67)	$2.94	$3.18	$110.66	8.65%
XCELENERGY	XEL	$1.82	NA	$1.92	$2.03	$2.15	5.71%	$26.66	$31.05	$66.26	$77.16		($64.89)	$1.92	$2.03	$77.70	8.18%
Maximum		$3.86	$0.00	$4.15	$4.46	$4.80	9.75%	$55.16	$64.05	$98.08	$116.95	$0.00	($29.58)	$4.15	$4.46	$118.15	13.50%
Minimum		$1.52	$0.00	$1.64	$1.76	$1.90	3.50%	$18.73	$22.15	$30.81	$35.61	$0.00	($95.19)	$1.64	$1.76	$36.10	6.95%
Median		$2.26	#NUM!	$2.43	$2.62	$2.75	6.74%	$35.66	$42.46	$60.78	$72.68	#NUM!	($59.26)	$2.43	$2.62	$73.26	8.77%
Average		$2.33	#DIV/0!	$2.48	$2.64	$2.81	6.61%	$35.04	$40.65	$64.80	$75.82	#DIV/0!	($63.05)	$2.48	$2.64	$76.53	$\boxed{9.29\%}$

Sources:

[A] Value Line: Most current data available at time of schedule preparation. 2024 data is VL forecast for 2023-25.

[B] Straight line interpolation based on Value Line data, assuming constant dividend growth for 2021-24.

[C] Straight line interpolation based on Value Line data, assuming constant book value growth for 2021-24.

[D] EOD Data: Market Data as of March 31, 2021.

[E] Stock Price projected assuming constant Market to Book Ratio (Exhibit ALR-5, page 1) and using VL projected Book Value.

[F] Cash Flow from purchasing stock on April 1, 2021, receiving dividends through 2024, and selling on March 31, 2024.
Negative number in 2021 reflects cash outflow required to purchase stock.
Cash flow sources are 1) dividends and 2) proceeds of stock sale.
3 of 4 dividends assumed received in 2021 and 1 of 4 in 2024 based on purchase and sale date.

[G] Total return on equity to investor who purchased, held, and sold stock as described above,
assuming Value Line projections of Dividends and Book Value are correct and
assuming Stock Price grows at same rate as Book Value.
DCF result is an Internal Rate of Return computation made using the "IRR" function built into Microsoft Excel
based on projected cash flows from 2021 to 2024.

COMMON SHARES OUTSTANDING AND EXTERNAL FINANCING RATE
RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		Common Stock Outstanding (Millions of Shares)								**Annual Growth Rate**		
		2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2024**	**2015-19**	**2019-24**	**2015-24**
		[A]	[A]	[A]	[A]	[A]	[A]	[A]	[A]	[B]	[B]	[B]
AMEREN	AEE	242.6	242.6	242.6	244.5	246.2	253.3	259.0	280.0	0.37%	2.61%	1.60%
AMERICANELEC.PWR.	AEP	491.1	491.7	492.0	493.3	494.2	496.6	504.0	550.0	0.16%	2.16%	1.27%
AVISTACORP.	AVA	62.3	64.2	65.5	65.7	67.2	69.0	70.0	73.0	1.90%	1.68%	1.77%
BLACKHILLSCORP.	BKH	51.2	53.4	53.5	60.0	61.5	62.8	64.5	65.5	4.69%	1.27%	2.78%
CMSENERGYCORP.	CMS	277.2	279.2	281.7	283.4	283.9	288.9	293.0	306.0	0.60%	1.51%	1.11%
CON.EDISON	ED	293.0	305.0	310.0	321.0	333.0	343.0	352.0	370.0	3.25%	2.13%	2.63%
EDISONINTERNAT'L	EIX	325.8	325.8	325.8	325.8	362.0	379.0	395.0	395.0	2.67%	1.76%	2.16%
EVERSOURCEENERGY	ES	317.2	316.9	316.9	316.9	329.9	345.0	349.0	365.0	0.99%	2.04%	1.57%
ENTERGYCORP.	ETR	178.4	179.1	180.5	189.1	199.2	200.2	203.0	210.0	2.79%	1.07%	1.83%
EVERGY,INC.	EVRG	--	--	--	255.3	226.6	226.8	230.0	230.0	NA	0.29%	NA
FORTIS INC.	FTS.TO	281.6	401.5	421.1	428.5	463.3	466.8	470.0	485.0	13.26%	0.92%	6.23%
IDACORP,INC.	IDA	50.3	50.4	50.4	50.4	50.4	50.5	50.5	50.5	0.04%	0.01%	0.02%
ALLIANTENERGY	LNT	226.9	227.7	231.4	236.1	245.0	249.9	255.0	270.0	1.94%	1.96%	1.95%
MGEENERGYINC.	MGEE	34.7	34.7	34.7	34.7	34.7	35.2	36.2	36.2	0.00%	0.85%	0.47%
NORTHWESTERN	NWE	48.2	48.3	49.4	50.3	50.5	50.6	51.5	53.0	1.16%	0.99%	1.07%
OGEENERGYCORP.	OGE	199.7	199.7	199.7	199.7	200.1	200.1	200.0	200.0	0.05%	-0.01%	0.02%
OTTERTAILCORP.	OTTR	37.9	39.4	39.6	39.7	40.2	41.5	41.6	42.0	1.49%	0.90%	1.16%
PINNACLEWEST	PNW	111.0	111.3	111.8	112.1	112.4	112.7	113.0	118.0	0.33%	0.97%	0.68%
PORTLANDGENERAL	POR	88.8	89.0	89.1	89.3	89.4	89.6	89.7	90.0	0.17%	0.14%	0.15%
SOUTHERNCOMPANY	SO	911.7	990.4	1,007.6	1,033.8	1,053.3	1,056.0	1,056.0	1,085.0	3.67%	0.59%	1.95%
WECENERGYGROUP	WEC	315.7	315.6	315.6	315.5	315.4	315.4	315.4	315.4	-0.02%	0.00%	-0.01%
XCELENERGY	XEL	507.5	507.2	507.8	514.0	524.5	539.0	542.0	555.0	0.83%	1.14%	1.00%
Maximum		911.7	990.4	1,007.6	1,033.8	1,053.3	1,056.0	1,056.0	1,085.0	13.26%	2.61%	6.23%
Minimum		34.7	34.7	34.7	34.7	34.7	35.2	36.2	36.2	-0.02%	-0.01%	-0.01%
Median		226.9	227.7	231.4	240.3	235.8	238.4	242.5	250.0	0.99%	1.03%	1.27%
Average		240.6	251.1	253.6	257.2	262.9	266.9	270.0	279.3	1.92%	1.14%	1.50%
								Sustainable Growth [C]				1.26%

Sources:
[A] Value Line: Most current data available at time of schedule preparation.
[B] Annualized Growth Rate calculation.
[C] Estimated Sustainable Growth in Common Stock based on analysis of historical and projected growth rates.

CAPITAL ASSET PRICING MODEL (CAPM) - INDICATED COST OF EQUITY

WEIGHTED - All Inputs Weighted From January 2021 to March 2021

RFC Electric Proxy Group

	3-Month Treasury Bill		30-Year Treasury Bond	
	Hybrid Beta	Forward Beta	Hybrid Beta	Forward Beta
Risk-Free Rate	0.04%	0.04%	2.20%	2.20%
Beta	0.59	0.58	0.59	0.58
Risk Premium	10.29%	10.29%	8.14%	8.14%
CAPM (Weighted)	6.15%	5.97%	7.02%	6.88%

CAPITAL ASSET PRICING MODEL (CAPM) - RISK-FREE RATE

Spot (Mar. 31, 2021)	
3-Month Treasury Bill	0.03%
30-Year Treasury Bond	2.41%
3-Mo. Weighted Average (Jan. to Mar. 2021)	
3-Month Treasury Bill	0.04%
30-Year Treasury Bond	2.20%

Source: www.treasury.gov

CAPITAL ASSET PRICING MODEL (CAPM) - BETAS
(BASED ON HISTORICAL AND OPTION-IMPLIED RETURNS)
RFC Electric Proxy Group

Betas	**12/29/2020**	**01/05/2021**	**01/12/2021**	**01/19/2021**	**01/26/2021**	**02/02/2021**	**02/09/2021**	**02/16/2021**	**02/23/2021**	**03/02/2021**	**03/09/2021**	**03/16/2021**	**03/23/2021**	**03/30/2021**	**Average**	**Time Avg.**
Forward (6 months)	0.59	0.55	0.61	0.60	0.64	0.56	0.56	0.54	0.61	0.57	0.55	0.56	0.53	0.62	0.579	0.576
Historical (6 months)	0.41	0.40	0.38	0.39	0.41	0.41	0.42	0.43	0.45	0.52	0.52	0.55	0.55	0.55	0.456	0.491
Historical (2 yrs)	0.78	0.78	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.78	0.78	0.78	0.774	0.775
Historical (5 yrs)	0.65	0.65	0.65	0.65	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.67	0.67	0.67	0.660	0.662
Weighting																
Forward (6 months)	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%		
Historical (6 months)	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%		
Historical (2 yrs)	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%		
Historical (5 yrs)	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%		
Hybrid Beta (Forward & Historical)	**0.58**	**0.56**	**0.58**	**0.58**	**0.60**	**0.57**	**0.57**	**0.56**	**0.60**	**0.60**	**0.59**	**0.60**	**0.59**	**0.63**	0.586	0.593
Slope	15%															
Points	0.00	1.00	1.15	1.32	1.52	1.75	2.01	2.31	2.66	3.06	3.52	4.05	4.65	5.35		
Time Weight	0.0%	2.9%	3.3%	3.8%	4.4%	5.1%	5.9%	6.7%	7.7%	8.9%	10.2%	11.8%	13.5%	15.6%		

CAPM Betas	**Spot (Mar 30, 2021)**	**Weighted (Jan - Mar 2021)**
Forward	0.62	0.58
Hybrid	0.63	0.59

Note: Historical betas are calculated on Tuesdays, following Value Line's methodology. Forward (option-implied) betas are also calculated on Tuesdays for the sake of compatibility.

CAPITAL ASSET PRICING MODEL (CAPM) - MARKET RISK PREMIUM

WEIGHTED - All Inputs Weighted From January 2021 to March 2021

Cumulative Probability	50.00%	
S&P 500 Option-Implied Growth Rate	8.85%	
S&P 500 Dividend Yield	1.49%	
S&P 500 Market Return	10.33%	
	3-Month Treasury Bill	**30-Year Treasury Bond**
Risk-Free Rate	0.04%	2.20%
Option-Implied Market Risk Premium (Weighted)	10.29%	8.14%

CAPITAL ASSET PRICING MODEL (CAPM) - INDICATED COST OF EQUITY

SPOT - All Inputs Based on Last Available Data as of March 31, 2021

RFC Electric Proxy Group

	3-Month Treasury Bill		30-Year Treasury Bond	
	Hybrid Beta	Forward Beta	Hybrid Beta	Forward Beta
Risk-Free Rate	0.03%	0.03%	2.41%	2.41%
Beta	0.63	0.62	0.63	0.62
Risk Premium	9.62%	9.62%	7.24%	7.24%
CAPM (Spot)	6.10%	5.98%	6.98%	6.89%

CAPITAL ASSET PRICING MODEL (CAPM) - MARKET RISK PREMIUM

SPOT - All Inputs Based on Last Available Data as of March 31, 2021

Cumulative Probability	50.00%	
S&P 500 Option-Implied Growth Rate	8.20%	
S&P 500 Dividend Yield	1.45%	
S&P 500 Market Return	9.65%	
	3-Month Treasury Bill	**30-Year Treasury Bond**
Risk-Free Rate	0.03%	2.41%
Option-Implied Market Risk Premium (Spot)	9.62%	7.24%

MARKET TO BOOK RATIO AND DIVIDEND YIELD

RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
		Book Value per Share															
		Actual				**Estimated**			**Market Price**			**Mkt. to Book Ratio**		**Dividend Rate**		**Dividend Yield**	
		12/31/17	**12/31/18**	**12/31/19**	**12/31/20**	**3/31/20**	**3/31/21**	**12/31/21**	**3/31/21**	**LTM High**	**LTM Low**	**3/31/21**	**LTM Avg.**	**MRQ**	**Annual**	**3/31/21**	**LTM Avg.**
		[A]	[A]	[A]	[A]	[B]	[B]	[A]	[C]	[C]	[C]	[D]	[D]	[A]	[E]	[F]	[F]
AMEREN	AEE	$29.61	$31.21	$32.73	$35.29	$33.37	$35.83	$37.45	$81.36	$86.90	$65.90	2.27	2.21	$0.550	$2.200	2.70%	2.88%
AMERICANELEC.PWR.	AEP	$37.17	$38.58	$39.73	$41.38	$40.14	$41.94	$43.60	$84.70	$94.21	$71.20	2.02	2.02	$0.740	$2.960	3.49%	3.58%
AVISTACORP.	AVA	$26.41	$26.99	$28.87	$29.35	$28.99	$29.50	$29.95	$47.75	$49.14	$32.26	1.62	1.39	$0.405	$1.620	3.39%	3.98%
BLACKHILLSCORP.	BKH	$31.92	$36.36	$38.42	$40.65	$38.98	$41.15	$42.65	$66.77	$70.80	$51.97	1.62	1.53	$0.565	$2.260	3.38%	3.68%
CMSENERGYCORP.	CMS	$15.77	$16.78	$17.68	$19.02	$18.02	$19.44	$20.70	$61.22	$67.98	$52.35	3.15	3.21	$0.435	$1.740	2.84%	2.89%
CON.EDISON	ED	$49.74	$52.11	$54.12	$55.45	$54.45	$55.88	$57.15	$74.80	$90.00	$65.56	1.34	1.41	$0.775	$3.100	4.14%	3.99%
EDISONINTERNAT'L	EIX	$35.82	$32.10	$36.75	$36.65	$36.73	$37.25	$39.05	$58.60	$66.68	$48.33	1.57	1.55	$0.663	$2.650	4.52%	4.61%
EVERSOURCEENERGY	ES	$34.99	$36.25	$38.29	$42.95	$39.46	$43.41	$44.80	$86.59	$96.66	$73.61	1.99	2.05	$0.568	$2.270	2.62%	2.67%
ENTERGYCORP.	ETR	$44.28	$46.78	$51.34	$54.56	$52.15	$55.28	$57.45	$99.47	$113.36	$82.81	1.80	1.83	$0.950	$3.800	3.82%	3.87%
EVERGY,INC.	EVRG	--	$39.28	$37.82	$38.50	$37.99	$38.81	$39.75	$59.53	$65.43	$48.61	1.53	1.48	$0.535	$2.140	3.59%	3.75%
FORTIS INC.	FTS.TO	$31.77	$34.80	$36.49	$36.58	$36.51	$36.94	$38.00	$54.53	$56.46	$48.97	1.48	1.44	$0.505	$2.020	3.70%	3.83%
IDACORP,INC.	IDA	$44.65	$47.01	$48.88	$50.70	$49.34	$51.16	$52.55	$99.97	$102.96	$78.91	1.95	1.81	$0.710	$2.840	2.84%	3.12%
ALLIANTENERGY	LNT	$17.21	$19.43	$21.24	$22.76	$21.62	$23.16	$24.35	$54.16	$58.10	$43.61	2.34	2.27	$0.403	$1.612	2.98%	3.17%
MGEENERGYINC.	MGEE	$22.45	$23.56	$24.68	$27.76	$25.45	$27.86	$28.15	$71.39	$74.49	$56.25	2.56	2.45	$0.370	$1.480	2.07%	2.26%
NORTHWESTERN	NWE	$36.44	$38.60	$40.42	$41.10	$40.59	$41.43	$42.40	$65.20	$66.27	$47.43	1.57	1.39	$0.600	$2.400	3.68%	4.22%
OGEENERGYCORP.	OGE	$19.28	$20.06	$20.69	$18.15	$20.06	$18.26	$18.60	$32.36	$35.24	$26.37	1.77	1.61	$0.403	$1.610	4.98%	5.23%
OTTERTAILCORP.	OTTR	$17.62	$18.38	$19.46	$21.00	$19.85	$21.21	$21.85	$46.17	$48.22	$35.36	2.18	2.04	$0.390	$1.560	3.38%	3.73%
PINNACLEWEST	PNW	$44.80	$46.59	$48.30	$50.10	$48.75	$50.50	$51.70	$81.35	$91.88	$67.29	1.61	1.60	$0.830	$3.320	4.08%	4.17%
PORTLANDGENERAL	POR	$27.11	$28.07	$28.99	$28.95	$28.98	$29.19	$29.90	$47.47	$53.42	$31.96	1.63	1.47	$0.408	$1.630	3.43%	3.82%
SOUTHERNCOMPANY	SO	$23.98	$23.92	$26.11	$26.55	$26.22	$26.73	$27.25	$62.16	$64.93	$49.26	2.33	2.16	$0.640	$2.560	4.12%	4.48%
WECENERGYGROUP	WEC	$29.98	$31.02	$32.06	$33.19	$32.34	$33.48	$34.35	$93.59	$106.85	$80.55	2.80	2.85	$0.678	$2.710	2.90%	2.89%
XCELENERGY	XEL	$22.56	$23.78	$25.24	$27.25	$25.74	$27.58	$28.55	$66.51	$76.44	$56.07	2.41	2.49	$0.430	$1.720	2.59%	2.60%
Maximum		$49.74	$52.11	$54.12	$55.45	$54.45	$55.88	$57.45	$99.97	$113.36	$82.81	3.15	3.21	$0.950	$3.800	4.98%	5.23%
Minimum		$15.77	$16.78	$17.68	$18.15	$18.02	$18.26	$18.60	$32.36	$35.24	$26.37	1.34	1.39	$0.370	$1.480	2.07%	2.26%
Median		$29.98	$31.66	$34.61	$35.94	$34.94	$36.38	$37.73	$65.86	$69.39	$52.16	1.88	1.82	$0.558	$2.230	3.41%	3.74%
Average		$30.65	$32.35	$34.01	$35.36	$34.35	$35.73	$36.83	$67.98	$74.38	$55.21	1.98	1.92	$0.570	$2.282	3.42%	3.61%

Sources:
[A] Value Line: Most current data available at time of schedule preparation.
[B] Straight-line interpolation of Actual and Estimated VL year-end values.
[C] EOD Data: Market Data as of March 31, 2021.
[D] Market Price divided by Book Value per Share.
[E] Most Recent Quarterly Dividend multiplied by 4.
[F] Dividend Rate divided by Market Price.

EARNINGS PER SHARE AND RETURN ON EQUITY

RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
		Earnings per Share				**Return on Equity**			
		2017	**2018**	**2019**	**2020**	**2018**	**2019**	**2020**	**VL Future Exp.**
		[A]	[A]	[A]	[A]	[B]	[B]	[B]	[A]
AMEREN	AEE	$2.77	$3.32	$3.35	$3.50	10.92%	10.48%	10.29%	10.00%
AMERICANELEC.PWR.	AEP	$3.62	$3.90	$4.08	$4.42	10.30%	10.42%	10.90%	11.00%
AVISTACORP.	AVA	$1.95	$2.07	$2.97	$1.85	7.75%	10.63%	6.36%	8.00%
BLACKHILLSCORP.	BKH	$3.38	$3.47	$3.53	$3.65	10.16%	9.44%	9.23%	8.50%
CMSENERGYCORP.	CMS	$2.17	$2.32	$2.39	$2.64	14.25%	13.87%	14.39%	14.00%
CON.EDISON	ED	$4.10	$4.55	$4.08	$3.90	8.93%	7.68%	7.12%	8.00%
EDISONINTERNAT'L	EIX	$4.51	($1.26)	$3.98	$1.70	-3.71%	11.56%	4.63%	10.50%
EVERSOURCEENERGY	ES	$3.11	$3.25	$3.45	$3.60	9.12%	9.26%	8.86%	9.00%
ENTERGYCORP.	ETR	$5.19	$5.88	$6.30	$6.90	12.91%	12.84%	13.03%	11.00%
EVERGY,INC.	EVRG	--	$2.50	$2.79	$2.72	NA	7.24%	7.13%	9.00%
FORTIS INC.	FTS.TO	$2.66	$2.52	$2.68	$2.60	7.57%	7.52%	7.12%	7.00%
IDACORP,INC.	IDA	$4.21	$4.49	$4.61	$4.65	9.80%	9.62%	9.34%	9.50%
ALLIANTENERGY	LNT	$1.99	$2.19	$2.33	$2.47	11.95%	11.46%	11.23%	10.50%
MGEENERGYINC.	MGEE	$2.20	$2.43	$2.51	$2.60	10.56%	10.41%	9.92%	9.50%
NORTHWESTERN	NWE	$3.34	$3.40	$3.53	$3.15	9.06%	8.93%	7.73%	9.00%
OGEENERGYCORP.	OGE	$1.92	$2.12	$2.24	$2.08	10.78%	10.99%	10.71%	13.00%
OTTERTAILCORP.	OTTR	$1.86	$2.06	$2.17	$2.34	11.44%	11.47%	11.57%	12.50%
PINNACLEWEST	PNW	$4.43	$4.54	$4.77	$5.10	9.94%	10.05%	10.37%	10.50%
PORTLANDGENERAL	POR	$2.29	$2.37	$2.39	$1.55	8.59%	8.38%	5.35%	9.50%
SOUTHERNCOMPANY	SO	$3.21	$3.00	$3.17	$3.15	12.53%	12.67%	11.96%	13.00%
WECENERGYGROUP	WEC	$3.14	$3.34	$3.58	$3.79	10.95%	11.35%	11.62%	13.00%
XCELENERGY	XEL	$2.30	$2.47	$2.64	$2.80	10.66%	10.77%	10.67%	10.50%
Maximum		$5.19	$5.88	$6.30	$6.90	14.25%	13.87%	14.39%	14.00%
Minimum		$1.86	($1.26)	$2.17	$1.55	-3.71%	7.24%	4.63%	7.00%
Median		$3.11	$2.76	$3.26	$2.98	10.30%	10.45%	10.10%	10.25%
Average		$3.06	$2.95	$3.34	$3.23	9.74%	10.32%	9.52%	10.30%

Sources:
[A] Value Line: Most current data available at time of schedule preparation.
[B] Earnings per Share divded by average Book Value. Book Values shown on Exhibit ALR-5, page 1.

RETURN ON EQUITY IMPLIED BY ZACKS GROWTH RATES

RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Book Value 12/31/20	EPS 2020	Annual Dividend Rate	Analyst 5 Year Growth Rate	Analyst-Implied Book Value before SV 12/31/2024	12/31/2025	Analyst-Implied Book Value Incl. SV 12/31/2024	12/31/2025	Implied EPS 2025	Analyst-Implied ROE
		[A]	[A]	[A]	[B]	[C]	[C]	[C]	[C]	[C]	[C]
AMEREN	AEE	$35.29	$3.50	$2.200	7.30%	$41.51	$43.36	$52.36	$57.97	$4.98	9.02%
AMERICANELEC.PWR.	AEP	$41.38	$4.42	$2.960	5.70%	$48.10	$50.03	$60.65	$66.84	$5.83	9.15%
AVISTACORP.	AVA	$29.35	$1.85	$1.620	6.90%	$30.44	$30.76	$33.31	$34.43	$2.58	7.62%
BLACKHILLSCORP.	BKH	$40.65	$3.65	$2.260	5.20%	$46.97	$48.76	$48.56	$50.83	$4.70	9.46%
CMSENERGYCORP.	CMS	$19.02	$2.64	$1.740	6.90%	$23.29	$24.54	$27.86	$30.72	$3.69	12.58%
CON.EDISON	ED	$55.45	$3.90	$3.100	2.00%	$58.81	$59.70	$64.27	$66.70	$4.31	6.58%
EDISONINTERNAT'L	EIX	$36.65	$1.70	$2.650	4.30%	$32.42	$31.25	$32.42	$31.25	$2.10	6.59%
EVERSOURCEENERGY	ES	$42.95	$3.60	$2.270	6.80%	$49.24	$51.09	$55.42	$59.23	$5.00	8.73%
ENTERGYCORP.	ETR	$54.56	$6.90	$3.800	5.10%	$68.62	$72.60	$74.41	$80.33	$8.85	11.44%
EVERGY,INC.	EVRG	$38.50	$2.72	$2.140	5.90%	$41.18	$41.96	$41.18	$41.96	$3.62	8.72%
FORTIS INC.	FTS.TO	$36.58	$2.60	$2.020	ND	NA	NA	NA	NA	NA	NA
IDACORP,INC.	IDA	$50.70	$4.65	$2.840	2.60%	$58.42	$60.48	$58.42	$60.48	$5.29	8.89%
ALLIANTENERGY	LNT	$22.76	$2.47	$1.612	5.80%	$26.72	$27.86	$31.86	$34.71	$3.27	9.84%
MGEENERGYINC.	MGEE	$27.76	$2.60	$1.480	4.70%	$32.79	$34.20	$32.79	$34.20	$3.27	9.77%
NORTHWESTERN	NWE	$41.10	$3.15	$2.400	4.40%	$44.44	$45.38	$47.20	$48.91	$3.91	8.13%
OGEENERGYCORP.	OGE	$18.15	$2.08	$1.610	4.40%	$20.25	$20.83	$20.25	$20.83	$2.58	12.56%
OTTERTAILCORP.	OTTR	$21.00	$2.34	$1.560	NA	NA	NA	NA	NA	NA	NA
PINNACLEWEST	PNW	$50.10	$5.10	$3.320	3.40%	$57.85	$59.95	$63.46	$67.31	$6.03	9.22%
PORTLANDGENERAL	POR	$28.95	$1.55	$1.630	13.40%	$28.51	$28.36	$28.75	$28.66	$2.91	10.13%
SOUTHERNCOMPANY	SO	$26.55	$3.15	$2.560	5.00%	$29.22	$29.97	$31.77	$33.27	$4.02	12.36%
WECENERGYGROUP	WEC	$33.19	$3.79	$2.710	6.10%	$38.21	$39.66	$38.21	$39.66	$5.10	13.09%
XCELENERGY	XEL	$27.25	$2.80	$1.720	6.20%	$32.28	$33.74	$34.82	$37.09	$3.78	10.52%
Maximum		$55.45	$6.90	$3.800	13.40%	$68.62	$72.60	$74.41	$80.33	$8.85	13.09%
Minimum		$18.15	$1.55	$1.480	2.00%	$20.25	$20.83	$20.25	$20.83	$2.10	6.58%
Median		$35.94	$2.98	$2.230	5.45%	$39.70	$40.81	$39.70	$40.81	$3.96	9.34%
Average		$35.36	$3.23	$2.282	5.61%	$40.46	$41.72	$43.90	$46.27	$4.29	9.72%

Sources:
[A] Value Line: Most current data available at time of schedule preparation.
[B] Zacks: Data as of April 13, 2021.
[C] Analyst-Implied Book Value and Return on Equity is obtained by escalating both Dividends and Earnings per Share by the stated Analyst Growth Rate and adding Earnings and subtracting Dividends for each projected year.
"SV" = S X V, where S = rate of continuous new stock financing and V = rate of return on common equity investment.

CAPITAL STRUCTURE WITH SHORT TERM DEBT
RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
		% Common Equity					($ millions)						Percentage			
		2016	2017	2018	2019	2020	Total Debt	LT Debt	ST Debt	Pfd Stock	Equity	Total Capital	LT Debt	ST Debt	Pfd Stock	Equity Ratio
		[A]	[A]	[A]	[A]	[A]	[A]	[A]	[A]	[A]	[A]	[A]	[B]	[B]	[B]	[B]
AMEREN	AEE	51.3%	49.8%	48.8%	47.1%	44.3%	$ 11,576.0	$ 11,078.0	$ 498.0	$ 142.0	$ 8,923.6	$ 20,641.6	53.7%	2.4%	0.7%	43.2%
AMERICANELEC.PWR.	AEP	50.0%	48.5%	46.8%	43.9%	41.5%	$ 33,552.0	$ 28,986.0	$ 4,566.0	$ -	$ 20,562.7	$ 54,114.7	53.6%	8.4%	0.0%	38.0%
AVISTACORP.	AVA	48.8%	52.8%	49.5%	50.6%	49.5%	$ 2,262.8	$ 2,060.8	$ 202.0	$ -	$ 2,020.0	$ 4,282.8	48.1%	4.7%	0.0%	47.2%
BLACKHILLSCORP.	BKH	33.5%	35.5%	42.5%	42.9%	45.0%	$ 3,621.1	$ 3,526.9	$ 94.2	$ -	$ 2,885.6	$ 6,506.7	54.2%	1.4%	0.0%	44.3%
CMSENERGYCORP.	CMS	32.6%	32.4%	30.7%	29.4%	28.6%	$ 15,196.0	$ 13,690.0	$ 1,506.0	$ 37.0	$ 5,498.5	$ 20,731.5	66.0%	7.3%	0.2%	26.5%
CON.EDISON	ED	49.2%	51.1%	48.9%	49.3%	50.5%	$ 23,000.0	$ 19,206.0	$ 3,794.0	$ -	$ 19,594.0	$ 42,594.0	45.1%	8.9%	0.0%	46.0%
EDISONINTERNAT'L	EIX	49.2%	45.8%	38.3%	39.9%	39.5%	$ 21,738.0	$ 18,958.0	$ 2,780.0	$ 2,193.0	$ 13,809.3	$ 37,740.3	50.2%	7.4%	5.8%	36.6%
EVERSOURCEENERGY	ES	54.4%	48.2%	46.9%	46.6%	40.5%	$ 16,415.0	$ 15,233.0	$ 1,182.0	$ 155.6	$ 10,474.6	$ 27,045.2	56.3%	4.4%	0.6%	38.7%
ENTERGYCORP.	ETR	35.5%	35.5%	35.9%	37.1%	33.7%	$ 23,997.0	$ 21,206.0	$ 2,791.0	$ 254.4	$ 10,908.2	$ 35,159.6	60.3%	7.9%	0.7%	31.0%
EVERGY,INC.	EVRG	--	--	60.0%	49.4%	48.7%	$ 10,321.0	$ 9,190.9	$ 1,130.1	$ -	$ 8,725.1	$ 19,046.1	48.3%	5.9%	0.0%	45.8%
FORTIS INC.	FTS.TO	36.2%	37.1%	37.2%	41.8%	40.5%	$ 24,830.0	$ 23,444.0	$ 1,386.0	$ 1,623.0	$ 17,062.4	$ 43,515.4	53.9%	3.2%	3.7%	39.2%
IDACORP,INC.	IDA	55.2%	56.3%	56.4%	58.7%	55.5%	$ 2,000.4	$ 2,000.4	$ -	$ -	$ 2,494.9	$ 4,495.3	44.5%	0.0%	0.0%	55.5%
ALLIANTENERGY	LNT	47.2%	48.6%	46.6%	48.5%	45.7%	$ 7,166.0	$ 6,769.0	$ 397.0	$ 400.0	$ 6,033.6	$ 13,599.6	49.8%	2.9%	2.9%	44.4%
MGEENERGYINC.	MGEE	65.4%	66.2%	62.3%	62.0%	64.5%	$ 594.1	$ 536.8	$ 57.3	$ -	$ 975.3	$ 1,569.4	34.2%	3.7%	0.0%	62.1%
NORTHWESTERN	NWE	48.0%	49.8%	47.8%	47.5%	51.0%	$ 2,307.0	$ 2,204.4	$ 102.6	$ -	$ 2,294.4	$ 4,601.4	47.9%	2.2%	0.0%	49.9%
OGEENERGYCORP.	OGE	58.9%	58.3%	58.0%	56.4%	51.0%	$ 3,589.4	$ 3,494.4	$ 95.0	$ -	$ 3,637.0	$ 7,226.4	48.4%	1.3%	0.0%	50.3%
OTTERTAILCORP.	OTTR	57.0%	58.7%	55.3%	53.1%	58.2%	$ 845.5	$ 624.4	$ 221.1	$ -	$ 869.4	$ 1,714.9	36.4%	12.9%	0.0%	50.7%
PINNACLEWEST	PNW	54.4%	51.1%	53.0%	52.9%	47.0%	$ 6,374.3	$ 6,316.4	$ 57.9	$ -	$ 5,601.3	$ 11,975.6	52.7%	0.5%	0.0%	46.8%
PORTLANDGENERAL	POR	51.6%	49.9%	53.5%	48.7%	46.5%	$ 3,058.0	$ 2,657.0	$ 401.0	$ -	$ 2,309.4	$ 5,367.4	49.5%	7.5%	0.0%	43.0%
SOUTHERNCOMPANY	SO	35.7%	35.0%	37.6%	39.5%	37.5%	$ 50,130.0	$ 45,581.0	$ 4,549.0	$ 291.0	$ 27,523.2	$ 77,944.2	58.5%	5.8%	0.4%	35.3%
WECENERGYGROUP	WEC	49.3%	51.9%	49.4%	47.4%	47.1%	$ 14,291.0	$ 11,728.0	$ 2,563.0	$ 30.4	$ 10,469.2	$ 24,790.6	47.3%	10.3%	0.1%	42.2%
XCELENERGY	XEL	43.7%	44.1%	43.6%	43.2%	43.0%	$ 20,861.0	$ 19,960.0	$ 901.0	$ -	$ 15,057.5	$ 35,918.5	55.6%	2.5%	0.0%	41.9%
Maximum		65.4%	66.2%	62.3%	62.0%	64.5%	$ 50,130.0	$ 45,581.0	$ 4,566.0	$ 2,193.0	$ 27,523.2	$ 77,944.2	66.0%	12.9%	5.8%	62.1%
Minimum		32.6%	32.4%	30.7%	29.4%	28.6%	$ 594.1	$ 536.8	$ -	$ -	$ 869.4	$ 1,569.4	34.2%	0.0%	0.0%	26.5%
Median		49.2%	49.8%	48.3%	47.5%	46.1%	$ 10,948.5	$ 10,134.5	$ 699.5	$ -	$ 7,379.3	$ 19,843.9	50.0%	4.5%	0.0%	43.8%
Average		48.0%	47.9%	47.7%	47.1%	45.9%	$ 13,533.0	$ 12,202.3	$ 1,330.6	$ 233.0	$ 8,987.7	$ 22,753.7	50.7%	5.1%	0.7%	**43.6%**

Sources:

[A] Value Line: Most current data available at time of schedule preparation.

[B] Percentage calculated on Total Capital including Short Term Debt.

CAPITAL STRUCTURE WITHOUT SHORT TERM DEBT
RFC Electric Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
		% Common Equity					($ millions)						Percentage			
		2016	**2017**	**2018**	**2019**	**2020**	**Total Debt**	**LT Debt**	**ST Debt**	**Pfd Stock**	**Equity**	**Total Capital**	**LT Debt**	**ST Debt**	**Pfd Stock**	**Equity Ratio**
		[A]	[A]	[A]	[A]	[A]	[A]	[A]	[B]	[A]	[A]	[A]	[B]	[B]	[B]	[B]
AMEREN	AEE	51.3%	49.8%	48.8%	47.1%	44.3%	$ 11,576.0	$ 11,078.0		$ 142.0	$ 8,923.6	$ 20,143.6	55.0%	0.0%	0.7%	44.3%
AMERICANELEC.PWR.	AEP	50.0%	48.5%	46.8%	43.9%	41.5%	$ 33,552.0	$ 28,986.0		$ -	$ 20,562.7	$ 49,548.7	58.5%	0.0%	0.0%	41.5%
AVISTACORP.	AVA	48.8%	52.8%	49.5%	50.6%	49.5%	$ 2,262.8	$ 2,060.8		$ -	$ 2,020.0	$ 4,080.8	50.5%	0.0%	0.0%	49.5%
BLACKHILLSCORP.	BKH	33.5%	35.5%	42.5%	42.9%	45.0%	$ 3,621.1	$ 3,526.9		$ -	$ 2,885.6	$ 6,412.5	55.0%	0.0%	0.0%	45.0%
CMSENERGYCORP.	CMS	32.6%	32.4%	30.7%	29.4%	28.6%	$ 15,196.0	$ 13,690.0		$ 37.0	$ 5,498.5	$ 19,225.5	71.2%	0.0%	0.2%	28.6%
CON.EDISON	ED	49.2%	51.1%	48.9%	49.3%	50.5%	$ 23,000.0	$ 19,206.0		$ -	$ 19,594.0	$ 38,800.0	49.5%	0.0%	0.0%	50.5%
EDISONINTERNAT'L	EIX	49.2%	45.8%	38.3%	39.9%	39.5%	$ 21,738.0	$ 18,958.0		$ 2,193.0	$ 13,809.3	$ 34,960.3	54.2%	0.0%	6.3%	39.5%
EVERSOURCEENERGY	ES	54.4%	48.2%	46.9%	46.6%	40.5%	$ 16,415.0	$ 15,233.0		$ 155.6	$ 10,474.6	$ 25,863.2	58.9%	0.0%	0.6%	40.5%
ENTERGYCORP.	ETR	35.5%	35.5%	35.9%	37.1%	33.7%	$ 23,997.0	$ 21,206.0		$ 254.4	$ 10,908.2	$ 32,368.6	65.5%	0.0%	0.8%	33.7%
EVERGY,INC.	EVRG	--	--	60.0%	49.4%	48.7%	$ 10,321.0	$ 9,190.9		$ -	$ 8,725.1	$ 17,916.0	51.3%	0.0%	0.0%	48.7%
FORTIS INC.	FTS.TO	36.2%	37.1%	37.2%	41.8%	40.5%	$ 24,830.0	$ 23,444.0		$ 1,623.0	$ 17,062.4	$ 42,129.4	55.6%	0.0%	3.9%	40.5%
IDACORP,INC.	IDA	55.2%	56.3%	56.4%	58.7%	55.5%	$ 2,000.4	$ 2,000.4		$ -	$ 2,494.9	$ 4,495.3	44.5%	0.0%	0.0%	55.5%
ALLIANTENERGY	LNT	47.2%	48.6%	46.6%	48.5%	45.7%	$ 7,166.0	$ 6,769.0		$ 400.0	$ 6,033.6	$ 13,202.6	51.3%	0.0%	3.0%	45.7%
MGEENERGYINC.	MGEE	65.4%	66.2%	62.3%	62.0%	64.5%	$ 594.1	$ 536.8		$ -	$ 975.3	$ 1,512.1	35.5%	0.0%	0.0%	64.5%
NORTHWESTERN	NWE	48.0%	49.8%	47.8%	47.5%	51.0%	$ 2,307.0	$ 2,204.4		$ -	$ 2,294.4	$ 4,498.8	49.0%	0.0%	0.0%	51.0%
OGEENERGYCORP.	OGE	58.9%	58.3%	58.0%	56.4%	51.0%	$ 3,589.4	$ 3,494.4		$ -	$ 3,637.0	$ 7,131.4	49.0%	0.0%	0.0%	51.0%
OTTERTAILCORP.	OTTR	57.0%	58.7%	55.3%	53.1%	58.2%	$ 845.5	$ 624.4		$ -	$ 869.4	$ 1,493.8	41.8%	0.0%	0.0%	58.2%
PINNACLEWEST	PNW	54.4%	51.1%	53.0%	52.9%	47.0%	$ 6,374.3	$ 6,316.4		$ -	$ 5,601.3	$ 11,917.7	53.0%	0.0%	0.0%	47.0%
PORTLANDGENERAL	POR	51.6%	49.9%	53.5%	48.7%	46.5%	$ 3,058.0	$ 2,657.0		$ -	$ 2,309.4	$ 4,966.4	53.5%	0.0%	0.0%	46.5%
SOUTHERNCOMPANY	SO	35.7%	35.0%	37.6%	39.5%	37.5%	$ 50,130.0	$ 45,581.0		$ 291.0	$ 27,523.2	$ 73,395.2	62.1%	0.0%	0.4%	37.5%
WECENERGYGROUP	WEC	49.3%	51.9%	49.4%	47.4%	47.1%	$ 14,291.0	$ 11,728.0		$ 30.4	$ 10,469.2	$ 22,227.6	52.8%	0.0%	0.1%	47.1%
XCELENERGY	XEL	43.7%	44.1%	43.6%	43.2%	43.0%	$ 20,861.0	$ 19,960.0		$ -	$ 15,057.5	$ 35,017.5	57.0%	0.0%	0.0%	43.0%
Maximum		65.4%	66.2%	62.3%	62.0%	64.5%	$ 50,130.0	$ 45,581.0		$ 2,193.0	$ 27,523.2	$ 73,395.2	71.2%	0.0%	6.3%	64.5%
Minimum		32.6%	32.4%	30.7%	29.4%	28.6%	$ 594.1	$ 536.8		$ -	$ 869.4	$ 1,493.8	35.5%	0.0%	0.0%	28.6%
Median		49.2%	49.8%	48.3%	47.5%	46.1%	$ 10,948.5	$ 10,134.5		$ -	$ 7,379.3	$ 18,570.7	53.3%	0.0%	0.0%	46.1%
Average		48.0%	47.9%	47.7%	47.1%	45.9%	$ 13,533.0	$ 12,202.3		$ 233.0	$ 8,987.7	$ 21,423.1	53.4%	0.0%	0.7%	**45.9%**

Sources:

[A] Value Line: Most current data available at time of schedule preparation.

[B] Percentage calculated on Total Capital excluding Short Term Debt.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3023618
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Aaron L. Rothschild, hereby state that the facts set forth in my Direct Testimony, OCA Statement 2, are true and correct (or are true and correct to the best of my knowledge, information, and belief) 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).

DATED: May 3, 2021
*307975

Signature: Aaron L. Rothschild
Aaron L. Rothschild

Consultant Address: Rothschild Financial Consulting
15 Lake Road
Ridgefield, CT 06877

OCA STATEMENT NO. 3

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3023618
	)	
UGI Utilities, Inc. – Electric Division	)	

DIRECT TESTIMONY
OF
JEROME D. MIERZWA

ON BEHALF OF
THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MAY 3, 2021

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Jerome D. Mierzwa. I am a Principal and Vice President of Exeter Associates, Inc. (“Exeter”). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I graduated from Canisius College in Buffalo, New York in 1981 with a Bachelor of Science Degree in Marketing. In 1985, I received a Master’s Degree in Business Administration with a concentration in finance, also from Canisius College. In July 1986, I joined National Fuel Gas Distribution Corporation (“NFGD”) as a Management Trainee in the Research and Statistical Services (“RSS”) Department. I was promoted to Supervisor RSS in January 1987. While employed with NFGD, I conducted various financial and statistical analyses related to the company's market research activity and state regulatory affairs. In April 1987, as part of a corporate reorganization, I was transferred to National Fuel Gas Supply Corporation's (“NFG Supply's”) rate department where my responsibilities included utility cost-of-service and rate design analysis, expense and revenue requirement forecasting, and activities related to federal regulation. I was also responsible for preparing NFG Supply's Federal Energy Regulatory Commission (“FERC”) Purchased Gas Adjustment (“PGA”) filings and developing interstate pipeline and spot market supply gas price projections. These forecasts were utilized for internal planning purposes as well as in NFGD’s 1307(f) proceedings.

In April 1990, I accepted a position as a Utility Analyst with Exeter. In December 1992, I was promoted to Senior Regulatory Analyst. Effective April 1996, I became a Principal of Exeter. Since joining Exeter, I have specialized in evaluating the gas purchasing practices and policies of natural gas utilities, utility class cost-of-service and rate design analyses, sales and rate forecasting, performance-based incentive regulation, revenue requirement analysis, the unbundling of utility services, and evaluation of customer choice natural gas transportation programs.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON UTILITY RATES IN REGULATORY PROCEEDINGS?

A. Yes. I have provided testimony on more than 350 occasions in proceedings before the FERC, utility regulatory commissions in Arkansas, Delaware, Georgia, Illinois, Indiana, Louisiana, Maine, Massachusetts, Montana, Nevada, New Hampshire, New Jersey, Ohio, Rhode Island, South Carolina, Texas, and Virginia, as well as before Pennsylvania Public Utility Commission ("PaPUC" or "the Commission").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. On February 8, 2021, UGI Utilities, Inc. – Electric Division ("UGI" or "the Company") filed a request to increase its distribution service revenues by $8.7 million, or 23.6 percent. Exeter was retained by the Pennsylvania Office of Consumer Advocate ("OCA") to review the reasonableness of the requested increase, as well as the allocated class cost-of-service study ("ACCOSS") and rate design proposals included in the Company's request. My testimony addresses the Company's ACCOSS and rate design proposals. I also address the Company's proposed battery storage project. My colleague, Mr. Lafayette K. Morgan, addresses the reasonableness of the Company's requested increase.

Q. HAVE YOU PREPARED EXHIBITS TO ACCOMPANY YOUR TESTIMONY?

A. Yes, I have. Schedules JDM-1 – JDM-5 are attached to my direct testimony.

Q. ARE THERE ADDITIONAL CONSIDERATIONS IN THIS PROCEEDING THAT ARE NOT OFTEN SEEN IN A TRADITIONAL BASE RATE CASE?

A. Yes. As explained in the Direct Testimony of Mr. Lafayette K. Morgan in OCA Statement No. 1, Mr. Roger Colton in OCA Statement No. 4, and Ms. Morgan N. DeAngelo in OCA Statement No. 5, Pennsylvania and the rest of the world has faced significant hardships due to the COVID-19 Pandemic. The impact of the COVID-19 Pandemic continues to adversely affect Pennsylvania residents. The Commission should consider the impacts of the COVID-19 Pandemic when reaching its decision as to whether any increase should be authorized for UGI in this proceeding. Authorizing a rate increase in this proceeding when unemployment numbers are close to record-highs would further increase the hardships caused by the COVID-19 Pandemic. Moreover, the economic effects of the COVID-19 Pandemic will not be fully known for some time. The Commission should carefully consider and weigh these important consumer interests when evaluating the Company's claims for a rate increase. Counsel for the OCA will further address UGI's request for rate relief in its briefs.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. If the Commission finds that no increase is appropriate in this proceeding, UGI's existing base rates and charges should remain unchanged. If the Commission determines that a base rate increase for UGI is warranted, that increase should be assigned to each customer class through proportionate system average increases to the base rates applicable for each customer class. If the Commission determines, however, that the traditional base rate setting process should be followed in this proceeding wherein rates are based on cost of service and other generally accepted rate design principles, I have reached the following conclusions and recommendations:

- The ACCOSS proposed by UGI should be modified to provide for the classification of the primary and secondary portion of upstream distribution plant and the associated costs as 100 percent demand-related rather than partially being classified as customer-related;

- If the Commission does not accept this proposed modification to the classification of primary and secondary distribution plant and the associated costs, the customer class non-coincident peak ("NCP") demands which UGI has relied upon to allocate the demand component of primary and secondary distribution facilities should be adjusted to reflect the peak load carrying capability ("PLCC") of the minimum system UGI has used to determine the customer component of its primary and secondary distribution facilities;

- The distribution of the proposed jurisdictional revenue increase among the rate classes proposed by UGI is inappropriately based on its ACCOSS and does not provide for sufficient gradualism. The revenue distribution in this proceeding should be based on the modified ACCOSS which classifies primary and secondary distribution facilities as 100 percent demand-related and provide for additional gradualism;

- UGI's proposed Residential customer charge is unreasonable, does not provide for gradualism, and should be rejected. UGI's existing Residential customer charge should be maintained; and

- UGI has not adequately demonstrated that its battery storage project should be approved by the Commission and that any portion of these costs should be included in distribution rates. To do so, UGI should demonstrate that the project performs a distribution function, provides a distribution reliability benefit, and is the most cost effective approach to meeting the demands of the customers it is intended to serve. If the battery storage project is approved by the Commission, all revenues generated by the project through its participation in the PJM frequency regulation market should be deferred and returned to ratepayers with interest in UGI's next rate case.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Including this introductory section, my testimony is divided into five sections. In the following section, I detail the reasons that support a finding that the Company's ACCOSS produces an inaccurate indication of the allocated costs of serving the various customer classes. Next, I address UGI's proposed distribution of the revenue increase authorized by the Commission in this proceeding, if any, to the various customer classes served by UGI. The next section of my testimony addresses the Company's proposed Residential rate design. The final section of my testimony addresses UGI's proposed battery storage project.

II. ALLOCATED CLASS COST OF SERVICE STUDY

Q. PLEASE DESCRIBE THE ATTRIBUTES OF AN ACCOSS AND EXPLAIN THE INTENDED PURPOSE OF SUCH A STUDY.

A. The Company's ACCOSS is sponsored by Mr. John D. Taylor, a Managing Partner at Atrium Economics, LLC ("Atrium"). The ACCOSS of the type performed by the Company's witness Mr. Taylor is performed in an attempt to determine the costs that are incurred to provide service to each class of customers. Such studies are referred to as average, embedded, ACCOSS because they attempt to directly assign or allocate to each customer class, actual book plant and related costs, adjusted to test year levels as authorized by the Commission. These ACCOSS are also referred to as "fully allocated" because they require that 100 percent of the allowed total jurisdictional costs of service be allocated among the various classes. This is done by determining the average costs of the various components of service (the total cost of the component divided by the units of service for that component), and then by allocating these component costs to each of the classes based on each class' service units that have caused, or benefit from, that cost.

In a typical electric distribution ACCOSS, costs are first functionalized into broad categories, such as primary and secondary distribution, and customer accounts and services. Costs are then classified as to whether they are demand-related, energy-related, customer-related or related to some other factor, such as labor costs or revenue. Finally, the costs are allocated among the customer classes on the basis of the most appropriate measure of demand, energy, or customers, in proportion to each class' share of the various allocation measures.

Q. PLEASE IDENTIFY THE CUSTOMER CLASSES REFLECTED IN THE COMPANY'S ACCOSS?

A. The following customer classes are included in the Company's ACCOSS:

- Residential;
- General Service - 1;
- General Service - 4;
- Large Power; and
- Lighting.

Q. WERE THE RESULTS OF UGI'S ACCOSS USED BY THE COMPANY TO DISTRIBUTE THE INCREASE REQUESTED BY THE COMPANY IN THIS PROCEEDING?

A. Yes.

Q. BEFORE CONTINUING, PLEASE SUMMARIZE THE RESULTS OF THE COMPANY'S ACCOSS AND THE COMPANY'S PROPOSED DISTRIBUTION OF THE REQUESTED INCREASE.

A. Table 1 summarizes for each customer class reflected in UGI's ACCOSS, revenues at existing rates, the revenue increase proposed by UGI, and the relative rate of return at current and proposed rates. Table 1 only reflects UGI's distribution revenues and costs and, therefore, purchased power costs have been excluded.

Table 1. Summary of Company Revenues and ACCOSS Results

	Revenues		Increase		Relative Rate of Return	
Class	**Existing**	**Proposed**	**Amount**	**Percent**	**Existing**	**Proposed**
Residential	$23,519	$31,639	$8,120	35%	(0.39)	0.71
General Service - 1	2,033	2,621	589	29	0.36	0.87
General Service - 4	4,952	4,952	0	0	6.14	2.10
Large Power	5,184	5,184	0	0	5.43	1.85
Lighting	1,160	1,160	0	0	8.40	2.88
Total:	**$36,847**	**$45,556**	**$8,709**	**24%**	**1.00**	**1.00**

Q. WHAT ASPECT OF THE COMPANY'S ACCOSS ARE OF PARTICULAR CONCERN IN THIS PROCEEDING?

A. Of particular concern is the manner in which primary and secondary distribution costs upstream of meters and service drops have been classified in the ACCOSS. Specifically, a significant share of these costs has been inappropriately classified as customer-related.

Q. PLEASE DESCRIBE THE METHODS FREQUENTLY USED TO CLASSIFY A PORTION OF UPSTREAM DISTRIBUTION PLANT AS CUSTOMER-RELATED.

A. The usual rationale for arguing that some portion of upstream distribution plant (Account 364 - Poles, Towers and Fixtures; Account 365 - Overhead Conductors and Devices; Account 367 - Underground Conductors and Devices; and Account 368 - Transformers) is customer-related is that a portion of these costs are incurred simply to "connect" customers to the system without providing any actual electric capacity or energy. There are generally two methods by which this customer portion is estimated. The "zero-intercept method" attempts to construct a regression for each major type of equipment (e.g., poles) that relates installed cost to the size or capacity of the equipment. This equation is then extended back to zero capacity (where no load is served) and the value on the y-axis is determined to be the customer-related component of this investment. Of course, if the extended equation intercepts the y-axis at a negative value, it is never suggested that the customer component is negative. The data are usually massaged until the analyst gets a result above zero. The "minimum system method" hypothetically reconstructs the distribution system with the smallest size poles and conductors possible. That is, it identifies the portion of costs required to serve a customer with minimum or no load. The cost of that hypothetical minimum system is deemed to be customer-related, and the remaining actual cost of the distribution system is deemed to be demand-related.

Q. HOW HAS MR. TAYLOR ESTIMATED THE CUSTOMER-RELATED PORTION OF UPSTREAM PRIMARY AND SECONDARY DISTRIBUTION PLANT FOR THE VARIOUS CUSTOMER CLASSES IN HIS ACCOSS?

A. Mr. Taylor has used a minimum system approach to estimate a customer-related portion of Accounts 364, 365, 367, and 368 in his ACCOSS. He has not developed a "zero intercept" regression analysis to estimate customer-related costs.

Q. HOW HAS MR. TAYLOR ALLOCATED THE DEMAND-RELATED PORTION OF UPSTREAM PRIMARY AND SECONDARY DISTRIBUTION PLANT?

A. Mr. Taylor has allocated the portion of upstream primary and secondary plant determined to be demand-related based on the NCP demand of each of the various customer classes.

Q. PLEASE SUMMARIZE MR. TAYLOR'S FINDINGS WITH RESPECT TO THE PORTION OF UGI'S UPSTREAM DISTRIBUTION PLANT THAT SHOULD BE CLASSIFIED AS DEMAND-RELATED AND THE PORTION THAT SHOULD BE CLASSIFIED AS CUSTOMER-RELATED.

A. Table 2 presents a summary of Mr. Taylor's findings with respect to the portion of UGI's upstream distribution plant that should be classified as demand-related and the portion that should be classified as customer-related.

Table 2. Summary of Minimum System Study

Primary Distribution Plant		
	Customer-Related	**Demand-Related**
Account 364	57.0%	43.0%
Account 365	36.5	63.5
Account 367	31.2	68.8
Account 368	N/A	N/A
Weighted Average	**43.3%**	**56.7%**
Secondary Distribution Plant		
	Customer-Related	**Demand-Related**
Account 364	60.5%	39.5%
Account 365	36.4	63.6
Account 367	40.2	59.8
Account 368	37.3	62.7
Weighted Average	**43.2%**	**56.8%**

Q. WHY DO YOU DISAGREE WITH MR. TAYLOR'S CLASSIFICATION OF A PORTION OF UPSTREAM PRIMARY AND SECONDARY DISTRIBUTION PLANT COSTS AS BEING CUSTOMER-RELATED?

A. These costs are not, in any meaningful way, directly related to the number of customers served. The cost of upstream distribution plant is incurred in order to meet the coincident loads of the customers that it serves. The size and costs of the required plant are a function of the diversity of customers' loads that must be served from this plant, as well as the expected future coincident loads that may have to be served from these facilities as growth occurs on the system. There is no direct relationship between the number of customers and the size or the cost of poles or conductors, and Mr. Taylor has presented no evidence of a direct relationship.

Q. DOES ANY RECOGNIZED AUTHORITY AGREE WITH YOUR CONCLUSION THAT IT IS IMPROPER TO ALLOCATE A PORTION OF AN ELECTRIC UTILITY'S UPSTREAM DISTRIBUTION FACILITIES ON THE BASIS OF BEING RELATED TO THE NUMBER OF CUSTOMERS?

A. Yes. Professor James Bonbright, at pages 491 and 492 of his *Principles of Public Utility Rates*,[1] states:

> But the really controversial aspect of customer-cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitely earmarked as incurred for the benefit of specific customers but also a substantial fraction of the annual maintenance and capital costs of the secondary (low voltage) distribution system – a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. This minimum capacity is sometimes determined by the smallest sizes of conductors deemed adequate to maintain voltage and to keep from falling of their own weight. In any case, the annual costs of this phantom, minimum-sized distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary indirectly with the number of customers.

[1] James Bonbright et al. Principles of Public Utility Rates, Public Utilities Report, Inc. 2nd Edition, 1988.

> What this last-named cost imputation overlooks, of course, is the **very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system**. For it makes no allowance for the density factor (customers per linear mile or per square mile). Indeed, if the Company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.
>
> While, for the reason just suggested, the inclusion of the costs of a minimum-sized distribution system among the customer related costs seems to me clearly indefensible, its exclusion from the demand-related costs stands on much firmer ground. [Emphasis added]

Q. DOES MR. TAYLOR RELY ON THE RATE DESIGN PRINCIPLES RECOMMENDED AND SUPPORTED BY PROFESSOR BONBRIGHT?

A. Yes, and indicates so on page 19 of his Direct Testimony.

Q. ALTHOUGH HE HAS NOT DONE SO, ASSUMING THAT MR. TAYLOR COULD DEMONSTRATE A DIRECT RELATIONSHIP BETWEEN THE NUMBER OF CUSTOMERS SERVED AND THE UPSTREAM DISTRIBUTION FACILITY COSTS INCURRED BY UGI, IS HIS APPROACH TO DETERMINING THE PORTION OF UGI'S DISTRIBUTION SYSTEM THAT IS CUSTOMER-RELATED AND THE PORTION THAT IS DEMAND-RELATED REASONABLE?

A. No, for at least two reasons. First, the UGI electric distribution system consists of approximately 1,250 miles of primary circuit. (OCA I-12, Docket No. R-2017-2640058). As indicated in Table 2, Mr. Taylor determined that approximately 43 percent of UGI's primary distribution system exists to connect customers to the system.

That is, 540 miles (1,250 miles x 43 percent), or 2,851,200 feet of the primary distribution system was installed to connect customers to the UGI system. UGI's system services 63,000 customers and, therefore, under Mr. Taylor's approach, each customer is allocated 45 feet of primary distribution conductor line (2,851,200 / 63,000). As indicated in the response to OCA I-6, UGI extended its primary distribution facilities by an average of 1,700 feet to connect three of its largest customers to its distribution system. Of the 5 largest customers served by UGI, the Company extended its primary distribution facilities by an average of 1,035 feet. Clearly, Mr. Taylor's assumption that UGI extends its primary distribution system by the same number of feet (i.e., 45 feet) to connect a large customer and a small customer results in a misallocation of costs.

Q. PLEASE EXPLAIN THE OTHER REASON YOU DISAGREE WITH MR. TAYLOR'S CLASSIFICATION OF PRIMARY AND SECONDARY UPSTREAM DISTRIBUTION FACILITIES AS PARTIALLY CUSTOMER-RELATED.

A. As previously explained, Mr. Taylor considers 43 percent of UGI's primary distribution facilities to reflect the minimum system and has allocated approximately 43 percent of UGI's primary distribution facilities costs based on the number of customers in each class. As shown in Table 2, Mr. Taylor has also determined that the minimum system component of UGI's secondary distribution facilities to be approximately 43 percent, and has allocated 43 percent of the costs associated with the secondary distribution facilities based on the number of customers. The remaining 57 percent of UGI's primary and secondary distribution system facility costs have been allocated based on the NCP demand of each class.

In allocating the costs associated with this theoretical minimum system, Mr. Taylor has failed to account for the portion of each classes' NCP that can be met by the minimum system, or the peak load carrying capability ("PLCC") of the minimum system. Since the PLCC will make up a larger percentage of the loads of small customers, the required adjustment is typically much larger for low-load customer classes, such as the Residential class. Failing to recognize the PLCC results in a double allocation of primary and secondary upstream distribution costs to Residential and other small customers. This issue was addressed by Mr. George J. Sterzinger in his article, "The Customer Charge and Problems of Double Allocation of Costs" published in the July 2, 1981 edition of *Public Utilities Fortnightly*.

Q. ARE THERE OTHER RECOGNIZED AUTHORITIES WHICH AGREE WITH YOUR POSITION THAT FAILING TO RECOGNIZE THE PLCC OF A THEORETICAL MINIMUM SYSTEM RESULTS IN A DOUBLE ALLOCATION OF DISTRIBUTION COSTS TO RESIDENTIAL CUSTOMERS?

A. Yes, in its publication *Electric Cost Allocation for a New Era, A Manual*,[2] at pages 146-147, the Regulatory Assistance Project ("RAP") finds that the minimum system analysis does not provide a reliable basis for classifying distribution investment and overstates the portion of distribution investment that is customer-related because the minimum system would meet a large portion of the average Residential customer's demand requirements. RAP finds that using a minimum system approach requires reducing the demand measure for each class for the PLCC of the minimum system.

RAP also finds the classification of distribution investment as customer related as unrealistic for additional reasons at pages 146-147 of its Manual. First, the minimum

[2] Lazar, J. , Chernick, P., Marchus, W., and LeBel, M. (Ed.). (2020, January). *Electric cost allocation for a new era*: *A manual*. Montpelier, VT: Regulatory Assistance Project.

system approach erroneously assumes that the minimum system would consist of the same number of poles and feet of conductors (units) as the actual system. In reality, load levels help determine the number of units as well as their size (and associated costs). RAP also notes that adding additional customers without adding peak demand or serving new areas does not require any additional poles or conductors, which are significant cost components of the minimum system. The minimum system approach assigns costs to customers which are added that do not add peak demand or are located in existing service areas and, therefore, did not require additional poles or conductors to be served.

Q. MR. TAYLOR, AT PAGES 8-9 OF HIS DIRECT TESTIMONY, CITES THE NATIONAL ASSOCIATION OF REGULATORY UTILITIES COMMISSION COST ALLOCATION MANUAL ("1992 NARUC MANUAL") TO SUPPORT HIS PROPOSED DEMAND-RELATED AND CUSTOMER-RELATED UPSTREAM PLANT ALLOCATIONS. WHAT IS YOUR RESPONSE?

A. Page 95 of the 1992 NARUC Manual states:

> …when the minimum-size distribution method is used to classify distribution plant….the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.

Therefore, the 1992 NARUC Manual has specifically recognized the need to consider the PLCC of the minimum system.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN A PROCEEDING WHERE MR. TAYLOR HAS RECOGNIZED THE PLCC OF A MINIMUM DISTRIBUTION SYSTEM?

A. Yes. Mr. Taylor and I were both witnesses in Chesapeake Utilities Corporation ("CUC") Docket No. 15-1734 before the Delaware Public Service Commission. While CUC is a natural gas distribution company ("NGDC"), the concept of a PLCC would also extend to a natural gas distribution minimum system. In that proceeding, Mr. Taylor, testifying on behalf of CUC, performed an ACCOSS which included a minimum system allocation for distribution mains similar to the approach he has proposed in his proceeding for UGI's upstream distribution facilities. In response to criticisms of his testimony I presented in my direct testimony in that proceeding, Mr. Taylor modified the ACCOSS that he had originally presented to account for the PLCC of the minimum system and recommended that the modified ACCOSS be utilized to evaluate CUC's rate design proposals.

Q. HAS THIS COMMISSION PREVIOUSLY ADDRESSED THE ALLOCATION OF UPSTREAM DISTRIBUTION PLANT BASED ON THE NUMBER OF CUSTOMERS IN A BASE RATE PROCEEDING OF A NGDC?

A. Yes. In Philadelphia Gas Works, Docket No. R-00061931, 2007 PAPUC Lexis 46 (2007), this Commission found that allocations of upstream distribution plant based on the number of customers are not acceptable.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE CLASSIFICATION OF UPSTREAM PRIMARY AND SECONDARY DISTRIBUTION PLANT?

A. I recommend that the Commission require the Company to classify 100 percent of its upstream primary and secondary distribution plant as demand-related. This approach is used in more than 30 states.[3] This classification will best reflect the factors that have

[3] *Charging for Distribution Services: Issues in Rate Design*. NARUC, December 2000.

caused this plant to be constructed—the need to meet local neighborhood peak demands and the need to deliver energy at usable voltages during all the hours of the year. The Company's proposal to classify a portion of upstream primary and secondary distribution plant as customer-related is unsupported and should be rejected because it fails to account for class differences between the distance between small and large customers and the PLCC of the minimum system.

Q. HAVE YOU REVISED THE COMPANY'S ACCOSS TO REFLECT AN ALLOCATION OF PRIMARY AND SECONDARY DISTRIBUTION PLANT 100 PERCENT BASED ON NCP DEMANDS?

A. Yes, I have revised the Company's ACCOSS to reflect a 100 percent demand allocation for Accounts 364, 365, 367, and 368. Table 3 provides a comparison of the results of the Company's ACCOSS and a revised ACCOSS which allocates primary and secondary distribution costs 100 percent based on NCP demands. Schedule JDM-1 attached to my testimony provides a more detailed summary of the revised ACCOSS.

Table 3. Comparison of Allocated Cost of Service Study Results
Company Study and 100 Percent Demand Study – Present Rates

	Company		**OCA**	
Rate Class	**Rate of Return**	**Index**	**Rate of Return**	**Index**
Residential	(1.28%)	(0.39)	0.65%	0.20
General Service - 1	1.16	0.36	7.89	2.44
General Service - 4	19.90	3.14	9.78	3.03
Large Power	17.60	5.43	5.09	1.57
Lighting	27.22	8.40	21.16	6.53
Total:	**3.24%**	**1.00**	**3.24%**	**1.00**

Q. WHAT EFFECT DOES THIS MODIFICATION TO THE COMPANY'S STUDY HAVE ON RELATIVE CLASS RATES OF RETURN?

A. As shown in Table 3, the rate of return for the Residential class increases, while the rate of return for the General Service - 4, the Large Power, and Lighting classes decline.

Q. IN UGI'S LAST BASE RATE PROCEEDING AT DOCKET NO. R-2017-2640058, YOU ALSO RECOMMENDED THAT PRIMARY AND SECONDARY DISTRIBUTION COSTS BE ALLOCATED 100 PERCENT BASED ON NCP DEMANDS, BUT THE COMMISSION DID NOT ACCEPT YOUR RECOMMENDATION. IF THE COMMISSION DOES NOT ACCEPT YOUR RECOMMENDED ALLOCATION OF PRIMARY AND SECONDARY DISTRIBUTION COSTS IN THIS PROCEEDING, SHOULD THE COMMISSION ACCEPT THE COMPANY'S ACCOSS?

A. No. As explained previously in my testimony, the Company's ACCOSS fails to account for the PLCC of the minimum system used to classify primary and secondary distribution costs as customer-related and, therefore, the Company's ACCOSS results in a double allocation of primary and secondary distribution costs to Residential and other small customers.

Q. HAVE YOU REVISED THE COMPANY'S ACCOSS TO REFLECT THE PLCC OF THE MINIMUM SYSTEM UTILIZED IN THE COMPANY'S ACCOSS TO CLARIFY COSTS AS CUSTOMER-RELATED?

A. Yes. I have alternatively revised the Company's ACCOSS to reflect the PLCC of the minimum system. Table 4 provides a comparison of the results of the Company's ACCOSS and an alternatively revised ACCOSS which accounts for the PLCC of the minimum system developed by the Company. Schedule JDM-2 attached to my testimony provides a more detailed summary of the alternatively revised ACCOSS.

Table 4. Comparison of Allocated Cost of Service Study Results
Company Study and Study Reflecting PLCC of Minimum System – Present Rates

	Company		OCA	
Rate Class	**Rate of Return**	**Index**	**Rate of Return**	**Index**
Residential	(1.28%)	(0.39)	0.22%	0.07
General Service - 1	1.16	0.36	5.92	1.83
General Service - 4	19.90	3.14	11.69	3.61
Large Power	17.60	5.43	7.09	2.19
Lighting	27.22	8.40	22.58	6.97
Total:	**3.24%**	**1.00**	**3.24%**	**1.00**

Q. HOW DID YOU REVISE THE COMPANY'S ACCOSS TO REFLECT THE PLCC OF THE MINIMUM SYSTEM?

A. The plant included in Accounts 364, 365, 367, and 368 is currently able to satisfy 100 percent of the NCP demands of UGI's customers. As shown on Table 2, UGI has classified a weighted average of 43 percent of the plant included in these accounts as customer-related. The average primary NCP demand of a Residential customer is 1.92 kW and the average secondary NCP demand of a Residential customer is 1.88 kW. Consistent with UGI's determination that 43 percent of primary and secondary distribution costs are customer-related, this indicates that 0.83 kW of Residential primary customer NCP demand (1.92 x 43 percent) and 0.81 kW of Residential secondary customer NCP demand (1.88 x 43 percent) can be met by the minimum system. To reflect the PLCC of the minimum system and eliminate the double allocation of primary and secondary upstream distribution costs, I reduced the primary and secondary NCP demands of each customer class reflected in UGI's ACCOSS by the Residential per customer NCP demand that can be met by the minimum system multiplied by the number of customers in each class. Table 5 identifies these adjustments by class.

Table 5. Adjustment to NCP Demands to Reflect the PLCC of Minimum System

	Primary		Secondary	
Rate Class	**Company**	**PLCC Adjusted**	**Company**	**PLCC Adjusted**
Residential	105,886	60,083	103,732	58,966
General Service - 1	6,342	1,712	6,213	1,687
General Service - 4	24,726	22,834	23,821	21,984
Large Power	42,875	42,711	17,775	17,645
Lighting	1,509	1,460	1,478	1,430
Total:	**181,308**	**128,800**	**153,019**	**101,711**

Q. WHAT EFFECT DOES THIS MODIFICATION TO THE COMPANY'S STUDY HAVE ON RELATIVE CLASS RATES OF RETURN?

A. As shown in Table 4, the rates of return for the Residential and General Service classes increase, while the rates of return for the other customer classes decline.

III. PROPOSED REVENUE DISTRIBUTION

Q. WHAT ARE SOME OF THE PRINCIPLES OF A SOUND REVENUE ALLOCATION?

A. As supported by Professor Bonbright, a sound revenue allocation should:

- Yield the total revenue requirement;
- Reflect fairness in the apportionment of the total cost of service among the various customer classes.
- Utilize class cost-of-service study results as a guide;
- Provide stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers or the utility (gradualism); and
- Provide for simplicity, certainty, convenience of payment, understandability, public acceptability, and feasibility of application.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED DISTRIBUTION OF THE REVENUE INCREASE AUTHORIZED BY THE COMMISSION IN THIS PROCEEDING.

A. The Company's proposed revenue distribution is presented by Mr. Taylor. The Company's proposed revenue distribution is based on the results of the ACCOSS presented by Mr. Taylor. The ACCOSS presented by Mr. Taylor indicates that the current revenue contributions of the Residential and General Service - 1 classes are significantly below the indicated cost of service, while the current revenue contributions of the other customer classes are significantly above the indicated cost of service. Therefore, UGI has proposed to assign the requested increase entirely to the Residential and General Service - 1 classes. The increase proposed for the Residential class is 35 percent, and 29 percent for the General Service - 1 class. As such, the concept of gradualism does not appear to have been a significant consideration in UGI's proposed revenue distribution. A summary of revenues by class at present and proposed rates was previously provided in Table 1.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED DISTRIBUTION OF THE REVENUE INCREASE IN THIS PROCEEDING?

A. No, I do not. The Company's proposed distribution is based on an ACCOSS that includes deficiencies and cost misallocations which have previously been discussed, and fails to provide for sufficient gradualism.

Q. WHAT IS YOUR RECOMMENDED REVENUE DISTRIBUTION IN THIS PROCEEDING?

A. Table 6 summarizes my recommended revenue distribution for UGI's claimed revenue deficiency. My recommendation is based on the results of my revised ACCOSS which classifies upstream distribution costs as 100 percent demand-related.

Table 6. OCA Proposed Revenue Distribution
Based on 100 Percent Demand ACCOSS
($000)

Rate Class	**Present Revenue**	**Proposed Revenue**	**Increase**	**Percent**
Residential	$23,519	$29,864	$6,345	27.0%
General Service – 1	2,033	2,321	289	14.2
General Service – 4	4,952	5,702	750	15.1
Large Power	5,184	6,509	1,325	25.6
Lighting	1,160	1,160	0	0.0
Total:	**$36,847**	**$45,556**	**$8,709**	**23.6%**

Q. HOW DID YOU DEVELOP YOUR PROPOSED REVENUE DISTRIBUTION?

Under my revised ACCOSS which classifies upstream distribution costs as 100 percent demand-related the Lighting class provides a rate of return at current rates which is significantly in excess of the system average return. Therefore, I have proposed no increase for the Lighting class. For the remaining rate classes, I have proposed increases which move the return for each class to approximately 75 percent of the system average return. Schedule JDM-3 provides additional information concerning the revenue distribution for each class under this proposed revenue distribution.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE SCALE-BACK OF YOUR PROPOSED REVENUE DISTRIBUTION TO REFLECT THE INCREASE ACTUALLY AUTHORIZED BY THE COMMISSION IN THIS PROCEEDING?

A. In the event that UGI's authorized increase is less than its requested increase, I recommend a proportionate scale-back of the increase for each rate class.

Q. WHAT IS YOUR RECOMMENDED REVENUE DISTRIBUTION IN THIS PROCEEDING IF THE COMMISSION DOES NOT ACCEPT YOUR ACCOSS WHICH CLASSIFIES UPSTREAM DISTRIBUTION PLANT 100 PERCENT DEMAND-RELATED AND ADOPTS YOUR ALTERNATIVE ACCOSS WHICH MODIFIES THE COMPANY'S ACCOSS TO REFLECT THE PLCC OF THE MINIMUM SYSTEM?

A. Table 7 summarizes my recommended revenue distribution for UGI's claimed revenue deficiency based on the ACCOSS, which reflects the PLCC of the minimum system.

Table 7. OCA Proposed Revenue Distribution
Based on PLCC of Minimum System ACCOSS
($000)

Rate Class	Present Revenue	Proposed Revenue	Increase	Percent
Residential	$23,519	$30,174	$6,655	28.3.0%
General Service – 1	2,033	2,411	379	18.6
General Service – 4	4,952	5,577	625	12.6
Large Power	5,184	6,234	1,050	20.3
Lighting	1,160	1,160	0	0.0
Total:	**$36,847**	**$45,556**	**$8,709**	**23.6%**

Q. HOW DID YOU DEVELOP THIS ALTERNATIVE PROPOSED REVENUE DISTRIBUTION?

A. Under my ACCOSS which accounts for the PLCC of the minimum system, the Lighting class provides a rate of return at current rates which is significantly in excess of the system average return. Therefore, I have proposed no increase for the Lighting class. For the remaining rate classes, I have proposed increases which moves the return for each class to approximately 75 percent of the system average return.

Schedule JDM-4 provides additional information concerning the revenue distribution for each class under my alternative proposed revenue distribution.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE SCALE-BACK OF YOUR ALTERNATIVE PROPOSED REVENUE DISTRIBUTION TO REFLECT THE INCREASE ACTUALLY AUTHORIZED BY THE COMMISSION IN THIS PROCEEDING?

A. In the event that UGI's authorized increase is less than its requested increase, I recommend a proportionate scale-back of the increase for each rate class.

IV. RATE DESIGN

Q. PLEASE IDENTIFY THE COMPANY'S PRESENT AND PROPOSED RESIDENTIAL RATES.

A. UGI's present Residential (Rate R) rates consist of an $8.74 per month customer charge and 2.812 cent per kWh distribution energy charge. UGI is proposing to increase the Rate R monthly customer charge to $13.00, or by nearly 50 percent, and increase the distribution energy charge to 3.971 cent per kWh, or by 41 percent.

Q. HOW DID THE COMPANY DEVELOP ITS PROPOSED RESIDENTIAL MONTHLY CUSTOMER CHARGE?

A. Mr. Taylor presents an analysis which he claims determines UGI's customer charge consistent with Pennsylvania precedent. That is, it includes the costs associated with meters and services and related O&M expenses, meter reading, billing and collection expenses, meter data management system, related employee benefits, and administrative and general expense. Using this approach, Mr. Taylor claims a cost-based Residential customer charge is $21.52 based on costs of $14,213,918, and that the proposed $13.00 charge is well below the cost-based charge, thereby justifying the significant increase in the charge.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED MONTHLY RESIDENTIAL CUSTOMER CHARGE?

A. No, for a number of reasons. First, as just explained, the Company's proposed increase in the monthly Residential customer charge reflects an increase of nearly 50 percent. Increases of this magnitude are inconsistent with the principal of gradualism, and will have a disproportionate impact on low-income and lower-usage customers as explained further by OCA witness Mr. Roger Colton in his direct testimony.

Second, the Company's calculated charge of $21.52 includes costs not appropriately included in a customer charge. Only those costs that directly increase with the addition of a customer or directly decrease with the subtraction of a customer should be included in a customer charge. Examples of expenses improperly reflected in UGI's calculated charge of $21.52 include:

- Universal Service Costs ($3,330,000);
- Uncollectible Expense ($1,663,000); and
- Administrative and General Salaries ($484,000).

Also improperly included in the calculated customer charge are the return and taxes and depreciation expenses associated with General and Common Plant. Since these costs do not vary directly with changes in the number of customers served, they should be removed from the calculated customer charge. Removing these costs reduces UGI calculated costs of $14,213,918 to $5,877,391, and the calculated charge from $21.52 to $8.90. The calculated charge of $8.90 is based on the increase requested in the Company's filing and will likely be further reduced based on the increase actually authorized by the Commission in this proceeding. Schedule JDM-5 presents my Residential customer charge calculation.

Finally, the cost structure of the Company's distribution system is dominated by costs which vary with changes in demand. As such, the customer charge does not provide price signals that are particularly relevant to the cost structure. The volumetric energy charge is the primary source of meaningful price signals. A lower customer charge ensures that a greater portion of costs are recovered through energy charges, is more consistent with the Commonwealth's energy conservation and efficiency goals, and will help minimize electric distribution system costs over the long-term.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE COMPANY'S MONTHLY RESIDENTIAL CUSTOMER CHARGE?

A. Since UGI's calculated customer charge will likely be less than $8.74 when the increase authorized by the Commission, if any, is reflected in the calculated charge, I recommend that UGI's current Residential customer charge be maintained at $8.74.

VI. BATTERY STORAGE PROJECT

Q. PLEASE DESCRIBE UGI'S BATTERY STORAGE PROJECT.

A. As further described by UGI witness Mr. Eric W. Sorber in Statement No. 3, UGI is planning a reliability improvement project to install and interconnect a utility-owned, small-scale energy storage battery into its primary distribution system. The Company claims it plans to use this technology as a targeted means to enhance resiliency and serviceability in a reliability-challenged part of its system. The Company further claims that battery resource will enhance the customer experience during major storm interruptions by establishing a quick responding resource, which can reduce potential hours of service interruptions.

The proposed project will include a 1.25 MWh lithium-ion based battery and will cost approximately $1.5 million. The Company claims the 1.25 MWh battery system is designed to support the expected peak load of 68 customers (in the battery footprint) a in a service territory near Wapwallopen, PA for up to approximately four hours. The Company has indicated that the goal of this project is to demonstrate the feasibility of this new technology to support system reliability and to provide the Company, and Company personnel, direct first-hand knowledge and experience with battery storage systems of this type. The expected life of the battery system is 20 years.

Q. ARE THERE OPPORTUNITIES TO REDUCE THE COST IMPACT OF THE BATTERY STORAGE PROJECT?

A. As explained in greater detail by UGI witness Mr. Taylor, there is an opportunity for this battery storage project to participate in PJM's frequency regulation market (Market D) and for UGI to receive revenues for providing frequency response to PJM with the use of this asset. Mr. Taylor estimates these revenues to be $88,653 annually. (OCA-I-26 Supplemental Response).

Q. HAS UGI DEMONSTRATED THAT THE PROPOSED BATTERY STORAGE PROJECT SHOULD BE APPROVED BY THE COMMISSION AND INCLUDED IN DISTRIBUTION RATES?

A. No. There are a number of concerns with the proposed battery storage project which must be addressed before it can be approved by the Commission and included in UGI's rates for distribution service. If UGI does not adequately address these concerns, the battery storage project should not be included in rates.

First, the battery storage project may perform a generation function and could then be considered a generation asset. Counsel informs me that UGI's proposed battery storage project may violate Section 2804(14) of the Public Utility Code, which prohibits the inclusion of generation assets in utility distribution rates. Therefore, prior to inclusion in its distribution rates, UGI must demonstrate what portion of the battery storage project performs a distribution function, provides a distribution system reliability benefit, and is eligible for inclusion in the rates for distribution service.

Second, UGI has not demonstrated that the battery storage project is the most cost effective approach to meeting the demands of the 68 customers in the battery footprint in the event of an outage. An appropriate prerequisite for Commission approval and distribution rate treatment would be a demonstration that the project is the most cost-effective approach to maintain reliability. The average cost of the project is over $22,000 per customer. There may be other distribution system improvements with an expected life greater than 20 years that may be more cost effective and able to meet demands during an outage for a period greater than 4 hours. This cost effectiveness demonstration should include consideration of any salvage costs of the battery storage project at the conclusion of its 20-year expected life.

Third, as indicated by Mr. Taylor, the battery storage project has the potential to generate revenues for the Company through participation in PJM's frequency regulation market. Participation in PJM's frequency regulation market may result in the battery not being sufficiently charged to provide reliable service in the event of an outage. UGI has not adequately addressed this possibility and concern.

Finally, UGI is proposing to recover 100 percent of the costs associated with the battery storage project from customers through distribution rates. If the Commission determines that the inclusion of the battery storage project in distribution rates does not violate Section 2804(14) of the Public Utility Code, is the most cost effective solution to address reliability concerns, and UGI has adequately addressed the availability of the battery to provide service in the event of an outage, 100 percent of the revenues generated through participation in PJM's frequency regulation market should be tracked, deferred for recovery, and returned to ratepayers with interest in UGI's next base rate proceeding.

Q. WHAT REPORTING REQUIREMENTS SHOULD BE ESTABLISHED FOR THE BATTERY STORAGE PROJECT IF IT IS APPROVED BY THE COMMISSION?

A. If the battery storage project is approved by the Commission, UGI should be required to maintain and provide information concerning the duration, extent, cause, and times for each outage, the duration and times the battery was used to maintain service during the outage, and loads on the facilities served by the battery just prior to and during the outage. UGI should also document its participation in any frequency regulation market and the associated revenues realized.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

308038

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
	)	
v.	**)**	**Docket No. R-2021-3023618**
	)	
UGI Utilities, Inc. – Electric Division	**)**	

SCHEDULES ACCOMPANYING THE
DIRECT TESTIMONY

OF

JEROME D. MIERZWA

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

May 3, 2021

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

UGI Utilities, Inc. - Electric Division
FPFTY Ending September 30, 2022

ALLOCATION OF PRIMARY AND SECONDARD DISTRIBUTION FACILITY COSTS BASED ON NON-COINCIDENT PEAK DEMANDS

Schedule JDM-1

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	Total Check	Residential	General Service-1	General Service-4	Large Power	Lighting
1	**Rate Base**							
2	Plant in Service	226,945	-	147,365	10,622	28,978	35,351	4,629
3	Accumulated Reserve	(74,795)	-	(49,612)	(3,917)	(9,261)	(10,265)	(1,739)
4	Other Rate Base Items	(20,319)	-	(12,711)	(1,016)	(2,981)	(3,191)	(420)
5	Total Rate Base	131,831	-	85,041	5,689	16,736	21,895	2,470
6	**Total Revenue at Current Rates**							
7	Total Distribution Margin	36,847	-	23,519	2,033	4,952	5,184	1,160
8	Purchased Power Revenue	41,179	-	33,355	1,606	4,736	1,235	247
9	Purchased Power GRT Revenue	2,430	-	1,968	95	279	73	15
10	USP Rider	3,330	-	3,330	-	-	-	-
11	EEC Rider	2,249	-	864	38	148	1,189	9
12	Forfeited Discounts	468	-	332	38	68	25	5
13	Miscellaneous Revenues Margin	562	-	356	20	78	103	5
14	Total Revenue	87,065	-	63,725	3,829	10,260	7,810	1,441
		42,426		27,713	2,070	5,100	6,374	1,169
15	**Expenses at Current Rates**							
16	O&M and A&G Expenses	28,516	-	20,691	1,169	2,358	3,867	431
17	Purchased Power Expense	41,179	-	33,355	1,606	4,736	1,235	247
18	Depreciation and Amortization Expense	7,114	-	4,731	338	854	1,041	151
19	Purchased Power GRT Expense	2,430	-	1,968	95	279	73	15
20	Taxes Other Than Income	3,499	-	2,423	166	376	465	68
21	Income Taxes	56	-	7	6	21	15	7
22	Total Expenses - Current	82,793	-	63,175	3,380	8,624	6,696	918
23	Operating Income - Current	4,272	-	550	449	1,636	1,114	523
24	Current Rate of Return	3.24%		0.65%	7.89%	9.78%	5.09%	21.16%
25	**Present Revenue at Equal Rates of Return**							
26	Present Return	3.24%		3.24%	3.24%	3.24%	3.24%	3.24%
27	Present Operating Income @ Equal Return	4,272	-	2,756	184	542	709	80
28	Income Taxes	56	-	36	2	7	9	1
29	Other Expenses	82,737	-	63,168	3,374	8,603	6,681	911
30	Total Revenue @ Equal Rates of Return	87,065	-	65,959	3,561	9,152	7,400	993
31	Present (Subsidies)/Excesses	-	-	(2,234)	268	1,108	410	448

UGI Utilities, Inc. - Electric Division
FPFTY Ending September 30, 2022

NON-COINCIDENT PEAK DEMANDS ADJUSTED TO REFLECT THE PEAK LOAD CARRYING CAPABILITY OF THE MINIMUM SYSTEM

Schedule JDM-2

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	Total Check	Residential	General Service-1	General Service-4	Large Power	Lighting
1	**Rate Base**							
2	Plant in Service	226,945	-	153,421	11,864	26,314	30,912	4,434
3	Accumulated Reserve	(74,795)	-	(51,868)	(4,377)	(8,282)	(8,600)	(1,668)
4	Other Rate Base Items	(20,319)	-	(13,247)	(1,126)	(2,745)	(2,799)	(403)
5	Total Rate Base	131,831	-	88,306	6,361	15,287	19,513	2,364
6	**Total Revenue at Current Rates**							
7	Total Distribution Margin	36,847	-	23,519	2,033	4,952	5,184	1,160
8	Purchased Power Revenue	41,179	-	33,355	1,606	4,736	1,235	247
9	Purchased Power GRT Revenue	2,430	-	1,968	95	279	73	15
10	USP Rider	3,330	-	3,330	-	-	-	-
11	EEC Rider	2,249	-	864	38	148	1,189	9
12	Forfeited Discounts	468	-	332	38	68	25	5
13	Miscellaneous Revenues Margin	562	-	410	31	55	63	3
14	Total Revenue	87,065	-	63,779	3,840	10,237	7,770	1,439
15	**Expenses at Current Rates**							
16	O&M and A&G Expenses	28,516	-	20,925	1,216	2,263	3,688	424
17	Purchased Power Expense	41,179	-	33,355	1,606	4,736	1,235	247
18	Depreciation and Amortization Expense	7,114	-	4,858	364	796	949	147
19	Purchased Power GRT Expense	2,430	-	1,968	95	279	73	15
20	Taxes Other Than Income	3,499	-	2,480	178	351	423	66
21	Income Taxes	56	-	2	5	23	18	7
22	Total Expenses - Current	82,793	-	63,588	3,463	8,450	6,387	906
23	Operating Income - Current	4,272	-	190	377	1,787	1,384	534
24	Current Rate of Return	3.24%		0.22%	5.92%	11.69%	7.09%	22.58%
25	**Present Revenue at Equal Rates of Return**							
26	Present Return	3.24%		3.24%	3.24%	3.24%	3.24%	3.24%
27	Present Operating Income @ Equal Return	4,272	-	2,861	206	495	632	77
28	Income Taxes	56	-	37	3	6	8	1
29	Other Expenses	82,737	-	63,586	3,458	8,426	6,369	899
30	Total Revenue @ Equal Rates of Return	87,065	-	66,485	3,667	8,928	7,009	976
31	Present (Subsidies)/Excesses	-	-	(2,706)	173	1,309	761	463

ALLOCATION OF PRIMARY AND SECONDARD DISTRIBUTION FACILITY COSTS BASED ON NON-COINCIDENT PEAK DEMANDS

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	Total Check	Residential	General Service-1	General Service-4	Large Power	Lighting
1	**Rate Base**							
2	Plant in Service	226,945	-	147,365	10,622	28,978	35,351	4,629
3	Accumulated Reserve	(74,795)	-	(49,612)	(3,917)	(9,261)	(10,265)	(1,739)
4	Other Rate Base Items	(20,319)	-	(12,711)	(1,016)	(2,981)	(3,191)	(420)
5	Total Rate Base	131,831	-	85,041	5,689	16,736	21,895	2,470
6	**Total Revenue at Current Rates**							
7	Total Distribution Margin	36,847	-	23,519	2,033	4,952	5,184	1,160
8	Purchased Power Revenue	41,179	-	33,355	1,606	4,736	1,235	247
9	Purchased Power GRT Revenue	2,430	-	1,968	95	279	73	15
10	USP Rider	3,330	-	3,330	-	-	-	-
11	EEC Rider	2,249	-	864	38	148	1,189	9
12	Forfeited Discounts	468	-	332	38	68	25	5
13	Miscellaneous Revenues Margin	562	-	356	20	78	103	5
14	Total Revenue	87,065	-	63,725	3,829	10,260	7,810	1,441
		42,426		27,713	2,070	5,100	6,374	1,169
15	**Expenses at Current Rates**							
16	O&M and A&G Expenses	28,516	-	20,691	1,169	2,358	3,867	431
17	Purchased Power Expense	41,179	-	33,355	1,606	4,736	1,235	247
18	Depreciation and Amortization Expense	7,114	-	4,731	338	854	1,041	151
19	Purchased Power GRT Expense	2,430	-	1,968	95	279	73	15
20	Taxes Other Than Income	3,499	-	2,423	166	376	465	68
21	Income Taxes	56	-	7	6	21	15	7
22	Total Expenses - Current	82,793	-	63,175	3,380	8,624	6,696	918
23	Operating Income - Current	4,272	-	550	449	1,636	1,114	523
24	Current Rate of Return	3.24%		0.65%	7.89%	9.78%	5.09%	21.16%
25	**Present Revenue at Equal Rates of Return**							
26	Present Return	3.24%		3.24%	3.24%	3.24%	3.24%	3.24%
27	Present Operating Income @ Equal Return	4,272	-	2,756	184	542	709	80
28	Income Taxes	56	-	36	2	7	9	1
29	Other Expenses	82,737	-	63,168	3,374	8,603	6,681	911
30	Total Revenue @ Equal Rates of Return	87,065	-	65,959	3,561	9,152	7,400	993
31	Present (Subsidies)/Excesses	-	-	(2,234)	268	1,108	410	448

ALLOCATION OF PRIMARY AND SECONDARD DISTRIBUTION FACILITY COSTS BASED ON NON-COINCIDENT PEAK DEMANDS

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	Total Check	Residential	General Service-1	General Service-4	Large Power	Lighting
				1.31%	1.31%	1.31%	1.31%	1.31%
32	**Revenue Requirement at Equal Rates of Return**							
33	Required Return	7.57%		7.57%	7.57%	7.57%	7.57%	7.57%
34	Required Operating Income	9,980	-	6,438	431	1,267	1,657	187
35	**Expenses at Required Return**							
36	O&M and A&G Expenses	28,516	-	20,691	1,169	2,358	3,867	431
37	Purchased Power Expense	41,179	-	33,355	1,606	4,736	1,235	247
38	Depreciation and Amortization Expense	7,114	-	4,731	338	854	1,041	151
39	Purchased Power GRT Expense	2,430	-	1,968	95	279	73	15
40	Taxes Other Than Income	3,499	-	2,423	166	376	465	68
41	Income Taxes	56	-	36	2	7	9	1
42	Gross Up - Income Taxes	2,319	-	1,496	100	294	385	43
43	Gross Up - Gross Receipts & Uncollectibles	682	-	471	32	73	94	13
44	Total Expenses - Required	85,794	-	65,171	3,508	8,977	7,170	969
45	Total Revenue Requirement at Equal Return	95,774	-	71,608	3,939	10,244	8,827	1,156
46	Current Miscellaneous Revenue	1,030	-	689	58	145	128	10
47	Total Revenue @ Equal Rates of Return	94,744	-	70,920	3,881	10,098	8,699	1,146
48	Revenue (Deficiency)/Surplus	(8,709)	1	(7,883)	(110)	16	(1,017)	285
49	Total Base Revenue as Proposed	45,556	1	29,864	2,321	5,702	6,509	1,160
50	Purchased Power Revenue and GRT	43,609	1	35,323	1,701	5,015	1,308	262
51	USP and EEC Revenue	5,579	1	4,195	38	148	1,189	9
52	Miscellaneous Revenue	1,030	-	689	58	145	128	10
53	Total Revenue as Proposed	95,774	-	70,070	4,118	11,010	9,135	1,441
54	Total Distribution Margin Increase as Proposed	8,709	1	6,345	289	750	1,325	0
55	Purchased Power Revenue and GRT Change	-		-	-	-	-	-
56	USP and EEC Revenue Change	-		-	-	-	-	-
57	Miscellaneous Revenues Change	-	-	-	-	-	-	-
58	Total Revenue as Proposed	8,709	1	6,345	289	750	1,325	0
59	Precent Total Revenue Change	10.00%		9.96%	7.54%	7.31%	16.97%	0.01%
60	Income Prior to Taxes	12,355	-	6,431	712	2,335	2,360	517
61	Income Taxes	2,375	-	1,236	137	449	454	99

ALLOCATION OF PRIMARY AND SECONDARD DISTRIBUTION FACILITY COSTS BASED ON NON-COINCIDENT PEAK DEMANDS

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	Total Check	Residential	General Service-1	General Service-4	Large Power	Lighting
62	Operating Income	9,980	-	5,195	575	1,886	1,906	417
63	**Proposed Return**	7.57%		6.11%	10.11%	11.27%	8.71%	16.90%
			END					
64	Current Relative Rate of Return	1.00		0.20	2.44	3.02	1.57	6.53
65	Proposed Relative Rate of Return	1.00		0.81	1.34	1.49	1.15	2.23

UGI Utilities, Inc. - Electric Division
FPFTY Ending September 30, 2022

NON-COINCIDENT PEAK DEMANDS ADJUSTED TO REFLECT THE PEAK LOAD CARRYING CAPABILITY OF THE MINIMUM SYSTEM

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	Total Check	Residential	General Service-1	General Service-4	Large Power	Lighting
1	**Rate Base**							
2	Plant in Service	226,945	-	153,421	11,864	26,314	30,912	4,434
3	Accumulated Reserve	(74,795)	-	(51,868)	(4,377)	(8,282)	(8,600)	(1,668)
4	Other Rate Base Items	(20,319)	-	(13,247)	(1,126)	(2,745)	(2,799)	(403)
5	Total Rate Base	131,831	-	88,306	6,361	15,287	19,513	2,364
6	**Total Revenue at Current Rates**							
7	Total Distribution Margin	36,847	-	23,519	2,033	4,952	5,184	1,160
8	Purchased Power Revenue	41,179	-	33,355	1,606	4,736	1,235	247
9	Purchased Power GRT Revenue	2,430	-	1,968	95	279	73	15
10	USP Rider	3,330	-	3,330	-	-	-	-
11	EEC Rider	2,249	-	864	38	148	1,189	9
12	Forfeited Discounts	468	-	332	38	68	25	5
13	Miscellaneous Revenues Margin	562	-	410	31	55	63	3
14	Total Revenue	87,065	-	63,779	3,840	10,237	7,770	1,439
15	**Expenses at Current Rates**							
16	O&M and A&G Expenses	28,516	-	20,925	1,216	2,263	3,688	424
17	Purchased Power Expense	41,179	-	33,355	1,606	4,736	1,235	247
18	Depreciation and Amortization Expense	7,114	-	4,858	364	796	949	147
19	Purchased Power GRT Expense	2,430	-	1,968	95	279	73	15
20	Taxes Other Than Income	3,499	-	2,480	178	351	423	66
21	Income Taxes	56	-	2	5	23	18	7
22	Total Expenses - Current	82,793	-	63,588	3,463	8,450	6,387	906
23	Operating Income - Current	4,272	-	190	377	1,787	1,384	534
24	Current Rate of Return	3.24%		0.22%	5.92%	11.69%	7.09%	22.58%
25	**Present Revenue at Equal Rates of Return**							
26	Present Return	3.24%		3.24%	3.24%	3.24%	3.24%	3.24%
27	Present Operating Income @ Equal Return	4,272	-	2,861	206	495	632	77
28	Income Taxes	56	-	37	3	6	8	1
29	Other Expenses	82,737	-	63,586	3,458	8,426	6,369	899
30	Total Revenue @ Equal Rates of Return	87,065	-	66,485	3,667	8,928	7,009	976
31	Present (Subsidies)/Excesses	-	-	(2,706)	173	1,309	761	463

UGI Utilities, Inc. - Electric Division
FPFTY Ending September 30, 2022

NON-COINCIDENT PEAK DEMANDS ADJUSTED TO REFLECT THE PEAK LOAD CARRYING CAPABILITY OF THE MINIMUM SYSTEM

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	Total Check	Residential	General Service-1	General Service-4	Large Power	Lighting
				1.31%	1.31%	1.31%	1.31%	1.31%
32	**Revenue Requirement at Equal Rates of Return**							
33	Required Return	7.57%		7.57%	7.57%	7.57%	7.57%	7.57%
34	Required Operating Income	9,980	-	6,685	482	1,157	1,477	179
35	**Expenses at Required Return**							
36	O&M and A&G Expenses	28,516	-	20,925	1,216	2,263	3,688	424
37	Purchased Power Expense	41,179	-	33,355	1,606	4,736	1,235	247
38	Depreciation and Amortization Expense	7,114	-	4,858	364	796	949	147
39	Purchased Power GRT Expense	2,430	-	1,968	95	279	73	15
40	Taxes Other Than Income	3,499	-	2,480	178	351	423	66
41	Income Taxes	56	-	37	3	6	8	1
42	Gross Up - Income Taxes	2,319	-	1,552	112	270	344	42
43	Gross Up - Gross Receipts & Uncollectibles	682	-	482	34	68	86	13
44	Total Expenses - Required	85,794	-	65,657	3,606	8,770	6,807	954
45	Total Revenue Requirement at Equal Return	95,774	-	72,342	4,088	9,928	8,284	1,133
46	Current Miscellaneous Revenue	1,030	-	742	69	122	88	8
47	Total Revenue @ Equal Rates of Return	94,744	-	71,599	4,019	9,805	8,196	1,124
48	Revenue (Deficiency)/Surplus	(8,709)	-	(8,563)	(248)	309	(514)	307
49	Total Base Revenue as Proposed	45,556	-	30,174	2,411	5,577	6,234	1,160
50	Purchased Power Revenue and GRT	43,609	-	35,323	1,701	5,015	1,308	262
51	USP and EEC Revenue	5,579	-	4,195	38	148	1,189	9
52	Miscellaneous Revenue	1,030	-	742	69	122	88	8
53	Total Revenue as Proposed	95,774	-	70,434	4,218	10,862	8,820	1,439
54	Total Distribution Margin Increase as Proposed	8,709	1	6,655	379	625	1,050	0
55	Purchased Power Revenue and GRT Change	-		-	-	-	-	-
56	USP and EEC Revenue Change	-		-	-	-	-	-
57	Miscellaneous Revenues Change	-	-	-	-	-	-	-
58	Total Revenue as Proposed	8,709	-	6,655	379	625	1,050	0
59	Precent Total Revenue Change	10.00%		10.43%	9.86%	6.11%	13.51%	0.01%
60	Income Prior to Taxes	12,355	-	6,366	727	2,368	2,366	528
61	Income Taxes	2,375	-	1,224	140	455	455	102

NON-COINCIDENT PEAK DEMANDS ADJUSTED TO REFLECT THE PEAK LOAD CARRYING CAPABILITY OF THE MINIMUM SYSTEM

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	Total Check	Residential	General Service-1	General Service-4	Large Power	Lighting
62	Operating Income	9,980	-	5,142	587	1,912	1,911	427
63	**Proposed Return**	7.57%		5.82%	9.23%	12.51%	9.79%	18.05%
			END					
64	Current Relative Rate of Return	1.00		0.07	1.83	3.61	2.19	6.97
65	Proposed Relative Rate of Return	1.00		0.77	1.22	1.65	1.29	2.38
				0.75	0.74	0.75	0.75	0.77

UGI Utilities, Inc. - Electric Division
FPFTY Ending September 30, 2022

~
~

Function & Classification : PA PUC Direct Customer Customer
PA PUC Direct Customer Customer

	ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE	ALLOCATOR	INT/EXT ALLOCATOR	Residential	General Service-1	General Service-4	Large Power	Lighting
1	ACCOUNT DESCRIPTION									
2	A PLANT IN SERVICE									
3	**Intangible Plant**									
4	Organization	302	4	INT_LABOR	INT	2	0	0	0	0
5	Franchise & Consent	302	1	INT_TOTPLT	INT	0	0	0	0	0
6	Miscellaneous Intangible Plant	303	-	INT_TOTPLT	INT	-	-	-	-	-
7	Subtotal - Intangible Plant		5			2	0	0	0	0
8	**Distribution Plant**									
9	Land & Land Rights	360	-	INT_D361_364	INT	-	-	-	-	-
10	Structures & Improvements	361	-		EXT	-	-	-	-	-
11	Station Equipment	362	-		EXT	-	-	-	-	-
12	Storage Battery Equipment	363	-		EXT	-	-	-	-	-
13	Poles, Towers and Fixtures - PRI DEM	364	-		EXT	-	-	-	-	-
14	Poles, Towers and Fixtures - PRI CUS	364	-	PRI_CUST	EXT	-	-	-	-	-
15	Poles, Towers and Fixtures - SEC DEM	364	-		EXT	-	-	-	-	-
16	Poles, Towers and Fixtures - SEC CUS	364	-	SEC_CUST	EXT	-	-	-	-	-
17	Overhead Conductors and Devices - PRI DEM	365	-		EXT	-	-	-	-	-
18	Overhead Conductors and Devices - PRI CUS	365	-	PRI_CUST	EXT	-	-	-	-	-
19	Overhead Conductors and Devices - SEC DEM	365	-		EXT	-	-	-	-	-
20	Overhead Conductors and Devices - SEC CUS	365	-	SEC_CUST	EXT	-	-	-	-	-
21	Underground Conduit	366	-	INT_D367	INT	-	-	-	-	-
22	Underground Conductors and Devices - PRI DEM	367	-		EXT	-	-	-	-	-
23	Underground Conductors and Devices - PRI CUS	367	-	PRI_CUST	EXT	-	-	-	-	-
24	Underground Conductors and Devices - SEC DEM	367	-		EXT	-	-	-	-	-
25	Underground Conductors and Devices - SEC CUS	367	-	SEC_CUST	EXT	-	-	-	-	-
26	Transformers and Transformer Installations - SEC DEM	368.1	-		EXT	-	-	-	-	-
27	Transformers and Transformer Installations - SEC CUS	368.2	-	SEC_CUST	EXT	-	-	-	-	-
28	Services	369	15,399	SERV	EXT	13,261	1,477	607	54	-
29	Meters	370.1	2,497	METERS	EXT	2,033	244	203	18	-
30	Meter Installations	370.2	1,978	METERS	EXT	1,610	193	161	14	-
31	Electronic Meters	370.3	4,908	METERS	EXT	3,995	479	398	35	-
32	Installations on Customers' Premises	371	-	CUSTPREMIS	EXT	-	-	-	-	-
33	Installations on Customers' Premises - EV Charging Stations	371.1	-	CUST	EXT	-	-	-	-	-
34	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-	LIGHT	EXT	-	-	-	-	-
35	Street Lighting and Signal Systems	373	-	LIGHT	EXT	-	-	-	-	-
36	Subtotal - Distribution Plant		24,782			20,899	2,393	1,368	122	-
37	**General & Common Plant**									
38	Land & Land Rights	389	228	INT_LABOR	INT		12	5	0	0
39	Structures & Improvements	390	2,431	INT_LABOR	INT		125	53	5	1
40	Office Furniture & Equipment	391	5,724	INT_LABOR	INT		294	124	11	3
41	Transportation Equipment	392	439	INT_LABOR	INT		23	10	1	0
42	Stores Equipment	393	1	INT_LABOR	INT		0	0	0	0
43	Tools & Garage Equipment	394	380	INT_LABOR	INT		20	8	1	0
44	Laboratory Equipment	395	21	INT_LABOR	INT		1	0	0	0
45	Power Operated Equipment	396	89	INT_LABOR	INT		5	2	0	0
46	Communication Equipment	397	205	INT_LABOR	INT		11	4	0	0
47	Miscellaneous Equipment	398	122	INT_LABOR	INT		6	3	0	0
48	Subtotal - General & Common Plant		9,639			-	495	209	18	5
49	**TOTAL PLANT IN SERVICE**		34,426			20,901	2,889	1,578	140	5

UGI Utilities, Inc. - Electric Division
FPFTY Ending September 30, 2022

~
~

Function & Classification : PA PUC Direct Customer Customer
PA PUC Direct Customer Customer

	ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE	ALLOCATOR	INT/EXT ALLOCATOR	Residential	General Service-1	General Service-4	Large Power	Lighting
1										
50	B ACCUMULATED DEPRECIATION									
51	**Intangible Plant**									
52	Organization	302	-	INT_LABOR	INT	-	-	-	-	-
53	Franchise & Consent	302	-	INT_TOTPLT	INT	-	-	-	-	-
54	Miscellaneous Intangible Plant	303	-	INT_TOTPLT	INT	-	-	-	-	-
55	Subtotal - Intangible Plant		-			-	-	-	-	-
56	**Distribution Plant**									
57	Land & Land Rights	360	-	INT_D361_364	INT	-	-	-	-	-
58	Structures & Improvements	361	-		EXT	-	-	-	-	-
59	Station Equipment	362	-		EXT	-	-	-	-	-
60	Storage Battery Equipment	363	-		EXT	-	-	-	-	-
61	Poles, Towers and Fixtures	364	-	INT_D364	INT	-	-	-	-	-
62	Overhead Conductors and Devices	365	-	INT_D365	INT	-	-	-	-	-
63	Underground Conduit	366	-	INT_D367	INT	-	-	-	-	-
64	Underground Conductors and Devices	367	-	INT_D367	INT	-	-	-	-	-
65	Transformers	368.1	-	INT_D368	INT	-	-	-	-	-
66	Transformer Installations	368.2	-	INT_D368	INT	-	-	-	-	-
67	Services	369	(7,546)	SERV	EXT	(6,498)	(724)	(297)	(27)	-
68	Meters	370.1	(1,858)	METERS	EXT	(1,512)	(181)	(151)	(13)	-
69	Meter Installations	370.2	(811)	METERS	EXT	(660)	(79)	(66)	(6)	-
70	Electronic Meters	370.3	(3,674)	METERS	EXT	(2,991)	(359)	(298)	(26)	-
71	Installations on Customers' Premises	371	-	CUSTPREMIS	EXT	-	-	-	-	-
72	Installations on Customers' Premises - EV Charging Stations	371.1	-	CUST	EXT	-	-	-	-	-
73	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-	LIGHT	EXT	-	-	-	-	-
74	Street Lighting and Signal Systems	373	-	LIGHT	EXT	-	-	-	-	-
75	Subtotal - Distribution Plant		(13,889)			(11,662)	(1,343)	(812)	(72)	-
76	**General Plant**									
77	Land & Land Rights	389	-	INT_LABOR	INT	-	-	-	-	-
78	Structures & Improvements	390	(291)	INT_LABOR	INT		(15)	(6)	(1)	(0)
79	Office Furniture & Equipment	391	(1,945)	INT_LABOR	INT		(100)	(42)	(4)	(1)
80	Transportation Equipment	392	(75)	INT_LABOR	INT		(4)	(2)	(0)	(0)
81	Stores Equipment	393	(1)	INT_LABOR	INT		(0)	(0)	(0)	(0)
82	Tools & Garage Equipment	394	(160)	INT_LABOR	INT		(8)	(3)	(0)	(0)
83	Laboratory Equipment	395	(16)	INT_LABOR	INT		(1)	(0)	(0)	(0)
84	Power Operated Equipment	396	(11)	INT_LABOR	INT		(1)	(0)	(0)	(0)
85	Communication Equipment	397	(68)	INT_LABOR	INT		(3)	(1)	(0)	(0)
86	Miscellaneous Equipment	398	(25)	INT_LABOR	INT		(1)	(1)	(0)	(0)
87	Subtotal - General Plant		(2,592)			-	(133)	(56)	(5)	(1)
88	**TOTAL ACCUMULATED DEPRECIATION**		(16,481)			(11,662)	(1,476)	(868)	(77)	(1)
89	C OTHER RATEBASE ITEMS									
90	Working Capital	Sch. A-1	1,162	INT_TOTPLT	INT	705	97	53	5	0
91	Accumulated Deferred Income Taxes	Sch. A-1	(4,261)	INT_TOTPLT	INT	(2,587)	(358)	(195)	(17)	(1)
92	Customer Deposits	Sch. A-1	(1,197)	DEPCUST	EXT	(421)	(125)	(485)	(138)	(29)
93	Materials & Supplies	Sch. A-1	468	INT_LABOR	INT	236	24	10	1	0
94	Subtotal - OTHER RATEBASE ITEMS		(3,828)			(2,067)	(361)	(616)	(149)	(29)
95	**TOTAL RATE BASE**		14,117			7,173	1,051	93	(87)	(26)

UGI Utilities, Inc. - Electric Division
FPFTY Ending September 30, 2022

~
~

Function & Classification : PA PUC Direct Customer Customer
PA PUC Direct Customer Customer

1	ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE	ALLOCATOR	INT/EXT ALLOCATOR	Residential	General Service-1	General Service-4	Large Power	Lighting
96	D OPERATING AND MAINTENANCE EXPENSES									
97	Other Power Generation Expense									
98	Purchased Power	555	-		EXT	-	-	-	-	-
99	Transmission of Electricty by Others	565	-		EXT	-	-	-	-	-
100	Subtotal - Other Power Generation Expense		-			-	-	-	-	-
101	Distribution Expenses - Operation									
102	Operation Supervision and Engineering	580	22	INT_DISTOPS	INT	18	2	1	0	-
103	Load Dispatching	581	60	INT_DISTPLT	INT	51	6	3	0	-
104	Line and Station Expenses	581.1	-	INT_DISTPLT	INT	-	-	-	-	-
105	Station Expenses	582	-		EXT	-	-	-	-	-
106	Overhead Line Expenses	583	-	INT_D365	INT	-	-	-	-	-
107	Underground Line Expenses	584	-	INT_D367	INT	-	-	-	-	-
108	Operation of Energy Storage Equipment	584.1	-	INT_DISTPLT	INT	-	-	-	-	-
109	Street Lighting and Signal System Expenses	585	-	LIGHT	EXT	-	-	-	-	-
110	Meter Expenses	586	-	METERS	EXT	-	-	-	-	-
111	Customer Installation Expenses	587	-	SERV	EXT	-	-	-	-	-
112	Miscellaneous Distribution Expenses	588	17	INT_DISTOPS	INT	15	2	1	0	-
113	Rents	589	-	INT_DISTOPS	INT	-	-	-	-	-
114	Subtotal - Distribution Expenses - Operation		99			83	10	5	0	-
115	Distribution Expenses - Maintenance									
116	Maintenance Supervision and Engineering	590	-	INT_DMAINT	INT	-	-	-	-	-
117	Maintenance of Structures	591	-		EXT	-	-	-	-	-
118	Maintenance of Station Equipment	592	-		EXT	-	-	-	-	-
119	Maintenance of Pipe Lines	592.1	-	INT_DISTPLT	INT	-	-	-	-	-
120	Maintenance of Structures and Equipment	592.2	-		EXT	-	-	-	-	-
121	Maintenance of Overhead Lines	593	-	INT_D365	INT	-	-	-	-	-
122	Maintenance of Underground Lines	594	-	INT_D367	INT	-	-	-	-	-
123	Maintenance of Lines	594.1	-	INT_D367	INT	-	-	-	-	-
124	Maintenance of Line Transformers	595	-	INT_D368	INT	-	-	-	-	-
125	Maintenance of Street Lighting and Signal Systems	596	-	LIGHT	EXT	-	-	-	-	-
126	Maintenance of Meters	597	-	METERS	EXT	-	-	-	-	-
127	Maintenance of Miscellaneous Distribution Plant	598	-	INT_DMAINT	INT	-	-	-	-	-
128	Subtotal - Distribution Expenses - Maintenance		-			-	-	-	-	-
129	OPERATING AND MAINTENANCE EXPENSES		99			83	10	5	0	-

UGI Utilities, Inc. - Electric Division
FPFTY Ending September 30, 2022

Function & Classification : PA PUC Direct Customer Customer
PA PUC Direct Customer Customer

1	ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE	ALLOCATOR	INT/EXT ALLOCATOR	Residential	General Service-1	General Service-4	Large Power	Lighting
130	E CUSTOMER ACCOUNTS AND SERVICE EXPENSE									
131	Customer Accounts Expense									
132	Supervision	901	97	CUST	EXT	85	9	4	0	0
133	Meter Reading Expenses	902	249	CUST	EXT	217	22	9	1	0
134	Customer Records and Collection Expenses	903	1,935	CUST	EXT	1,687	171	70	6	2
135	Customer Records and Collection Expenses (USP)	903	3,330	USPREV	EXT		-	-	-	-
136	Uncollectible Accounts	904	1,853	UNCOL	EXT		34	65	87	4
137	Miscellaneous Customer Accounts Expenses	905	241	CUST	EXT	210	21	9	1	0
138	Subtotal - Customer Accounts Expense		7,706			2,199	256	156	94	7
139	Customer Service & Information Expense									
140	Customer Service and Informational Expenses	906	-	CUST	EXT	-	-	-	-	-
141	Supervision	907	10	CUST	EXT	9	1	0	0	0
142	Customer Assistance Expenses	908	1	CUST	EXT	1	0	0	0	0
143	Information and Instructional Advertising Expenses	909	-	CUST	EXT	-	-	-	-	-
144	Miscellaneous Customer Service & Informational Exps (EEC)	910	2,239	EECREV	EXT	861	37	148	1,184	9
145	Subtotal - Customer Service & Information Expense		2,250			870	38	148	1,184	9
146	Sales Expense									
147	Supervision	911	-	CUST	EXT	-	-	-	-	-
148	Demonstrating and Selling Expenses	912	-	CUST	EXT	-	-	-	-	-
149	Advertising Expenses	913	77	CUST	EXT	67	7	3	0	0
150	Miscellaneous Sales Expenses	916	(10)	CUST	EXT	(9)	(1)	(0)	(0)	(0)
151	Sales Expenses	917	-	CUST	EXT	-	-	-	-	-
152	Subtotal - Sales Expense		67			58	6	2	0	0
153	ACCOUNTS AND SERVICE EXPENSE		10,023			3,128	301	307	1,279	16
154	F ADMINISTRATIVE AND GENERAL EXPENSE									
155	Administrative and General Salaries	920	523	INT_LABOR	INT		27	11	1	0
156	Office Supplies and Expenses	921	597	INT_LABOR	INT	300	31	13	1	0
157	Administrative Expenses Transferred - Credit	922	-	INT_LABOR	INT	-	-	-	-	-
158	Outside Services Employed	923	740	INT_LABOR	INT	373	38	16	1	0
159	Property Insurance	924	4	INT_TOTPLT	INT	2	0	0	0	0
160	Injuries and Damages	925	182	INT_LABOR	INT	92	9	4	0	0
161	Employee Pensions and Benefits	926	486	INT_LABOR	INT	244	25	11	1	0
162	Franchise Requirements	927	-	INT_DISTOM	INT	-	-	-	-	-
163	Regulatory Commission Expenses	928	3	INT_DISTOM	INT	3	0	0	0	-
164	Duplicate Charges - Credit	929	-	INT_DISTOM	INT	-	-	-	-	-
165	General Advertising Expenses	930.1	-	INT_TOTPLT	INT	-	-	-	-	-
166	Miscellaneous General Expenses	930.2	137	INT_LABOR	INT	69	7	3	0	0
167	Rents	931	1	INT_LABOR	INT	0	0	0	0	0
168	Transportation Expenses	933	-	INT_DISTOM	INT	-	-	-	-	-
			-		EXT	-	-	-	-	-
169	Maintenance of General Plant	935	15	INT_GENPLT	INT	-	1	0	0	0
170	Subtotal - ADMINISTRATIVE AND GENERAL EXPENSE		2,689			1,084	138	59	5	1
171	ADMINISTRATIVE AND GENERAL EXPENSE		2,689			1,084	138	59	5	1
172	TOTAL OPERATING AND MAINTENANCE COST		12,811			4,295	449	371	1,284	18

UGI Utilities, Inc. - Electric Division
FPFTY Ending September 30, 2022

~
~

Function & Classification : PA PUC Direct Customer Customer
PA PUC Direct Customer Customer

		FERC ACCOUNT	ACCOUNT BALANCE	ALLOCATOR	INT/EXT ALLOCATOR	Residential	General Service-1	General Service-4	Large Power	Lighting
1	ACCOUNT DESCRIPTION									
173	G DEPRECIATION AND AMORTIZATION EXPENSE									
174	Intangible Plant									
175	Organization	302	-	INT_LABOR	INT	-	-	-	-	-
176	Franchise & Consent	302	-	INT_TOTPLT	INT	-	-	-	-	-
177	Miscellaneous Intangible Plant	303	-	INT_TOTPLT	INT	-	-	-	-	-
178	Subtotal - Intangible Plant		-			-	-	-	-	-
179	Distribution Plant									
180	Land & Land Rights	360	-	INT_D361_364	INT	-	-	-	-	-
181	Structures & Improvements	361	-		EXT	-	-	-	-	-
182	Station Equipment	362	-		EXT	-	-	-	-	-
183	Storage Battery Equipment	363	-		EXT	-	-	-	-	-
184	Poles, Towers and Fixtures	364	-	INT_D364	INT	-	-	-	-	-
185	Overhead Conductors and Devices	365	-	INT_D365	INT	-	-	-	-	-
186	Underground Conduit	366	-	INT_D367	INT	-	-	-	-	-
187	Underground Conductors and Devices	367	-	INT_D367	INT	-	-	-	-	-
188	Transformers	368.1	-	INT_D368	INT	-	-	-	-	-
189	Transformer Installations	368.2	-	INT_D368	INT	-	-	-	-	-
190	Services	369	278	SERV	EXT	239	27	11	1	-
191	Meters	370.1	46	METERS	EXT	37	4	4	0	-
192	Meter Installations	370.2	26	METERS	EXT	21	3	2	0	-
193	Electronic Meters	370.3	171	METERS	EXT	139	17	14	1	-
194	Installations on Customers' Premises	371	-	CUSTPREMIS	EXT	-	-	-	-	-
195	Installations on Customers' Premises - EV Charging Stations	371.1	-	CUST	EXT	-	-	-	-	-
196	Installations on Customers' Premises- Dusk-Dawn Lights	371.5	-	LIGHT	EXT	-	-	-	-	-
197	Street Lighting and Signal Systems	373	-	LIGHT	EXT	-	-	-	-	-
198	Subtotal - Distribution Plant		521			437	50	31	3	-
199	General Plant									
200	Land & Land Rights	389	-	INT_LABOR	INT		-	-	-	-
201	Structures & Improvements	390	82	INT_LABOR	INT		4	2	0	0
202	Office Furniture & Equipment	391	551	INT_LABOR	INT		28	12	1	0
203	Transportation Equipment	392	52	INT_LABOR	INT		3	1	0	0
204	Stores Equipment	393	-	INT_LABOR	INT		-	-	-	-
205	Tools & Garage Equipment	394	19	INT_LABOR	INT		1	0	0	0
206	Laboratory Equipment	395	2	INT_LABOR	INT		0	0	0	0
207	Power Operated Equipment	396	6	INT_LABOR	INT		0	0	0	0
208	Communication Equipment	397	20	INT_LABOR	INT		1	0	0	0
209	Miscellaneous Equipment	398	12	INT_LABOR	INT		1	0	0	0
210	Subtotal - General Plant		745			-	38	16	1	0
211	Amortization Expense									
212	Amortization Expense & Depreciation Adjustments		44	INT_TOTPLT	INT	27	4	2	0	0
213	DEPRECIATION AND AMORTIZATION EXPENSE		1,311			464	92	49	4	0

UGI Utilities, Inc. - Electric Division
FPFTY Ending September 30, 2022

Function & Classification : PA PUC Direct Customer Customer
PA PUC Direct Customer Customer

1	ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE	ALLOCATOR	INT/EXT ALLOCATOR	Residential	General Service-1	General Service-4	Large Power	Lighting
214	H TAXES									
215	Taxes Other Than Income									
216	PURTA & Property Taxes		9	INT_TOTPLT	INT	6	1	0	0	0
217	Gross Receipts Tax		844	INT_RRxOTHR	INT	252	39	22	55	1
218	GRT - Purchased Power		-		EXT	-	-	-	-	-
219	Payroll related		175	INT_LABOR	INT	88	9	4	0	0
220	Real estate		41	INT_TOTPLT	INT	25	3	2	0	0
221	PA Local Use and Miscellaneous		12	INT_TOTPLT	INT	7	1	1	0	0
222	Subtotal - Taxes Other Than Income		1,081			378	53	29	55	1
223	Income Taxes									
224	State Income Tax expense		(33)	INT_RATEBASE	INT	(17)	(2)	(0)	0	0
225	Federal Income Tax expense		39	INT_RATEBASE	INT	20	3	0	(0)	(0)
226	Subtotal - Income Taxes		6			3	0	0	(0)	(0)
227	TOTAL TAXES		1,087			381	53	29	55	1
228	I REVENUES									
229	Total Customer and Distribution Revenue	440-447	11,829	DISTREV	EXT	7,550	653	1,590	1,664	372
230	Purchased Power Revenue		-		EXT	-	-	-	-	-
231	Purchased Power GRT Revenue		-		EXT	-	-	-	-	-
232	USP Rider		1,069	USPREV	EXT	1,069	-	-	-	-
233	EEC Rider		722	EECREV	EXT	278	12	48	382	3
			-		EXT	-	-	-	-	-
234	Forfeited Discounts	450	150	FORTDISC	EXT	107	12	22	8	2
235	Miscellaneous Service Revenues	451	5	UNCOL	EXT	4	0	0	0	0
236	Rent from Electric Properties	454	-	INT_D364	INT	-	-	-	-	-
237	Interest on Undercollection - Refunded	456.1	4	UNCOL	EXT	4	0	0	0	0
238	Subtotal - REVENUES		13,780			9,012	677	1,659	2,055	377
239	TOTAL REVENUES		13,780			9,012	677	1,659	2,055	377
240	NET INCOME		(1,429)			3,872	83	1,211	711	358

UGI Utilities, Inc. - Electric Division
FPFTY Ending September 30, 2022

Function & Classification : PA PUC Direct Customer Customer
PA PUC Direct Customer Customer

1	ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE	ALLOCATOR	INT/EXT ALLOCATOR	Residential	General Service-1	General Service-4	Large Power	Lighting
241	J LABOR BALANCE									
242	**Other Power Generation**									
243	Purchased Power	555	-		EXT	-	-	-	-	-
244	Transmission of Electricty by Others	565	-		EXT	-	-	-	-	-
245	Subtotal - Other Power Generation		-			-	-	-	-	-
246	**Distribution Expenses**									
247	Operation Supervision and Engineering	580	18	INT_DISTOPS	INT	16	2	1	0	-
248	Load Dispatching	581	46	INT_DISTPLT	INT	39	4	3	0	-
249	Line and Station Expenses	581.1	-	INT_DISTPLT	INT	-	-	-	-	-
250	Station Expenses	582	-		EXT	-	-	-	-	-
251	Overhead Line Expenses	583	-	INT_D365	INT	-	-	-	-	-
252	Underground Line Expenses	584	-	INT_D367	INT	-	-	-	-	-
253	Operation of Energy Storage Equipment	584.1	-	INT_DISTPLT	INT	-	-	-	-	-
254	Street Lighting and Signal System Expenses	585	-	LIGHT	EXT	-	-	-	-	-
255	Meter Expenses	586	-	METERS	EXT	-	-	-	-	-
256	Customer Installation Expenses	587	-	SERV	EXT	-	-	-	-	-
257	Miscellaneous Distribution Expenses	588	8	INT_DISTOPS	INT	7	1	0	0	-
258	Rents	589	-	INT_DISTOPS	INT	-	-	-	-	-
259	Subtotal - Distribution Expenses		72			61	7	4	0	-
260	Maintenance									
261	Maintenance Supervision and Engineering	590	-	INT_DMAINT	INT	-	-	-	-	-
262	Maintenance of Structures	591	-		EXT	-	-	-	-	-
263	Maintenance of Station Equipment	592	-		EXT	-	-	-	-	-
264	Maintenance of Pipe Lines	592.1	-	INT_DISTPLT	INT	-	-	-	-	-
265	Maintenance of Structures and Equipment	592.2	-		EXT	-	-	-	-	-
266	Maintenance of Overhead Lines	593	-	INT_D365	INT	-	-	-	-	-
267	Maintenance of Underground Lines	594	-	INT_D367	INT	-	-	-	-	-
268	Maintenance of Lines	594.1	-	INT_D367	INT	-	-	-	-	-
269	Maintenance of Line Transformers	595	-	INT_D368	INT	-	-	-	-	-
270	Maintenance of Street Lighting and Signal Systems	596	-	LIGHT	EXT	-	-	-	-	-
271	Maintenance of Meters	597	-	METERS	EXT	-	-	-	-	-
272	Maintenance of Miscellaneous Distribution Plant	598	-	INT_DMAINT	INT	-	-	-	-	-
273	Subtotal - Maintenance		-			-	-	-	-	-
274	**OPERATING AND MAINTENANCE EXPENSES**		72			61	7	4	0	-

UGI Utilities, Inc. - Electric Division
FPFTY Ending September 30, 2022

~
~

Function & Classification : PA PUC Direct Customer Customer
PA PUC Direct Customer Customer

	ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE	ALLOCATOR	INT/EXT ALLOCATOR	Residential	General Service-1	General Service-4	Large Power	Lighting
1										
275	CUSTOMER ACCOUNTS AND SERVICE EXPENSE									
276	Customer Accounts Expense									
277	Supervision	901	46	CUST	EXT	40	4	2	0	0
278	Meter Reading Expenses	902	245	CUST	EXT	214	22	9	1	0
279	Customer Records and Collection Expenses	903	391	CUST	EXT	341	34	14	1	0
280	Customer Records and Collection Expenses (USP)	903	672	USPREV	EXT		-	-	-	-
281	Uncollectible Accounts	904	-	UNCOL	EXT	-	-	-	-	-
282	Miscellaneous Customer Accounts Expenses	905	159	CUST	EXT	138	14	6	0	0
283	Subtotal - Customer Accounts Expense		1,514			733	74	30	3	1
284	Customer Service & Information Expense									
285	Customer Service and Informational Expenses	906	-	CUST	EXT	-	-	-	-	-
286	Supervision	907	9	CUST	EXT	8	1	0	0	0
287	Customer Assistance Expenses	908	1	CUST	EXT	1	0	0	0	0
288	Information and Instructional Advertising Expenses	909	-	CUST	EXT	-	-	-	-	-
289	Miscellaneous Customer Service & Informational Exps (EEC)	910	-	EECREV	EXT	-	-	-	-	-
290	Subtotal - Customer Service & Information Expense		10			9	1	0	0	0
291	Sales Expense									
292	Supervision	911	-	CUST	EXT	-	-	-	-	-
293	Demonstrating and Selling Expenses	912	-	CUST	EXT	-	-	-	-	-
294	Advertising Expenses	913	-	CUST	EXT	-	-	-	-	-
295	Miscellaneous Sales Expenses	916	-	CUST	EXT	-	-	-	-	-
296	Sales Expenses	917	-	CUST	EXT	-	-	-	-	-
297	Subtotal - Sales Expense		-			-	-	-	-	-
298	ACCOUNTS AND SERVICE EXPENSE		1,524			742	75	31	3	1
299	TOTAL O&M LABOR EXPENSE		1,596			803	82	35	3	1

UGI Utilities, Inc. - Electric Division
FPFTY Ending September 30, 2022

~
~

Function & Classification : PA PUC Direct Customer Customer
PA PUC Direct Customer Customer

1	ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE	ALLOCATOR	INT/EXT ALLOCATOR	Residential	General Service-1	General Service-4	Large Power	Lighting
300	K REVENUE REQUIREMENT SUMMARY									
301	PLANT IN SERVICE									
302	Intangible Plant		5			2	0	0	0	0
303	Distribution Plant		24,782			20,899	2,393	1,368	122	-
304	General Plant		9,639			-	495	209	18	5
305	Subtotal - Plant in Service		34,426			20,901	2,889	1,578	140	5
306	ACCUMULATED DEPRECIATION									
307	Intangible Plant		-			-	-	-	-	-
308	Distribution Plant		(13,889)			(11,662)	(1,343)	(812)	(72)	-
309	General Plant & Miscellaneous		(2,592)			-	(133)	(56)	(5)	(1)
310	Subtotal - Accumulated Depreciation		(16,481)			(11,662)	(1,476)	(868)	(77)	(1)
311	OTHER RATEBASE ITEMS		(3,828)			(2,067)	(361)	(616)	(149)	(29)
312	TOTAL RATEBASE		14,117			7,173	1,051	93	(87)	(26)
313	RETURN ON RATEBASE		1,069			543	80	7	(7)	(2)

UGI Utilities, Inc. - Electric Division
FPFTY Ending September 30, 2022

~
~

Function & Classification : PA PUC Direct Customer Customer
PA PUC Direct Customer Customer

	ACCOUNT DESCRIPTION	FERC ACCOUNT	ACCOUNT BALANCE	ALLOCATOR	INT/EXT ALLOCATOR	Residential	General Service-1	General Service-4	Large Power	Lighting
1										
314	EXPENSES									
315	Other Power Generation Expenses		-			-	-	-	-	-
316	Distribution Expenses - Operations		99			83	10	5	0	-
317	Distribution Expenses - Maintenance		-			-	-	-	-	-
318	Customer Accounts Expense		7,706			2,199	256	156	94	7
319	Customer Service & Information Expense		2,250			870	38	148	1,184	9
320	Sales Expense		67			58	6	2	0	0
321	Administrative and General Expense		2,689			1,084	138	59	5	1
322	Depreciation and Amortization Expense		1,311			464	92	49	4	0
323	Taxes Other Than Income		1,081			378	53	29	55	1
324	Income Taxes		6			3	0	0	(0)	(0)
325	Subtoal - Expenses		15,209			5,140	594	449	1,344	19
326	REVENUE		13,780			9,012	677	1,659	2,055	377
327	INCOME		(1,429)			3,872	83	1,211	711	358
328	REVENUE DEFICIENCY (EXCESS)		2,498			(3,329)	(3)	(1,204)	(717)	(360)
329	REVENUE GROSS UP									
330	Federal Income Tax		162	INT_RATEBASE	INT	83	12	1	(1)	(0)
331	State Income Tax		86	INT_RATEBASE	INT	44	6	1	(1)	(0)
332	Gross Receipts Tax		177	INT_RRxOTHR	INT	53	8	5	12	0
333	Uncollectible		44	INT_REVREQxPWR	INT	15	2	1	4	0
334	Subtotal - Revenue Gross Up		469			194	28	8	14	(0)
335	GROSS REVENUE DEFICIENCY (EXCESS)		2,967			(3,135)	25	(1,196)	(704)	(361)
336	TOTAL REVENUE REQUIREMENT		16,747			5,877	702	463	1,351	16
337	ANNUAL RESIDENTIAL BILLS					660,460				
338	RESIDENTIAL CUSTOMER CHARGE					$ 8.90				
339	CUSTOM INTERNAL ALLOCATOR									
340	INT_D361_364		0			0	0	0	0	0
341	INT_D364		0			0	0	0	0	0
342	INT_D365		0			0	0	0	0	0
343	INT_D367		0			0	0	0	0	0
344	INT_D368		0			0	0	0	0	0
345	INT_DISTPLT		24,782			20,899	2,393	1,368	122	0
346	INT_GENPLT		9,639			0	495	209	18	5
347	INT_TOTPLT		34,426			20,901	2,889	1,578	140	5
348	INT_RATEBASE		14,117			7,173	1,051	93	(87)	(26)
349	INT_DISTOPS		60			51	6	3	0	0
350	INT_DMAINT		0			0	0	0	0	0
351	INT_DISTOM		99			83	10	5	0	0
352	INT_CUSTACCT		1,514			733	74	30	3	1
353	INT_REVREQxPWR		16,747			5,877	702	463	1,351	16
354	INT_LABOR		1,596			803	82	35	3	1
355	INT_RRxOTHR		14,796			4,416	678	394	961	12
356										

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3023618
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Jerome D. Mierzwa, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 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).

DATED: May 3, 2021
*307972

Signature: Jerome D. Mierzwa
Jerome D. Mierzwa

Consultant Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044-3575

OCA Statement No. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2021-3023618
UGI Utilities – Electric Division	:	

Direct Testimony of
Roger D. Colton

On Behalf of:
Office of Consumer Advocate

May 3, 2021

Table of Contents

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, MA.

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 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 Maryland, Pennsylvania, Ohio, Michigan, Tennessee, Illinois, and Missouri. My clients include state agencies (e.g., Pennsylvania Office of Consumer Advocate, Maryland Office of People's Counsel, Illinois Office of Attorney General), federal agencies (e.g., the U.S. Department of Health and Human Services), community-based organizations (e.g., National Housing Trust, Natural Resources Defense Council, Advocacy 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-specific 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 the federal Low-Income Home Energy Assistance Program ("LIHEAP"). In 2007, I was part of a team that performed a multi-sponsor public/private national study of low-income energy assistance programs. In 2020, I completed a study of water affordability in twelve U.S. cities for the London-based newspaper, The Guardian. In 2020, also, I prepared comments for a set of national consumer stakeholders (e.g., National Consumer Law Center, National Housing Trust, National Community Action Foundation) to submit to the U.S. Environmental Protection Agency regarding water affordability. 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.

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 35 states and various Canadian provinces on a wide range of utility issues. A list of the states 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 ongoing impacts that the ongoing economic crisis created by COVID-19 has on low-income customers and on their future ability-to-pay UGI Electric bills;
- Second, I examine the disproportionate harms that the proposed UGI Electric residential customer charge will impose on low-income customers of UGI Electric, as well as the relationship between income and electricity consumption;
- Third, I discuss whether the allocation of universal service amongst all customer classes should be considered in this proceeding;

- Fourth, I examine the extent to which UGI Electric should be directed to improve CAP outreach (and its relationship to claims of costs associated with nonpayment); and
- Finally, I examine certain changes that UGI Electric proposes to make to its electric tariffs.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Based on the data and discussion presented below, I recommend as follows:

1. that the residential customer charge set forth in the Direct Testimony of OCA witness Mierzwa be adopted.

2. that the issue of the allocation of universal service costs not be considered in this proceeding, but instead be reserved for a future proceeding.

3. that UGI Electric insert a tariff provision defining a "confirmed low-income customer." That tariff provision should reflect the PUC definition that a confirmed low-income customer includes any account where UGI Electric "has obtained information that would reasonably place the customer in a low-income designation." UGI Electric should specifically state that it will accept self-certification of low income status for purposes of identifying "confirmed low-income customers" in the same way that self-certification is required to be accepted by the UGI gas affiliates.

4. that UGI Electric be directed to develop a Public Partnership Outreach Plan (PPOP) seeking to accomplish three objectives: (1) identify confirmed low-income customers; (2) enroll income-eligible customers in CAP; and (3) identify customers who income-qualify for winter shutoff protections. The PPOC should be comprised of the three steps presented in my Direct Testimony.

5. that in response to the ongoing COVID-19 economic emergency, the COVID emergency response program be adopted largely based on principles established in the UGI proposal to the PUC in Docket R-2021-3023839.

6. that in the *absence* of the adoption of a COVID-19 Emergency Response Program that corresponds to that which I propose immediately above, the UGI Electric tariff should modify the CAP enrollee count in its universal service rider (i.e., Rider C) to reflect the year-end CAP enrollment for the historic test year. The year-end CAP enrollment, for the historic test year ending September 2020, was 3,231 participants (OCA-IV-51(a)). Rider C should be modified to substitute 3,231 for the count of 2,448 participants that currently exists in Rider C.

7. that UGI Electric should revise its Electric tariff regarding "income verification" underlying winter shutoff protections. UGI should accept income declarations that would be used to support the terms of deferred payment agreements. It should also accept any reasonable documentation, irrespective of the agency or entity providing such documentation (e.g., DHS, Department of Health, Department of Education, local Housing Authority, local Community Action Agency) that would reasonably establish that a customer is income-eligible for winter shutoff protections.

8. that the UGI Electric tariff, which is silent on whose income will be used to establish eligibility for the winter shutoff protections, be modified to be consistent with Chapter 14's definition of household income, and consistent with UGI's own USECP. The UGI Electric tariff should make explicit that "UGI does not include income earned from an occupant under the age of 18, nor does it include income received for the benefit of a minor, in its calculation of household income."

9. that Section 3-d of the UGI Electric tariff, relating to the size of a customer cash security deposit, be modified to provide that no later than three months after the delivery of usage reduction services to a residential low-income customer, whether the delivery of such services are indicated by UGI Electric internal records or indicated by notice provided to UGI Electric by a weatherization provider, any cash security deposit held by the company be reduced by the expected percentage annual bill reduction resulting from the delivery of the usage reduction investment. Notification of the delivery of such services through a non-UGI Electric program shall be deemed to be a "request of the customer" for such a modification pursuant to the PUC regulation. Under the regulation, modifications based on internal recordkeeping of the utility need not be made by the customer, but can instead be made at the initiation of the utility.

PART 1. The Ongoing Economic Emergency Related to COVID-19.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I document the ongoing economic emergency facing residential customers as caused by the past and ongoing impacts of the COVID-19 pandemic. I review the UGI Electric response, as well as its proposed response, to that economic emergency and recommend modifications.

Q. PLEASE EXPLAIN THE DATA UPON WHICH YOU BASE YOUR DISCUSSION OF COVID-19 IMPACTS IN PENNSYLVANIA.

A. I base my discussion of Pennsylvania below largely on the Census Bureau's Phase 3 PULSE Survey. According to the Census Bureau, "[t]he Household Pulse Survey is designed to deploy quickly and efficiently, collecting data to measure household experiences during the coronavirus pandemic." Data collection for Phase 3 of the Household Pulse Survey ran from October 28, 2020 – March 29, 2021 and is now closed. Data collection for the next Phase of the survey is scheduled to begin on April 14, 2021, with the next data release on May 5, 2021.

Q. IS THE DATA FROM THE PULSE SURVEY THAT YOU EXAMINE SPECIFIC TO THE UGI ELECTRIC SERVICE TERRITORY?

A. No. While the Census releases data on various metropolitan areas, including Philadelphia, it does not release data on geographic areas that could be aggregated into the UGI Electric service territory. Accordingly, I examine state-specific data for

Pennsylvania as a whole. The data I examine is from Week 18 (October 28, through November 9, 2020) (the first week of Phase 3 of the PULSE Survey), from Week 22 (January 6 through January 18, 2021), and from Week 27 (March17 through March 29, 2021) (the last week of Phase 3).[1]

Q. WHAT DO YOU CONCLUDE ABOUT PENNSYLVANIA EMPLOYMENT INCOME AS IT IS RELATED TO COVID-19?

A. The Census PULSE Survey documents that a large number of Pennsylvania residents report having lost employment income since March 20, 2020, the time defined to be the beginning of the COVID-19 pandemic. Table 1 shows that as recently as Week 27 of the PULSE Survey (March 17 through March 29, 2021), more than four million Pennsylvania residents (41.3%) had lost employment income. The Table shows further that, while the numbers have improved from the Week 18 Survey to the Week 27 Survey, as recently as Week 27, substantially more than 1.6 million Pennsylvania residents ***expect*** to lose employment income "in the next 4 weeks." More than one-in-six Pennsylvania residents, in other words, expect to lose income in the next four weeks.

[1] All PULSE Survey data cited in my testimony can be accessed at: https://www.census.gov/programs-surveys/household-pulse-survey/data.html#phase1 (last accessed April 21, 2021).

Table 1. Experienced and Expected Loss of Employment Income (Pennsylvania) (Total = 9,776,154 for each Week) (PULSE Survey)

	Experienced Loss of Employment Income Since March 13, 2020								
	Week 18			Week 22			Week 27		
	Yes	No	% Yes	Yes	No	% Yes	Yes	No	% Yes
Total	4,485,147	5,270,435	45.9%	4,431,022	5,216,809	45.3%	4,041,816	5,646,730	41.3%
	Expected Loss of Employment Income in next 4 weeks								
	Week 18			Week 22			Week 27		
	Yes	No	% Yes	Yes	No	% Yes	Yes	No	% Yes
Total	2,313,787	7,438,787	23.7%	2,243,173	7,382,173	22.9%	1,644,963	8,068,693	16.8%

On a percentage basis, this loss of employment income was over-represented in the lower income brackets in Pennsylvania. Table 2 shows the proportionate representation of Pennsylvania residents who have experienced a loss of income since March 13, 2020. By "proportionate representation," I mean that I first compare the percentage of total population in each income range. I then compare the percentage of population in each income range reporting a loss of employment income. Those income ranges which are over-represented in the income ranges having lost employment income are highlighted in yellow. With the exception of residents with income between $35,000 and $49,999, the income range that disproportionately experienced a loss of employment income were those incomes less than $75,000. Persons in the income range of $50,000 to $74,999 were the most over-represented in that population having experienced a loss of employment income. This further supports the conclusion that the economic crisis associated with COVID-19 is not simply a "low-income" issue, but instead reaches beyond those households with income at or below 150% of Poverty Level. While the percentage in that income range declined in Week 22, and declined somewhat more in

Week 27, of Pennsylvania residents who have experienced a loss of employment income nearly one-in-four (22.9%) fell in that income range even though that income range represented less than one-in-five (18.1%) of the total population reporting data.

Table 2. Loss of Employment Income by Household Income since March 13, 2020
(Income Range as Percent of Total) (PULSE Survey)
(yellow shade: income ranges disproportionately represented in loss of employment income)

	Week 18		Week 22		Week 27	
	Total	Yes	Total	Yes	Total	Yes
<$25,000	11.8%	14.4%	9.8%	10.5%	12.0%	13.2%
$25,000 - $34,999	11.0%	12.9%	10.4%	12.7%	9.8%	14.9%
$35,000 - $49,999	12.2%	11.5%	12.1%	8.6%	12.3%	10.0%
$50,000 - $74,999	21.2%	27.0%	22.2%	23.7%	18.1%	22.9%
$75,000 - $99,999	13.5%	13.6%	13.4%	15.9%	17.7%	15.0%
$100,000 - $149,999	17.0%	12.1%	15.9%	15.2%	13.9%	11.3%
$150,000 - $199,999	6.5%	4.9%	8.4%	8.8%	7.6%	7.5%
$200,000 and above	6.9%	3.6%	7.7%	4.5%	8.6%	5.2%
Sum of those reporting	100%	100%	100%	100%	100%	100%

Based on this data, it is necessary to conclude that while the loss of employment income certainly disproportionately affected the lowest income households, that loss of employment income was not ***exclusively*** a low-income phenomenon.

Q. HOW HAS COVID-19 AFFECTED THE ABILITY OF PENNSYLVANIA RESIDENTS TO PAY THEIR USUAL HOUSEHOLD EXPENSES?

A. Pennsylvania residents have continuing difficulties in paying for their basic living expenses under COVID-19. The Census PULSE survey reports on the "difficulty paying for usual household expenses during the coronavirus pandemic." Table 3 presents the data for Pennsylvania. As this Table shows, the economic conditions for Pennsylvania residents are improving. Compared to the 1.435 million residents who said it was “very difficult” to pay for their usual household expenses in Week 18 of the PULSE survey, 840,000 reported that it was “very difficult” in Week 27 (a decrease from 15.0% to 9.1%). Nonetheless, those 840,000 persons represent nearly 1-of-10 of all persons reporting. Moreover, the combined total of people reporting that they found it either “very difficult” or “somewhat difficult” to pay for usual household expenses in Week 27 was 26.5%, more than one-in-four of all Pennsylvania residents reporting. The decline in the combined “somewhat difficult” and “very difficult” responses was not substantial (from 30.7% in Week 18 to 26.5% in Week 27).

In contrast, there was only a very small increase in both the number and the percentage of persons reporting that it was “not at all difficult” to pay for their usual household expenses, from 45.1% in Week 18 to 48.2% in Week 27. The percentage of Pennsylvania residents reporting that they found it “not at all difficult” to pay for their usual household expenses in the past seven days during the coronavirus pandemic still remained at less than 50% of the total population reporting.

Table 3. Difficulty in Paying for Usual Household Expenses in Past 7 Days During the Coronavirus Pandemic (PULSE Survey) (Total = 9,776,154 for all three Weeks of Survey) (in millions)[2]											
Week 18				Week 22				Week 27			
Not at All	A Little	Some what	Very	Not at All	A Little	Some what	Very	Not at All	A Little	Some what	Very
4.321	2.317	1.508	1.435	3.960	2.421	1.554	1.172	4.423	2.321	1.595	0.840
45.1%	24.2%	15.7%	15.0%	43.5%	26.6%	17.1%	12.9%	48.2%	25.3%	17.4%	9.1%

As with the data on the loss of employment income, the data on difficulties in paying for usual household expenses during the coronavirus pandemic shows a marked difference based on income levels. The data is set forth in Table 4 below. Not surprisingly, the biggest reduction in the percentage having a "very difficult" time in paying for usual household expenses occurs in the income groups with the largest percentage of population having such difficulties in the first instance. Even with the 20%+ reduction for households with income less than $25,000, however, more than one-in-four (26.9%) of households in this range continue to report having a "very difficult" time in paying their bills.

The "very difficult" data, however, does not tell the entire story. More than half of the population with income less than $25,000 report having a "very difficult" or a "somewhat difficult" time (26.8% + 26.9% = 53.7%) in paying for usual household expenses in the past seven days. Problems in the next two income ranges also remain very prevalent. Roughly one-in-three persons in households with income between $25,000 and $50,000 (33.2% in the income range of $25,000 to $34,999; 30.8% in the income range of

[2] Percentage is of those reporting.

$35,000 to $49,999) report having a "somewhat difficult" or "very difficult" time in paying usual household expenses in the past seven days as of Week 27. Even in the income range as high as $50,000 to $74,999, more than one-in-four (25.1%) Pennsylvania residents report having either a "somewhat difficult" or a "very difficult" time paying for their usual household expenses.

Table 4. Difficulty in Paying for Usual Household Expenses in Past 7 Days
During the Coronavirus Pandemic by Annual Income (PULSE Survey)
(Total = 9,776,154 for all three Weeks of Survey) (in millions)[3]

	Week 18				Week 22				Week 27			
	Not at All	A Little	Some what	Very	Not at All	A Little	Some what	Very	Not at All	A Little	Some what	Very
<$25,000	11.4%	23.1%	17.1%	48.4%	29.6%	12.3%	30.2%	27.9%	31.3%	15.0%	26.8%	26.9%
$25-$34,999	23.5%	20.5%	30.1%	25.9%	26.9%	31.5%	14.5%	27.0%	38.9%	27.9%	26.3%	6.9%
$35 - $49,999	38.1%	19.2%	30.3%	12.4%	46.6%	26.9%	17.5%	9.0%	35.2%	34.0%	25.8%	5.0%
$50 - $74,999	37.4%	33.4%	7.8%	21.3%	37.2%	35.0%	11.4%	16.4%	45.5%	29.4%	19.5%	5.6%
$75 - $99,999	53.9%	27.1%	12.0%	6.9%	35.1%	37.4%	19.1%	8.4%	51.7%	31.0%	12.3%	5.1%
$100 - $149,999	64.6%	22.8%	8.6%	3.9%	64.8%	16.5%	15.0%	3.7%	64.6%	18.3%	11.7%	5.4%
$150 - $199,999	74.6%	14.4%	5.8%	5.2%	75.3%	19.0%	3.5%	2.1%	65.5%	21.7%	8.6%	4.2%
$200,000+	88.5%	9.1%	2.4%	---	76.6%	14.5%	5.0%	3.9%	86.6%	10.3%	1.8%	1.3%

Q. WHAT DO YOU CONCLUDE?

A. Even as the public vaccination against the coronavirus becomes more widespread, the economic crisis caused by the COVID-19 pandemic continues to hit Pennsylvania residents, including UGI Electric customers, hard. The economic impacts will result in a long-term economic disruption for customers of UGI Electric.

[3] Percentage is of those reporting.

Q. WHAT IS THE FIRST LONG-TERM ECONOMIC IMPACT OF COVID-19?

A. The resolution of the COVID-19 health crisis will not end the economic crisis facing low-income customers. One analysis by the Center on Poverty and Social Policy at Columbia University projects the longer-term effects of the COVID-19 economic crisis.[4] The Columbia University research center forecasted poverty rates under three alternative unemployment scenarios: 10 percent; 20 percent, and 30 percent. The Center assumed that such high levels of unemployment lasted for two different scenarios: (1) one quarter, and (2) one year. The Center uses the "Supplemental Poverty Measure" (SPM), which differs somewhat from the Federal Poverty Level.[5]

The Center began with a projected SPM of 12.4% in February 2020, the lowest recorded poverty rate since 2001. Its projected poverty rates after the onset of the COVID-19 pandemic, however:

> point to higher poverty rates today. If unemployment rates rise to 10 percent, comparable to the unemployment rate during the peak of the Great Recession, we project that poverty rates would rise to 15 percent. This is

---

[4] Parolin and Wimer (April 16, 2020). Forecasting Estimates of Poverty During the COVID-19 Crisis: Poverty Rates in the United States Could Reach Highest Levels in Over 50 Year, available at https://www.povertycenter.columbia.edu/news-internal/coronavirus-forecasting-poverty-estimates, (last accessed April 21, 2021).

[5] In simplified terms, the Census Bureau explains that the Supplemental Poverty Measure, "takes into account family resources and expenses not included in the official measure as well as geographic variation. First, it adds the value of in-kind benefits that are available to buy basic goods to cash income. In-kind benefits include nutritional assistance, subsidized housing and home energy assistance. Then it subtracts necessary expenses for critical goods and services not included in the thresholds from resources. Necessary expenses that are subtracted include income taxes, Social Security payroll taxes, child care and other work-related expenses, child support payments to another household, and contributions toward the cost of medical care and health insurance premiums." What is the Supplemental Poverty Measure and How Does it Differ from the Official Measure, available at, https://www.census.gov/newsroom/blogs/random-samplings/2018/09/what_is_the_suppleme.html (last accessed April 21, 2021).

> approximately the same rate of poverty observed in 2010. (note omitted). If unemployment rates rise to 20 percent, we project a poverty rate of 16.9 percent—the highest rate of poverty since 1967, the first year for which reliable estimates of poverty are available. Finally, if annual unemployment rates rise to 30 percent, we project a poverty rate of 18.9 percent. This would mark the highest rate of poverty over the past 50 years.[6]

Two observations are appropriate. On the one hand, unemployment in Pennsylvania did not reach the 20% or 30% levels represented by the two upper ranges in this analysis. Accordingly, the 20% and 30% unemployment scenarios are set aside for this discussion. Even with this lowest scenario, the Center stated: "under an optimistic scenario, in which employment rates return to pre-crisis levels during the summer of 2020, annual SPM poverty rates are still projected to reach levels comparable to the Great Recession."[7] On the other hand, employment rates, as we now know, did *not* return to the pre-crisis levels in the summer of 2020.

This increase in Poverty is important for purposes of this proceeding because it is not likely to be resolved in the short-term. The long-term danger arises because when people lose their jobs, the long-lasting effects are not just on their income. Unemployment has a negative effect on workers' skills and education, even on their health—people who are unemployed become sicker. Human capital, the skills of the overall workforce, decays over time because of the loss of jobs. Moreover, with the COVID-19 pandemic, it is generally recognized that many of the jobs that have been lost will never come back. One recent research paper from the Becker Freidman Institute for Economics at the

[6] Id., at 4 - 5.

[7] Forecasting Estimates of Poverty, supra note 4, at 9.

University of Chicago estimates that between 32% and 42% of COVID-19 induced layoffs will be permanent.[8]

Q. IS THERE A SECOND ECONOMIC IMPACT THAT SHOULD BE CONSIDERED IN THIS PROCEEDING?

A. Yes. Nearly 40% of U.S. households, including nearly all low-wage workers, fall into a category referred to as "liquid asset poor." "Liquid asset poor" is a term-of-art that refers to households who lack sufficient liquid assets to replace income in order to subsist at the Poverty Level for three months in the absence of income. According to a Pew Research Center report, "only about one-in-four (23%) [lower income adults] say they have rainy day funds set aside that would cover their expenses for three months in case of an emergency such as job loss, sickness or an economic downturn, compared with 48% of middle-income and 75% of upper-income adults." [9]

As the COVID-19 economic crisis moves into a more prolonged period, the impact of the lack of savings will become increasingly pronounced, with low-income customers, in particular, unable to draw on resources to pay day-to-day bills. A Pew Research Center study published in late September reported that half of all adults who said they had lost a job due to the coronavirus were still unemployed "roughly six months since the

---

[8] Davis et al. (June 2020). COVID-19 is also a Reallocation Shock, available at: https://bfi.uchicago.edu/wp-content/uploads/BFI_WP_202059.pdf (last accessed April 21, 2021).

[9] Parker, Horowitz and Brown (April, 2020). About Half of Lower-Income Americans Report Household Job or Wage Loss Due to COVID-19, Pew Research Center: Washington D.C. Available at https://www.pewsocialtrends.org/2020/04/21/about-half-of-lower-income-americans-report-household-job-or-wage-loss-due-to-covid-19/ (last accessed April 21, 2021).

coronavirus outbreak sent shockwaves through the U.S. economy."[10] Moreover, according to Pew, even those who did not lose their job, but who nonetheless lost income, were still in bad economic shape. Pew reported:

> Of those who say they personally lost a job, half say they are still unemployed, a third have returned to their old job and 15% are in a different job than before. Lower-income adults who were laid off due to the coronavirus are less likely to be working now than middle- and upper-income adults who lost their jobs (43% vs. 58%). Adults ages 18 to 29 are less likely than those 30 to 64 to have returned to their previous job.
>
> Even if they didn't lose a job, many workers have had to reduce their hours or take a pay cut due to the economic fallout from the pandemic. About a third of all adults (32%) say this has happened to them or someone in their household, with 21% saying this happened to them personally. Most workers who've experienced this (60%) are earning less now than they were before the coronavirus outbreak, while 34% say they are earning the same now as they were before the outbreak and only 6% say they are earning more.[11]

Pew continues, however, to note that "lower-income adults who lost their jobs because of the coronavirus outbreak are more likely than those with middle or upper incomes to remain unemployed. Some 56% of workers with lower incomes who lost their job because of the coronavirus outbreak say they are currently unemployed, compared with 42% of middle- and upper-income adults."[12]

---

[10] Kim Parker, Rachel Minkin and Jesse Bennett (September 24, 2020). Economic Fallout from COVID-19 Continues to Hit Lower-Income Americans the Hardest, at 1, Pew Research Center (Washington D.C.). (hereafter COVID-19 Economic Fallout), https://www.pewsocialtrends.org/2020/09/24/economic-fallout-from-covid-19-continues-to-hit-lower-income-americans-the-hardest/ (last accessed April 21, 2021).

[11] Id., at 5, 7, 8.

[12] Id., at 7 – 8.

This long-term job loss is significant because one of the long-term economic implications of the job loss and other loss of income is just now becoming more evident. Economic difficulties, particularly for lower-income households, will prevail for an extended period of time not only because these households have been forced to use their emergency savings, but also because they have been forced to incur substantial debt during the COVID-19 pandemic to date. According to Pew:

> Those affected by coronavirus related job loss or pay cuts are much more likely than those who have not experienced these setbacks to have drawn on additional resources. Fully 46% of adults who say they or someone in their household have either been laid off or taken a pay cut as a result of the coronavirus outbreak say they have used money from a savings or retirement account to pay their bills, compared with 17% of those who have not experienced these setbacks.[13]

As the COVID-19 economic crisis continues, these households are now running out of savings to draw down. A Bankrate survey found that "of households with income below $50,000, about 44% say their savings has dropped, compared with 27% of those earning above that amount. . ." Bankrate reported that 27% of Americans say that they now have emergency savings that would last less than three months; 20% say their emergency savings would last from three to five months; and 25% say their emergency savings would last six months.[14]

[13] Covid-19 Economic Fallout, supra note 10, at 12.

[14] Survey: Nearly 3 times as many Americans say they have less emergency savings versus more since pandemic, available at https://www.bankrate.com/banking/savings/emergency-savings-survey-2020/ (last accessed April 21, 2021).

Q. HAVE YOU EXAMINED DATA SPECIFIC TO THE COMMONWEALTH OF PENNSYLVANIA?

A. Yes. The discussion below is based on the U.S. Census Bureau's "Pulse Survey" as I discussed above. As in my discussion above, I examine data from three different points in time: (1) Week 18 (October 28 through November 9, 2020 (the first week of Phase 3 of the PULSE Survey); (2) Week 22 (January 6 through January 18, 2021); and (3) Week 27 (March17 through March 29, 2021) (the last week of Phase 3).

Q. WHAT DO YOU KNOW ABOUT PENNSYLVANIA IN PARTICULAR?

A. The problems posed by consumers being forced to use credit and/or savings to pay household bills during the pandemic can be seen from data specific to Pennsylvania. And they continue through today. According to the Census Bureau's PULSE Survey:

- In Week 18 of the PULSE Survey, households using such resources had substantially greater difficulties in meeting their household needs. While 22.8% of Pennsylvania residents using credit cards or loans, and 32.2% drawing down savings (or selling assets), found it "very difficult" to pay "usual household expenses," only 5.6% using their usual pre-pandemic income sources did so. While 24.1% (money from savings or selling assets) to 22.4% (credit cards or loans) of Pennsylvania residents found it "somewhat difficult" to pay their "usual household expenses," only roughly one-half that number (13.9%) using their normal pre-pandemic incomes sources did so. In total, nearly half of Pennsylvania residents who have been forced to use credit cards or loans (22.4% + 22.8% = 45.2%), and more than half forced to draw down savings or sell assets (24.1% + 32.2% = 56.3%), found it either "somewhat" or "very" difficult to pay their usual household expenses during the pandemic (Week 18). In contrast, only 24.1% (credit cards or loans) to 14.7% using savings or selling assets found it "not at all difficult" to pay their usual household expenses, compared to 57.0% of those who can use their normal pre-pandemic income sources.

- By Week 27, conditions had improved, but remained severe for Pennsylvania residents. The Census PULSE Survey reports that while 15.8% of residents relying on credit cards or loans, and 11.0% drawing down savings or selling

> assets had a “very difficult” time paying for usual household expenses, only 4.3% of residents using their regular pre-pandemic income sources did. Similarly, while 41.6% of residents using credit cards or loans (25.8% + 15.8%), and 44.1% (33.1% + 11.0%) reported having either a “somewhat difficult” or ‘very difficult’ time paying their usual household expenses, “only” 19.5% of persons using their usual pre-pandemic source of income did. In the most recent week of the Census PULSE Survey, in other words, nearly one-in-five Pennsylvania residents relying on their regular pre-pandemic source of income were having difficulties paying their bills.

Not all of the data showed improvement in the economic crisis facing Pennsylvania residents. The percentage of Pennsylvania residents having either a “somewhat difficult” or “very” difficult time in paying their usual household expenses ticked upwards in Week 27 (relative to Week 22) for both persons relying on their regular pre-pandemic source of income (17.5% in Week 22; 18.5% in Week 27) and persons forced to rely on credit cards or loans (37.7% in Week 22; 41.6% in Week 27).

Moreover, even though the ***number*** of persons being forced to rely on credit cards or loans to pay usual household expenses dropped noticeably in Pennsylvania from Week 18 to Week 22 (a drop of 511,921 persons, from 2,503,191 in Week 18 to 1,991,270 in Week 22), that decline did not continue through Week 27. Only 28,796 fewer persons relied on credit cards or loans to pay usual household expenses in Week 27 (relative to Week 22) (1,991,270 in Week 22 vis a vis 1,962,474 in Week 27), even as a higher percentage of these persons reported having a somewhat difficult or very difficult time paying their usual household expenses (37.7% in Week 22 versus 41.6% in Week 27).

Table 5. Difficulty paying for usual household expenses during the coronavirus pandemic (Pennsylvania) (PULSE Survey)					
Used in last seven days to meet spending needs	Total # Reporting	Not at all difficult	A little difficult	Somewhat difficult	Very difficult
			PULSE Survey: Week 18:		
Regular income sources like those used before the pandemic	6,560,156	57.0%	23.5%	13.9%	5.6%
Credit cards or loans	2,503,191	24.1%	30.7%	22.4%	22.8%
Money from savings or selling assets	2,400,637	14.7%	29.0%	24.1%	32.2%
Borrowing from friends or family	987,231	1.4%	5.3%	15.8%	77.5%
Money saved from deferred or forgiven payments (to meet spending needs)	470,061	6.6%	14.1%	17.0%	62.2%
			PULSE Survey: Week 22:		
Regular income sources like those used before the pandemic	6,035,061	54.4%	28.1%	12.6%	4.9%
Credit cards or loans	1,991,270	25.4%	36.8%	23.9%	13.8%
Money from savings or selling assets	1,865,258	20.6%	26.6%	26.4%	26.4%
Borrowing from friends or family	614,567	1.7%	6.6%	25.0%	66.7%
Money saved from deferred or forgiven payments (to meet spending needs)	256,368	9.7%	46.7%	28.4%	15.2%
			PULSE Survey: Week 27		
Regular income sources like those used before the pandemic	6,444,148	58.9%	22.6%	14.2%	4.3%
Credit cards or loans	1,962,474	29.6%	28.8%	25.8%	15.8%
Money from savings or selling assets	1,557,580	18.7%	37.1%	33.1%	11.0%
Borrowing from friends or family	628,977	0.7%	27.4%	33.7%	38.2%
Money saved from deferred or forgiven payments (to meet spending needs)	276,096	21.3%	39.4%	24.7%	14.6%

1

Q. WHAT DO YOU CONCLUDE?

A. The conclusion to be drawn from this data is that low-wage households are a long ways away from achieving any post-pandemic economic stability. Even should the public health crisis associated with COVID-19 be mitigated through widespread vaccination in the coming months, the associated economic crisis will continue. It is that economic crisis far more than the public health crisis that UGI Electric should address. It is the ongoing economic crisis that will adversely affect the ability-to-pay of UGI Electric customers.

Q. HAS UGI ELECTRIC TAKE ANY ACTION TO ADDRESS THE ECONOMIC IMPACTS ASSOCIATED WITH THE COVID-19 PANDEMIC?

A. Yes. UGI Electric filed a Petition to implement a COVID-19 Emergency Relief Program (ERP) at Docket No. P-2021-3023992. UGI Electric's proposal was consistent with an existing ERP in place for UGI Utilities Inc. – Gas Division ("UGI Gas"). Essentially, UGI Electric proposed to implement voluntary, temporary modifications to its Universal Service and Energy Conservation Plan ("USECP") and to provide arrearage forgiveness, long-term payment arrangements, and bill credits to eligible customers that are currently struggling financially during the emergency health period. More specifically, UGI Electric proposed to do the following:

- Upon enrollment, suspension of collection efforts for any amounts due for service beginning as of the March 2020 billing cycle and continuing through April 2021 billing period; and

- Upon enrollment, a residential customer in arrears shall be entitled to a one-time credit (minimum of $200 and maximum of $400) in an amount equal to 25% of the customer's applicable balance as of the ERP Enrollment Termination Date, defined as the end of the April 2021 billing period. To the extent that a residential customer satisfies all eligibility criteria, but is not in arrears and is at or below 300% FPIG, this customer will be eligible for a one-time credit not to exceed more than $200. Grants to customers not in arrears will be provided on a first-come, first-serve basis and will be capped at a total amount not to exceed $100,000.

- Upon occurrence of the ERP Enrollment Termination Date, all ERP customers will be screened for CAP and Operation Share eligibility, and those who may be eligible will be encouraged to apply for the most appropriate program to address their needs. For customers who are ineligible for CAP, any remaining current applicable balance shall be subject to a long-term deferred payment arrangement (including the suspended amount). For purposes of establishing a deferred payment arrangement for applicable balances accrued through the Phase II ERP Enrollment Termination Date, the Company shall offer payment arrangement terms consistent with Section 1405(b) of the Public Utility Code or 12 months, whichever is longer, unless a shorter arrangement is affirmatively requested by the consumer. Longer payment arrangements may be offered to ERP participants at the discretion of the Company.

This proposal is largely consistent with UGI Gas' previously-approved ERP at Docket No. R-2019-3015162, except that the Company's proposal to provide a bill credit for customers not presently in arrears is a new provision.

Q. WHAT WAS THE COMMISSION'S DISPOSITION OF THE UGI ELECTRIC PETITION TO ADOPT AN ERP IN THE DOCKET YOU REFERENCE?

A. The ERP proposed for UGI Electric was neither approved nor disapproved by the PUC. At the Public Meeting on March 25, 2021, two Commissioners released a statement that would have disapproved the proposal, while two other Commissioners released a statement that would have approved the program. In concluding that "UGI has not carried its burden of proof in its request to reopen its bill credit program for its Gas division and to establish a new bill credit program for its Electric division,” Commissioner Coleman and Commissioner Yanora stated in relevant part:

> UGI has not provided enrollment projections or a proposed budget for the bill credit programs. UGI also has not provided any cost data or enrollment numbers for the first phase of the bill credit program. Further, UGI did not provide a customer needs assessment that would justify the amount of the bill credit for either program.

(Statement of Commissioner John F. Coleman, Jr. and Commissioner Ralph V. Yanora, Docket No. P-2021-30323839, at 2, March 25, 2021).

Q. HOW DOES THE COVID-19 TESTIMONY YOU PRESENT ABOVE RESPOND TO THE COMMISSIONERS’ CONCERNS?

A. This base rate proceeding provides an opportunity for UGI Electric to build on the needs identified in its original Petition to implement an Emergency Relief Program. My testimony also addresses the lack of evidentiary basis that Commissioners Coleman and Yanora identified. As to a needs assessment, I have demonstrated above that, through Week 27 of the Census Bureau’s PULSE Survey (March 17 through March 29):

- Between 25% and 40% of Pennsylvania residents have lost income since the beginning of the COVID-19 pandemic (Table 2), with these percentages present for households with an annual income up to $100,000;
- More than one-in-four households report having a “somewhat” (17.4%) or “very” (9.1%) time paying their usual household expenses (Table 3);
- When higher income households are excluded, the percentage reporting having a “somewhat” or “very” difficult time in paying their usual household

expenses increases to between 25% (income at $50,000 - $74,999) to 53% (income below $25,000) (Table 4);

Moreover, we know from the data I have presented above that in Week 27 of the PULSE Survey (March 17 through March 29), nearly two million Pennsylvania residents have been forced to use credit cards or loans to pay their usual household expenses such as utility bills, and that more than 40% of those residents have found it “somewhat difficult” or “very difficult” to pay those usual household expenses. (Table 5). We know that nearly 1.6 million Pennsylvania residents haven forced to use their savings (or to sell assets) to pay their usual household expenses, and that those savings are running out (Table 5 and accompanying text). We know that these savings are running out and that the use of credit card debt has become non-sustainable.

Q. WHAT DOES THAT DATA TELL YOU ABOUT THE NEED FOR THE ERP AS PROPOSED BY UGI ELECTRIC?

A. When one applies this data to UGI Electric, by income range, the need for the ongoing ERP proposed by UGI Electric becomes evident. More than 25,000 UGI Electric customers (25,396) are projected to live with annual income less than $50,000. An additional 9,604 UGI Electric customers are projected to live with annual income between $50,000 and $75,000.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Company continue to pursue implementation of its proposed ERP in the context of this rate proceeding. Now is the opportunity for the Company to provide any data previously requested by the Commissioners in the petition proceeding necessary to make a decision in this case.

To control costs, I recommend that the UGI Electric arrearage credits be limited to customers with an unpaid balance of more than 60 days old. In this fashion, UGI Electric is not providing a grant to someone who has simply happened to miss a payment in the short-term. In this fashion, UGI Electric rather is limiting credits to those who are beginning to demonstrate real payment difficulties. In addition, I recommend the proposed cost control mechanism of limiting arrearage grants to $200 or 25% of the outstanding balance, whichever is more (with the creation of credit balances not being permitted). Finally, UGI Electric has proposed to cap its credits for accounts without an unpaid balance at $100,000.

Finally, I recommend that UGI Electric carefully track the number of its ERP recipients who subsequently become a CAP participant. A customer who subsequently becomes a CAP participant would, of course, have any arrearages incurred prior to CAP enrollment made subject to arrearage forgiveness. UGI should be prepared to explain to the Commission and to other stakeholders what proportion of its ERP arrearage credits it would have been required to spend through arrearage forgiveness even without an ERP.

Q. HOW DO YOU PROPOSE UGI ELECTRIC RECOVER THE COSTS OF ITS ERP?

A. While I do not propose a ceiling on participation in the program component providing credits for unpaid balances, I find that the costs of an arrearage grant program, given an estimated participation rate of 30%, which reflects CAP participation rates, would be roughly $1.0 million. This is calculated by multiplying the average number of accounts in arrears for January/February 2021 (the two most recent months available) by the expected arrearage credit[15] by an estimated participation rate of 30%. This $1.0 million in arrearage forgiveness is in addition to the projected $100,000 UGI Electric previously identified as being the expenditure ceiling for credits to accounts without arrears.

I recommend that UGI Electric accrue its ERP costs as a regulatory asset the recovery of which will be determined in its next base rate case. While I recommend deferring the decision on rate recovery to the next base rate case, I recommend that three principles be applied: (1) the rate recovery of ERP costs be treated as other extraordinary expenses that are amortized over a substantial period of time; (2) the deferral of ERP costs be without the recovery of interest pending their recovery; and (3) UGI Electric be required to provide a complete accounting of ERP participants who subsequently become CAP participants and identify the overlap between arrearage credits and what would have become pre-program arrears.

PART 2. UGI Electric's Proposed Increase to its Residential Customer Charge.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

[15] The expected arrearage credit for accounts 60 – 90 days in arrears would be $200. The expected arrearage credit for accounts 90+ days in arrears would be $360. (OCA-IV-43).

A. In this section of my testimony, I review the expected disproportionate impact that the UGI Electric proposal to increase its residential customer charge will have on low-income, low use customers. I find that the proposed increase in the residential customer charge will have an unreasonable, and disproportionately adverse, impact on low-income customers.

A. UGI Electric's CAP Does Not Protect Low-Income Customers from Increased Fixed Charges.

Q. TO WHAT EXTENT WOULD THE UGI ELECTRIC CAP PROTECT THE COMPANY'S LOW-INCOME POPULATION FROM THE DISPROPORTIONATE ADVERSE IMPACTS OF INCREASING THE CUSTOMER CHARGE?

A. The UGI Electric Customer Assistance Program (CAP) would protect low-income customers from any increase in rates, including the increased customer charge, if and to the extent that the program limits the UGI Electric bill to an affordable percentage of income. This protection, however, is limited. The UGI Electric CAP program protects a very small percentage of its low-income customer base from the harms of an increased customer charge. While the UGI Electric's 3,331 CAP participants represent 6.1% of the Company's 54,605 total residential customer base (OCA-IV-54), the percentage of population in the UGI Electric service territory with annual income less than 150% of Poverty Level is 22.6%. Three-of-four low-income customers in the UGI Electric service territory, in other words, are not served by the Company's CAP and thus gain no protection against the increase in this unavoidable fixed charge.

Q. CAN YOU PUT THE DOLLAR IMPACT OF THE INCREASED CUSTOMER CHARGE, STANDING ALONE, ON UGI ELECTRIC LOW-INCOME CUSTOMERS INTO SOME CONTEXT?

A. Yes. In 2020, UGI Electric reported having 16,084 estimated low-income customers. (OCA-IV-53(b)). Using that number, UGI Electric's proposed customer charge increase, standing alone (i.e., without taking into account any other aspect of the UGI Electric rate increase), will draw $822,204 a year out of the Company's low-income population ($13.00 proposed customer charge - $8.74 existing customer charge = $4.26 monthly increase x 12 months x 16,084 estimated low-income customers = $822,214). As shown in the Table below, that is more than 3.5 times (3.57x) the total amount of LIHEAP cash assistance received by UGI Electric customers in program year 2019, and nearly two times (1.88x) the total amount of LIHEAP cash assistance received by UGI Electric customers in program year 2020.

Table 6. LIHEAP Cash Grants Received by UGI Electric Customers by Year (OCA-IV-20)

Program Year[16]	Date Range	Count	Dollars
2018-2019	10/1/18 - 9/30/19	678	$230,591
2019-2020	10/1/19 - 9/30/20	1,038	$436,996

One should keep in mind that the amount of LIHEAP benefits will not increase simply because UGI Electric's rates (and thus bills) increase. Pennsylvania's allocation of federal LIHEAP dollars is set by a statutory formula. That allocation will remain

[16] Program year 2020-2021 is not included since it is a partial year. (OCA-IV-20).

constant even if the number of residential customers needing assistance increases, or even if the dollar amount of need for assistance increases.

Q. WHAT DO YOU CONCLUDE?

A. The UGI Electric proposed increase in its residential customer charge will have an adverse impact on low-income customers. Most of the UGI Electric low-income customers are not protected from rate increases, including this proposed increase in the unavoidable part of the utility's rate structure, by the Company's CAP. While CAP is a critically important low-income program, it serves only 1-of-4 of the Company's low-income customers. Moreover, the proposed increase in the customer charge –just the amount of the proposed increase, not the customer charge as a whole—will take more money out of the UGI Electric low-income population than those customers have been receiving in federal fuel assistance (LIHEAP). Merely because UGI Electric's rates are increasing, including the unavoidable fixed charge element of the UGI Electric rates, does not mean that the amount of federal fuel assistance will increase. Increasing the customer charge will impose unavoidable fixed charges on UGI Electric's low-income customers with no offsetting increase in federal fuel assistance to help ensure that those bills can be paid. In short, the proposed increase in the UGI Electric customer charge, standing alone, will dilute the efficacy of federal fuel assistance (i.e., LIHEAP) benefits, along with generating increased utility costs on low-income households, in addition to the social consequences appurtenant thereto.

My observation is more than that UGI Electric has no role in setting LIHEAP benefits. My observation is that, by law, LIHEAP appropriations to Pennsylvania are set by a federal statutory formula. An increase in the unavoidable fixed customer charge imposed by UGI Electric not only ***will*** not be offset by increased federal fuel assistance, it ***can***not be offset by increased federal fuel assistance. Increasing the fixed customer charge, standing alone, has the same financial effect on low-income customers as completely eliminating LIHEAP benefits (and more) to UGI Electric customers.

B. Harms to Low-Income from Increased Residential Customer Charge.

Q. HOW WOULD THE PROPOSED INCREASE IN THE FIXED RESIDENTIAL CUSTOMER CHARGE HARM LOW-INCOME CUSTOMERS?

A. Without limitation, I find that the UGI Electric proposal to increase its customer charge will harm low-income customers in each of the following ways (with each bullet below incorporating every other bullet):

- It will increase both the breadth and depth of arrears, each of which imposes additional utility costs on low-income households along with the social consequences appurtenant thereto.

- It will increase the incidence of service disconnections for nonpayment, along with the increased utility costs on low-income households in addition to the social consequences appurtenant thereto.

- It will decrease the ability of low-income customers to maintain deferred payment arrangements through which they can retire past-due balances outside of their participation in CAP.

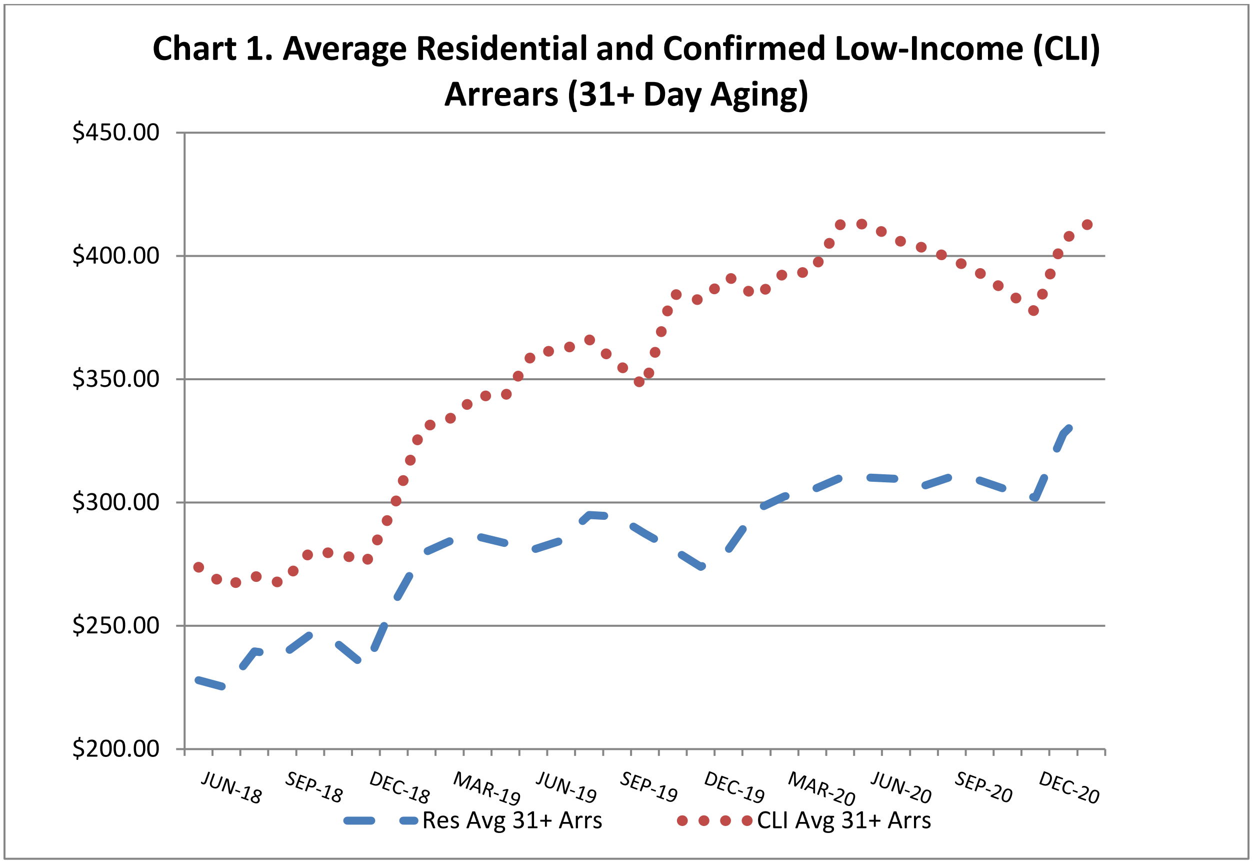
➢ It will increase Home Energy Insecurity, along with the resulting utility costs on low-income households, in addition to the social consequences appurtenant thereto.[17]

Q. WHY IS IT SIGNIFICANT THAT UGI ELECTRIC UNDER-ENROLLS ITS CONFIRMED LOW-INCOME CUSTOMER POPULATION INTO ITS CAP PROGRAM?

A. The under-enrollment of the UGI Electric confirmed low-income population into CAP is significant because the Company's confirmed low-income population has substantially greater payment difficulties than does the residential population as a whole. Chart 1 below sets forth the data on the average arrearages of accounts with receivables aged 31 days old or older for the period June 2018 through February 2021. (OCA-IV-43). Two observations stand out in this Chart. First, while the average arrearage balance is increasing for both residential and confirmed low-income residential accounts, the rate at which the average arrears for confirmed low-income accounts is increasing is much steeper than residential accounts as a whole. Second, the average arrearage for confirmed low-income customers is more than 20% higher than the average arrearage for residential accounts as a whole. In February 2020, for example, the average confirmed low-income arrears exceeded the average arrears by 29% ($383 vs. $297), while in February 2021, the average confirmed low-income arrears exceeded residential arrears by 22% ($414 vs. $339). Similarly, in December 2019, the average confirmed low-income arrears exceeded the average residential

[17] See, Colton, Measuring the Outcomes of Home Energy Assistance Programs through a Home Energy Insecurity Scale, which, by this reference thereto, is incorporated herein as if fully set forth, available at http://fsconline.com/05_FSCLibrary/lib2.html (last accessed April 21, 2021).

arrears by 39% ($382 vs. $274), while in December 2020, the average confirmed low-income arrears exceeded the residential arrears by 25% ($377 vs. $302).



Moreover, Chart 2 shows that the confirmed low-income customers of UGI Electric are more seriously in arrears than are residential customers generally. Focusing on September 2019 to present in particular, while roughly 40% of the residential arrears that were aged 31 days or more were, in fact, aged 60 days or more, 50% of the confirmed low-income arrears aged 31 days or more were, in fact, 60 days old or older.

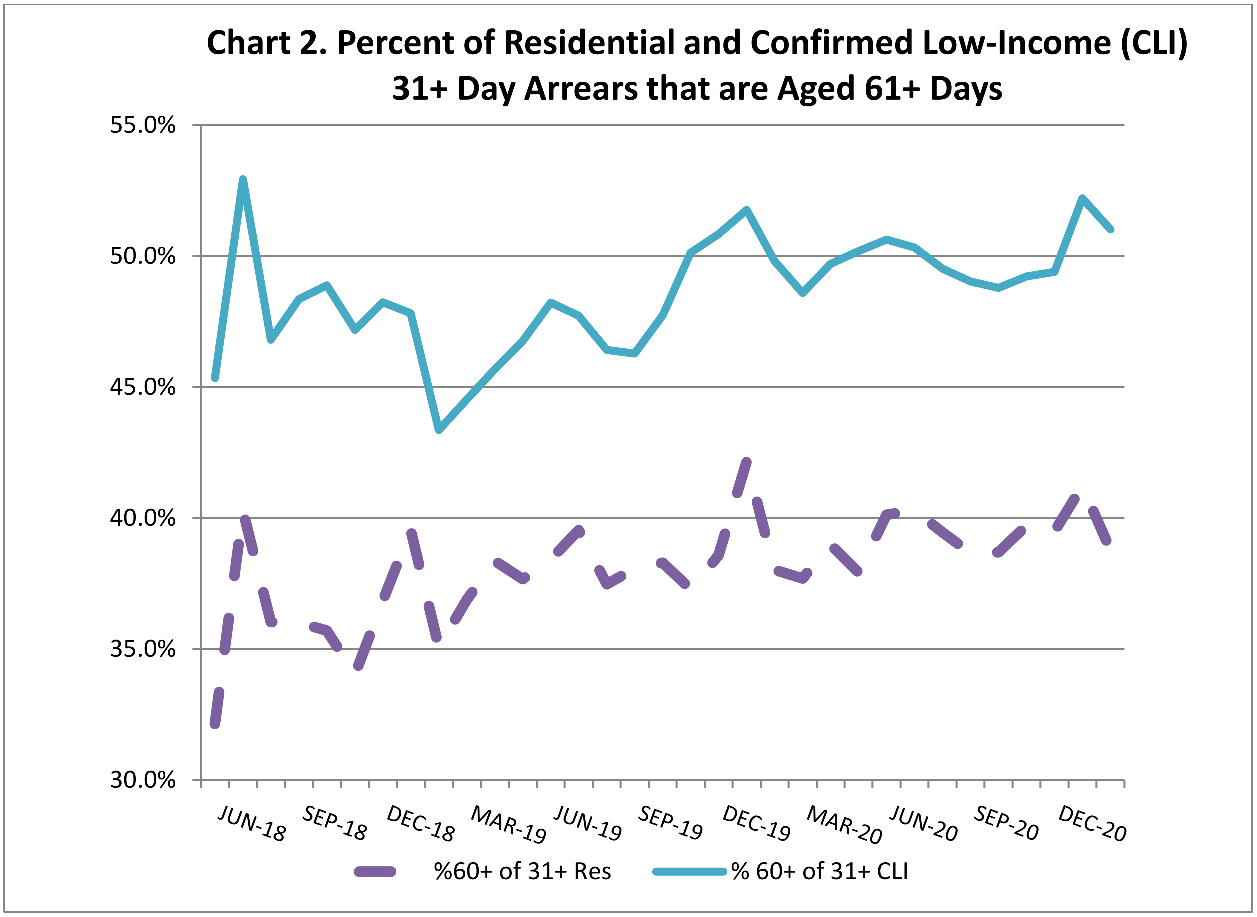
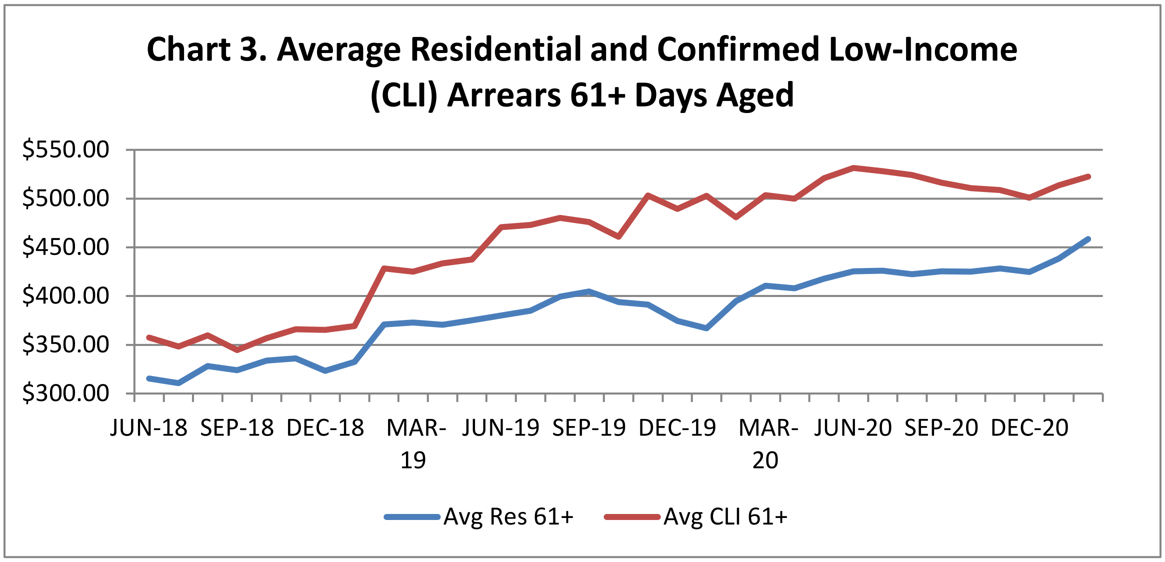


Chart 2. Percent of Residential and Confirmed Low-Income (CLI) 31+ Day Arrears that are Aged 61+ Days

Chart 3 shows that the average 61+ day old arrearage balance of confirmed low-income customers is consistently higher than the average balance of residential customers.



Indeed, for each of the metrics examined above, the difference is even greater than shown. The "Residential" class has, as one sub-component, the "Confirmed Low-Income" customers. The higher numbers for the Confirmed Low-Income customers, in other words, will pull the Residential customer numbers upwards. If the comparison was between customers who are Confirmed Low-Income and those who are *not* Confirmed Low-Income, the differences identified above would be even greater.

Q. WHAT IS THE SIGNIFICANCE OF THE PAYMENT DIFFICULTIES THAT YOU IDENTIFY ABOVE?

A. The data on payment difficulties that I discuss above is directly relevant to assessing the reasonableness of the UGI Electric proposal to increase its residential customer charge. What UGI Electric is doing is increasing the unavoidable fixed monthly customer charge, resulting in a disproportionately higher percentage bill increase, to those customers who can least afford to make their bill payments in the first instance. Not only does this place the continuation of service to these low-income customers in jeopardy, but this also causes UGI Electric to incur credit and collection costs that will, in turn, be passed on to all ratepayers in future rates.

C. The Relationship between Income and Electric Usage.

Q. WHAT DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I examine the relationship between electric usage and low-income status in the UGI Electric service territory. Using data specific to the UGI Electric service territory, I conclude that low-income customers are disproportionately likely to be low use customers and, as a result, will be disproportionately harmed by the Company's proposal to increase its residential fixed monthly customer charge. I do not assert that all low-income customers are low use. However, I do conclude that low-income customers are disproportionately, and on average, low use customers.

Q. HAS UGI ELECTRIC UNDERTAKEN A STUDY OF RESIDENTIAL ELECTRIC USAGE BY HOUSING TYPE OR HOUSING SIZE?

A. No. When asked to provide all studies undertaken by, or on behalf of the Company, within the past ten years of residential usage by housing type, or of residential usage by housing size, UGI Electric responded that "the Company has not undertaken such studies." (OCA-IV-57).

Q. PLEASE EXPLAIN THE DATA WITH WHICH YOU BEGIN YOUR EXAMINATION OF INCOME AND ELECTRICITY USAGE.

A. My review of the relationship between electricity use and income in the UGI Electric service territory begins with the 2015 Residential Energy Consumption Survey ("RECS") published by the Energy Information Administration of the U.S. Department of Energy ("EIA/DOE").[18] In examining this RECS data, it is important to understand what I am and am not asserting. I use the RECS data for the Northeast region of the country to identify those characteristics that are associated with lower electricity usage. I do *not* assert that because usage is lower for the Northeast region as a whole, usage is also lower in the UGI Electric service territory. Instead, I separately examine the extent to which the characteristics identified as associated with lower electric consumption are prevalent in the UGI Electric service territory, and, if so, the extent to which those characteristics have patterns that align with low-income status.

Q. WHAT DOES THE RECS FIND WITH RESPECT TO USAGE LEVELS AND HOUSING PATTERNS?

A. The 2015 RECS presents data on three relevant housing characteristics that are relevant to whether low-income electricity consumption is higher or lower: (1) the type of housing structure; (2) the ownership of housing (often referred to as the "tenure" of residents); and (3) the size of housing. That 2015 data is discussed below.

The Table immediately below examines the relationship between the type of housing structure and electricity usage for the Northeast region of the United States, the region of

[18] The 2015 RECS is the most recent data published by EIA/DOE. Available at: https://www.eia.gov/consumption/residential/data/2015/index.php?view=consumption#undefined (last accessed April 21, 2021).

which Pennsylvania is a part. The RECS reports electricity consumption by type of structure both in millions of BTUs and in "physical units" (kWh). The data clearly demonstrates that single-family detached housing units have the highest electricity consumption, nearly 50% higher than single-family attached units, and more than 2.5 times higher than buildings with five or more units per building. In contrast, multi-family buildings are also clearly the structures with the lowest electricity usage. Both multi-family buildings with 2 to 4 units and multi-family buildings with 5 or more units have electricity consumption lower than either type of 1-family housing structure (1-family detached, 1-family attached).

Table 7. **Average Site Energy Consumption (per household using the fuel) (Northeast) (Electricity) (RECS Table CE2.2) (2015)**

	mMBtu	**kWh**
Housing Unit Type		
Single-Family		
Single-Family Detached	36.2	10,599
Single-Family Attached	24.6	7,202
Multi-Family		
Apartments in 2-4 Unit Buildings	21.6	6,334
Apartments in 5 or More Unit Buildings	14.1	4,120

Table 8 next presents data on electricity usage by the tenure status of the occupant. The relationship between single-family homes and higher usage is again shown, with single-family homes (whether owed or rented) having higher consumption. Owner-occupied single-family homes, however, have considerably higher usage than do any other type of tenure status. In contrast, multi-family homes, whether owned or rented, have the lowest consumption. Nonetheless, rental status is shown to be related to lower electricity consumption. Rented single-family homes have lower consumption than do owner-occupied single-family homes. Rented multi-family homes have lower consumption than do owner-occupied multi-family homes.

Table 8. **Average Site Energy Consumption (per household using the fuel) (Northeast) (Electricity) (RECS Table CE2.2) (2015)**

	mMBtu	kWh
Ownership of Housing Unit		
Owned	33.9	9,930
Single-Family	35.7	10,458
Multi-Family	19.1	5,585
Rented	18.7	5,476
Single-Family	25.5	7,487
Multi-Family	16.7	4,892

The RECS next shows the sharp relationship between the size of the housing unit structure and the level of electricity consumption. There is a continuum of usage for electricity when such usage is viewed by size of a housing unit. The lowest consumption is found in the smallest housing units. The highest consumption is found in the largest housing units. Indeed, housing units with 2,000 to 2,499 square feet have 50% higher electricity consumption than housing units with 1,000 to 1,499 square feet. Housing units with 3,000 or more square feet have usage 2.5 times as high as housing units with fewer than 1,000 square feet.

Table 9. **Average Site Energy Consumption (per household using the fuel) (Northeast) (Electricity) (RECS Table CE2.2) (2015)**		
	mMBtu	**kWh**
Total Square Footage		
Fewer than 1,000	16.3	4,775
1,000 to 1,499	22.3	6,542
1,500 to 1,999	30.7	8,987
2,000 to 2,499	31.2	9,155
2,500 to 2,999	31.9	9,356
3,000 or more	40.4	11,843

Finally, Table 10 shows that the decreased usage associated with the three characteristics examined above is not specific to any particular type of end use electricity consumption. Lower electricity consumption, for example, is not uniquely tied to lower electric space heating consumption. For each end use (space heating, water heating, air-conditioning, refrigerators, and appliances (other)), the relationships reported above are also evident. Multi-family housing has lower usage than single-family housing. Renter-occupied housing has lower usage than owner-occupied housing. Smaller housing has lower usage than larger housing units.

Table 10. **Electricity (kWh per household using the end use) (Northeast) (2015) (RECS Table CE4.7)**

	Total	Space heating	Water heating	Air condi-tioning	Refrig-erators	Other
Housing unit type						
Single-family detached	10,599	3,447	3,572	1,264	846	6,364
Single-family attached	7,202	2,901	2,611	1,143	638	3,963
Apartments in buildings with 2-4 units	6,334	2,789	2,757	653	522	3,401
Apartments in buildings with 5 or more units	4,120	1,519	1,801	553	442	2,177
Ownership of housing unit						
Owned	9,930	3,386	3,336	1,208	827	5,859
Single-family	10,458	3,530	3,419	1,279	848	6,240
Apartments	5,585	1,531	2,165	794	675	3,168
Rented[7]	5,476	2,192	2,603	624	462	2,915
Single-family	7,487	2,083	3,707	970	581	4,339
Apartments	4,892	2,158	2,199	549	432	2,566
Total square footage						
Fewer than 1,000	4,775	2,173	2,432	484	446	2,403
1,000 to 1,499	6,542	2,402	2,719	673	576	3,507
1,500 to 1,999	8,987	2,722	3,118	1,151	809	5,251
2,000 to 2,499	9,155	3,777	3,235	1,126	747	4,880
2,500 to 2,999	9,356	2,962	3,277	1,263	784	5,683
3,000 or greater	11,843	3,800	3,921	1,480	903	7,371

Q. HOW DOES THE DATA ABOVE RELATE TO THE ASSOCIATION BETWEEN INCOME AND ELECTRIC CONSUMPTION IN THE UGI SERVICE TERRITORY?

A. In my discussion below, I examine data specific to the UGI Electric service territory to assess the extent to which, if at all, the characteristics I discuss above are, in turn, related to income in the UGI Electric service territory. I find that they are.

In reaching this conclusion, I match the zip codes that UGI Electric reports comprise its service territory with corresponding Census Data.[19] Using that Census data, I rank each zip code from low to high. I then divide the UGI Electric zip codes into "quartiles."[20] I compare patterns of association between the quartiles for relevant characteristics and the penetration of low-income households in each zip code.

The Figure below, for example, presents the data comparing the percentage of renter-occupied housing units with the percentage of households with annual income less than $15,000. The relationship between renter-status and income can be seen. There are three (3) zip codes in the quartile of zip codes with the three lowest percentages of low-income households *__and__* the three lowest percentages of renter-occupied housing units. In contrast, there are five zip codes in the quartile of zip codes with both the highest percentage of low-income households and the highest percentage of renters. This is the

[19] More specifically, I examine Census data for Zip Code Tabulation Areas (5-digit) (ZCTA). When I match Census Data to UGI Electric data, I am matching Zip Code Tabulation Areas (ZCTAs) to Zip Codes. ZCTAs are virtually, but not quite, identical to Zip Codes. ZCTAs are used by the U.S. Census Bureau, while Zip Codes are creatures of the U.S. Postal Service. According to the Census Bureau: "ZIP Code Tabulation Areas (ZCTAs) are generalized areal representations of United States Postal Service (USPS) ZIP Code service areas. The USPS ZIP Codes identify the individual post office or metropolitan area delivery station associated with mailing addresses. USPS ZIP Codes are not areal features but a collection of mail delivery routes." U.S. Census Bureau, Zip Code Tabulation Areas (ZVTAs), https://www.census.gov/programs-surveys/geography/guidance/geo-areas/zctas.html (last accessed April 21, 2021). In my testimony, the terms "ZCTA" and "zip code" are used interchangeably.

[20] When a group of values is divided into four equal parts, each part is called a "quartile."

pattern which one would expect if there is a relationship between annual income and renter status. Similarly, as expected, no zip code falls within the quartile with the lowest percentage of low-income households and the highest percentage of renters, or in the quartile of zip codes with the highest percentage of low-income households and the lowest percentage of renters.

Quartiles of Percentage of Population with Income <$15,000	Quartiles of Zip Codes by Percent of Housing Renter-Occupied: Lowest	Highest
Lowest	3	0
Highest	0	5

Figure 1. Percentage of Households with Annual Income <$15,000 vs. Percentage of Housing Units Renter-Occupied

Figure 2 below further documents the relationship between low-use characteristics and low-income status. In this instance, I examine the overlap between low-income status and the percentage of housing units that are in buildings with five or more units. As can be seen, in the UGI Electric service territory, three zip codes fall in the quartile of zip codes containing both lowest percentage of low-income households and the lowest percentage of housing units in buildings with five or more units, while three more zip codes fall within the quartile with the highest percentage of low-income households and the highest percentage of units in buildings with five or more units.

As expected, the opposite is also demonstrated. When the percentage of low-income households is highest, the zip codes with a low percentage of 5+ unit buildings is lowest (0 zip codes in that quartile), while when the percentage of low-income households is lowest, the zip codes with a high percentage of 5+ unit buildings is also low (only one zip code in that quartile).

Quartiles of Percentage of Population with Income <$15,000		**Quartiles of Zip Codes by Percentage of Housing Units in Buildings with 5+ Units**	
		Lowest	Highest
	Lowest	3	1
	Highest	0	3

Figure 2. Percentage of Households with Annual Income <$15,000 vs. Percentage of Housing Units in Buildings with Five or More Units.

Low-income status is also associated with housing unit size. While the RECS data discussed above examines housing unit size in terms of square feet, the Census does not report data in those terms. To examine the size of housing units, therefore, I examine both the number of rooms in a housing unit and the number of bedrooms in a housing unit. In the UGI Electric service territory, low-income is associated with smaller housing units while higher incomes are associated with larger housing units. The Figure below, for example, demonstrates that three (3) zip codes have both the smallest percentage of low-income households and the smallest percentage of small housing units (i.e., units with three or fewer rooms); three (3) more zip codes fall within the quartile with the largest percentage of low-income households and the largest percentage of small housing units. In contrast, the counter-relationship does not exist. Only one (1) zip code falls within the quartile with the lowest percentage of low-income households and the highest percentage of small housing units; only one (1) more falls within the quartile with the highest percentage of low-income households and the lowest percentage of small housing units.

		Quartiles of Zip Codes by Housing Units with 3 or Fewer Rooms	
		Lowest	Highest
Quartiles of Percentage of Population with Income <$15,000	Lowest	3	1
	Highest	1	3

Figure 3.Percentage of Households with Annual Income <$15,000 vs. Percentage of Housing Units with Three or Fewer Rooms

The same relationship is demonstrated when housing unit size is measured by the number of bedrooms rather than the number of rooms. A substantial number of zip codes (4) fall within the quartile of zip codes with the lowest penetration of low-income households and the lowest percentage of small housing units; in addition, a substantial number of zip codes (5) also fall within the quartile of zip codes with the highest percentage of low-income households and the highest percentage of small housing units.

In contrast, there are no zip codes (0) in the UGI Electric service territory that fall within the quartile having the lowest percentage of low-income households and the highest percentage of small housing units, just as there are no zip codes (0) that fall within the quartile having the highest percentage of low-income households and the lowest percentage of small housing units.

		Quartiles of Zip Codes by Housing Units with 2 or Fewer Bedrooms	
		Lowest	Highest
Quartiles of Percentage of Population with Income <$15,000	Lowest	4	0
	Highest	0	5

Figure 4. Percentage of Households with Annual Income <$15,000 vs. Percentage of Housing Units with Two or Fewer Bedrooms

Figure 5 and Figure 6 below show the same relationships from the converse perspective. Figure 5 shows that when the percentage of low-income households is cross-tabulated with larger housing units, those zip codes in the quartile with the highest percentage of low-income households also fall within the quartile having the lowest percentage of larger housing units (5); those zip codes with the lowest percentage of low-income households fall within the quartile of zip codes with the highest percentage of larger housing units (3). The same relationship between income and the size of housing is found going the other direction. No (0) zip codes falling in the quartile with the lowest percentage of low-income households also falls within the quartile with the lowest percentage of large housing units; only one (1) zip code with the highest percentage of low-income households also falls within the quartile of zip codes with the highest percentage of larger housing units.

		Quartiles of Zip Codes by Percent of Housing Units with 7 or More Rooms	
		Lowest	Highest
Quartiles of Percentage of Population with Income <$15,000	Lowest	0	3
	Highest	5	1

Figure 5. Percentage of Households with Annual Income <$15,000 vs. Percentage of Housing Units with Seven or More Rooms

The same relationship between low-income status and the lack of larger housing units is shown in the Figure below, when the size of housing units is measured by number of bedrooms (rather than number of rooms). The zip codes with the highest percentage of low-income households have the lowest percentage of larger housing units. The zip codes with the largest percentage of larger housing units have the lowest percentage of low-income households.

		Quartiles of Zip Codes by Percent of Housing Units with 4 or More Bedrooms	
		Lowest	Highest
Quartiles of Percentage of Population with Income <$15,000	Lowest	0	3
	Highest	5	0

Figure 6. Percentage of Households with Annual Income <$15,000 vs. Percentage of Housing Units with Four or More Bedrooms

Q. WHAT DO YOU CONCLUDE?

A. Given what we know from the RECS data I discussed above, I conclude that low-income households in the UGI Electric service territory are disproportionately likely to be low-use customers. This is not to say that all low-income customers are low-use customers, nor that all low-use customers are low-income. It can hardly be questioned, however, that in the UGI Electric service territory, low-income customers will disproportionately be low-use customers. Accordingly, UGI Electric's proposal to substantially increase its residential customer charge will disproportionately harm the utility's low-income customer base.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the residential customer charge set forth in the Direct Testimony of OCA witness Mierzwa be adopted.

PART 3. The Allocation of Universal Service Costs.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I briefly explain why UGI Electric's universal service costs should be allocated amongst all customer classes, rather than being allocated exclusively to the residential customer class. Despite this explanation, I do not propose that the PUC consider a reallocation in this proceeding.

Q. PLEASE EXPLAIN.

A. A decision on the allocation of universal service costs would affect UGI Utilities (including both its natural gas and electric divisions) as a whole. The size of the UGI Gas universal service programs (including both CAP and LIURP) is far greater than the UGI Electric universal service programs. In 2019, for example, UGI Gas collected $8,973,420 through its USP Rider. In contrast, UGI Electric reports that it collected $2,519,877 through its Universal Service Rider in 2019. (OCA-IV-34). A decision on how to allocate universal service costs for UGI Utilities as a whole should be undertaken where it is possible to consider the implications for the utility as a whole.

In UGI Gas's most recent base rate proceeding at Docket No. R-2019-3015162, the OCA entered into a settlement deferring the issue of universal service cost allocation until UGI Gas' next base rate proceeding. Given the significant size disparities between the UGI

Utilities' electric and gas divisions, it would be more appropriate to raise the issue during UGI Gas' next base rate proceeding as agreed to in that settlement.

Q. PLEASE EXPLAIN WHY YOU MENTION THIS ISSUE GIVEN THAT YOU DO NOT PROPOSE A CHANGE IN THE UNIVERSAL SERVICE COST ALLOCATION IN THIS PROCEEDING.

A. In its 2019 Final Policy Statement and Order in the PUC's generic investigation into energy affordability in Pennsylvania (Docket M-2019-3012599),[21] the Commission explicitly acknowledged that, historically, it allocated universal service costs exclusively to residential customers, but then stated that "our review of Pennsylvania's current universal service model in the *Review* and *Energy Affordability* proceedings has provided reasons to reconsider this position." (Final Policy Statement and Order, at 92). The Commission observed that "[t]he current cost-recovery method for universal services, including CAP costs, is putting a significant burden on residential customer bills. . ." (Id.). The Commission's decision to substantially reduce the definition of an "affordable" burden will create even more universal service costs and will increase that "significant burden" even more. According to the Commission:

> Given the significant past increase in EDC universal service spending – and the anticipated increases in both EDC and NGDC universal spending through 2021 – the Commission is concerned that recovering CAP costs (as well as other universal service costs) from only residential ratepayers will continue to make electric and/or natural gas bills increasingly unaffordable for non-CAP customers, especially those with incomes between 151-200% of the FPIG.

---

[21] http://www.puc.pa.gov/about_puc/consolidated_case_view.aspx?Docket=M-2019-3012599 (November 5, 2019) (last accessed April 21, 2021).

(Id., at 95). I agree with these observations. There is a substantial population of UGI Electric customers who have difficulties in paying their utility bills without being sufficiently "low-income" to qualify for CAP. The current CAP costs could prove to be problematic for these customers, and those costs will increase in the future, both for the reasons identified in the Commission's Final Order (pages 94 – 95) and for the reason that the Commission has revised its Final Policy Statement recommending reductions of the percentage of income payments to be charged to CAP customers.[22]

The Commission stated in its Final Order that "the Commission finds it appropriate to consider recovery of the costs of CAP costs from all ratepayer classes. Utilities and stakeholders are advised to be prepared to address CAP cost recovery in utility-specific rate cases consistent with the understanding that the Commission will no longer routinely exempt non-residential classes from universal service obligations. . ." (Id., at 99, notes omitted).[23]

Q. HOW DO YOU RESPOND TO THIS PUC GUIDANCE?

A. While I am not recommending that universal service costs be allocated across all customer classes in this proceeding, for the reasons set forth above and further below, I agree that:

[22] While the Office of Consumer Advocate has urged that CAP is designed to address long-term structural poverty, these costs might increase even more to the extent that COVID-19 results in structural job loss. Temporary loss of income due to COVID-19 should be considered to be addressed through a PUC-approved emergency relief program.

[23] The Commission observed that it was not making "a final precedential decision regarding cost recovery in this docket. We are merely providing that the recovery of CAP costs in particular can be fully explored in utility rate cases henceforth. " (Id., at note 150).

- the PUC's observation was accurate when it found in its 2019 Final Order that poverty is "not just [a] residential class problem."

- the Pennsylvania PUC's observation was accurate when it found in its Final Order (2019) that several factors "contribute to households struggling to afford utility service" and that, amongst those factors are "poverty, poor housing stock, and other factors."

- the Pennsylvania PUC was correct when it found in Final Order (2019) that poverty is a broad-based social problem not associated with any particular customer class, including specifically not being associated with the residential class exclusively.

- the Pennsylvania PUC was correct when it found in its Final Order (2019) that "helping low-income families maintain utility service and remain in their homes is also a benefit to the economic climate of a community."

- the Pennsylvania PUC was correct when it found in its Final Order (2019) that "Clearly, there is a persuasive argument to be made that home heating and energy assistance for low-income households serves a public good whose responsibility is not merely other residential ratepayers."

- The Pennsylvania PIC was correct when it found in its Final Order (2019) that "while there are strong arguments to be made that non-residential classes do benefit from universal services, there are also strong arguments to be made in favor of multi-class allocation even if one discounts any non-residential benefits."

Finally, I agree that the PUC's observation is applicable to UGI Utilities, when the Commission observed in its Final Order (2019), quoted above, that: "In approving PGW's practice of recovering such costs across all ratepayer classes, we noted that 'all firm customers, including commercial and industrial customers, benefit indirectly from PGW's extensive low-income assistance programs.'" (internal note omitted).

Q. WHAT DO YOU CONCLUDE AS TO UNIVERSAL SERVICE COST ALLOCATION FOR UGI ELECTRIC?

A. Notwithstanding this willingness and ability to demonstrate the applicability of these previous PUC findings to UGI Utilities, for the reasons stated above, I do not present the issue of the allocation of universal service costs in this proceeding, but reserve this issue for a future proceeding.

PART 4. Confirmed Low-Income and CAP Outreach and Education Plan.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I examine the need for UGI Electric to undertake more extensive outreach to enroll low-income customers in the utility's Customer Assistance Program ("CAP"). This outreach should focus on customers who have annual income at or below 50% of the Federal Poverty Level.

Q. HOW MANY UGI ELECTRIC CAP PARTICIPANTS DO YOU USE FOR YOUR ASSESSMENT?

A. UGI Electric provided different numbers as a count of its CAP participants. I do not question those numbers. The differences can reflect different time periods, or different ways in which the data is reported (e.g., end of month number; average monthly number). The figure I use, however, is the count of CAP participants that UGI Electric provided by zip code (OCA-IV-54(b)). To derive a total CAP participation, I simply summed the participation by zip code. In this fashion, I found that UGI Electric reported a total of 3,328 CAP participants.

Q. PLEASE COMPARE THE NUMBER OF CAP PARTICIPANTS UGI ELECTRIC REPORTS TO ITS TOTAL LOW-INCOME CUSTOMER BASE.

A. The "total low-income customer base" can be defined in two different ways. On the one hand, there is the "estimated" number of low-income customers. Multiplying its residential customer numbers by the percentage of households with income at or below 150% of Poverty, UGI Electric estimates that it has 16,069 low-income customers. (CEO-I-7). On the other hand, there is the "confirmed low-income" customer base. Noting that there are "some" customers in this count with income above 150% of Poverty (who received a hardship grant), UGI reports that it had 4,959 confirmed low-income customers as of September 30, 2020 and 5,009 confirmed low-income customers as of February 28, 2021. (CEO-I-6).

As is evident, therefore, UGI Electric serves only roughly one-in-five of its estimated low-income customers through CAP (3,328 / 16,069 = 0.207). UGI does not even serve its entire confirmed low-income customer base through CAP, reaching roughly two-of-three (3,328 / 4,959 = 0.67; 3,328 / 5,009 = 0.66). The large difference between these two numbers (i.e., percent CAP of estimated low-income; percent CAP of confirmed low-income) does not indicate that CAP enrollment is high. It instead indicates that UGI Electric uses the same criterion to confirm low-income status as it uses to enroll CAP participants. According to the PUC's Bureau of Consumer Services, for example, on average statewide, Pennsylvania's confirmed low-income customer base is more than half (51.7%) of its estimated low-income customer base. In contrast, UGI Electric's confirmed low-income customer base is only 31% of its estimated low-income customer base.

Q. WHY IS THE IDENTIFICATION OF CONFIRMED LOW-INCOME CUSTOMERS IMPORTANT?

A. Aside from the application of regulatory winter shutoff protections, various other regulatory protections are available to low-income customers. For example, the Commission may order a waiver of late payment charges for low-income customers. Security deposits may not be charged to confirmed low-income customers. Certain rules attach to low-income accounts where customers are seeking restoration of service. In general, utilities are required to provide notice to customers including "information indicating that additional consumer protections may be available for. . .low income households." (Section 56.201, Section 56.431).

Q. HOW DOES THE PUC DEFINE A "CONFIRMED LOW-INCOME" CUSTOMER FOR PURPOSES OF AN ELECTRIC DISTRIBUTION UTILITY?

A. The PUC makes clear that "Accounts are classified by the following categories: all residential accounts and confirmed low-income residential accounts." (52 PA Code §54.72). The PUC's regulations (§54.72) then continue to define a "confirmed low-income" account as: "Accounts where the EDC has obtained information that would reasonably place the customer in a low-income designation." This electric language can further be read in conjunction with the corresponding natural gas language, wherein the PUC defines a "confirmed low-income customer" as being "Accounts where the NGDC has obtained information that would reasonably place the customer in a low-income designation. This information may include receipt of LIHEAP funds, *self-certification by the customer, income source or information obtained in § 56.97(b)* (relating to procedures upon rate-payer or occupant contact prior to termination).” (emphasis added). (52 Pa Code §62.2).

Q. WHAT DO YOU RECOMMEND?

A. I recommend that UGI Electric insert a tariff provision defining a “confirmed low-income customer.” That tariff provision should reflect the PUC definition that a confirmed low-income customer includes any account where UGI Electric “has obtained information that would reasonably place the customer in a low-income designation.” UGI Electric should specifically state that it will accept self-certification of low income status for purposes of identifying “confirmed low-income customers” in the same way that self-certification is required to be accepted by the UGI gas affiliates. UGI Electric should not be allowed to modify the PUC’s regulations by internal procedures which are in conflict with the regulation.[24]

Q. HAVE YOU EXAMINED THE LEVEL OF CAP PARTICIPATION FOR UGI ELECTRIC?

A. Yes. UGI Electric substantially under-enrolls its low-income population into CAP. I reach this conclusion based not only on the small number of participants enrolled in UGI

[24] Programs such as CAP, LIURP and the Hardship Fund, of course, would have their own independent requirements for income certification and verification.

Electric's CAP –as documented above, UGI Electric enrolls only one-in-five of its estimated low-income customers in CAP—but it under-enrolls customers in CAP relative to the enrollment of low-income households in other public assistance programs.

In reaching this conclusion, I obtained from the Census Bureau the number of households in each zip code comprising the UGI Electric service territory participating in similar assistance programs (and calculated the percentage of households who were so participating). I then multiplied this percentage times the number of customers in each zip code.[25]

If UGI Electric were to enroll customers in CAP at the same rate as its customer base was enrolled in Food Stamps (SNAP), for example, it would have an additional 5,068 CAP participants. If UGI Electric enrolled customers in CAP at the same rate as its customer base was enrolled in either public assistance or Food Stamps (SNAP), it would have an additional 5,527 CAP participants.

Out of the 22 zip codes which comprise the UGI Electric service territory, there are 12 zip codes where CAP participation would increase by more than 100 customers if UGI Electric simply enrolled low-income customers at the same rate as UGI Electric households enroll in Food Stamps. In eight zip codes, CAP participation would increase by 250, while in one zip code, CAP participation would increase by nearly 2,000.

[25] This is the same calculation UGI Electric makes on a county-wide basis to determine the number of estimated low-income customers in its service territory. (CEO-I-7).

Q. IS THERE OTHER DATA THAT SUPPORTS YOUR CONCLUSION THAT UGI ELECTRIC UNDER-ENROLLS ITS CAP POPULATION?

A. Yes. UGI Electric could beneficially partner with the local school districts which comprise its service territory. UGI Electric serves communities in the following school districts: Dallas, Greater Nanticoke Area, Hanover Area, Lake-Lehman, Northwest Area, Wyoming Area, and Wyoming Valley West. Those school districts document pockets of poverty. Through a school district, one can identify low-income households through the Free and Reduced School Breakfast/School Lunch Program (collectively referred to as "subsidized school meals"). Maximum income eligibility for free school meals is set at 130% of the Federal Poverty Level, while reduced price school meals are available to households with income between 130% and 185% of Poverty.

In the UGI Electric service territory, the Greater Nanticoke School district reported that, in February 2020 (the last month before the COVID-19 pandemic was recognized), more than 66% of its students qualified for the subsidized school meals. In addition, the Hanover Area School District reported nearly 100% (96.7%) of its students qualified for subsidized school meals, while the Wyoming Valley West School District reported that 83% of its students did. The Northwest Area School District (44.8%) and Wyoming Area School District (42.9%) both had more than 40% of their students eligible for subsidized school meals.

Nonetheless, UGI Electric's CAP enrollment does not reflect these high poverty rates. If UGI Electric's CAP enrollment simply reflected the same rate of enrollment as the federal Food Stamp program, the additional CAP participation would be as reflected in Table 11 below.

Table 11. Current CAP Enrollment vs. CAP Enrollment if at Food Stamp Enrollment Rate
(High Poverty School Districts Served by UGI Electric—Luzerne County)

School District	Actual Current CAP	CAP if at Food Stamp Rate	Additional CAP
Hanover	366	907	541
Nanticoke	642	1,381	739
Northwest Area	177	580	403
Wyoming Area	112	426	314
Wyoming Valley West	1,624	3,968	2,344

It would be unreasonable for UGI Electric to assume that a household would be sufficiently in need of, and sufficiently interested in, assistance to the point that they would apply for both Food Stamps for their family and subsidized school meals for their children, but would actively decline to apply for, and participate in, the UGI Electric energy assistance program if given the opportunity to do so. Substantial partnerships exist for UGI Electric to pursue, which it is not pursuing at this point, to make CAP participation more widely available in its service territory.

Q. WHY IS THE ENROLLMENT OF INCOME-ELIGIBLE CUSTOMERS IN CAP AN APPROPRIATE ISSUE TO CONSIDER IN THIS UGI ELECTRIC RATE CASE?

A. Whether UGI Electric is adequately and appropriately enrolling low-income customers in CAP is not simply a universal service issue to be considered in UGI's proceeding considering its USECP. The under-enrollment of low-income customers in CAP presents rate issues as well. As I explained in detail above, confirmed low-income customers experience a greater breadth of arrears than do residential customers as a whole. Moreover, low-income customers experience a greater depth of arrears as well. Not only are more low-income customers in arrears, in other words, but they are deeper in arrears as well. One result of these payment patterns is that low-income customers have service disconnected at a higher rate than do residential customers as a whole. Once disconnected, a smaller percentage of low-income customers have service reconnected. A further result is that low-income customers impose greater uncollectible costs, and higher collection costs than do residential customers as a whole.[26] Improving enrollment in CAP is a positive response to these factors that tend to increase rates to residential customers. CAP enrollment improves payment patterns for participating low-income customers. As a result, improving enrollment in CAP will help decrease expenses and improve revenues.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that UGI Electric be directed to develop a Public Partnership Outreach Plan (PPOP) seeking to accomplish three objectives: (1) identify confirmed low-income customers; (2) enroll income-eligible customers in CAP; and (3) identify customers who

[26] BCS Annual Reports on Collections Performance and Universal Service Programs, available at: https://www.puc.pa.gov/filing-resources/reports/universal-service-reports/ (last accessed on April 20, 2021).

income-qualify for winter shutoff protections. This PPOP should consist of the following four steps:

- Identification of public assistance programs which have income-eligibility guidelines at or below the income-eligibility guidelines for being deemed a confirmed low-income customer; being income-eligible for CAP; or being income-eligible for winter shutoff protections.

- Contact by UGI Electric with the administrators of each program requesting that enrollment in each program include a specific and explicit request at the time of program application with respect to which a program applicant shall designate whether they wish UGI Electric to be informed of their income eligibility for various customer service protections propounded by the Pennsylvania PUC. Each household answering in the affirmative shall be identified by UGI Electric as either (or both) a Confirmed Low-Income customer and/or a customer eligible for winter shutoff protections;

- Affirmative outreach shall be directed to each customer identified in this fashion informing the customer of the availability of CAP, and explaining both the reduced bill aspects, and arrearage forgiveness aspects, of the CAP, along with corollary program responsibilities.

As a universal service outreach program, the costs of such outreach should be passed-through to ratepayers via the UGI Electric universal service rider.

PART 5. Proposed Changes to UGI Electric Tariffs.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I review one change that UGI Electric proposes to make to its residential tariff (regarding Rider C, the mechanism for recovering universal service costs). In addition, I examine the reasonableness of two existing tariff sections that merit modification. UGI Electric does not propose changes in the percentage offsets currently included in its Tariff. I accept that as being reasonable.

A. Universal Service Rider (participant count).

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. UGI Witness Epler (UGI Electric St. 8) proposes to modify the language of UGI Electric's Universal Service Rider to "set the number of CAP enrollees as of September 30, 2021" for purposes of calculating a cost-offset "to account for write-offs of bad debt that would arguably have occurred if not for CAP." (UGI Electric St. 8, at 10). According to Witness Epler, setting the CAP participant count in this fashion will "provide an enrollee figure that reflect[s] the actual ongoing impacts on CAP enrollment caused by the COVID-19 Pandemic." (Id.) She argues that setting the CAP participant count in this fashion "is consistent with the establishment of the CAP enrollee figure in the UGI Gas tariff in the last UGI Gas rate case at Docket No. R-2019-3015162." (Id., at 10 – 11).

While Witness Epler's observation about the proposal being "consistent with" the "establishment of the CAP enrollee figure" in the 2020 UGI Gas proceeding may be correct, it is incomplete. She fails to note that the process established in that UGI Gas proceeding was established by settlement. As the settlement itself notes, "The Settlement reflects a *carefully balanced compromise* of the interests of the Joint Petitioners, who represent a broad array of residential, commercial, industrial and other important customer interests." (Joint Petition for Approval of Unopposed Settlement of All Issues, at 7, Docket R-2019-3015162). (hereafter UGI Gas Joint Settlement Petition). (emphasis added).

Q. WERE THERE OTHER ASPECTS OF THAT SETTLEMENT THAT WOULD AFFECT THE COUNT OF CAP ENROLLEES?

A. Yes. Within the UGI Gas Joint Settlement Petition, other agreements that were reached included:

- That UGI Gas would "Conduct outreach to all customers for which UGI Gas has income documentation on file indicating the customer is confirmed low income and screen for CAP eligibility." (UGI Gas Joint Settlement Petition, at 10).

- That UGI Gas would "Conduct enhanced customer screening to determine CAP and LIHEAP eligibility and process related enrollments (enhancements include auto-enrollment in CAP for Non-CAP LIHEAP recipients and generation of pre-populated LIHEAP applications for Non-LIHEAP CAP customers). (iii) Suspend CAP recertification requirements for the duration of the PUC Emergency Order. When CAP recertification requirements resume, CAP customers whose recertification was due during the pendency of the PUC Emergency Order will recertify their income and be eligible for reinstatement using the same process as set forth in Paragraph 28(a), below, for the self-verifying CAP customers." (UGI Gas Joint Settlement Petition, at 10 – 11).[27] and

- That UGI Gas would: "Accept self-verification of income for new CAP enrollments or modification of CAP payment determinations for existing customers with income modifications for the duration of the PUC Emergency Order. Within 10 days of the expiration of the PUC Emergency Order, UGI will initiate a notice to CAP CBOs requiring them to recertify all self-verified CAP customers according to UGI's standard

[27] The referenced "Section 28(a) is the section discussed in the bullet immediately below.

> CAP recertification process to be completed in 110 days or less. If a participant does not submit income documentation within UGI's standard 90-day CAP recertification process, they will be removed from CAP. Any such customer will not be subject to a stay-out of the CAP and will be reinstated into the program without upfront payment if they submit the required income documentation within 6 months of their CAP removal date. Upon reinstatement into CAP, the customer will have all arrearage accrued while not enrolled in CAP reclassified as pre-program arrearage These modified reinstatement rules shall be applicable only to the identified 6 month period following a customer's removal pursuant to the foregoing and are not a permanent change to the Company CAP program terms and conditions." (UGI Gas Joint Settlement Petition, at 11 – 12).

When, in other words, Witness Epler makes the statement that the UGI Gas Joint Settlement in the Company's 2020 rate proceeding set the CAP enrollee count at the September 2020 level to "reflect the actual ongoing impacts on CAP enrollment caused by the COVID-19 Pandemic," it is not merely the fact that more residential customers might qualify for CAP because of the economic disruption caused by COVID-19, but also the fact that UGI Gas ***agreed*** to undertake specific action steps in response to the COVID-19 economic crisis which accompanied the COVID-19 health emergency, which steps might have the impact of increasing CAP enrollment.

Q. HOW DO THESE OTHER ASPECTS OF THE UGI GAS SETTLEMENT RELATE TO THE CIRCUMSTANCES NOW FACING UGI ELECTRIC?

A. For all the reasons I outlined in Part 1 of my testimony, the economic crisis facing UGI Electric customers not only prevails today, but that economic crisis is likely to continue for the foreseeable future. Based on that continuing economic crisis, I recommended an ongoing COVID-19 emergency response program for UGI Electric in Part 1 of my testimony. That ongoing program is largely based on principles established in the UGI proposal to the PUC in Docket R-2021-3023839. If one does *not* adopt the ongoing COVID-19 emergency response program that might give rise to an increase in CAP enrollment as I recommend, no reason exists to also adopt the agreement to base the CAP enrollee count for purposes of the universal service rider on a future CAP enrollment. One cannot, in other words, adopt the agreement to use a future CAP enrollee count without also adopting the emergency provisions which make the agreement to use that future enrollee count reasonable.

Q. IN THE ABSENCE OF ADOPTING THE COVID-19 EMERGENCY RESPONSE PROGRAM, WHAT CAP ENROLLMENT COUNT SHOULD BE ADOPTED FOR UGI ELECTRIC?

A. In the absence of the adoption of a COVID-19 Emergency Response Program that corresponds to that which I propose in Part 1, which, in turn, is closely based on principles agreed to in the UGI Gas Joint Petition Settlement, the UGI Electric tariff should modify the CAP enrollee count in its universal service rider (i.e., Rider C) to reflect the year-end CAP enrollment for the historic test year. The year-end CAP enrollment, for the historic test year ending September 2020, was 3,231 participants (OCA-IV-51(a)). Rider C should be modified to substitute 3,231 for the count of 2,448 participants that currently exists in Rider C.

B. Winter Moratorium Income Verification.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. The purpose of this section of my testimony is to review Section 14-c of UGI Electric's tariff to determine whether it reasonably implements the Commission's regulation on winter shutoff restrictions. The Commission's regulation provides in relevant part that "unless otherwise authorized by the Commission, during the period of December 1 through March 31, an electric distribution utility. . .may not terminate service to customers with household incomes at or below 250% of the Federal poverty level." (Section 56.100(b)).

The UGI Electric tariff provision (Rule 14-c) purporting to implement this regulation provides as follows:

> Income Verification. 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.

Q. DO YOU HAVE ANY OVERARCHING OBSERVATION ABOUT THE PUC REGULATION ON WINTER RESTRICTIONS?

A. Yes. In implementing this PUC regulation, UGI Electric need not learn the exact income of one of its customers in order to know that the customer should be protected by the PUC's winter shutoff restrictions. Unlike CAP, for example, where the exact income level is an input into calculating a bill, the winter restriction is a yes/no toggle. A customer is either eligible for protection or the customer is not eligible. It matters not for Section 56.100, for example, if a customer has income equal to 249% of Poverty or 24% of Poverty. Under either circumstance, a customer is equally protected from winter shutoffs.

Q. WHY IS THAT IMPORTANT IN REVIEWING THE UGI ELECTRIC TARIFF PROVISION?

A. Given this observation, the limitations created by the UGI Electric tariff present problems. UGI Electric, for example, accepts income documentation from the Department of Public Welfare (DPW) –DPW has been renamed the Department of Human Services and the tariff should be updated in that regard--but does not accept documentation from the Department of Health , which administers dollars from the U.S. Department of Agriculture for the Women, Infants and Children ("WIC") program. The Free and Reduced School Lunch Program is administered by local school districts (and the state Department of Education), and has income eligibility well below 250% of Poverty, but participation in the Free and Reduced School Lunch is not accepted as verification of income eligibility for the winter moratorium. Eligibility for free school meals is set at 130% of Poverty and below, while eligibility for reduced price school meals is set at 130% to 180% of Poverty. UGI Electric's tariff does not provide for a consideration of any of the 1,600 residents of subsidized housing in Luzerne County who live with income less than 30% of area median income, since subsidized housing is not administered by DPW/DHS. The Center for Disease Control's Unintentional Injury prevention program, targets households with members over age 65 and with children under age 5, using programs such as WIC and Head Start. My objective here is not to list every public assistance program with income eligibility that would establish eligibility for Pennsylvania's winter shutoff protections. My objective is instead to note not only that the UGI Electric tariff is out-of-date (referencing DPW rather than DHS), but also to note that the UGI Electric tariff is unreasonably limited in the documentation that it states it will accept to establish eligibility for the PUC's winter shutoff protections.

The exclusion of certain documentation by UGI Electric's tariff is problematic as well. For example, UGI Electric reports that in 2020, more than 1,000 customers received LIHEAP. But the UGI Electric tariff does not specifically identify LIHEAP participation as an accepted verification of income for purposes of the winter shutoff protections. Instead, the tariff requires "a verification letter from DPW of any approved cash or crisis grant applicable to the current heating season." (UGI Electric Tariff, Section 14-c). I recognize that UGI Electric would not have internal records for LIHEAP grants provided to energy suppliers other than the Company. Nonetheless, given that many Pennsylvania LIHEAP payments ***are*** made directly to UGI Electric, it is not clear why the Company could not identify those LIHEAP recipients by reference to its own customer information system, but would instead require, pursuant to its existing tariff language, "a verification letter from DPW of any approved cash. . .grant applicable to the current heating season."

Moreover, under the UGI Electric tariff, if a customer receives a "crisis" grant (e.g., through LIHEAP), that grant must be again be supported by a "verification letter from DPW." The receipt of hardship grants, often administered by private entities, is not accepted as a verification of income. No provision is made within the tariff of accepting an income verification from a community-based organization such as a Community Action Agency ("CAA"), even though the UGI's currently effective Universal Service and Energy Conservation Plan (USECP) states that UGI heavily relies on such community-based organizations to help administer its universal service programs. (UGI USECP, December 2019, at Appendix C and Appendix D).

Q. ARE THERE OTHER WAYS IN WHICH THE UGI ELECTRIC TARIFF IMPLEMENTING WINTER SHUTOFF RESTRICTIONS HAS PROBLEMS?

A. Yes. The UGI Electric tariff says that it will accept the ***previous year's*** income tax statement; references to a W-2 form or a "filed" 1099 form, as income tax documents, also focus on income from the previous tax year. However, if someone wants to establish eligibility through their receipt of "any approved cash or crisis grant," that grant must be "applicable to the current heating season." If a customer needs to access a crisis grant to avoid an eviction --it is important to note that not all "crisis grants" are LIHEAP Crisis grants (for example, there can be emergency rent relief through the Pennsylvania Housing Finance Agency or through the Pennsylvania Homeless Assistance Program)-- they must avoid needing that grant in September, and they must be sure to apply to a DHS program, because the requirement in the UGI Electric tariff is that the "crisis grant" must be "applicable to the current heating season" and must also be supported by "a verification letter from DPW. . ."

Q. IS THE UGI ELECTRIC TARIFF INCONSISTENT WITH ANY OTHER UGI PRACTICE?

A. Yes. UGI Electric reports that in 2020, it had an average of 9,021 "confirmed low-income customers," while in 2021 (YTD), it had 8,958 "confirmed low-income" customers. (OCA-IV-53). While a "confirmed low-income" customer must reasonably be expected to have income at or below 150% of Poverty, the UGI Electric tariff does not identify "confirmed low-income" status as a way to establish eligibility for the winter shutoff protections applicable to customers with income below 250% of Poverty.

Q. IS THERE ANY FINAL UNREASONABLE AMBIGUITY IN THE UGI ELECTRIC WINTER SHUTOFF PROTECTION TARIFF?

A. Yes. The UGI Electric tariff is silent on the time period that can be used to establish income eligibility for the PUC's winter shutoff restrictions. As discussed above, the tariff's reference to "previous year's income tax forms," to a "filed" 1099 form, or to a W-2 form, all imply an examination of an ***annual*** income. However, the UGI Electric tariff also provides that a customer may use "recent" pay stubs, and provides further, that to the extent receipt of a "cash or crisis grant" is relied upon, that grant must be "applicable to the current heating season." No guidance is provided on the time period applicable to any of the other listed forms of income verification that UGI Electric will accept.

Q. WHAT DO YOU RECOMMEND?

A. UGI Electric should revise its Electric tariff regarding "income verification" underlying winter shutoff protections. UGI should accept income declarations that would be used to support the terms of deferred payment agreements. It should also accept any reasonable documentation, irrespective of the agency or entity providing such documentation (e.g., DHS, Department of Health, Department of Education, local Housing Authority, local Community Action Agency) that would reasonably establish that a customer is income-eligible for winter shutoff protections.

Finally, the UGI Electric tariff is silent on whose income will be used to establish eligibility for the winter shutoff protections. Consistent with Chapter 14's definition of household income, and consistent with UGI's own USECP, the UGI Electric tariff should make explicit that "UGI does not include income earned from an occupant under the age of 18, nor does it include income received for the benefit of a minor, in its calculation of household income." (UGI USECP, December 2019, at page 18).

C. Deposit Adjustment after Weatherization.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I examine the UGI Electric tariff provision regarding the establishment of the amount of residential cash security deposits to be used to guarantee payment of a customer bill. The tariff provision, set forth as Section 3-d of the UGI

Electric tariff, states in relevant part that "for Residential Applicants, the deposit shall not be more than one sixth of the Residential Applicant's estimated annual bill, with such estimated annual bill determined at the time the deposit is required. . .For Residential Customers, the amount of the cash deposit shall not be more than the estimated charges for service based on the Residential Customer's prior consumption for the period equal to one average billing period plus one average month, not to exceed two (2) months." This tariff provision is further limited by Section 1404(a.1) of the Public Utility Code (66 PA Con Stat § 1404(a.1)), which provides that ". . .no public utility may require a customer or applicant that is confirmed to be eligible for a customer assistance program to provide a cash deposit." [28]

Q. WHAT PUC REGULATION PERTAINS TO THE ESTABLISHMENT OF THE AMOUNT OF A CASH SECURITY DEPOSIT BY AN ELECTRIC UTILITY SUCH AS UGI ELECTRIC?

A. Section 56.51 of the PUC's customer service regulations provides that "[t]he amount of a cash deposit may be adjusted at the request of the customer <u>*or the public utility*</u> whenever the character or degree of the usage of the customer has materially changed or when it is clearly established that the character or degree of service will materially change in the immediate future." (emphasis added).

---

[28] While the statutory definition of a "customer assistance program" lists "universal service" generally, and "energy conservation" specifically, the definition then limits the scope of the statute to instances where the plan or program in "which customers make monthly payments based on household income and household size and under which customers must comply with certain responsibilities and restrictions in order to remain eligible for the program."

Note that this section is not at odds with the PUC regulation that the ***initial*** deposit amount should be set based on usage at the time of setting that deposit amount. Instead, the regulation provides for subsequent changes to the deposit amount. Moreover, note that this section does not provide for changes in a deposit based merely on changes in rates or weather. Rather, changes are appropriate "whenever the *character or degree of the usage* of the customer has *materially changed.* . ." (Section 56.51, emphasis added).

Q. DOES THE UGI ELECTRIC TARIFF ON CASH SECURITY DEPOSITS PROVIDE FOR THIS MODIFICATION OF CASH SECURITY DEPOSIT REQUESTED BY UGI ELECTRIC?

A. No. The UGI Electric tariff is silent as to the potential, either at the customer's request, or at the initiation of UGI Electric, to modify a customer's cash security deposit.

Q. ARE THERE SITUATIONS IN WHICH THE "CHARACTER OR DEGREE OF THE USAGE OF THE CUSTOMER" MIGHT BE EXPECTED TO "MATERIALLY CHANGE" AFTER A DEPOSIT HAS BEEN IMPOSED?

A. Yes. Even though being a small electric utility, UGI Electric operates a Low-Income Usage Reduction Program ("LIURP"). According to the USECP Plan that UGI Electric filed (along with the two UGI Gas divisions), UGI Electric completed 71 LIURP jobs per year from 2014 through 2016. (USECP, at 25). In addition, the USECP filed with the Commission estimated that it would have an annual participation level of 66 customers in its LIURP from 2020 through 2025. (USECP, at A-2). UGI Electric targets its LIURP toward very high usage electric customers. In its 2020-2025 USECP, UGI Electric stated that the minimum annual usage required to be eligible to receive LIURP services will be 12,788 kWh, 25% higher than average annual consumption. (USECP, at 27) . This high usage amount would also imply a high bill for purposes of UGI Electric imposing a deposit.

Given this high usage, it is probable that the LIURP investments will generate substantial usage reduction (and thus substantial bill reductions) for the participating customers. While UGI Electric does not, because of its size, file annual data reports with BCS, the UGI Gas data filed with BCS indicates that a portion of, but certainly not all, of its LIURP recipients in a given year also participate in CAP. Given, however, that CAP participation changes on a year-to-year basis, there is no effort to report which LIURP participants over time are also CAP participants. (OCA-IV-19).

It is not merely LIURP that would deliver usage reduction services to low-income customers. The federal Weatherization Assistance Program ("WAP") (operated through the Department of Energy) is also designed to make investments that would reduce low-income usage (and thus low-income bills).

In addition, according to the UGI Electric Energy Efficiency and Conservation Plan (EE&C Plan) filing (August 28, 2020), "UGI Electric developed and filed for approval to launch a new low-income program effective June 1, 2020. The program will cover the full cost of a direct installation of a heat pump water heater ("HPWH") and/or ENERGYSTAR smart thermostats for low-income customers who are not eligible for

LIURP due to usage and/or limited billing history." (EE&CP Report, at 3, August 28, 2020).

Finally, UGI reported in its EE&CP Report that:

> During Program Year 8, the EE&C portfolio included the following programs:
>
> 1. Appliance Rebate Program (Residential/Low Income Customers)
> 2. School Energy Education Program (Residential/Low Income Customers)
> 3. Energy Efficient Lighting Program (Residential/Low Income Customers)
> 4. Appliance Recycling Program (Residential/Low Income Customers)
> 5. CBO Marketing Program (Residential/Low Income Customers)
> 6. Custom Incentive Program (Commercial/Industrial/Governmental Customers).
>
> These six programs were designed to meet the goals and guidelines established in the Commission's Secretarial Letter. In PY8, UGI Electric designed and received approval for a seventh program, the Residential Low-Income Program, that delivers energy savings to low-income customers and will be launched in PY9. All the EE&C programs were voluntary and offered UGI Electric customers a wide range of energy efficiency and conservation measures to decrease electric consumption and, in turn, their annual energy costs.

As can be seen, there are any number of opportunities through which, either through UGI Electric investments or through federal investments, in usage reduction, the "character or degree of the usage of the customer" might be expected to "materially change" (in the words of the PUC regulation) after a cash security deposit has been collected from a customer. Nonetheless, as I note above, the UGI Electric tariff does not provide for a corresponding downward adjustment in a cash security deposit held by the utility based on this material change in the character or degree of usage.

Q. IS THERE REASON TO BELIEVE THAT USAGE REDUCTION INVESTMENTS WOULD REDUCE THE RISK OF NON-PAYMENT FROM A CUSTOMER HAVING RECEIVED SUCH INVESTMENTS?

A. Yes. According to the Penn State University (PSU) evaluation of LIURP's long-term impacts, prepared for the Commission in 2008, "thirty-seven percent of electric industry households reduce their arrearage" after receiving LIURP services (of households having arrears).[29] Moreover, the PSU study reported that:

> Various studies conclude that weatherization also improves payment behavior. LIURP records the number of full, partial, and missed payments for each household for both the pre- and post-period. Because these variables are optional, we have only limited data available for analyses. Although the average number of full payments made does not vary from the pre- to post-period, the percent of households with missed payments decreased and the average number of partial payments increased. (internal citations omitted).

(PSU, at 41). PSU reported that "By the end of the year following weatherization, 68 percent of the households have an energy bill arrearage, a decrease of 29 points. Further, there is also an increase in the percent of households with a credit on their energy bill during this period, from 106 households at the beginning of the pre-period to 2705 households by the end of the post-period." (Id., at 39).

As can be seen, the delivery of usage reduction services to low-income customers in particular can be expected not only to reduce their annual usage (and thus their annual bills), but can be expected to improve payment patterns as well.

---

[29] Penn State University (2008). Long-Term Study of Pennsylvania's Low Income Usage Reduction Program: Results of Analyses and Discussion, at 42.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that Section 3-d of the UGI Electric tariff, relating to the size of a customer cash security deposit, be modified to provide that no later than three months after the delivery of usage reduction services to a residential low-income customer, whether the delivery of such services are indicated by UGI Electric internal records or indicated by notice provided to UGI Electric by a customer or a weatherization provider, any cash security deposit held by the company be reduced by the expected percentage annual bill reduction resulting from the delivery of the usage reduction investment. Notification of the delivery of such services through a non-UGI Electric program shall be deemed to be a "request of the customer" for such a modification pursuant to the PUC regulation. Under the regulation, modifications based on internal recordkeeping of the utility need not be made by the customer, but can instead be made at the initiation of the utility.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

308029

Appendices

Roger Colton
Fisher, Sheehan & Colton
Public Finance and General Economics
Belmont, MA
*** ***

EDUCATION:

J.D. (Order of the Coif), University of Florida (1981)

M.A. (Regulatory Economics), McGregor School, Antioch University (1993)

B.A. Iowa State University (1975) (journalism, political science, speech)

PROFESSIONAL EXPERIENCE:

Fisher, Sheehan and Colton, Public Finance and General Economics: 1985 - present.

As a co-founder of this economics consulting partnership, Colton provides services in a variety of areas, including: regulatory economics, poverty law and economics, public benefits, fair housing, community development, energy efficiency, utility law and economics (energy, telecommunications, water/sewer), government budgeting, and planning and zoning.

Colton has testified in state and federal courts in the United States and Canada, as well as before regulatory and legislative bodies in more than three dozen states. He is particularly noted for creative program design and implementation within tight budget constraints.

PROFESSIONAL AFFILIATIONS:

Past Chair:	Belmont Zoning By-law Review Working Committee (climate change)
Member:	Board of Directors, Massachusetts Rivers Alliance
Columnist:	Belmont Citizen-Herald
Producer:	Belmont Media Center: BMC Podcast Network
Host:	Belmont Media Center: Belmont Journal
Member:	Belmont Town Meeting
Vice-chair:	Belmont Light General Manager Screening Committee
Past Chair:	Belmont Goes Solar
Coordinator:	BelmontBudget.org (Belmont's Community Budget Forum)
Coordinator:	Belmont Affordable Shelter Fund (BASF)
Past Chair:	Belmont Solar Initiative Oversight Committee
Past Member:	City of Detroit Blue Ribbon Panel on Water Affordability
Past Chair:	Belmont Energy Committee
Member:	Massachusetts Municipal Energy Group (Mass Municipal Association)

Past Chair:	Housing Work Group, Belmont (MA) Comprehensive Planning Process
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*.
Past Member:	ASHRAE Guidelines Committee, GPC-8, *Energy Cost Allocation of Comfort HVAC Systems for Multiple Occupancy Buildings*
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.

PROFESSIONAL ASSOCIATIONS:

National Association of Housing and Redevelopment Officials (NAHRO)
National Society of Newspaper Columnists (NSNC)
Association for Enterprise Opportunity (AEO)
Iowa State Bar Association
Energy Bar Association
Association for Institutional Thought (AFIT)
Association for Evolutionary Economics (AEE)
Society for the Study of Social Problems (SSSO)
Association for Social Economics

BOOKS

Colton, *et al.*, ***Access to Utility Service***, National Consumer Law Center: Boston (4th edition 2008).

Colton, *et al.*, ***Tenants' Rights to Utility Service***, National Consumer Law Center: Boston (1994).

Colton, ***The Regulation of Rural Electric Cooperatives***, National Consumer Law Center: Boston (1992).

BOOK CHAPTERS

Colton (2018). The equities of efficiency: distributing energy usage reduction dollars, Chapter in Energy Justice: US and International Perspectives (Edited by Raya Salter, Carmen Gonzalez and Elizabeth Ann Kronk Warner), Edward Elgar Publishing (London, England).

JOURNAL PUBLICATIONS

65 publications in industry and academic journals, primarily involving utility regulation and affordable housing. (list available upon request)

TECHNICAL REPORTS

200 technical reports for public-sector and private-sector clients (list available upon request)

JURISDICTIONS IN WHICH EXPERT WITNESS PROVIDED

1. Maine
2. New Hampshire
3. Vermont
4. Massachusetts
5. Massachusetts
6. Rhode Island
7. Connecticut
8. New Jersey
9. Maryland
10. Pennsylvania
11. Washington D.C.
12. Virginia
13. North Carolina
14. South Carolina
15. Florida (Federal Court)
16. Alabama
17. Mississippi
18. Tennessee
19. Kentucky
20. Ohio
21. Indiana
22. Michigan
23. Wisconsin
24. Illinois
25. Minnesota
26. Iowa
27. Missouri
28. Arkansas
29. Texas (Federal Court)
30. South Dakota
31. North Dakota
32. Montana
33. Colorado
34. New Mexico
35. Arizona
36. Utah
37. Idaho
38. Nevada
39. Washington
40. Oregon
41. California
42. Hawaii

Canadian Provinces

1. Nova Scotia
2. Ontario
3. Manitoba
4. British Columbia

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3023618
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 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).

DATED: May 3, 2021
*307973

Signature: ______________________
Roger D. Colton

Consultant Address: Fisher, Sheehan, & Colton
34 Warwick Road
Belmont, MA 02478

OCA STATEMENT NO. 5

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3023618
	:	
UGI Utilities, Inc. – Electric Division	:	

DIRECT TESTIMONY
OF
MORGAN N. DEANGELO

ON BEHALF OF
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MAY 3, 2021

<u>**TABLE OF CONTENTS**</u>

<u>Introduction:</u>

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

A. My name is Morgan N. DeAngelo. My business address is 555 Walnut Street, Forum Place, 5th Floor, Harrisburg, Pennsylvania 17101. I am currently employed as a Regulatory Analyst by the Pennsylvania Office of Consumer Advocate (OCA).

Q. Please describe your educational background and qualifications to provide testimony in this case.

A. I have a Master's degree in Business Administration and a Bachelor's degree in Finance from Wilkes University. My educational background and qualifications are described in Appendix A.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Office of Consumer Advocate.

<u>Purpose of Direct Testimony:</u>

Q. Please describe the purpose of your Direct Testimony.

A. The purpose of my Direct Testimony is to identify impacts the ongoing COVID-19 Pandemic has had, and continues to have, on Pennsylvania. I will go into detail regarding the statistical analysis of unemployment rates, what groups are affected most by the impacts and how these groups are affected. I will also discuss how the pandemic has affected small businesses in Pennsylvania, the retail and restaurant / food service industry and examine the Pennsylvania State Coincidence Index. With the on-going Pandemic, it is important to balance the interests of consumers and shareholders. The Pennsylvania Public Utility Commission (Commission) should consider the specific facts described in my testimony below, when reaching its decision as to any revenue increase in this matter.

<u>The Pandemic's Impact on People in Pennsylvania:</u>

Q. What is the current unemployment rate in Pennsylvania?

A. As the Commonwealth has been faced with the struggles of unemployment due to the COVID-19 Pandemic, the unemployment rate across Pennsylvania reached up to 16.2% just one year ago, in April 2020. Although that number has since decreased, the current unemployment rate remains much higher than before the pandemic, at 7.3%.[1] This rate has remained relatively steady since September 2020.[2]

Q. How does the unemployment rate in Pennsylvania compare to the overall United States unemployment rate?

A. Pennsylvania's unemployment rate of 7.3% remains higher than the United States' unemployment rate of 6.2%.

Q. What does the unemployment rate look like in UGI Utilities, Inc. – Electric Division (UGI Electric) Service Territories?

A. UGI Electric offers service in cities and townships throughout Luzerne and Wyoming counties. According to the PA Monthly Work Stats Report issued in February 2021,

---

1 The pre-pandemic unemployment rate in January 2020 was 4.8%.

2 https://www.bls.gov/eag/eag.pa.htm

Luzerne County fell into the ">8.1%" category at a 9.7% unemployment rate, while Wyoming County fell into the "6.6% - 7.6%" category at a 7.6% rate.[3] Both counties have unemployment rates higher than the state average. This data reflects the effects of the closures implemented to mitigate the spread of COVID-19.

Q. What is an At-Risk Account?

A. An At-Risk Account refers to customers who have not been submitting payments toward their utility bills, resulting in putting their accounts at risk for disconnections and shut offs.

Q. Please describe the At-Risk Accounts in regards to UGI Electric customers.

A. The Pennsylvania Public Utility Commission has requested all utility companies to comply with temporary, monthly reporting of at-risk customer accounts. The latest report for UGI Electric was received April 13, 2021, with data collected most recently from March 2021 and can be found at Docket No. M-2020-3019244. The data is broken down in categories showing the numbers for all residential customers, residential customers that are classified as low income, residential customers in the customer assistance program (CAP) and non-residential customers. Table 1 compares the total number of customers at risk for termination as of 3/31/20 and 3/31/21, as well as total aggregate dollars of arrears as of 3/31/20 and 3/31/21. There is still a significant number of customers at risk, despite the fact that the total number of customers at risk of termination decreases in all residential categories. In addition, Table 1 shows the dollars in arrears and the percent increase of average aggregate dollars of arrears per customer from March 2020 to March 2021. The

[3] https://www.workstats.dli.pa.gov/Documents/PAMW/PAMW.pdf

average amount each customer owes to UGI Electric is increasing as time goes on even though the number of residential customers at risk of termination is decreasing.

Table 1: **UGI-E**	Total Number of Customers at Risk for Termination as of **3/31/20**	Total Number of Customers at Risk for Termination as of **3/31/21**	Total Aggregate Dollars of Arrears as of **3/31/20**	Total Aggregate Dollars of Arrears as of **3/31/21**	% Increase of Average Aggregate Dollars of Arrears per Customer
Residential - All	6,242	6,051	$ 4,902,091	$ 6,416,947	35%
Residential - Low Income	2,378	2,140	$ 2,048,792	$ 1,980,863	7%
Residential - CAP	1,921	1,889	$ 1,628,450	$ 1,749,990	9%
Non-Residential	210	227	$ 70,572	$ 168,502	121%
Total	6,452	6,278	$ 4,972,663	$ 6,585,449	36%

Q. Has UGI Electric terminated any of its customers during the COVID-19 Pandemic?

A. Yes. Table 2 shows the total number of customers terminated from November 2020 up until March 2021. At this point, no low income or CAP customers have been terminated. However, the data shows increasing numbers of customer terminations in both residential and non-residential categories. These customers had their services disconnected for non-payment. Table 3 shows the total aggregate dollars owed by terminated customers with disconnected accounts. Customers with terminated accounts are still responsible for the dollars owed.

Table 2:	**Total Number of Customers Terminated**					
UGI-E	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Grand Total**
Residential - All	0	0	17	7	16	40
Residential - Low Income	0	0	0	0	0	0
Residential - CAP	0	0	0	0	0	0
Non-Residential	0	7	18	5	4	34
Total	0	7	35	12	20	74

Table 3:	Total Aggregate Dollars Terminated					
UGI-E	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Grand Total
Residential - All	-	-	$ 16,975	$ 4,585	$ 13,068	$ 34,628
Residential - Low Income	-	-	-	-	-	-
Residential - CAP	-	-	-	-	-	-
Non-Residential	-	$ 12,996	$ 16,593	$ 3,002	$ 2,186	$ 34,777
Total	-	$ 12,996	$ 33,568	$ 7,587	$ 15,254	$ 69,405

Q. Are these trends something you would expect to see?

A. Yes, given the economic circumstances of the pandemic and the moratorium on terminations, these trends are not surprising. Being that the UGI Electric service territory falls in areas with high unemployment rates, we can assume some at-risk customers are experiencing negative impacts from the current economic conditions, causing them to fall behind in utility payments.

Q. What is the Household Pulse Survey (Pulse Survey)?

A. The Household Pulse Survey is organized by the United States Census Bureau. It is an experimental project in which data is collected to discover the impacts of the COVID-19 Pandemic. The data is then organized by state to display how people are affected through different categories. Some categories, but not all, include employment status, food security, housing, educational disruption, etc. The data has been organized into three different phases running from (1) April 23, 2020 – June 2, 2020, (2) June 4, 2020 – July 21, 2020 and (3) August 19, 2020 – Present.

Q. Does the Pulse Survey show data for specific locations throughout Pennsylvania, i.e., the UGI Electric service division?

A. No, the data found in the Pulse Survey is collected from residents in Pennsylvania as a whole. However, we do know the unemployment rates for the specific counties UGI Electric services. Seeing that both Luzerne and Wyoming counties have unemployment rates higher than the state average, it is likely there are UGI Electric customers experiencing some of the hardships brought forth by the pandemic.

Q. Which phase is the following data from?

A. The following data is collected from Phase 3, Week 17 of the Pulse Survey from March 17, 2021 through March 29, 2021.[4] The data extrapolates trends using survey responses collected from a portion of Pennsylvania residents, 18 years of age and older.[5]

Q. Please list the select characteristics the Pulse survey categorizes responses by.

A. The characteristics used in the Pulse survey are: Age, Sex, Hispanic Origin and Race, Education, Martial Status, Household Size, Presence of Children Under 18 Years Old, Household Income and Used in the Last 7 Days to Meet Spending Needs.

---

[4] Phase 3, Week 17 was the most recent data at the time of writing.

[5] https://www.census.gov/programs-surveys/household-pulse-survey/data.html (All data collected from the US Census Household Pulse Survey can be found here) Last accessed 4/16/2021.

Q. From this data, who is experiencing the greatest impact from the COVID-19 Pandemic?

A. The data shows people ages 40-54, and those who identify as Hispanic or Latino, and two or more races (not Hispanic) are experiencing the greatest impact. Similarly, the lower a household's income, the greater the impact of the pandemic has on income loss. This is shown in Tables 4, 5 and 6 below and is directly from the Household Pulse Survey. However, the COVID-19 Pandemic impacts are not limited to these groups, and the effects can be felt throughout each of the other categories to an extent.

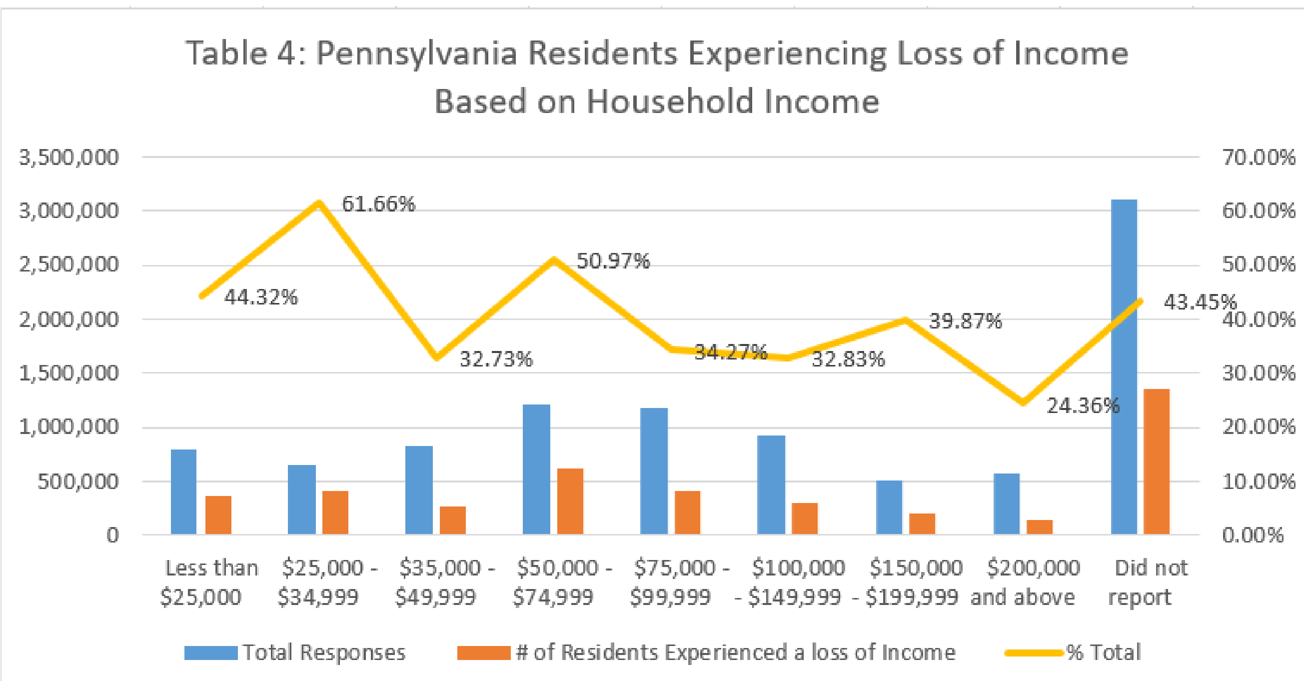


Table 4: Pennsylvania Residents Experiencing Loss of Income Based on Household Income

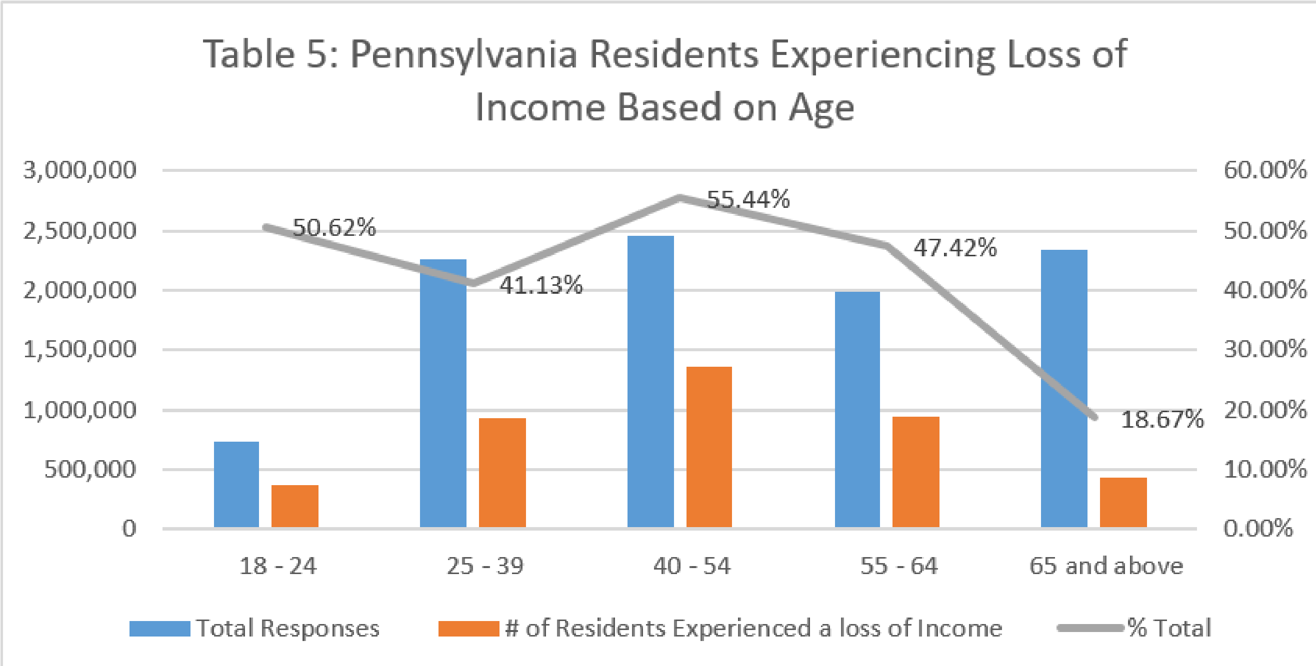


Table 5: Pennsylvania Residents Experiencing Loss of Income Based on Age
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
50.62%
41.13%
55.44%
47.42%
18.67%
18 - 24
25 - 39
40 - 54
55 - 64
65 and above
Total Responses
# of Residents Experienced a loss of Income
% Total

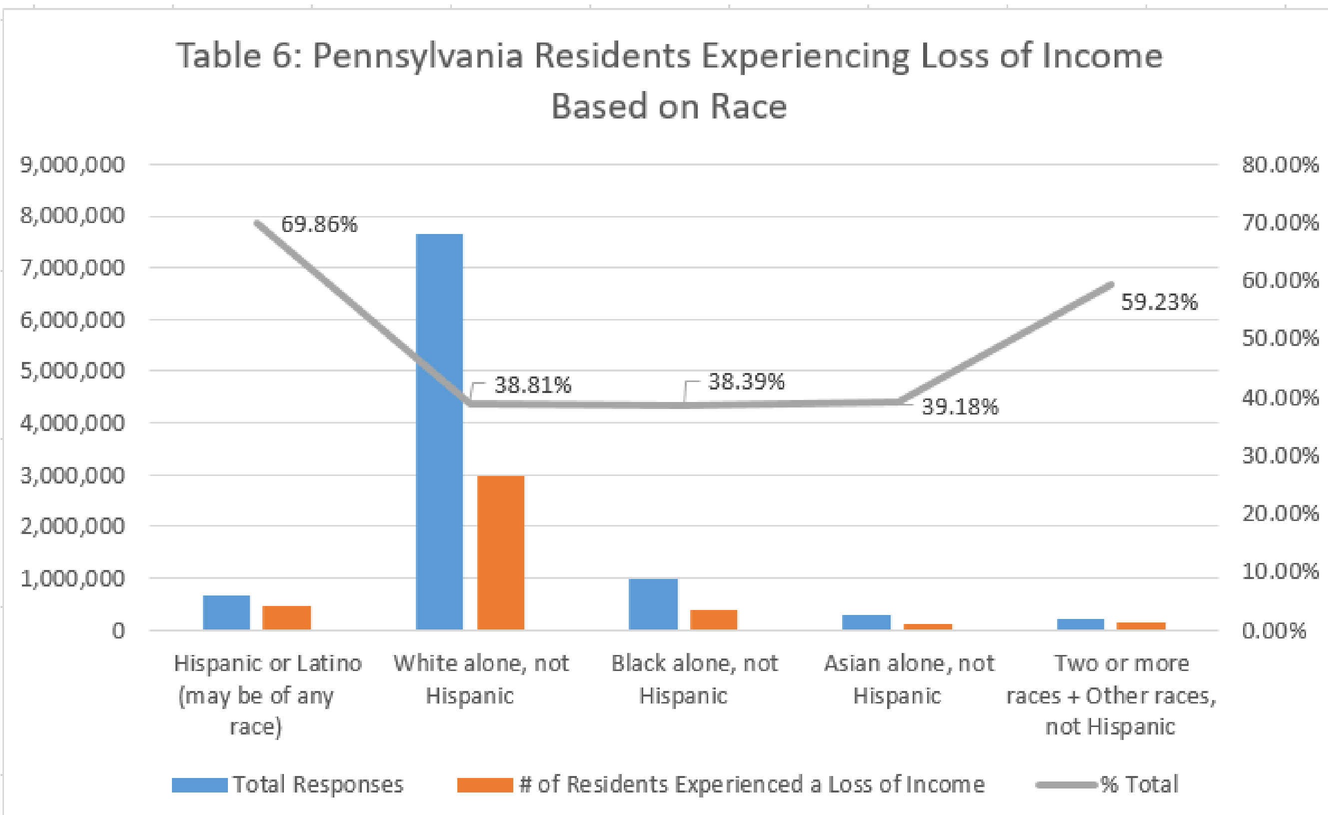


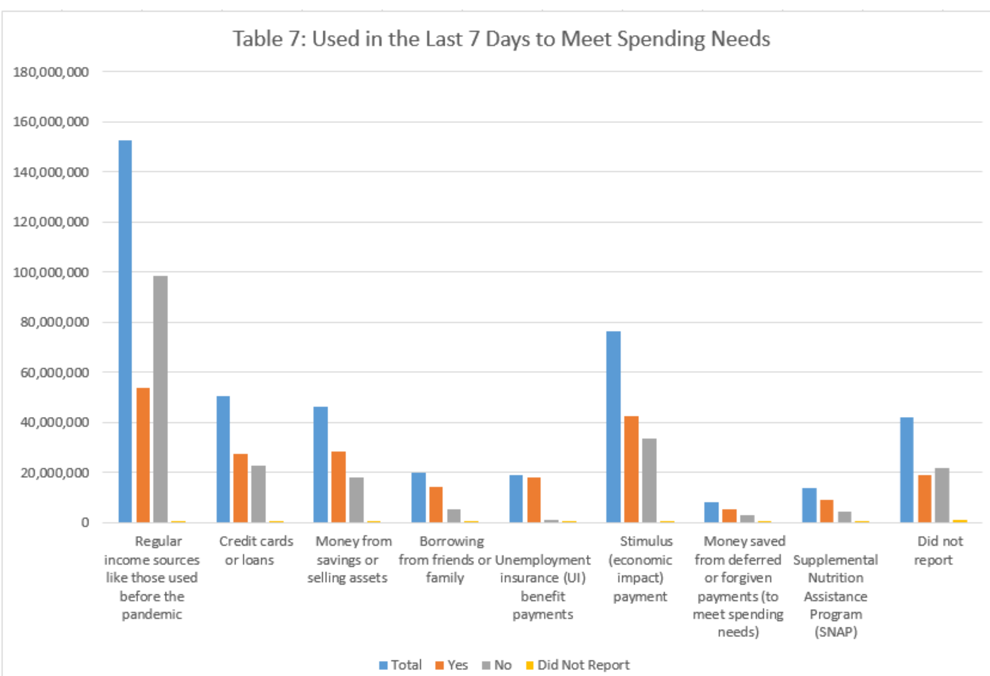
Table 6: Pennsylvania Residents Experiencing Loss of Income Based on Race
9,000,000
8,000,000
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
69.86%
38.81%
38.39%
39.18%
59.23%
Hispanic or Latino (may be of any race)
White alone, not Hispanic
Black alone, not Hispanic
Asian alone, not Hispanic
Two or more races + Other races, not Hispanic
Total Responses
# of Residents Experienced a Loss of Income
% Total

Q. What can you conclude about employment income in Pennsylvania?

A. The Week 27 survey results show that 41.3% of Pennsylvania residents experienced loss of employment income since March 13, 2020. Although we see improvement in these numbers each week, 16.8% of residents still expect a loss of employment income in the next 4 weeks, for either themselves or their households.

Q. What can you conclude about how Pennsylvania residents met their spending needs in the last seven days?

A. In the last 7 days, only 34.6% of Pennsylvanians reported they were able to meet their spending needs using regular income sources like those used before the COVID-19 Pandemic. As seen in Table 7 below, more than 50% of residents used other means of payment to meet their spending needs in each category, aside from those using regular income sources.



Of those that reported, 25.3% say they have had a little difficulty paying for household expenses, 17.4% have somewhat difficult time and 9.1% have a very difficult time due to the COVID-19 Pandemic. Furthermore, 11.7% of residents made changes to household spending on goods and services in the last seven days due to loss of income, while an additional 7% made changes after having concerns about being laid off or having reduced hours.

Q. How many Pennsylvania residents received a Stimulus payment in the last seven days?

A. 5.9 million or 63.6% received a Stimulus payment, while 3.3 million or 36.4% did not.

Q. How did those surveyed spend their Stimulus payment?

A. The most reported uses of the Stimulus payment was put toward food/groceries, paying down credit cards/loans and paying for utilities and telecommunications.

Q. How did those that put their payment toward utilities, utilize the funds?

A. Approximately 1.9 million put their payment toward utilities and telecommunication. 19.9% mostly spent it on utilities, 15% mostly saved it and 65.1% used it to pay off utility debt.

The Pandemic's Impact on Small Businesses in Pennsylvania:

Q. How has the COVID-19 Pandemic impacted small businesses in Pennsylvania?

A. The U.S. Census Bureau also surveyed small businesses starting in May 2020. The latest survey results were published on the Census website for April 5, 2021 – April 11, 2021. 29.1% of small businesses in Pennsylvania reported they have experienced a large negative effect due to the pandemic. This is 1.9% higher than the national average. 48.7% reported they have experienced a moderate negative effect, which is 5% higher than the national average. 37.3% of small businesses report that they will not return to normal business operations for more than 6 months, while 8.6% say they will never return to their normal level of operations.[6]

The Pandemic's Impact on Future Employment:

Q. Are there any future projections on employment?

A. Yes. There is still a lot of uncertainty for future employment over the next decade. The U.S. Bureau of Labor Statistics (BLS) published an article in February 2021 that projects employment from 2019-2029. When the COVID-19 Pandemic first started, many industries took a hit, causing their employment to decline, i.e. hotel, air transportation, food services. BLS uses the terms "moderate" and "strong" to describe the extent of long-term economic impacts on such industries in their article.

[6] https://portal.census.gov/pulse/data/#data

Q. What do the "moderate" and "strong" long-term economic impacts look like?

A. The moderate impacts are those brought on by teleworking, where the strong impacts are much more amplified. In the moderate case, the increased number of people teleworking results in less office space being used, less spending on the commute to and from work and less non-residential construction. However, we may see an increase in the need for informational technology (IT) and computer-related occupations, grocery store workers, medical researchers, etc. The strong impacts will be felt in industries such as retail, in-person services, entertainment, performing arts, and travel[7] as large group gatherings and being indoors is still a concern.

Q. Which industry is expected to have the largest employment loss?

A. The retail industry, including department stores, big box stores and brick and mortar stores, is expected to face the largest employment loss. The industry is projected to see a 4.4%-7.2% decrease between now and 2029.[8] In other words, the industry is expected to suffer a loss of another 90,000 jobs. For example, fewer cashiers are needed with the customer's ability to complete transactions using smart phone applications and self-service kiosks. In addition, there has been a decrease in foot traffic as teleworking and e-commerce become more popular. The food and beverage sector of the retail industry however, is expected to see an increase in employment.

[7] Lindsey Ice, Michael J. Rieley, and Samuel Rinde, "Employment projections in a pandemic environment," *Monthly Labor Review*, U.S. Bureau of Labor Statistics, February 2021, https://doi.org/10.21916/mlr.2021.3.

[8] Lindsey Ice, Michael J. Rieley, and Samuel Rinde, "Employment projections in a pandemic environment," *Monthly Labor Review*, U.S. Bureau of Labor Statistics, February 2021, https://doi.org/10.21916/mlr.2021.3.

Q. How has the restaurant / food service industry been affected in Pennsylvania?

A. The Pennsylvania Restaurant and Lodging Association released a COVID-19 Restaurant Impact Survey for April 1-14, 2021. In this survey, it was found that sales are 30% below normal levels, while 31% of respondents said they expect sales to remain like this and 21% said they expect their sales to decrease even more over the next 3 months. The survey also found that 53% of respondents said their staffing levels are 20% below normal. Additionally, 80% of respondents said their profit margin is lower than it was pre COVID-19 Pandemic.[9]

Q. What can be concluded about future employment?

A. As places are beginning to increase their operational capacity, the long-term impacts employment will face are still unknown. Consumer spending behaviors and workplace structure will be key factors in how future employment looks.

<u>Pennsylvania State Coincident Index:</u>

Q. What is the State Coincident Index?

A. The State Coincident Index is published monthly by the Federal Reserve Bank of Philadelphia. "The Coincident Indexes combine four state-level indicators to summarize current economic conditions in a single statistic, such as (1) nonfarm payroll employment, (2) average hours worked in manufacturing by production workers, (3) the unemployment rate and (4) wage and salary disbursements deflated by the consumer

[9] https://www.prla.org/coronavirus.html

price index (U.S. city average). The trend for each state's index is set to the trend of its gross domestic product (GDP), so long-term growth in the state's index matches long-term growth in its GDP."[10] The index is set so that the level of economic activity in 2007 is equal to 100. A rise in the index shows economic activity is expanding and a decline indicates a contraction in economic activity.

Q. What can you conclude about the Pennsylvania Coincident Index?

A. The Pennsylvania State Coincident Index for February 2021 was released on April 9, 2021. Since November 2020, the coincident index for Pennsylvania rose 1.1% to 113.3. The level of payroll employment increased over the past three months but remained lower than that of February 2020. The unemployment rate increased from November 2020 to February 2021 and remains higher than the pre-pandemic level. Although the index has recovered from the plunge it took in April 2020 to an 89.5, the February 2021 index still remains 6.9% lower than 12 months prior.

<u>Conclusion:</u>

Q. What is the overall impact of the COVID-19 Pandemic on people in Pennsylvania?

A. Over the last 13 months, Pennsylvania, along with the rest of the world has faced many different hardships due to the COVID-19 Pandemic. The impacts continue to affect Pennsylvania residents, as we can see in the Household Pulse surveys, small business

[10] https://www.philadelphiafed.org/surveys-and-data/regional-economic-analysis/state-coincident-indexes

surveys and the State Coincident Index. Numbers still remain significantly higher than before the Pandemic, causing long-term impacts to be faced in the months to come.

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

A. Yes, it does. I reserve the right to modify or supplement my testimony if necessary.

307302

Appendix A

QUALIFICATIONS OF
MORGAN N. DEANGELO

Education:

2020 M.B.A., Wilkes University

2018 B.B.A. Finance, Wilkes University

Positions:

June 2020 – Present	Regulatory Analyst, Pennsylvania Office of Consumer Advocate
2018 – 2020	Graduate Assistant, Office of Student Development, Wilkes University

Experience:

I am currently employed by the Pennsylvania Office of Attorney General, Office of Consumer Advocate (OCA) as a Regulatory Analyst. In this position, my responsibilities of reviewing utility company filings with the Pennsylvania Public Utility Commission (PA PUC) and analyzing the financial, economic, rate of return, and policy issues that are relevant to the filings. Additionally, I am tasked with preparing recommendations for the OCA's involvement in utility filings with the PA PUC, writing testimony and presenting oral testimony on behalf of the OCA.

Relevant Training:

IPU Accounting and Ratemaking Course, August 2020

Previous Cases where testimony was submitted:

P-2020-3020914	Twin Lakes Utilities, Inc.
A-2020-3019634	Borough of Royersford

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3023618
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Morgan N. DeAngelo, hereby state that the facts set forth in my Direct Testimony, OCA Statement 5, are true and correct (or are true and correct to the best of my knowledge, information, and belief) 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).

DATED: May 3, 2021
*307974

Signature: Morgan N. DeAngelo
Morgan N. DeAngelo

Consultant Address: Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923

OCA STATEMENT NO. 3-R

BEFORE
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3023618
	)	
UGI Utilities, Inc. – Electric Division	)	

REBUTTAL TESTIMONY
OF
JEROME D. MIERZWA

ON BEHALF OF
THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

MAY 27, 2021

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Jerome D. Mierzwa. I am a Principal at and the President of Exeter Associates, Inc. ("Exeter"). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY IN THIS PROCEEDING?

A. Yes. My Direct Testimony was filled as OCA Statement No. 3 on May 3, 2021

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to certain aspects of the Direct Testimony of Mr. Robert D. Knecht presented on behalf of the Office of Small Business Advocate ("OSBA") which addressed the allocated cost of service study ("ACOSS") and rate design proposals presented by UGI Utilities, Inc. – Electric Division ("UGI") in this proceeding.

Q. THE ACOSS PRESENTED BY UGI UTILIZES A 'MINIMUM SYSTEM" APPROACH TO CLASSIFY FUNCTIONALIZED UPSTREAM PRIMARY AND SECONDARY DISTRIBUTION FACILITIES AS EITHER DEMAND-RELATED OR CUSTOMER-RELATED. IN YOUR DIRECT TESTIMONY DID YOU AGREE THAT UPSTREAM DISTRIBUTION FACILITIES SHOULD BE CLASSIFIED AS EITHER DEMAND-RELATED OR CUSTOMER-RELATED?

A. No. For a number of reasons which I describe in detail in my Direct Testimony, upstream primary and secondary distribution plant and the associated costs should be classified as

100 percent demand-related. Nevertheless, in my Direct Testimony I recognized that this Commission has previously accepted the minimum system approach and the classification of upstream distribution facilities as partially demand-related and partially customer-related. In response, in my Direct Testimony, I presented an alternative recommendation that adjusted the allocation of minimum system determined demand-related costs to account for the peak load carrying capability ("PLCC") of the minimum system.

Q. DID MR. KNECHT ACCEPT THE COMPANY'S MINIMUM SYSTEM ANALYSIS AND RESULTING DEMAND-RELATED AND CUSTOMER-RELATED CLASSIFICATIONS OF FUNCTIONALIZED UPSTREAM PRIMARY AND SECONDARY DISTRIBUTION FACILITY COSTS?

A. No. Mr. Knecht raised concerns with respect to the Company's minimum system analysis. More specifically, he raised concerns with the functionalization and classification of the following upstream distribution plant items and presented modifications to the Company's analysis:

- Poles;
- Overhead Conductors:
- Underground Conductors:
- Overhead Transformers; and
- Underground Transformers.

In raising these concerns, Mr. Knecht indicated his analysis was preliminary, pending clarification from the Company in its Rebuttal Testimony. As such, I will defer addressing the concerns raised by Mr. Knecht until I have also reviewed the Company's Rebuttal Testimony.

Q. WERE THERE OTHER CONCERNS RAISED BY MR. KNECHT CONCERNING THE COMPANY'S ACOSS?

A. Yes. According to Mr. Knecht, the Company's ACOSS utilizes 12-month averages of each class' monthly non-coincident peak ("12 NCP") demand to allocate the demand component of upstream primary and secondary distribution plant. Mr. Knecht recommends that upstream distribution plant be allocated based on the annual NCP peak ("1 NCP") demand of each class. Mr. Knecht also: (1) proposed to modify the allocation of the costs associated with the Company's proposed battery storage project and the electric vehicle ("EV") charging initiative; (2) adjusted the allocation of customer deposits; (3) adjusted the revenues in the ACOSS to match the Company's proof of revenues; and (4) corrected an inadvertent transposition error in the depreciation values for Accounts 371 and 371.5.

Q. DO YOU AGREE WITH MR. KNECHT THAT THE DEMAND COMPONENT OF UPSTREAM DISTRIBUTION FACILITY COSTS SHOULD BE ALLOCATED BASED ON 1 NCP RATHER THAN 12 NCP DEMANDS?

A. No. However, as with the other preliminary modifications proposed by Mr. Knecht, I will address this proposal after review of the Company's Rebuttal Testimony. Initially I would note that UGI is both a summer and winter peaking utility. As such, it would not be unreasonable to use a 12 NCP allocation factor to smooth out year to year allocations that may otherwise fluctuate depending on whether peak demands occurred in the summer or winter.

Q. DO YOU AGREE WITH MR. KNECHT'S CHANGES TO THE ALLOCATION OF BATTERY STORAGE PROJECT COSTS, EV CHARGING STATION COSTS, CUSTOMER DEPOSITS, DISTRIBUTION REVENUES, AND DEPRECIATION VALUES?

A. OCA witness Mr. Lafayette K. Morgan, Jr has recommended that the costs associated with the Company's EV charging initiative be removed from the costs of service, and in my Direct Testimony I found that the Company has not adequately demonstrated that any portion of the costs associated with the battery storage project should be included in the cost of service. If the Commission does not accept these recommendations, Mr. Knecht's proposed modifications to the allocation of these costs appear reasonable. I agree with Mr. Knecht's proposed changes concerning customer deposits, distribution revenues, and depreciation values.

Q. DESPITE ALL OF THE CHANGES TO THE COMPANY'S ACOSS PROPOSED BY MR. KNECHT, IN THE END MR. KNECHT INDICATES THAT HE HAS NO MATERIAL DISAGREEMENT WITH THE COMPANY'S PROPOSED DISTRIBUTION OF THE REVENUE INCREASE REQUESTED BY THE COMPANY WHICH IS BASED ON THE RESULTS OF THE COMPANY'S ACOSS. WHAT IS YOUR RESPONSE?

A. For the reasons presented in my Direct Testimony, distribution of the revenue increase authorized by the Commission in this proceeding should be based on an ACOSS which provides for the classification of upstream primary and secondary upstream distribution plant as 100 percent demand-related. For the reasons also presented in my Direct Testimony, if the Commission does not accept the classification of upstream distribution plant as 100 percent demand-related, the revenue increase authorized in this proceeding should be based on an ACOSS which adjusts the allocation of demand-related costs to account for the PLCC of the minimum system.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3023618
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Jerome D. Mierzwa, hereby state that the facts above set forth in my Rebuttal Testimony, OCA Statement 3-R, 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).

DATED: May 27, 2021
*309776

Signature: ______________________
Jerome D. Mierzwa

Consultant Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044-3575

OCA Statement No. 1-SR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
	)	
v.	**)**	**Docket No. R-2021-3023618**
	)	
UGI Utilities, Inc. – Electric Division	**)**	

SURREBUTTAL TESTIMONY

OF

LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

June 10, 2021

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

TABLE OF CONTENTS

Introduction

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lafayette K. Morgan, Jr. My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland, 21044. I am a Public Utilities Consultant working with Exeter Associates, Inc. (Exeter). Exeter is a consulting firm specializing in issues pertaining to public utilities.

Q. ARE YOU THE SAME LAFAYETTE K. MORGAN, JR. WHO SUBMITTED PRE-FILED DIRECT TESTIMONY ON MAY 3, 2021 IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to address the issues discussed in the rebuttal testimonies of UGI Electric witnesses Brown, Anzaldo, Sorber, and Ressler, which were filed on May 27, 2021.

Q. ARE YOU INCLUDING UPDATED SCHEDULES SUMMARIZING THE OCA'S CURRENT REVENUE REQUIREMENT POSITION IN THIS PROCEEDING?

A. Yes. I have attached Surrebuttal Schedules LKM-1 to LKM-17 to this surrebuttal testimony which present the OCA's updated position after taking the Company's rebuttal position on certain issues into account.

Q. PLEASE SUMMARIZE THE OCA'S UPDATED RECOMMENDATION AS A RESULT OF THE CHANGES DISCUSSED IN THIS TESTIMONY.

A. In this testimony, I respond to UGI Electric witnesses' rebuttal testimonies on various adjustments I recommended in my direct testimony. I have considered the issues addressed in their rebuttal testimonies and, in some instances, I have modified my adjustments where necessary. As a result of these changes, if the Commission finds a revenue increase is warranted in this proceeding, my revised recommended total revenue requirement results in an increase in revenues of $4,986,000 instead of the $4,479,000 increase that I recommended in my direct testimony.

To the extent that the Company has rebutted my position on an issue that I challenged in my direct testimony, but I did not address in this surrebuttal testimony, it should not be construed that I am in agreement with the Company.

Q. DO THE OCA AND UGI ELECTRIC AGREE ON ANY OF THE ISSUES YOU RAISED IN YOUR DIRECT TESTIMONY?

A. Yes. There appears to be no difference between the OCA and the Company on the following issues:

- **FICA Tax**. In my direct testimony, I made an adjustment to correct an error identified by the Company in its response to discovery question I&E-RE-15-D. The Company has now corrected the error in its rebuttal position.
- **State Unemployment Tax (SUTA)**. In my direct testimony, I made an adjustment to correct an error identified by the Company in its response to discovery question I&E-RE-17-D. The Company has now corrected the error in its rebuttal position.
- **Customer Deposits**. The Company has updated the period over which its average Customer Deposit balance is calculated to reflect the use of the 13-month average balance through April 2021. I have accepted that change.
- **Materials & Supplies**. The Company has updated the period over which its average Materials & Supplies balance is calculated to reflect the use of the 13-month average balance through April 2021. I have accepted that change.

- **UNITE ADC Project**. I have accepted the changes and updated information related to this project and no longer recommend its removal from rate base.
- **Postretirement Benefits Expense**. The Company revised its claim related to Postretirement Benefits Expense consistent with my adjustment to update for more recent information identified after the initial case was prepared.

Impact of the COVID-19 Pandemic

Q. COMPANY WITNESSES BROWN AND ANZALDO ARE CRITICAL OF YOUR TESTIMONY WITH RESPECT TO THE IMPACT OF THE COVID-19 PANDEMIC ON THE COMPANY'S FILED COST OF SERVICE. PLEASE RESPOND.

A. In my direct testimony, I explained my concerns about whether the projected data and assumptions contained in the Company's filing provide a fair or reasonable forecast of the Company's cost of service during the rate effective period, given the uncertainty in the U.S. economy as a result of the COVID-19 pandemic. I stated my concerns about whether the forecasted/budgeted data can be relied upon as representative of normal operations.

Both witnesses have taken the point of my testimony out of context. For example, Mr. Brown claims I have indicated "that none of the Company's budget assumptions can be relied upon because the budget and planning for fiscal years 2021 and 2022 were created around the same time (Spring of 2020) as the start of the pandemic." I have made no claim that "none" of the Company's budgeting assumptions can be relied upon. Mr. Brown claims the discussion in my testimony was based on generalizations. Mr. Anzaldo admits that the budgeting decision were made in a vacuum. In his rebuttal testimony, he states: "[t]he Fiscal Year 2021 budget was prepared in the spring and summer of 2020. While this budget was prepared in the midst of the pandemic, it is important to note that the budget was prepared under assumed normal non-pandemic conditions."[1]

My testimony provided an overview of the impact of the COVID-19 pandemic on the U.S. economy and, by extension, the Company's service territory. I cited that the CARES Act, the largest stimulus package to ever be passed into law, was passed during the time the budget was being prepared. I cited that unemployment surged in April 2020 to 14.7 percent from 4.4 percent in March 2020, again, during the time the budget was prepared. I also cited significant changes in the National Association of Home Builders' ("NAHB") Housing Market Index ("HMI") because it clearly shows the type of volatility at the time the budgets were being prepared, which one would expect to affect planning and budgeting.

I do not believe that it is reasonable to assume a budget prepared under the assumption of business as usual is realistic amidst the changes and uncertainty that have been experienced. The lack of any updates or revisions to the budget assumptions that underly the FPFTY should be reason for questioning the reasonableness of the cost of service. Therefore, the Commission should reject the Company's position on the accuracy of its budgets.

Asset Data Collection Project

Q. PLEASE RESPOND TO MS. RESSLER'S DISAGREEMENT WITH YOUR ADJUSTMENT TO REMOVE THE ASSET DATA COLLECTION PROJECT.

A. In my direct testimony, I stated my concerns with respect to this project. First, at the time my testimony was prepared, the information I had indicated the project had not

[1] Rebuttal Testimony of Mr. Anzaldo at page 9, lines 4-7.

been approved by the Company's Board of Directors. Second, I had doubts about the date on which the project will become used and useful.

The Company has provided additional information to show the approval of the project and detail of the cost changes. After additional consideration, I have decided to withdraw the adjustment.

EV Charging Stations

Q. MR. SORBER'S REBUTTAL TESTIMONY RESPONDS TO THE VARIOUS PARTIES' POSITION ON THE COMPANY-PROPOSED EV CHARGING STATION OWNERSHIP. PLEASE DISCUSS YOUR POSITION BASED ON THE ISSUES RAISED IN MR. SORBER'S REBUTTAL TESTIMONY.

A. In my direct testimony, I recommended that the Company's proposed ownership of EV charging stations not be authorized because I believe a regulated utility has certain competitive advantage over third party competitors. In Mr. Sorber's rebuttal testimony, he offers some clarification and modifications on the Company's proposal as he responds the various parties. I will respond to certain positions the Company has taken in response to other intervenors.

Q. PLEASE RESPOND TO MR. SORBER'S PROPOSAL TO FLOW BACK ALL REVENUE IT RECEIVES FROM THE PROPOSED CHARGING STATION.

A. Mr. Sorber states that UGI Electric proposes to flow back all net revenues it receives from its proposed EV charging stations. The Company proposes to accomplish this by establishing a regulatory liability that would track all revenues received from its ownership and operation of the EV charging stations and then flow back those revenues to ratepayers in the Company's future base rate cases.

From my perspective, this proposal does not resolve the concern that I have raised relating to the Company's ability to use the funds it collects from captive ratepayers to build and operate company-owned EV charging stations. It would still negatively affect the competitive market because it would open the door to unfair competition. Moreover, if authorized, this approach would guarantee the Company will recover the costs of owning and operating the EV charging stations because it proposes to flow back "net-revenue" which, by definition, is revenues less expenses. Therefore, the Commission should not accept this proposal.

Q. PLEASE COMMENT ON MR. SORBER'S RESPONSE TO RESA AND NRG'S EDUCATION CAMPAIGN PROPOSAL.

A. Mr. Sorber states that UGI Electric is not opposed to RESA and NRG's proposal of a coordinated education campaign in which the Company works directly with impacted stakeholders. However, he proposes to capture any incremental costs in a regulatory asset account for future recovery in utility rates. I disagree with this proposal. Captive ratepayers should not be responsible for these costs. To the extent that such costs are incurred, the stakeholders and the Company should absorb them. Not ratepayers. In fact, this position is consistent with RESA and NRG's witness Danita Park's direct testimony. On page 14, line 14 to 18, she states:

> UGI Electric's captive ratepayers should not bear the risk of utility investment in a market that is clearly competitive and benefiting from investment by numerous competitive companies, as noted above. The competitive market, and most importantly private shareholders, should take on the burden and risk of funding research and development of innovative products and services in this burgeoning market.

Therefore, the Commission should reject the proposal by the Company to capture education campaign costs as a regulatory asset for future recovery.

Q. IF THE COMPANY'S ELECTRIC VEHICLE PROPOSAL IS APPROVED, WHAT DO YOU RECOMMEND?

A. If the Company's EV proposal regarding the charging stations and make-ready infrastructure is approved, it should only be approved as a pilot program that requires the Company to seek Commission approval in future base rate cases if it seeks to continue to operate this program.

Rate Case Expense

Q. MR. ANZALDO DISAGREES WITH YOUR ADJUSTMENT TO NORMALIZE RATE CASE EXPENSE USING A 3-YEAR AVERAGE. PLEASE RESPOND.

A. In my direct testimony, I recommended an adjustment to normalize rate case expense using a 3-year average. I demonstrated that the average period between rate cases has been seven years to point out the unreasonableness of the Company's 2-year normalization period.

Mr. Anzaldo disagrees with my adjustment and argues that the Company's past history of rate case filing is not a way to determine the appropriate normalization period for rate case expense. Instead, in his direct testimony, he claims the Company will file another rate case in two years, so a 2-year period should be used.

The Commission should reject the proposed 2-year normalization because an assertion that in two years the Company will file another rate case is not a known and certain event on which to base the normalization period. The Commission examined this issue in the last rate case and determined that a 3-year period is a reasonable period for rate case expense normalization, and the Company has not provided any additional information that justifies a change from the Commission's 3-year normalization. Therefore, the Company's position should be rejected.

<u>Payroll Expense</u>

Q. PLEASE RESPOND TO MR. ANZALDO'S DISAGREEMENT WITH YOUR ADJUSTMENT TO PAYROLL EXPENSE.

A. In my direct testimony, I recommended a 2.5 percent increase be used to annualize non-exempt and exempt payroll. The 2.5 percent increase is based upon the most recent actual pay increase granted by UGI Electric to exempt and non-Exempt employees.

Mr. Anzaldo disagrees with my adjustment and states that the Company uses the <u>Conference Board Salary Increases Budget Survey</u> to help determine the target merit increase and salary structure change each year. He goes on to explain that The Conference Board is an independent, non-partisan, and non-profit think tank that provides insights and recommendations to businesses. Therefore, he presents the conference board's data to support the Company's claim.

The Commission should reject this claim because, as stated by Mr. Anzaldo, the Conference board data is simply a survey of what certain businesses expect the increase to be for labor costs. Based upon his description of the organization, in his rebuttal testimony, the survey results do not make up a binding corporate resolution to increase labor rates. The Conference Board is also not a consulting practice hired to provide professional advice on UGI Electric's salary rate increases. Therefore, it is not a valid support for the proposed 3.0 percent increase.

Uncollectible Expense

Q. PLEASE RESPOND TO MS. RESSLER'S DISAGREEMENT WITH YOUR ADJUSTMENT TO THE COVID-RELATED UNCOLLECTIBLE EXPENSE.

A. In my direct testimony, I recommended using a five-year period to normalize the uncollectible claim related to the COVID-related Regulatory Asset. Ms. Ressler criticizes my adjustment, stating that I provided no basis for suggesting a five-year recovery period for the regulatory asset associated with excess uncollectible expenses resulting from the COVID-19 pandemic, and that the selection of the five-year recovery period was arbitrary in order to artificially reduce the Company's claim.

Ms. Ressler's interpretation of my adjustment is not a fair assessment. The two directives related to the creation of the regulatory asset, the Commission's declaration of a moratorium on the termination of utility services in Docket No. M-2020-3019244 and the Commission's Secretarial Letter dated May 13, 2020, recognized the economic hardship faced by some customers. The directives appear to provide a reasonable means by which customers can continue to receive service during the difficult period, that the recovery of uncollectibles would not negatively impact the customers' ability to pay their utility bills, and the Company would also have a fair chance to recover the uncollectibles. The Company's accelerated recovery negates the positive measures provided in the directives and serves as a means to justify a higher rate increase. In other words, it is somewhat contradictory to provide relief for ratepayers only to recover the cost of providing the relief on an accelerated basis. Hence, Ms. Ressler's criticism of my adjustment is without merit. Therefore, the Commission should reject the Company's adjustment.

COVID-Related Regulatory Asset

Q. MS. RESSLER ALSO TAKES ISSUE WITH YOUR ADJUSTMENT TO DISALLOW RECOVERY OF THE COVID-RELATED REGULATORY ASSET. PLEASE RESPOND.

A. As I explained in my direct testimony, I do not recommend recovery of these costs because they do not appear to be incremental nor does the magnitude of these costs appear to be large enough to impact the financial viability of the Company.

In the Commission's Secretarial Letter dated May 13, 2020, the directive states that public utilities were to account for prudently incurred incremental extraordinary, nonrecurring expenses related to COVID-19. The costs UGI Electric claimed were:

- Lost Late Fees and other Miscellaneous Fees
- Incremental Salaries and Benefits
- Other Incremental Costs (e.g., PPEs, Vehicle Rentals, etc.)

First, the salaries and benefits described by the Company as incremental were salaries that would have been incurred regardless of the pandemic. These were costs that would have been captured as capital expenditures. Because of the two directives, the Company is attempting to treat these costs as incremental O&M expenses when those costs were already part of the cost of service. Simply stated, these are not new or incremental costs.

The remaining costs, Lost Late Fees and other Miscellaneous Fees and other incremental costs did not reach the threshold to be considered extraordinary. These costs are neither rare nor infrequent in their occurrence and the dollar value are not so large as to impact the ability of the Company to deliver safe and reliable service. Therefore, the Commission should not allow recovery of these costs.

Incentive Compensation

Q. PLEASE COMMENT ON MS. RESSLER'S DISAGREEMENT WITH YOUR ADJUSTMENT TO INCENTIVE COMPENSATION.

A. In my direct testimony, I stated that I am recommending an adjustment to remove these incentive compensation costs that are tied to earnings goals. I stated that because these types of incentive compensation are tied to increasing shareholder value, they are not properly recoverable from ratepayers. Instead, they should be absorbed by shareholders.

To bolster her testimony, Ms. Ressler states, in her rebuttal testimony, that I have not argued that UGI Electric's method of compensating its employees, as a whole, is unreasonable. Ms. Ressler is correct. However, she misses the point of my adjustment. The issue is whether ratepayers should bear the cost of obtaining benefits that go to shareholders. I believe they should not and recommend the Commission reject the Company's claim.

Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

310799

OCA Statement No. 1-SR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**Docket No. R-2021-3023618**
UGI Electric Utilities, Inc. - Electric Division	)	

SCHEDULES ACCOMPANYING THE SURREBUTTAL TESTIMONY

OF

LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

OFFICE OF CONSUMER ADVOCATE

PUBLIC VERSION

June 10, 2021

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

UGI Utilities, Inc. - Electric Division

Summary of Operating Income
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Company Amounts at Present Rates	OCA Adjustments	Amounts After OCA Adjustments	Pro Forma Change in Revenues	Amounts After Change in Revenues
	Operating Revenues					
1	Customer & Distribution Revenue	$ 34,216	$ -	$ 34,216	$ -	$ 34,216
2	Revenue - Cost of Purchased Power	51,819	-	51,819	-	51,819
3	Other Revenue	1,079	-	1,079	-	1,079
4	Revenue Increase	-	-	-	4,986	4,986
5	Total Operating Revenues	$ 87,114	$ -	$ 87,114	$ 4,986	$ 92,100
6						
7	Operating Revenue Deductions					
8	Other Power Supply Expenses	$ 41,603	$ -	$ 41,603	$ -	$ 41,603
9	Operating & Maintenance Expense	28,485	(1,076)	27,409	78	27,487
10	Depreciation & Amortization Expense	7,128	(124)	7,004	-	7,004
11	Taxes Other Than Income Taxes	5,909	(51)	5,858	313	6,171
12	Total Operating Revenue Deductions	$ 83,125	$ (1,251)	$ 81,874	$ 391	$ 82,265
13						
14	Operating Income Before Income Taxes	3,989	1,251	5,240	4,595	9,835
15						
16	Income Taxes	(10)	374	364	1,328	1,692
17						
18	Net Operating Income	$ 3,999	$ 877	$ 4,876	$ 3,267	$ 8,144
19						
20	Rate Base	$ 132,394		$ 130,511		$ 130,511
21						
22	Return On Rate Base	3.02%		3.74%		6.24%

UGI Utilities, Inc. - Electric Division

Summary of Revenue Increase at OCA Rate of Return
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description		Amount	Source
1	Adjusted Rate Base		$ 130,511	Schedule LKM-2, Page 2
2	Required Rate of Return		6.240%	
3				
4	Net Operating Income Required		$ 8,144	
5	Net Operating Income at Present Rates		4,876	Schedule LKM-1, Page 1
6				
7	Income Deficiency/(Surplus)		$ 3,268	
8	Revenue Multiplier		1.525733	
9				
10	Required Change in Company Revenue		$ 4,986	
11				
12	Proposed Revenue Change		$ 4,986	
13	Less: Uncollectibles	1.5570%	78	
14	Revenues After Uncollectibles		4,908	
15	Gross Receipts Tax	6.2700%	313	
16				
17	Income Before State Taxes		$ 4,595	
18	State Income Tax Effect Tax Rate	9.9900%		
19	Less: State Income Tax		459	
20				
21	Income Before Federal Taxes		$ 4,136	
22	Federal Income Tax	21.0000%	869	
23				
24	Net Income Surplus/(Deficiency)		$ 3,267	

UGI Utilities, Inc. - Electric Division

Summary of Rate Base
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount per Company Filing	OCA Rate Base Adjustments	Amount After OCA Adjustments
1	Utility Plant	$ 227,180	$ (1,800)	$ 225,380
2	Accumulated Depreciation	(74,829)	-	(74,829)
3	Net Plant in Service	$ 152,351	$ (1,800)	$ 150,551
4				
5	Working Capital	$ 7,718	$ (83)	$ 7,635
6	Accumulated Deferred Income Taxes	(28,088)	-	(28,088)
7	Customer Deposits	(1,062)	-	(1,062)
8	Materials & Supplies	1,475	-	1,475
9				
10	Total Rate Base	$ 132,394	$ (1,883)	$ 130,511

UGI Utilities, Inc. - Electric Division

Summary of Rate Base Adjustments
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.		Source	Amount
1	Rate Base per Company Filing	Schedule LKM-2, Page 1	$ 132,394
2			
3			
4	OCA Adjustments:		
5	Remove EV Charging Stations	Schedule LKM-4	$ (300)
6	Remove EAM Costs	Schedule LKM-5	-
7	Remove Battery Storage Cost	Schedule LKM-6	(1,500)
8	Update Materials& Supplies	Schedule LKM-7	-
9	Update Customer Deposits	Schedule LKM-8	-
10	Cash Working Capital	Schedule LKM-9	(83)
11			
12	Total Ratemaking Adjustments		$ (1,883)
13			
14	Adjusted Rate Base per OCA		$ 130,511

UGI Utilities, Inc. - Electric Division

Summary of Adjustments to Income Before Income Taxes
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.		Amount	Source
1	Operating Income per Company	$ 3,999	Surrebuttal Schedule LKM-1
2			
3	OCA Adjustments:		
4	Annualize Payroll	$ 88	
5	Remove Stock Based Incentive Compensation	176	
6	Annualize OPEB	-	
7	Normalize Rate Case Expense	118	
8	Normalize Uncollectibles	216	
9	Normalize Incremental COVID-Related Expenses	166	
10	Adjustment to Annualize Payroll Taxes	36	
11	Remove EV Charging Station	24	
12	Remove EAM Cost	-	
13	Remove Battery Storage Cost	64	
14	Interest Synchronization	(11)	
15	Total OCA Adjustments	877	
16			
17	Total OCA Adjustments	$ 4,876	

UGI Utilities, Inc. - Electric Division

Summary of Adjustments to Income Before Income Taxes
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.		Operating Revenues	O&M Expenses	Depreciation & Amortization	Taxes Other Than Income	Income Taxes	Operating Income Before Income Taxes
1	Amount per Company	$ 87,114	$ 70,088	$ 7,128	$ 5,909	$ (10)	$ 3,999
2							
3	OCA Adjustments:						
4	Annualize Payroll	$ -	$ (124)	$ -	$ -	$ 36	$ 88
5	Remove Stock Based Incentive Compensation	-	[redacted]	-	-	[redacted]	[redacted]
6	Annualize OPEB	-	-	-	-	-	-
7	Normalize Rate Case Expense	-	[redacted]	-	-	[redacted]	[redacted]
8	Normalize Uncollectibles	-	(304)	-	-	88	216
9	Normalize Incremental COVID-Related Expenses		(234)		-	68	166
10	Adjustment to Annualize Payroll Taxes		-	-	(51)	15	36
11	Remove EV Charging Station	-	-	(34)	-	10	24
12	Remove EAM Cost	-	-	-	-	-	-
13	Remove Battery Storage Cost	-	-	(90)	-	26	64
14	Interest Synchronization	-	-	-	-	11	(11)
15							
16	Total OCA Adjustments	$ -	$ (1,076)	$ (124)	$ (51)	$ 374	$ 877
17							
18	Total Adjusted Income Before Income Taxes	$ 87,114	$ 69,012	$ 7,004	$ 5,858	$ 364	$ 4,876

UGI Utilities, Inc. - Electric Division

Adjustment to Remove EV Charging Stations
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	**Rate Base**	
2	EV Charging Station Capital Costs	$ 300 [1/]
3		
4	Accumulated Depreciation	-
5		
6	Adjustment to Rate Base	$ (300)
7		
8	**Depreciation Expense**	
9	EV Charging Station Capital Costs	$ 300 [1/]
10		
11	Depreciation Rate	11.35%
12		
13	Adjustment to Depreciation Expenses	$ (34)

Notes:
[1/] UGI Filing Book VI, Schedule C, Page II-3.

UGI Utilities, Inc. - Electric Division

Adjustment to Remove Asset Data Collection (ADC) Costs
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	**Rate Base**	
2	ADC Capital Costs	$ - 1/
3		
4	Accumulated Depreciation	-
5		
6	Adjustment to Rate Base	$ -
7		
8	**Depreciation Expense**	
9	Adjustment to Depreciation Expenses	$ - 1/

Notes:
1/ Response to OCA-VIII-2.

UGI Utilities, Inc. - Electric Division

Adjustment to Remove Battery Storage Equipment
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount
1	**Rate Base**	
2	Battery Storage Equipment	$ 1,500 [1/]
3		
4	Accumulated Depreciation	
5		
6	Adjustment to Rate Base	$ (1,500)
7		
8	**Depreciation Expense**	
9	Battery Storage Equipment	$ 1,500 [1/]
10		
11	Depreciation Rate	6.01% [1/]
12		
13	Adjustment to Depreciation Expenses	$ (90)

Notes:
[1/] UGI Filing Book VI, Schedule C, Page II-3.

UGI Utilities, Inc. - Electric Division

Adjustment to 13-Month Average Materials & Supplies
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount	
1	13-Month Average Materials & Supplies per OCA	$ 1,475	1/
2			
3	13-Month Average Materials & Supplies per UGI	1,475	2/
4			
5			
6	Adjustment to Rate Base	$ 0	

Notes:
1/ Schedule LKM-6, Page 2.
2/ UGI Gas Exhibit A, Schedule C-8.

UGI Utilities, Inc. - Electric Division

Calculation of 13-Month Average Materials & Supplies Balances
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount [1/]
1	April, 2020	$ 1,520
2	May	1,300
3	June	1,255
4	July	1,210
5	August	1,258
6	September	1,217
7	October	1,351
8	November	1,750
9	December	1,745
10	January, 2021	1,693
11	February	1,690
12	March	1,598
13	April	1,590
14		
15	13-Month Average Materials & Supplies	$ 1,475

Notes:
1/ UGI Gas Exhibit A, Schedule C-8.

UGI Utilities, Inc. - Electric Division

Adjustment to 13-Month Average Customer Deposits
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount	
1	13-Month Average Customer Deposits per OCA	$ 1,062	1/
2			
3	13-Month Average Customer Deposits per UGI	1,062	2/
4			
5	Adjustment to Rate Base	$ (0)	
6			

Notes:
1/ Schedule LKM 7, Page 2.
2/ UGI Gas Exhibit A, Schedule C-7.

UGI Utilities, Inc. - Electric Division

Calculation of 13-Month Average Customer Deposits Balances
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description		Amount [1/]
1	April, 2020	$	1,154
2	May		1,140
3	June		1,120
4	July		1,102
5	August		1,082
6	September		1,070
7	October		1,068
8	November		1,069
9	December		1,041
10	January, 2021		1,021
11	February		1,005
12	March		982
13	April		947
14			
15	13-Month Average Customer Deposits	$	1,062

Notes:
1/ UGI Gas Exhibit A, Schedule C-7.

UGI Utilities, Inc. - Electric Division

Adjustment to Cash Working Capital
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No	Description	Amount per OCA	Amount per UGI	OCA Adjustment
1	Working Capital for O & M Expense	$ 5,661	$ 5,755	$ (94)
2	Interest Payments	(222)	(234)	12
3	Tax Payment Lag Calculations	174	175	(1)
4	Prepaid Expenses	1,962	1,962	(0)
5	Total Cash Working Capital Requirements	$ 7,575	$ 7,658	$ (83)

UGI Utilities, Inc. - Electric Division
Combined Operations
Summary of Working Capital
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No	Description	Test Year Expenses	OCA Adjustments	Test Year Expenses	Factor	Number of (Lead) / Lag Days	Totals
	WORKING CAPITAL REQUIREMENT						
1	Revenue Lag Days						59.98
2							
3	Expense Lag Days						
4	Payroll	$ 5,911	$ (124)	$ 5,787	12.00	$ 69,446	
5	Purchased Power Costs	41,179	-	41,179	30.63	1,261,313	
6	Other Expenses	20,752	(648)	20,104	30.70	617,193	
7							
8	Total	$ 67,842	$ (772)	$ 67,070		$ 1,947,952	
9							
10	O & M Expense Lag Days						29.04
11							
12	Net (Lead) Lag Days						30.94
13	Operating Expenses Per Day						$ 183
14							
15	Working Capital for O & M Expense						$ 5,661
16							
17	Interest Payments						(222)
18							
19	Tax Payment Lag Calculations						174
20							
21	Prepaid Expenses						1,962
22							
23	Total Working Capital Requirement						$ 7,575

UGI Utilities, Inc. - Electric Division

Calculation of Interest Payments
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No	Description	# of Days	# of Days	Total
1	Measure of Value at September 30, 2020			$ 130,511
2				
3	Long-term Debt Ratio			48.80%
4				
5	Embedded Cost of Long-term Debt			4.07%
6				
7	Pro forma Interest Expense			$ 2,592
8				
9	Daily Amount	365		$ 7
10				
11	Days to mid-point of interest payments		91.25	
12				
13	Less: Revenue Lag Days		59.98	
14				
15	Interest Payment lag days			(31.3)
16				
17	Total Interest for Working Capital			$ (222)

UGI Utilities, Inc. - Electric Division

Calculation of Prepaid Expenses
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	TOTAL	Insurance	PUC Assessment	Gross Receipts Tax	Subscriptions	Miscellaneous	Maintenance & Services
1		$ 1,179	$ 397	$ -	$ 389	$ 14	$ 53	$ 326
2		1,156	351	250	156	9	40	350
3		912	305	159	-	5	133	310
4		1,140	271	137	-	-	455	277
5		1,023	225	114	-	56	399	229
6		738	179	91	-	51	187	230
7		4,312	133	68	3,595	46	60	410
8		3,400	114	46	2,777	41	65	357
9		3,001	76	23	2,451	36	58	357
10		3,008	70	-	2,439	30	41	428
11		2,060	483	-	1,102	25	38	412
12		1,733	436	-	769	20	36	472
13		1,838	389	217	724	16	45	447
14	TOTAL	$ 25,500	3,429	1,105	14,402	349	1,610	4,605
15								
16	13-Montth Average		$ 264	$ 85	$ 1,108	$ 27	$ 124	$ 354
17	Rate Base Amount	$ 1,962						

UGI Utilities, Inc. - Electric Division

Adjustment to Annualize Payroll
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount Per Company
1	OCA Annual Payroll Expense	$ 5,751
2	Annualizing Adjustment	50
3	Annualized Payroll per OCA	5,801
4	Annualized Payroll per UGI	5,911
5		
6	Adjustment to Payroll	$ (110)
7		
8	Adjustment to Remove Potential Double Count of Payroll Increase on New employees	(14)
9		
10	Adjustment to O&M Expense	$ (124)

UGI Utilities, Inc. - Electric Division

Calculation of FPFTY Payroll Based on Removing 2 Temporary Employees
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount Per Company
1	Total FPFTY Budgeted Unadjusted Payroll	$ 5,854
2	Number of FPFTY Employees per Company	83
3		
4	Payroll per Employee	$ 71
5	Most Recent average Number of Employees	81
6		
7	Annual Payroll Based on Most Recent Average Employee	$ 5,751

UGI Utilities, Inc. - Electric Division

Calculation of FPFTY Payroll Increase
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line #	Description	Union Increase At 6-1	Non-Exempt	Exempt	Pro Forma Total Payroll
1	Budgeted Payroll For TY 9-30-22	$ 1,428	$ 1,289	$ 3,034	$ 5,751
2					
3	**Annualize for Wage Increase to 9-30-22**				
4	Percent Increase	3.00%	2.50%	2.50%	
5	Union Increase At 4-1 Annualization Factor	50%			
6	Non-Exempt Annualization Factor		50%		
7	Exempt Annualization Factor			17%	
8	Increase for wage rate changes	21	16	13	$ 50
13					
14	Pro Forma Salaries & Wages for TY	$ 1,450	$ 1,305	$ 3,046	
15					
16	Pro Forma Adjustment to S&W				$ 50

Surrebuttal Schedules LKM-11 through LKM-13
have been omitted from the Public Version

UGI Utilities, Inc. - Electric Division

Adjustment to Normalize Uncollectibles Expense
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount	
1	**COVID-Related Uncollectible Regulatory Asset**		
2	Regulatory Asset balance as of 9/30/20	$ 1,013	
3			
4	Normalization Period	5	
5			
6	Normalized COVID-Related Uncollectible Regulatory Asset per OCA	$ 203	
7			
8	Normalized COVID-Related Uncollectible Regulatory Asset per Company	507	
9			
10	Adjustment to Normalized COVID-Related Uncollectible Regulatory Asset		(304)
11			
12	Adjustment to Uncollectible Expense		$ (304)

UGI Utilities, Inc. - Electric Division

Adjustment to Normalize Incremental COVID-Related Expenses
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description	Amount	Total
1	Normalization of Incremental COVID Expenses per Company		$ 234
2			
3	Adjustment to O&M Expenses		$ (234)

UGI Utilities, Inc. - Electric Division

Adjustment to Annualize Payroll Taxes
For the Rate Year Ending September 30, 2022
($ in Thousands)

Line No.	Description		Amount Per Company	
1	Adjustment to Payroll	$	(124)	1/
2	Adjustment to incentive Compensation		(248)	
3				
4	Total Adjustment to Labor Costs	$	(372)	
5	Payroll Tax Rate		7.65%	
6				
7	Annualized Payroll Taxes to Reflect OCA Decrease in Payroll	$	(28)	
8				
9	Correct FICA Tax Rate		(11)	2/
10				
11	Correct Payroll Unemployment Tax Rate		(12)	3/
12				
13	Adjustment to Payroll Taxes	$	(51)	

Notes:
1/ Response IE-RE-15.
2/ Response IE-RE-17.

UGI Utilities, Inc. - Electric Division

Interest Synchronization Adjustment
For the Rate Year Ending September 30, 2022

Line No.	Description	Amount	
1	Company Rate Base	$ 130,511	1/
2	Weighted Cost of Debt	1.990%	
3			
4	Adjusted Interest Deduction	$ 2,597	
5	Interest Deduction Per Company	2,635	2/
6			
7	Adjustment to Synchronize Interest Expense	$ (38)	
8	Effective State Income Tax Rate	9.99%	
9			
10	Adjustment to State Income Taxes	$ 4	
11			
12	Federal Income Tax Base	$ (34)	
13	Federal Income Tax Rate	21.00%	
14			
15	Adjustment to Federal Income Taxes	$ 7	

Notes:
1/ Schedule LKM-2, Page 1.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3023618
	:	
UGI Utilities, Inc. – Electric Division	:	

<u>VERIFICATION</u>

I, Lafayette K. Morgan, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement 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).

DATED: June 10, 2021
*310226

Signature: Lafayette Morgan Jr.
Lafayette K. Morgan

Consultant Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044-3575

OCA STATEMENT NO. 2-SR

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	
	:	
v.	**:**	
	:	**Docket No. R-2021-3023618**
	:	
UGI Utilities, Inc. – Electric Division	**:**	

SURREBUTTAL TESTIMONY

OF

AARON L. ROTHSCHILD

ON BEHALF OF

THE OFFICE OF CONSUMER ADVOCATE

June 10, 2021

Contents

I. SUMMARY OF MR. MOUL'S COMMENTS

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my Surrebuttal Testimony is to respond to the following issues addressed in Company witness Paul Moul's Rebuttal Testimony:

1. Comparable Companies;
2. Discounted Cash Flow (DCF);
3. DCF growth rate;
4. Capital Assets Pricing Model (CAPM);
5. Leverage Adjustment.

As addressed below, Mr. Moul's criticisms are invalid and should be rejected. Additionally, I provide an updated rate of return recommendation for UGI to account for UGI's updated embedded cost of long-term debt as discussed on page 9, lines 2-14 of Mr. Moul's Rebuttal Testimony.

II. INTRODUCTION

Q. MR. MOUL CLAIMS ON PAGE 5, LINES 1-4 OF HIS REBUTTAL TESTIMONY THAT YOUR PROPOSED 8.30% COST OF EQUITY IS SIMPLY NOT

REPRESENTATIVE OF RETURN INVESTORS CAN EARN ON OTHER INVESTMENTS OF COMPARBLE RISK. PLEASE RESPOND.

A. As discussed in my Direct Testimony, Mr. Moul and I recommend a different cost of equity for UGI Electric because we have fundamentally different analytical approaches. I focus on using market data (e.g., stock prices, bond yields, stock option prices) to measure investors' expectations as much as possible. On the other hand, Mr. Moul relies almost exclusively on non-market data, including economists' interest rate forecasts even when market data is available.

Additionally, Mr. Moul fundamentally distracts us from the purpose of rate of return regulation and how to go about determining the appropriate cost of equity. All rate of return witnesses that I am aware of define the cost of equity as market-based somewhere in their testimony. On page 3, lines 17-19 of Mr. Moul's Direct Testimony he states that "The cost of common equity is established using capital market and financial data relied on by investors". Despite mentioning capital market data, he often defines the cost of equity as accounting returns (return on book equity) instead of return on market prices. For example, on page 5, lines 17-20 of Mr. Moul's Rebuttal Testimony states "the expected return on equity for Mr. Rothschild's Electric Proxy Group is 10.00% (10.30% according to Value Line), which represents a benchmark for the types of returns that investors expect for electric utilities."

Q. PLEASE RESPOND TO MR. MOUL'S CLAIM THAT THE EXPECTED RETURN ON EQUITY FOR YOUR PROXY GROUP IS 10.00% AND 10.30% ACCORDING TO VALUE LINE.

A. Mr. Moul's claim that investors expect to earn a 10.00% or 10.30% return on equity is a mischaracterization of the cost of equity because these are accounting figures, not investors' returns. If Pennsylvania consumers' rates are set based on accounting returns instead of market returns, they will be significantly overcharged. The return to the equity investor should be commensurate with returns on investments in other enterprises having corresponding risks. An investment is made at the market price of a utility's stock, not the accounting value. Therefore, UGI's authorized ROE should be based on the return investors expect on the market price of utility stocks of comparable risk. The average market price of the electric utility stocks in my proxy group is about two times book value. If investors are willing to pay twice book value for an expected 10.00% return on book value for electric utilities, they are expecting to earn a return significantly less than 10.00% on market value. It makes sense that my DCF market-based cost of equity is between 7.61% and 8.99%.

Q. ON PAGES 14-15 OF HIS REBUTTAL TESTIMONY MR. MOUL CLAIMS THAT IF A COMPANY HAS A MARKET-TO-BOOK RATIO ABOVE 1, IT IS NOT OVEREARNING. DOES HE PROVIDE A CONVINCING ARGUMENT?

A. No. As explained on page 44-45 of my Direct Testimony, the return on book equity expectation used in the DCF method to compute growth must not be confused with the cost of equity. Since the stock prices for the comparative companies are substantially higher than their book value, the return investors expect to receive on their market price investment is considerably less than the anticipated return on book value. If the market price is low relative to book value, the cost of equity will be higher than the future expected return on book equity, and if the market price is high, then the return on book equity will be less than the cost of equity.

The difference between return on market and return on book can be seen with the following hypothetical real estate investment. If an investor rents an investment property for $1,000 per month that he built for $100,000, the investment return is 12% annually ($1,000 per month X 12 months/$100,000 = 12%). If this person sells the building to another investor for $200,000, the market return on investment to this new owner is 6% ($1,000 per month X 12 months/$200,000 = 6%). Original cost ratemaking requires that consumers rates are set based on the market return applied to the original cost of the investment. Therefore, in the hypothetical real estate investment example above, the cost of equity is 6% and rates would be set based on applying this 6% market return to the original cost, or book value, of the property.

In essence, Mr. Moul argues that market-to-book ratios do not indicate that the cost of equity is lower than the return on book equity because market values have exceeded book value in 74% of the years since 1945. As discussed above, if investors are willing to pay twice book value (market-to-book ratio of 2) for a 10% return on book value they are expecting to earn significantly less than a 10% return on their investment. The fact that the market-to-book ratios have been high for a long time does not change fact that the market-based cost of equity is lower than the expected return on book value.

III. COMPARABLE COMPANIES

Q. PLEASE RESPOND TO MR. MOUL'S CLAIM THAT THE CORRECT SCREENING CRITERION IS THE PERCENTAGE OF ELECTRIC ASSETS TO TOTAL ASSETS.

A. All the companies in my proxy group have at least 80% of its assets dedicated to regulated operations.

Q. PLEASE RESPOND TO MR. MOUL'S CLAIM THAT YOUR PROXY GROUP IS LARGE AND CUMBERSOME AND PROVIDES ESSENTIALLY A GENERIC COST OF EQUITY.

A. It is not cumbersome to analyze a group of 22 companies because computer programs can download data and make calculations for even thousands of companies if necessary. As explained on page 34 of my Direct Testimony, I selected 22 publicly traded electric utility companies to include in my comparable proxy group based on 5 criteria, including requiring the companies to have a minimum of 80% of its assets dedicated to regulated assets. The benefit of calculating a cost of equity based on a larger proxy group ensures that any one company does not distort the results. Applying my cost of equity models to a proxy group of 22 companies provides more reliable results than if I had used a smaller proxy group.

IV. DISCOUNTED CASH FLOW

Q. ON PAGE 15-16 OF HIS REBUTTAL TESTIMONY, MR. MOUL CLAIMS THAT YOU SHOULD HAVE RELIED ON EARNINGS PER SHARE (EPS) GROWTH RATES INSTEAD OF RETENTION GROWTH RATES. HOW DO YOU RESPOND?

A. I disagree. A study conducted by McKinsey & Company in 2010 found that "analysts have been persistently over optimistic for the past 25 years with estimates ranging from 10 to 12 percent a year, compared with actual earnings growth."[1]

On average, analysts' forecasts have been almost 100 percent too high.[2] Additionally, the further a projection predicts into the future, the likelihood of the projection being correct decreases.

Capital markets, on the other hand, are notably less giddy in their predictions. Except during the market bubble of 1999-2001, actual price-to-earnings (P/E) ratios have been 25 percent lower than implied P/E ratios based on analyst forecasts.

Even if equity analysts' forecasts were not upwardly biased, as discussed in my Direct Testimony, adding earnings per share growth forecasts to a dividend yield without considering the retention rate produces a flawed result. Using an earnings per share growth forecast as the growth component in a DCF model is like measuring how much money you will have in your bank account by simply adding up your paychecks. If you do not consider

---

[1] Marc H. Goedhart, Rishi Raj and Abhishek Saxena, *Equity Analysts: Still too bullish*, Spring 2010

[2] Ibid.

what percentage of your paycheck you will retain in your account and what percentage you will spend, your calculations will not be accurate.

V. CAPITAL ASSET PRICING MODEL (CAPM)

A. PLEASE SUMMARIZE MR. MOUL'S CRITICISMS OF YOUR CAPM APPROACH.

A. Mr. Moul claims that my CAPM method is not useful in this case for the following reasons:

1. It relies on data not available to investors (e.g. betas);
2. There is no evidence that the betas (option-implied) I use impact expected returns;
3. It uses made up prices/values instead of "actual market data;"

Q. PLEASE RESPOND TO THESE CRITICISMS.

A. My CAPM directly measures investors' expectations as represented in the prices of securities. My CAPM is 100 percent based on market data that is available to investors: (1) stock prices, (2) bond yields, (3) option prices, (4) implied volatility, (5) Skew of S&P 500. This information is all publicly available on Yahoo Finance, Wall Street Journal, the Chicago Board of Options Exchange, and many other sources. My CAPM method is derived from the prices investors actually pay for securities (e.g. stocks, bonds, options). My method does not require assumptions regarding what model(s) investors use. Regardless of what models investors use, or how they make their investment decisions, their return expectations, and the appropriate cost of equity for UGI Electric, are represented in the prices investors are willing to pay for stocks, bonds, and options. As such, Mr. Moul's criticisms are without merit.

Q. PLEASE COMMENT ON MR. MOUL'S CLAIM THAT YOU USE DATA THAT IS NOT AVAIALBLE TO INVESTORS.

A. The data I have used is available to any investor that has access to the internet. This means the data I use is more widely available than the data Mr. Moul has used. The betas used by Mr. Moul (Value Line's published 5-year historical betas) are based on the past and therefore it is unlikely they measure current investors' expectations regarding utility betas in particular and risk and return in general. It is inappropriate to use backward looking measures when data regarding current investor expectations is not available. The purpose of this proceeding is to determine the current, market-based cost of equity. Not only is using historical betas inconsistent with the purpose of this proceeding, research discussed below shows that CAPM results based on historical betas are not consistent with CAPM theory. In other words, Mr. Moul is criticizing me for not implementing the CAPM in a way that has been falsified.

Q. PLEASE COMMENT ON MR. MOUL'S CLAIM THAT THERE IS NO EVIDENCE THAT BETAS (OPTION-IMPLIED) IMPACT INVESTOR EXPECTED RETURNS.

A. Mr. Moul's statement is analogous to saying the following: there is no evidence that the sale price of a house impacts what real estate investors are willing to pay for a house. The option data that I use to calculate the betas of each of the companies in the Electric Group is a direct measure of what investors are willing to pay for securities. Mr. Moul's historical betas are based on the co-variance of historical price movements over the past five years. There is evidence that supports the superiority of using option-implied betas over historical betas. CAPM results based on historical betas leads to "counter-CAPM predictions." On the other hand, when option-implied betas are used, as I have done, "the traditional CAPM prediction holds: The higher the beta, the higher the average return."

Q. PLEASE COMMENT ON MR. MOUL'S CLAIM THAT YOU SHOULD HAVE USED VALUE LINE'S PUBLISHED HISTORICAL BETAS INSTEAD OF CALCULATING BETAS BASED ON STOCK OPTION PRICES.

A. Mr. Moul's claim that I should have used Value Line's published betas implies the investors only uses Value Line's published betas and that I could have implemented my CAPM without making calculations. Of course, investors have access to betas published by many different sources and Mr. Moul and I both had to decide which published betas to use if we do not calculate our own.

It is not possible to implement a CAPM without making calculations and decisions regarding which data to use. Mr. Moul also makes decisions regarding which data to use, and he also makes calculations. For example, Mr. Moul chose to use historical betas published by Value Line instead of Yahoo Finance, Reuters, Market Watch, NASDAQ, YCharts or many other publications available to investors. Many of these sources publish different beta values for the same companies because their calculations vary. Mr. Moul also chose to use a historical risk premium in his CAPM based on the arithmetic average of one year returns from 1926-2019 instead of a time-frame consistent with using a risk-free rate of yields on 30-year U.S. Treasuries and instead of using the geometric average return.

Regarding the option data that I use to calculate the beta component of my CAPM, option prices reflect the risk of a stock or stock index. The level of risk conveyed by option prices is often referred to as implied volatility." It has been found that "the CAPM beta can be estimated from a single day of options" and as discussed above, "the traditional CAPM prediction holds" when option-implied betas are used. When historical betas are used, the CAPM predictions do not hold.

Q. DO YOU THINK OPTION-IMPLIED BETAS SHOULD BE USED IN COST OF CAPITAL CALCULATIONS?

A. Yes. I think option-implied betas are one of the best tools currently available to measure the overall risk expected by investors at any given moment in time, and that is fundamentally what cost of capital determinations should be based on. As with other tools and methodologies we use regularly, option-implied betas are not a silver bullet and should be used in conjunction with other valid approaches to determine ranges of reasonableness for the cost of capital. The more valid tools we use, the more we can narrow down or confirm these ranges of reasonableness to ensure a more accurate result.

VI. LEVERAGE ADJUSTMENT

A. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING MR. MOUL'S LEVERAGE ADJUSTMENT?

Q. No. As stated in on pages 53-56 of my Direct Testimony, Mr. Moul's leverage adjustment goes against original cost rate making and should be rejected.

VII. UPDATED RATE OF RETURN RECOMMENDATION

Q. WHY ARE YOU UPDATING YOUR RATE OF RETURN RECOMMENDATION FOR UGI?

A. I am updating my rate of return recommendation because as stated on page 9, lines 2-14 of Mr. Moul's Rebuttal Testimony, since its original filing, UGI issued $175 million of new long-term debt with a lower interest rate than expected. The net effect of the lower interest rate of these new bonds is to reduce UGI's embedded cost of long-term debt from 4.25% to 4.07%.

Q. PLEASE PROVIDE YOUR UPDATED RATE OF RETURN RECOMMENDATION FOR UGI.

A. My updated rate of return recommendation is shown in the table below. As a result of UGI's updated embedded cost of long-term debt, my overall rate of return recommendation has decreased from 6.32%[3] to 6.24%. The numbers highlighted in yellow have changed because of this update.

[3] Mr. Rothschild's Direct Testimony, page 4, Table 1.

TABLE 1: ALR RECOMMENDED RANGE MIDPOINT (UPDATED JUNE 9 2020) Docket No. R-2021-3023618			
	Capital Structure Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	48.80%	4.07%	1.99%
Short-Term Debt	0.00%	0.00%	0.00%
Preferred Equity	0.00%	0.00%	0.00%
Common Equity	51.20%	8.30%	4.25%
Rate of Return			6.24%

Exhibit ALR-1, page 1

VIII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RESPONSE TO MR. MOUL'S REBUTTAL TESTIMONY.

Q. Mr. Moul's criticisms of my Direct Testimony are invalid. His Rebuttal Testimony arguments are unfounded and should therefore be rejected. As explained in my Direct Testimony, my DCF method maintains its accuracy irrespective of the market-to-book ratio of utility stocks. Mr. Moul's comparison of projected returns on book equity to DCF results leaves out the most important piece of information in determining the cost of equity which is: what are investors willing to pay for what they expect to receive in the future? Return on book equity is not the cost of equity. Although I use my cost of equity models to determine my cost of equity recommendation, the "cost of equity in today's financial market" shows that stocks are expensive and interest rates remain near historic lows. My cost of equity recommendation of 8.30% is market-based and would allow UGI Electric to raise capital on reasonable terms in today's capital markets.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

310797

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3023618
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Aaron L. Rothschild, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 2-SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) 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).

Aaron L. Rothschild

DATED: June 10, 2021
*310230

Signature: ______________________
Aaron L. Rothschild

Consultant Address: Rothschild Financial Consulting
15 Lake Road
Ridgefield, CT 06877

OCA STATEMENT NO. 3-SR

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-2021-3023618**
	)	
UGI Utilities, Inc. – Electric Division	)	

SURREBUTTAL TESTIMONY

OF

JEROME D. MIERZWA

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JUNE 10, 2021

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Jerome D. Mierzwa. I am a Principal and Vice President of Exeter Associates, Inc. ("Exeter"). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. My direct testimony was submitted as OCA Statement No. 3 and my rebuttal testimony was submitted as OCA Statement No. 3-R.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of UGI Utilities, Inc. – Electric Division ("UGI") witnesses John D. Taylor and Eric W. Sorber, and the rebuttal testimony of the Office of Small Business Advocate ("OSBA") witness Robert D. Knecht.

II. UGI WITNESS: JOHN D. TAYLOR

Q. MR. TAYLOR CLAIMS THAT THE NATIONAL ASSOCIATION OF REGULATORY UTILITIES COMMISSION ("NARUC") COST ALLOCATION MANUAL ("1992 NARUC MANUAL") DOES NOT MENTION THE ALLOCATION OF UPSTREAM DISTRIBUTION FACILITIES AS DEMAND-RELATED AS AN ALTERNATIVE FOR CLASSIFYING AND ALLOCATING DISTRIBUTION PLANT. (UGI ST. NO. 6-R AT PG. 14). WHAT IS YOUR RESPONSE?

A. The 2000 NARUC Manual identified in my direct testimony provides:

> There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. <u>The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach used in more than thirty states</u>. A variation is to treat poles, wires, and transformers as energy-related driven by kilowatt-hour sales but, though it has obvious appeal, only a small number of jurisdictions have gone this route.
>
> …
>
> Any approach to classifying costs has virtues and vices. The first potential pitfall lies in the assumptions, explicit and implicit, that a method is built upon. In the basic customer method, it is the *a priori* classification of expenditures (which may or may not be reasonable). In the case of the minimum-size and zero-intercept methods, the threshold assumption is that there is some portion of the system whose costs are unrelated to demand (or to energy for that matter). From one perspective, this notion has a certain intuitive appeal [sic] these are the lowest costs that must be incurred before any or some minimal amount of power can be delivered but from another viewpoint it seems absurd, since in the absence of any demand no such system would be built at all. Moreover, firms in competitive markets do not indeed, cannot price their products according to such methods: they recover their costs through the sale of goods and services, not merely by charging for the ability to consume, or access. (Pages 29 & 30).

Thus, many (if not most) state regulatory commissions endorse a method in which all distribution plant from substations through line transformers is classified and allocated based solely on demand.

Q. MR. TAYLOR CITES SEVERAL PUBLICATIONS WHICH SUPPORT THE CLASSIFICATION OF A PORTION OF UPSTREAM DISTRIBUTION FACILITIES AS CUSTOMER-RELATED. (UGI ST. NO. 6-R, PGS. 17-18). WHAT IS YOUR RESPONSE?

A. As noted in my direct testimony a major concern with Mr. Taylor's use of a minimum system to classify a portion of UGI's upstream distribution facilities as customer-related is that he failed to consider the Peak Load Carrying Capability ("PLCC") of the minimum system. This failure results in a double allocation of upstream distribution costs to Residential and other small customers. As Mr. George J. Sterzinger noted in his July 2, 1981 article, "The Customer Charge and Problem of Double Allocation of Costs," published in *Public Utilities Fortnightly*:

> One way to solve the double allocation problem would be to determine, for each piece of minimum equipment, the demand level it would be capable of serving, and then adjusting the demand allocation factors used to allocate the costs of all equipment of that type in order to assure that minimum use customers and the residential class were not charged twice. In many cases this would mean calculating several allocation factors for each FERC distribution account, since more than one type of equipment is used in the account. Even after overcoming all the problems of this approach one is still confronted with the dubious value of charging for equipment on an up-front basis rather than through a per kilowatt-hour charge at a time when conservation is recognized as an important goal of energy policy.
>
> The direct way to assure that problems of overcollection are not built into the methodology used to determine class costs of service is to classify all distribution costs as demand costs. If this methodology is used in embedded cost studies, the studies will produce more equitable estimates of the cost of serving low-use residential customers.

Q. MR. TAYLOR CITES THE 2006 PHILADELPHIA GAS WORKS PROCEEDING WHERE THIS COMMISSION FOUND THAT ALLOCATIONS OF UPSTREAM DISTRIBUTION PLANT BASED ON THE NUMBER OF CUSTOMERS ARE NOT ACCEPTABLE. (UGI ST. NO. 6-R, PG. 18). HAS THE COMMISSION MORE RECENTLY FOUND THAT ALLOCATIONS OF UPSTREAM DISTRIBUTION PLANT BASED ON THE NUMBER OF CUSTOMERS TO BE UNREASONABLE?

A. Yes. In Docket No. R-2020-3018835, Columbia Gas of Pennsylvania ("Columbia") submitted an ACOSS which allocated distribution mains investment partially based on the number of customers and partially based on the peak demands of the customers in each rate class (Customer-Demand method). The ACOSS presented by Mr. Taylor utilizes a Customer-Demand method to allocate primary and secondary upstream distribution investment to each customer class. In its Opinion and Order entered in the Columbia proceeding on February 19, 2021, the Commission rejected the Customer-Demand method and adopted the Peak and Average method I supported for the allocation of distribution mains investment. (Order, at 211). Under the Peak & Average method, distribution mains investment is allocated 50 percent based on peak demands and 50 percent based on the annual volumes of each class.

Q. MR. TAYLOR CLAIMS THAT IN THIS MINIMUM SYSTEM ANALYSES HE DID NOT ALLOCATE 45 FEET OF PRIMARY CONDUCTOR LINE TO EACH CUSTOMER AND, THEREFORE, YOUR CLAIM THAT HE DID IS NOT CORRECT. (UGI ST. NO. 6-R, PG. 19). WHAT IS YOUR RESPONSE?

A. Mr. Taylor contends that he did not allocate footage to each class but rather a determination of costs. I found there to be no distinction between allocating the costs associated with 45 feet of primary conductor line to each customer and allocating 45 feet of primary conductor line to each customer for purposes of evaluating Mr. Taylor's proposals.

Q. IN YOUR DIRECT TESTIMONY YOU CRITIQUED THE COMPANY'S ACOSS BECAUSE IT DID NOT ACCOUNT FOR THE PLCC OF THE MINIMUM SIZE DISTRIBUTION SYSTEM. WHAT WAS MR. TAYLOR'S RESPONSE?

A. Mr. Taylor acknowledges that the Company's minimum system has some load carrying capability, but claims that failure to account for that capability does not provide a basis for rejecting the Company's ACOSS. He subsequently claims that he has only classified the no-load portion of transformers as customer-related. He further claims that the minimum size pole does not have a load carrying capability. For conductors, he claims that estimating the load carrying capability would be a formidable task requiring significant resources. (UGI St. No. 6-R, pg. 21).

Q. WHAT IS YOUR RESPONSE TO MR. TAYLOR'S CLAIMS CONCERNING THE LOAD CARRYING CAPABILITY OF MINIMUM SYSTEM TRANSFORMERS, POLES, AND CONDUCTORS?

A. Mr. Taylor's claims should be dismissed. The sole purpose of a transformer or pole is to carry load to meet customer requirements. If there was no load, a transformer or pole would not be installed by UGI. Since transformers are only installed to serve load, there is no no-load portion of a transformer. Similarly, a pole is only installed to carry load and, therefore, there is no no-load carrying portion of a pole. That would also be true for a minimum size pole, or it would be irrational to refer to it as a pole. For conductors, it may be a formidable task to determine the load carrying capability which would require significant resources. That does not mean the load carrying capability of the conductors included in the minimum system should be ignored in an ACOSS. As subsequently discussed, in my direct testimony, I presented a logical and rationale method to determine the load carrying capability of the minimum system reflected in the Company's ACOSS.

Q. IN YOUR DIRECT TESTIMONY, HOW DID YOU RECOMMEND THAT THE LOAD CARRYING CAPABILITY OF THE MINIMUM SYSTEM BE REFLECTED IN YOUR ALTERNATIVE ACOSS?

A. To account for the load carrying capability of the minimum system, I reduced the primary and secondary NCP demands of each customer class reflected in UGI's ACOSS by the Residential per customer NCP demand that can be met by the minimum system. I calculated the per customer NCP demand that can be met by the minimum system by multiplying the average NCP demand of the Residential class by the customer component of upstream distribution plant which was 43 percent.

Q. WHAT WAS MR. TAYLOR'S RESPONSE TO YOUR ADJUSTMENT TO REFLECT THE LOAD CARRYING CAPABILITY OF THE MINIMUM SYSTEM?

A. Mr. Taylor claims that my assumption of the minimum system meeting 43 percent of the average customer-demand is baseless, and is not supported by any analysis of the engineering or operating capacities of the minimum size conductor used in the analysis. Nevertheless, Mr. Taylor acknowledges there is some load carrying capability of the minimum system. (UGI St. No. 6-R, pg. 23).

Q. WHAT IS YOUR RESPONSE TO MR. TAYLOR'S CLAIM CONCERNING YOUR ADJUSTMENT TO ACCOUNT FOR THE LOAD CARRYING CAPABILITY OF THE MINIMUM SYSTEM?

A. My assumption of the minimum system meeting 43 percent of average customer demand is not baseless. As explained in my direct testimony, in total, the plant accounts included in Mr. Taylor's minimum system analysis are currently able to satisfy 100 percent of the NCP demands of UGI's customers. In his direct testimony, Mr. Taylor determined that an average 43 percent of the costs included in these accounts represented UGI's minimum system. Therefore, it is reasonable and logical to assume that the minimum system can meet 43 percent of customer NCP demands.

Q. MR. TAYLOR PRESENTS A REBUTTAL ACOSS IN HIS REBUTTAL TESTIMONY WHICH REFLECTS CERTAIN MODIFICATIONS AND UPDATES TO THE ACOSS FILED IN HIS DIRECT TESTIMONY. (UGI ST. NO. 6-R, PG. 25, 26; UGI ELECTRIC EXHIBIT D - ALLOCATED COST OF SERVICE STUDY (REBUTTAL)). DO YOU AGREE WITH THESE MODIFICATIONS AND UPDATES?

A. The Rebuttal ACOSS presented by Mr. Taylor reflects certain modifications proposed by Mr. Knecht to the minimum system analyses supporting the ACOSS presented by Mr. Taylor in his direct testimony. (UGI St. No. 6-R, pg. 24). I am not challenging those modifications. The Rebuttal ACOSS also adopts the recommendation of Mr. Knecht to use a single NCP demand allocation rather than an average of 12 monthly NCPs. (UGI St. No. 6-R, pg. 25). I disagree with this modification.

Q. WHY DO YOU DISAGREE WITH THE USE OF A SINGLE NCP DEMAND ALLOCATOR AND SUPPORT THE USE OF AN AVERAGE OF 12 MONTHLY NCPS?

A. At times, UGI has experienced its peak demands during the winter months and at other times peak demands have been experienced during the summer months. As explained in my rebuttal testimony, it is reasonable to use a 12 NCP allocation factor to smooth out year to year allocations that may otherwise fluctuate depending on whether peak demands occurred in the summer or winter.

Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S REBUTTAL ACOSS?

A. The Company's Rebuttal ACOSS should continue to reflect a 12 NCP demand allocation factor used in the originally filed ACOSS. The Rebuttal ACOSS also reflects the Company's updated revenue requirement claim in this proceeding. The Company's updated revenue requirement claim will be addressed by OCA witness Lafayette K. Morgan.

Consistent with my direct testimony recommendation, the Company's Rebuttal ACOSS should also be modified to provide for the classification of the primary and secondary portion of upstream distribution plant as 100 percent demand-related rather than partially being classified as customer-related. Also consistent with my direct testimony recommendation, alternatively, if the Commission does not accept my proposal to classify primary and secondary distribution plant as 100 percent demand-related, the customer class 12 NCP demands which UGI has relied on to allocate the demand component of primary and secondary distribution facilities in its initial ACOSS should be utilized and adjusted to reflect the load carrying capability of the minimum system Mr. Taylor has used to determine the customer component of the Company's primary and secondary distribution facilities.

Q. IN THIS REBUTTAL ACOSS, HAS MR. TAYLOR REVISED HIS INITIAL MINIMUM SYSTEM ANALYSIS AND THE PERCENTAGES OF UPSTREAM PRIMARY AND SECONDARY DISTRIBUTION PLANT HE DETERMINED TO BE CUSTOMER-RELATED?

A. Yes. As shown in Table 2 of my direct testimony, Mr. Taylor's initial minimum system analysis determined that 43 percent of both primary and secondary distribution plant are customer-related. In his Rebuttal ACOSS, 52 percent of primary distribution plant and 65 percent of secondary distribution plant were determined to be customer-related.

Q. HAVE YOU REVISED THE COMPANY'S REBUTTAL ACOSS TO REFLECT AN ALLOCATION OF PRIMARY AND SECONDARY DISTRIBUTION PLANT 100 PERCENT BASED ON 12 NCP DEMANDS?

A. Yes, I have revised the Company's Rebuttal ACOSS to reflect a 100 percent demand allocation for Accounts 364, 365, 367, and 368 and on 12 NCP demands. Table 1-S provides a comparison of the results of the Company's Rebuttal ACOSS and a revised Rebuttal ACOSS which allocates primary and secondary distribution costs 100 percent based on NCP demands. Schedule JDM-1S attached to my testimony provides a more detailed summary of the revised ACOSS.

Table 1-S. Comparison of Allocated Cost of Service Study Results, Company Study, and 100 Percent Demand Study – Present Rates

	Company		OCA	
Rate Class	**Rate of Return**	**Index**	**Rate of Return**	**Index**
Residential Class	(2.65%)	(3.88)	0.27%	0.09
General Service-1	(0.17)	(0.06)	8.07	2.67
General Service-4	26.97	8.93	9.61	3.18
Large Power	33.49	11.09	5.26	1.74
Lighting	33.70	11.16	21.62	7.16
Total:	**3.02%**	**1.00**	**3.02**	**1.00**

Q. HAVE YOU ALSO REVISED THE COMPANY'S REBUTTAL ACOSS TO REFLECT THE PLCC OF THE MINIMUM SYSTEM UTILIZED IN THE COMPANY'S REBUTTAL ACOSS TO CLARIFY COSTS AS CUSTOMER-RELATED AND THE USE OF A 12 NCP ALLOCATION FACTOR?

A. Yes. (UGI St. No. 6-R, pg. 25). I have also alternatively revised the Company's Rebuttal ACOSS to reflect the PLCC of the minimum system. Table 2-S provides a comparison of the results of the Company's Rebuttal ACOSS and an alternatively revised Rebuttal ACOSS which accounts for the PLCC of the minimum system developed by the Company. Schedule JDM-2S attached to my testimony provides a more detailed summary of the alternatively revised Rebuttal ACOSS.

Table 2-S. Comparison of Allocated Cost of Service Study Results, Company Rebuttal Study, and Rebuttal Study Reflecting PLCC of Minimum System – Present Rates

	Company		OCA	
Rate Class	**Rate of Return**	**Index**	**Rate of Return**	**Index**
Residential Class	(2.65%)	(3.88)	(0.82%)	(0.27)
General Service-1	(0.17)	(0.06)	3.88	1.28
General Service-4	26.97	8.93	14.15	4.69
Large Power	33.49	11.09	10.46	3.46
Lighting	33.70	11.16	24.64	8.16
Total:	**3.02%**	**1.00**	**3.02%**	**1.00**

Q. DID YOU REVISE THE COMPANY'S REBUTTAL ACOSS TO REFLECT THE PLCC OF THE MINIMUM SYSTEM UTILIZING THE SAME METHOD YOU UTILIZED IN YOUR DIRECT TESTIMONY?

A. Yes. The plant included in Accounts 364, 365, 367, and 368 is currently able to satisfy 100 percent of the NCP demands of UGI's customers. In its Rebuttal ACOSS, UGI has classified a weighted average of 52 percent of the primary plant included in these accounts as customer-related and 65 percent of the secondary plant included in these accounts as customer-related. The average primary 12 NCP demand of a Residential customer in the Company's initial ACOSS was 1.92 kW and the average secondary 12 NCP demand of a Residential customer was 1.88 kW. Consistent with UGI's determination that 52 percent of primary and 65 percent of secondary distribution costs are customer-related, this indicates that 1.00 kW of Residential primary customer NCP demand (1.92 x 52%) and 1.22 kW of Residential secondary customer NCP demand (1.88 x 65%) can be met by the minimum system. To reflect the PLCC of the minimum system and eliminate the double allocation of primary and secondary upstream distribution costs, I reduced the primary and secondary 12 NCP demands of each customer class reflected in UGI's initial ACOSS by the Residential per customer NCP demand that can be met by the minimum system multiplied by the number of customers in each class. Table 3-S identifies these adjustments by class.

Table 3-S. Adjustment to 12 NCP Demands to Reflect the PLCC of Minimum System

	Primary		Secondary	
Rate Class	**Company**	**PLCC Adjusted**	**Company**	**PLCC Adjusted**
Residential Class	105,886	60,083	103,732	58,966
General Service-1	6,342	1,712	6,213	1,687
General Service-4	24,726	22,834	23,821	21,984
Large Power	42,875	42,711	17,775	17,645
Lighting	1,509	1,460	1,478	1,430
Total:	**181,338**	**128,800**	**153,019**	**101,711**

Q. HAVE YOU REVISED THE REVENUE DISTRIBUTION PRESENTED IN YOUR DIRECT TESTIMONY BASED ON YOUR REBUTTAL ACOSS WHICH CLASSIFIES UPSTREAM DISTRIBUTION PLANT AS 100 PERCENT DEMAND-RELATED?

A. Yes. Table 4-S summarizes my revenue distribution for UGI's claimed revenue deficiency based on the Rebuttal ACOSS which classifies upstream distribution plant or 100 percent demand-related.

Table 4-S. OCA Proposed Revenue Distribution Based on 100 Percent Demand Rebuttal ACOSS
($000)

Rate Class	Present Revenue	Proposed Revenue	Increase	Percent
Residential Class	$23,050	$29,305	$6,255	27.1%
General Service-1	2,029	2,338	309	15.2
General Service-4	4,893	5,718	825	16.9
Large Power	5,155	6,475	1,320	25.6
Lighting	1,162	1,162	0	0.0
Total:	**$36,289**	**$44,998**	**$8,709**	**24.0%**

Q. HOW DID YOU DEVELOP THIS PROPOSED REVENUE DISTRIBUTION?

A. Under my revised ACOSS which classifies upstream distribution costs as 100 percent demand-related the Lighting class provides a rate of return at current rates which is significantly in excess of the system average return. Therefore, I have proposed no increase for the Lighting class. For the remaining rate classes, I have proposed increases which move the rate of return for each class to approximately 75 percent of the system average rate of return. Schedule JDM-3S provides additional information concerning the revenue distribution for each class under this proposed revenue distribution.

Q. HAVE YOU REVISED THE REVENUE DISTRIBUTION PRESENTED IN YOUR DIRECT TESTIMONY BASED ON YOUR ALTERNATIVE REBUTTAL ACOSS WHICH ACCOUNTS FOR THE PLCC OF THE MINIMUM SYSTEM?

A. Yes. Table 5-S summarizes my recommended revenue distribution for UGI's claimed revenue deficiency based on the alternative Rebuttal ACOSS which reflects the PLCC of the minimum system.

Table 5-S. OCA Proposed Revenue Distribution Based on PLCC of Minimum System Rebuttal ACOSS
($000)

Rate Class	Present Revenue	Proposed Revenue	Increase	Percent
Residential Class	$23,050	$29,905	$6,855	29.7%
General Service-1	2,029	2,483	454	22.4
General Service-4	4,893	5,443	550	11.2
Large Power	5,155	6,005	850	16.5
Lighting	1,162	1,162	0	0.0
Total:	**$36,289**	**$44,998**	**$8,749**	**24.0%**

Q. HOW DID YOU DEVELOP THIS ALTERNATIVE PROPOSED REVENUE DISTRIBUTION?

A. Under my ACOSS which accounts for the PLCC of the minimum system, the Lighting class provides a rate of return at current rates which is significantly in excess of the system average return. Therefore, I have proposed no increase for the Lighting class. For the remaining rate classes, I have proposed increases which moves the return for each class to approximately 75 percent of the system average return. Schedule JDM-4S provides additional information concerning the revenue distribution for each class under my alternative proposed revenue distribution.

Q. IN YOUR DIRECT TESTIMONY YOU RECOMMENDED THAT UGI'S PROPOSED INCREASE IN THE MONTHLY RESIDENTIAL CUSTOMER CHARGE FROM $8.74 TO $13.00 BE REJECTED, AND THAT THE CURRENT CHARGE BE MAINTAINED. WHAT WAS THE BASIS FOR THIS RECOMMENDATION?

A. I recommended that the proposed increase in the monthly Residential customer charge be rejected for several reasons:

- The proposed increase of nearly 50 percent was inconsistent with the concept of gradualism;
- The monthly Residential customer charge calculated by the Company of

$21.52 to support the increase included costs not appropriately included in a customer charge; and

- A lower customer charge ensures a greater portion of costs are recovered through energy charges which promotes the Commonwealth's energy conservation and efficiency goals and will help minimize electric distribution costs over the long term.

Q. WHAT IS MR. TAYLOR'S RESPONSE TO YOUR CLAIM THAT THE PROPOSED INCREASE IN THE MONTHLY RESIDENTIAL CUSTOMER CHARGE OF NEARLY 50 PERCENT IS INCONSISTENT WITH THE CONCEPT OF GRADUALISM?

A. Mr. Taylor claims that the customer charge is only one component of the customers' bill and customers will see a much lower impact on their entire bill. (UGI St. No. 6-R, pg. 29).

Q. WHAT IS YOUR RESPONSE TO THIS CLAIM?

A. Mr. Taylor claims that the principle of gradualism should be applied to the entire rate increase and not the individual rate components assessed to a customer. I disagree. Customers have different usage levels and will be affected differently by changes in customer charges and usage charges. The Company's nearly 50 percent increase in the monthly Residential customer charge will not provide gradualism for low-use customers.

Q. WHAT IS MR. TAYLOR'S RESPONSE TO YOUR CLAIM THAT THE COMPANY'S CALCULATED MONTHLY RESIDENTIAL CUSTOMER CHARGE OF $21.52 INCLUDES COSTS NOT APPROPRIATELY INCLUDED IN A CUSTOMER CHARGE?

A. Mr. Taylor claims that the costs I have determined should be excluded from a customer charge calculation—universal service costs; uncollectible expense; administrative and general salaries; expenses; and common plant—are properly included in a customer charge. (UGI St. No. 6-R, pg. 30).

Q. WHAT IS YOUR RESPONSE TO THIS CLAIM?

A. As explained in my direct testimony, only those costs that directly increase or decrease with the addition of a customer should be included in a customer charge. The costs I have proposed to remove from the Company's customer charge calculation such as uncollectible accounts expense, universal service program costs, administrative and general salaries, and expenses and common plant do not directly increase or decrease with the addition of a customer and, therefore, should not be included in a customer charge.

Q. WHAT IS MR. TAYLOR'S RESPONSE TO YOUR CLAIM THAT A LOWER CUSTOMER CHARGE WILL PROMOTE ENERGY CONSERVATION AND EFFICIENCY?

A. Mr. Taylor claims I provided no basis or support for this conclusion. He also claims that many of the costs incurred by UGI are fixed, so a reduction in usage will not reduce UGI costs. (UGI St. No. 6-R, pg. 32).

Q. WHAT IS YOUR RESPONSE TO THIS CLAIM?

A. In Columbia Gas, Docket No. R-2020-3018835 previously identified in this testimony, the Administrative Law Judge ("ALJ") found that Columbia's proposed 37 percent increase in the Residential customer charge was contrary to the Commission's goal of encouraging customers to conserve energy. (Order, at 264). In its Opinion and Order, the Commission adopted the ALJ's decision. (Order, at 265).

Q. MR. TAYLOR PRESENTS A TABLE WHICH INDICATES THAT THE MONTHLY CUSTOMER CHARGES OF PENNSYLVANIA'S ELECTRIC COOPERATIVES ARE SIGNIFICANTLY HIGHER THAN THE CHARGE

PROPOSED BY UGI. (UGI ST. NO. 6-R, PG. 35). WHAT IS YOUR RESPONSE?

A. As Mr. Taylor acknowledges, Pennsylvania's electric cooperatives are not regulated by this Commission. Therefore, they are irrelevant to this issue.

III. UGI WITNESS: ERIC W. SORBER

Q. IN YOUR DIRECT TESTIMONY YOU INDICATED THAT UGI'S PROPOSED BATTERY STORAGE PROJECT MAY BE CONSIDERED A GENERATION ASSET AND, THEREFORE, PROHIBITED FROM INCLUSION IN UTILITY DISTRIBUTION RATES BY SECTION 2804(14) OF THE PUBLIC UTILITY CODE. WHAT WAS MR. SORBER'S RESPONSE?

A. Mr. Sorber claims that when viewed by its primary function of reliability support, the battery storage project is a distribution asset, and its costs are properly recovered in distribution rates.

Q. WHAT IS YOUR RESPONSE TO MR. SORBER'S CLAIM?

A. Electricity supply is provided to customers by generation technologies deployed within the electric power industry. The battery storage project will be used to supply electricity to customers within the battery footprint during outages when it discharges, thereby performing a generation function. Attached to my surrebuttal testimony as Schedule JDM-5S is a U.S. Energy Information Administration document entitled "Cost and Performance Characteristics of New Generating Technologies, *Annual Energy Outlook 2021*." Tables 1 and 2 in that document identify battery storage as an electricity generating technology. It remains my position that the proposed battery storage project is a generation asset not eligible for inclusion in utility distribution rates.

Q. IN YOUR DIRECT TESTIMONY YOU ALSO INDICATED THAT UGI FAILED TO DEMONSTRATE THAT THE BATTERY STORAGE PROJECT WAS THE MOST COST EFFECTIVE APPROACH TO MAINTAIN RELIABILITY FOR THE 68 CUSTOMERS LOCATED IN THE BATTERY FOOTPRINT. WHAT WAS MR. SORBER'S RESPONSE?

A. Mr. Sorber claims that the Company evaluated four alternatives to the battery storage project and that the project was the most cost effective.

Q. WHAT IS YOUR RESPONSE TO THIS CLAIM?

A. As indicated in my direct testimony the useful life of the battery storage project is 20 years, and there may be other distribution system improvements with an expected life greater than 20 years. In addition, there may be salvage costs at the conclusion of the 20-year expected life of the storage project. UGI has not factored into its analysis of alternatives the expected life of the alternatives and the potential salvage costs associated with the battery storage project.

Q. DOES MR. SORBER DISCUSS OTHER NON-INFRASTRUCTURE RELIABILITY IMPROVEMENTS IN THE BATTERY FOOTPRINT THAT UGI HAS PERUSED?

A. Yes. Mr. Sorber claims the Company has already performed non-capital reliability improvements, including vegetation management. He claims that the Company has completed all trimming of accessible danger tree removals in 2020.

Q. COULD UGI'S RECENT VEGETATION MANAGEMENT IN THE BATTERY FOOTPRINT SIGNIFICANTLY REDUCE OUTAGES?

A. Potentially, yes. Based on UGI Electric Exhibit EWS-4R, there was only one outage in the battery footprint during 2020, compared to four in 2019, eleven in 2018, and eight in 2017. No outages were reported for 2021. Therefore, UGI's vegetation management in the battery footprint may have significantly reduced the need for the battery storage project and additional time may be needed to determine whether the project will provide customers with a significant benefit.

Q. IF THE BATTERY STORAGE PROJECT IS APPROVED BY THE COMMISSION, DID THE COMPANY AGREE TO REPORTING REQUIREMENTS RELATED TO OPERATION OF THE BATTERY?

A. Yes, on page 32 of Company witness Sorber's testimony, UGI St. 3-R, the Company agreed to implement my reporting requirement recommendation that I discussed in my direct testimony if this proposal is approved by the Commission. This includes information concerning the duration, extent, cause, and times for each outage, the duration and times the battery was used to maintain service during the outage, and loads on the facilities served by the battery just prior to and during the outage. This also includes information about the battery's participation in any frequency regulation market and the associated revenues realized by the Company. Such information should be provided on an annual basis.

IV. <u>OSBA WITNESS: ROBERT D. KNECHT</u>

Q. MR. KNECHT CLAIMS THAT YOUR ACOSS WHICH CLASSIFIES THE PRIMARY AND SECONDARY PORTION OF UPSTREAM DISTRIBUTION PLANT AS 100 PERCENT DEMAND-RELATED IMPROPERLY ASSUME THAT THERE ARE NO SCALE ECONOMIES TO PROVIDING ELECTRIC DISTRIBUTION SERVICE TO A LARGER CUSTOMER THAN TO SMALLER CUSTOMERS. (OSBA ST. NO. 1-R, PG. 2). WHAT IS YOUR RESPONSE?

A. As indicated in my direct testimony, UGI electric distribution system consists of approximately 1,250 miles of primary circuit and UGI serves 63,000 customers. Therefore, on average UGI installed approximately 100 feet of primary circuit to serve each customer. As also explained in my direct testimony, UGI extended its primary distribution conductor line by an average of 1,700 feet or 17 times further, to serve three of its largest customers. Of the five largest customers served by UGI, the Company extended its primary distribution conductor line by 1,035 feet, or 10 times further. Clearly it costs more to extend service to a larger customer than a smaller customer.

Q. WHAT IS MR. KNECHT'S RECOMMENDATION CONCERNING YOUR ALTERNATIVE ACOSS WHICH ADJUSTS THE NCP ALLOCATION FACTORS TO ACCOUNT FOR THE PLCC OF THE MINIMUM SYSTEM?

A. Mr. Knecht acknowledges that the concept of adjusting the NCP allocation factors to account for the PLCC of the minimum system has theoretical appeal, and refers to this ACOSS as the OCA PLCC ACOSS. However, he does not recommend adoption of the OCA PLCC ACOSS for two reasons:

(1) For the reasons presented in this direct testimony, Mr. Knecht claims that the Company's ACOSS contains various technical errors relative to the determination of the minimum system costs and the allocation factor used for demand-related costs, and the OCA PLCC ACOSS, which modified the Company's ACOSS, similarly includes those errors; and

(2) The adjustment to the demand allocation factors does not reasonably reflect the PLCC of the minimum system. (OSBA St. No. 1-R, pg. 3).

Q. WHAT IS YOUR RESPONSE TO MR. KNECHT'S CLAIM THAT THE OCA PLCC ACOSS INCLUDES THE SAME MINIMUM SYSTEM ANALYSIS ERRORS REFLECTED IN THE COMPANY'S ACOSS?

A. In his rebuttal testimony, Mr. Taylor claims to have revised the Company's initial ACOSS to correct the minimum system analysis errors identified by Mr. Knecht in Mr. Knecht's direct testimony. As explained in my response to Mr. Taylor, I have accepted the Company's adjustments to correct the errors identified by Mr. Knecht in its Rebuttal ACOSS with respect to the minimum system analysis. Therefore, the errors identified by Mr. Knecht have been eliminated in the OCA PLCC ACOSS.

Q. WHAT IS YOUR RESPONSE TO MR. KNECHT'S CLAIM THAT YOUR ADJUSTMENT TO THE DEMAND ALLOCATION FACTORS DOES NOT REASONABLY REFLECT THE PLCC OF THE MINIMUM SYSTEM?

A. Mr. Knecht claims that any attempt to develop a realistic measure of the PLCC of the minimum system requires an in-depth evaluation of the distribution system, and that the PLCC of the minimum system can vary based on the location of an asset within the distribution system. As explained in my response to Mr. Taylor, the method I have used to determine the PLCC of the minimum system is logical and rational. The PLCC of the minimum system should not be ignored because UGI did not perform an in-depth analysis of its distribution system.

Q. MR. KNECHT CLAIMS THAT IT IS UNCLEAR WHY YOU USED THE RESIDENTIAL CLASS TO DEVELOP YOUR MINIMUM SYSTEM PLCC ADJUSTMENT. (OSBA ST. NO. 1-R, PG. 4). WHAT IS YOUR RESPONSE?

A. UGI serves 63,000 customers, of which 55,000, or nearly 90 percent, are Residential. In its ACOSS, the Company allocated minimum system costs based on the number of customers. Since minimum system cost were allocated based on the number of customers and the vast majority of UGI's customers are Residential, I used the Residential class to determine the PLCC adjustment.

Q. IN YOUR DIRECT TESTIMONY, YOU PRESENTED TWO ACOSS, AND DEVELOPED A CLASS REVENUE DISTRIBUTION BASED ON EACH ACOSS. WHAT IS MR. KNECHT'S RESPONSE TO YOUR PROPOSED REVENUE DISTRIBUTIONS?

A. In my direct testimony I used the indexed rate of return as the metric to determine the movement toward cost based rates under each revenue distribution. Mr. Knecht claims that using the indexed rate of return metric as a measure of progress toward cost based rates is not a reliable approach. (OSBA St. No. 1-R, pg. 7).

Q. WHAT IS YOUR RESPONSE TO MR. KNECHT'S CLAIMS THAT THE INDEXED RATE OF RETURN METRIC IS NOT A RELIABLE APPROACH?

A. The revenue distributions presented in my direct testimony each moved the indexed rate of return for each class 75 percent of the way from the present value towards unity. As shown in Table IEc-R2 in Mr. Knecht's rebuttal testimony, my proposed revenue distributions significantly reduced the subsidy being received by the Residential class, and significantly reduced the subsidies being provided by the other rate classes. Therefore, the indexed rate of return metric is a valid basis to move rates toward the cost of service.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

310732

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
	)	
v.	**)**	**Docket No. R-2021-3023618**
	)	
UGI Utilities, Inc. – Electric Division	**)**	

SCHEDULES ACCOMPANYING THE
SURREBUTTAL TESTIMONY

OF

JEROME D. MIERZWA

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

June 10. 2021

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

UGI Utilities, Inc. - Electric Division
FPFTY Ending September 30, 2022

ALLOCATION OF PRIMARY AND SECONDARY DISTRIBUTION FACILITY COSTS BASED
100 PERCENT ON AVERAGE MONTHLY NON-COINCIDENT PEAK DEMANDS

Schedule JDM-1S

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	Total Check	Residential	General Service-1	General Service-4	Large Power	Lighting
1	**Rate Base**							
2	Plant in Service	227,180	-	147,890	10,677	29,116	34,864	4,633
3	Accumulated Reserve	(74,828)	-	(49,756)	(3,937)	(9,312)	(10,084)	(1,739)
4	Other Rate Base Items	(19,957)	-	(12,534)	(994)	(2,913)	(3,104)	(412)
5	Total Rate Base	132,395	-	85,600	5,745	16,891	21,677	2,482
6	**Total Revenue at Current Rates**							
7	Total Distribution Margin	34,312	-	21,765	1,932	4,655	4,855	1,106
8	Purchased Power Revenue	44,166	-	35,791	1,704	5,074	1,337	260
9	STAS Revenue	(17)	-	(13)	(1)	(2)	(2)	(0)
10	DSIC Revenue	1,995	-	1,298	98	240	302	56
11	USP Rider	3,330	-	3,330	-	-	-	-
12	EEC Rider	2,249	-	864	38	148	1,189	9
13	Forfeited Discounts	517	-	367	41	75	28	6
14	Miscellaneous Revenues	563	-	360	21	78	99	5
15	Total Revenue	87,114	-	63,764	3,833	10,268	7,808	1,442
16	**Expenses at Current Rates**							
17	O&M and A&G Expenses	28,485	-	20,671	1,168	2,356	3,859	430
18	Purchased Power Expense	41,603	-	33,714	1,605	4,779	1,259	245
19	Depreciation and Amortization Expense	7,128	-	4,748	340	858	1,031	151
20	Purchased Power GRT Expense	2,563	-	2,077	99	294	78	15
21	Taxes Other Than Income	3,345	-	2,318	159	361	443	65
22	Income Taxes	(10)	-	(1)	(1)	(4)	(3)	(1)
23	Total Expenses - Current	83,114	-	63,529	3,369	8,644	6,667	905
24	Operating Income - Current	4,000	-	235	464	1,623	1,141	537
25	Current Rate of Return	3.02%		0.27%	8.07%	9.61%	5.26%	21.62%
26	**Present Revenue at Equal Rates of Return**							
27	Present Return	3.02%		3.02%	3.02%	3.02%	3.02%	3.02%
28	Present Operating Income @ Equal Return	4,000	-	2,586	174	510	655	75
29	Income Taxes	(10)	-	(7)	(0)	(1)	(2)	(0)
30	Other Expenses	83,124	-	63,529	3,371	8,648	6,670	906
31	Total Revenue @ Equal Rates of Return	87,114	-	66,109	3,544	9,157	7,323	981
32	Present (Subsidies)/Excesses	-	-	(2,345)	289	1,110	485	460

UGI Utilities, Inc. - Electric Division
FPFTY Ending September 30, 2022

ALLOCATION OF PRIMARY AND SECONDARY DISTRIBUTION FACILITY COSTS BASED MINIMUM SYSTEM ANALYSIS AND AVERAGE OF MONTHLY NON-COINCIDENT PEAK DEMAND FACTORS ADJUSTED TO REFLECT THE PEAK LOAD CARRYING CAPABILITY OF THE MINIMUM SYSTEM

Schedule JDM-2S

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	Total Check	Residential	General Service-1	General Service-4	Large Power	Lighting
1	**Rate Base**							
2	Plant in Service	227,180	-	157,360	12,696	24,605	28,215	4,303
3	Accumulated Reserve	(74,828)	-	(53,139)	(4,662)	(7,685)	(7,723)	(1,620)
4	Other Rate Base Items	(19,957)	-	(13,351)	(1,169)	(2,522)	(2,531)	(384)
5	Total Rate Base	132,395	-	90,870	6,865	14,398	17,962	2,300
6	**Total Revenue at Current Rates**							
7	Total Distribution Margin	34,312	-	21,765	1,932	4,655	4,855	1,106
8	Purchased Power Revenue	44,166	-	35,791	1,704	5,074	1,337	260
9	STAS Revenue	(17)	-	(13)	(1)	(2)	(2)	(0)
10	DSIC Revenue	1,995	-	1,298	98	240	302	56
11	USP Rider	3,330	-	3,330	-	-	-	-
12	EEC Rider	2,249	-	864	38	148	1,189	9
13	Forfeited Discounts	517	-	367	41	75	28	6
14	Miscellaneous Revenues	563	-	406	30	58	65	3
15	Total Revenue	87,114	-	63,809	3,842	10,247	7,775	1,440
16	**Expenses at Current Rates**							
17	O&M and A&G Expenses	28,485	-	21,350	1,301	2,086	3,337	410
18	Purchased Power Expense	41,603	-	33,714	1,605	4,779	1,259	245
19	Depreciation and Amortization Expense	7,128	-	4,985	390	745	866	143
20	Purchased Power GRT Expense	2,563	-	2,077	99	294	78	15
21	Taxes Other Than Income	3,345	-	2,430	182	311	360	62
22	Income Taxes	(10)	-	2	(1)	(5)	(5)	(1)
23	Total Expenses - Current	83,114	-	64,558	3,576	8,211	5,895	874
24	Operating Income - Current	4,000	-	(749)	266	2,037	1,879	567
25	Current Rate of Return	3.02%		-0.82%	3.88%	14.15%	10.46%	24.64%
26	**Present Revenue at Equal Rates of Return**							
27	Present Return	3.02%		3.02%	3.02%	3.02%	3.02%	3.02%
28	Present Operating Income @ Equal Return	4,000	-	2,745	207	435	543	69
29	Income Taxes	(10)	-	(7)	(1)	(1)	(1)	(0)
30	Other Expenses	83,124	-	64,557	3,577	8,216	5,900	875
31	Total Revenue @ Equal Rates of Return	87,114	-	67,295	3,784	8,650	6,441	944
32	Present (Subsidies)/Excesses	-	-	(3,485)	59	1,598	1,333	496

**ALLOCATION OF PRIMARY AND SECONDARY DISTRIBUTION FACILITY COSTS BASED
100 PERCENT ON AVERAGE MONTHLY NON-COINCIDENT PEAK DEMANDS**

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	Total Check	Residential	General Service-1	General Service-4	Large Power	Lighting
1	**Rate Base**							
2	Plant in Service	227,180	-	147,890	10,677	29,116	34,864	4,633
3	Accumulated Reserve	(74,828)	-	(49,756)	(3,937)	(9,312)	(10,084)	(1,739)
4	Other Rate Base Items	(19,957)	-	(12,534)	(994)	(2,913)	(3,104)	(412)
5	Total Rate Base	132,395	-	85,600	5,745	16,891	21,677	2,482
6	**Total Revenue at Current Rates**							
7	Total Distribution Margin	34,312	1	21,765	1,932	4,655	4,855	1,106
8	Purchased Power Revenue	44,166	-	35,791	1,704	5,074	1,337	260
9	STAS Revenue	(17)	-	(13)	(1)	(2)	(2)	(0)
10	DSIC Revenue	1,995	-	1,298	98	240	302	56
11	USP Rider	3,330	-	3,330	-	-	-	-
12	EEC Rider	2,249	-	864	38	148	1,189	9
13	Forfeited Discounts	517	-	367	41	75	28	6
14	Miscellaneous Revenues	563	-	360	21	78	99	5
15	Total Revenue	87,114	-	63,764	3,833	10,268	7,808	1,442
16	**Expenses at Current Rates**							
17	O&M and A&G Expenses	28,485	-	20,671	1,168	2,356	3,859	430
18	Purchased Power Expense	41,603	-	33,714	1,605	4,779	1,259	245
19	Depreciation and Amortization Expense	7,128	-	4,748	340	858	1,031	151
20	Purchased Power GRT Expense	2,563	-	2,077	99	294	78	15
21	Taxes Other Than Income	3,345	-	2,318	159	361	443	65
22	Income Taxes	(10)	-	(1)	(1)	(4)	(3)	(1)
23	Total Expenses - Current	83,114	-	63,529	3,369	8,644	6,667	905
24	Operating Income - Current	4,000	-	235	464	1,623	1,141	537
25	Current Rate of Return	3.02%		0.27%	8.07%	9.61%	5.26%	21.62%
26	**Present Revenue at Equal Rates of Return**							
27	Present Return	3.02%		3.02%	3.02%	3.02%	3.02%	3.02%
28	Present Operating Income @ Equal Return	4,000	-	2,586	174	510	655	75
29	Income Taxes	(10)	-	(7)	(0)	(1)	(2)	(0)
30	Other Expenses	83,124	-	63,529	3,371	8,648	6,670	906
31	Total Revenue @ Equal Rates of Return	87,114	-	66,109	3,544	9,157	7,323	981
32	Present (Subsidies)/Excesses	-	-	(2,345)	289	1,110	485	460

ALLOCATION OF PRIMARY AND SECONDARY DISTRIBUTION FACILITY COSTS BASED 100 PERCENT ON AVERAGE MONTHLY NON-COINCIDENT PEAK DEMANDS

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	Total Check	Residential	General Service-1	General Service-4	Large Power	Lighting
				-0.25%	-0.25%	-0.25%	-0.25%	-0.25%
33	**Revenue Requirement at Equal Rates of Return**							
34	Required Return	7.49%		7.49%	7.49%	7.49%	7.49%	7.49%
35	Required Operating Income	9,916.386	-	6,411	430	1,265	1,624	186
36	**Expenses at Required Return**							
37	O&M and A&G Expenses	28,485	-	20,671	1,168	2,356	3,859	430
38	Purchased Power Expense	41,603	-	33,714	1,605	4,779	1,259	245
39	Depreciation and Amortization Expense	7,128	-	4,748	340	858	1,031	151
40	Purchased Power GRT Expense	2,563	-	2,077	99	294	78	15
41	Taxes Other Than Income	3,345	-	2,318	159	361	443	65
42	Income Taxes	(10)	-	(7)	(0)	(1)	(2)	(0)
43	Gross Up - Income Taxes	2,404	-	1,554	104	307	393	46
44	Gross Up - Gross Receipts & Uncollectibles	707	-	488	33	76	97	13
45	Total Expenses - Required	86,225	-	65,565	3,507	9,029	7,158	965
46	Total Revenue Requirement at Equal Return	96,142	-	71,977	3,938	10,294	8,782	1,151
47	Current Miscellaneous Revenue	1,080	-	728	62	153	126	11
48	Total Revenue @ Equal Rates of Return	95,062	-	71,249	3,876	10,141	8,655	1,140
49	Revenue (Deficiency)/Surplus	(9,028)	-	(8,213)	(105)	(27)	(974)	291
50	Total Base Revenue as Proposed	44,998	-	29,305	2,339	5,718	6,475	1,161
51	Purchased Power Revenue and GRT	44,166	-	35,791	1,704	5,074	1,337	260
52	USP and EEC Revenue	5,579	-	4,195	38	148	1,189	9
53	Miscellaneous Revenue	1,080	-	728	62	153	126	11
54	Total Revenue as Proposed	95,823	-	70,018	4,142	11,093	9,128	1,442
55	Total Distribution Margin Increase as Proposed	8,709	-	6,255	309	825	1,320	0
56	Purchased Power Revenue and GRT Change	-	-	-	-	-	-	-
57	USP and EEC Revenue Change	-	-	-	-	-	-	-
58	Miscellaneous Revenues Change	-	-	-	-	-	-	-
59	Total Revenue as Proposed	8,709	-	6,255	309	825	1,320	0
60	Precent Total Revenue Change	10.00%		9.81%	8.07%	8.03%	16.91%	0.00%
61	Income Prior to Taxes	11,992	-	6,001	739	2,369	2,362	522
62	Income Taxes	2,394	-	1,198	148	473	471	104
63	Operating Income	9,598	-	4,803	591	1,896	1,890	418
64	**Proposed Return**	7.25%		5.61%	10.29%	11.22%	8.72%	16.83%

ALLOCATION OF PRIMARY AND SECONDARY DISTRIBUTION FACILITY COSTS BASED
100 PERCENT ON AVERAGE MONTHLY NON-COINCIDENT PEAK DEMANDS

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY		ACCOUNT BALANCE	Total Check	Residential	General Service-1	General Service-4	Large Power	Lighting
				END					
65	Current Relative Rate of Return		1.00		0.09	2.67	3.18	1.74	7.16
66	Proposed Relative Rate of Return		1.00		0.77	1.42	1.55	1.20	2.32
67	Current Revenue to Cost Ratio		0.92		0.89	0.99	1.01	0.90	1.26
68	Current Parity Ratio		1.00		0.98	1.08	1.10	0.98	1.38
69	Proposed Revenue to Cost Ratio		1.01		0.98	1.07	1.09	1.05	1.26
70	Proposed Parity Ratio		1.00		0.97	1.06	1.09	1.05	1.25
71	Difference from Parity				0.91	(1.67)	(2.18)	(0.74)	(6.16)
72	Movement Percentage	75%			0.68	(1.25)	(1.64)	(0.56)	(4.62)
73	OCA Target Relative Rate of Return				0.77	1.42	1.55	1.19	2.54

ALLOCATION OF PRIMARY AND SECONDARY DISTRIBUTION FACILITY COSTS BASED ON MINIMUM SYSTEM ANALYSIS AND AVERAGE OF MONTHLY NON-COINCIDENT PEAK DEMAND FACTORS ADJUSTED TO REFLECT THE PEAK LOAD CARRYING CAPACITY OF THE MINIMUM SYSTEM

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	Total Check	Residential	General Service-1	General Service-4	Large Power	Lighting
1	**Rate Base**							
2	Plant in Service	227,180	-	157,257	12,912	24,545	28,166	4,299
3	Accumulated Reserve	(74,828)	-	(53,103)	(4,737)	(7,664)	(7,705)	(1,618)
4	Other Rate Base Items	(19,957)	-	(13,342)	(1,188)	(2,517)	(2,527)	(383)
5	Total Rate Base	132,395	-	90,812	6,988	14,364	17,934	2,298
6	**Total Revenue at Current Rates**							
7	Total Distribution Margin	34,312	-	21,765	1,932	4,655	4,855	1,106
8	Purchased Power Revenue	44,166	-	35,791	1,704	5,074	1,337	260
9	STAS Revenue	(17)	-	(13)	(1)	(2)	(2)	(0)
10	DSIC Revenue	1,995	-	1,298	98	240	302	56
11	USP Rider	3,330	-	3,330	-	-	-	-
12	EEC Rider	2,249	-	864	38	148	1,189	9
13	Forfeited Discounts	517	-	367	41	75	28	6
14	Miscellaneous Revenues	563	-	406	31	58	65	3
15	Total Revenue	87,114	-	63,809	3,843	10,247	7,775	1,440
16	**Expenses at Current Rates**							
17	O&M and A&G Expenses	28,485	-	21,344	1,314	2,083	3,334	410
18	Purchased Power Expense	41,603	-	33,714	1,605	4,779	1,259	245
19	Depreciation and Amortization Expense	7,128	-	4,982	396	743	864	143
20	Purchased Power GRT Expense	2,563	-	2,077	99	294	78	15
21	Taxes Other Than Income	3,345	-	2,429	184	311	360	61
22	Income Taxes	(10)	-	2	(1)	(5)	(5)	(1)
23	Total Expenses - Current	83,114	-	64,548	3,598	8,205	5,891	873
24	Operating Income - Current	4,000	-	(739)	245	2,042	1,884	567
25	Current Rate of Return	3.02%		-0.81%	3.51%	14.22%	10.51%	24.68%
26	**Present Revenue at Equal Rates of Return**							
27	Present Return	3.02%		3.02%	3.02%	3.02%	3.02%	3.02%
28	Present Operating Income @ Equal Return	4,000	-	2,743	211	434	542	69
29	Income Taxes	(10)	-	(7)	(1)	(1)	(1)	(0)
30	Other Expenses	83,124	-	64,546	3,598	8,210	5,895	875
31	Total Revenue @ Equal Rates of Return	87,114	-	67,283	3,809	8,643	6,436	944
32	Present (Subsidies)/Excesses	-	-	(3,474)	34	1,604	1,339	496

ALLOCATION OF PRIMARY AND SECONDARY DISTRIBUTION FACILITY COSTS BASED ON MINIMUM SYSTEM ANALYSIS AND AVERAGE OF MONTHLY NON-COINCIDENT PEAK DEMAND FACTORS ADJUSTED TO REFLECT THE PEAK LOAD CARRYING CAPACITY OF THE MINIMUM SYSTEM

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	Total Check	Residential	General Service-1	General Service-4	Large Power	Lighting
				-0.25%	-0.25%	-0.25%	-0.25%	-0.25%
33	**Revenue Requirement at Equal Rates of Return**							
34	Required Return	7.49%		7.49%	7.49%	7.49%	7.49%	7.49%
35	Required Operating Income	9,916.386	-	6,802	523	1,076	1,343	172
36	**Expenses at Required Return**							
37	O&M and A&G Expenses	28,485	-	21,344	1,314	2,083	3,334	410
38	Purchased Power Expense	41,603	-	33,714	1,605	4,779	1,259	245
39	Depreciation and Amortization Expense	7,128	-	4,982	396	743	864	143
40	Purchased Power GRT Expense	2,563	-	2,077	99	294	78	15
41	Taxes Other Than Income	3,345	-	2,429	184	311	360	61
42	Income Taxes	(10)	-	(7)	(1)	(1)	(1)	(0)
43	Gross Up - Income Taxes	2,404	-	1,647	126	262	327	42
44	Gross Up - Gross Receipts & Uncollectibles	707	-	512	38	65	79	13
45	Total Expenses - Required	86,225	-	66,698	3,762	8,536	6,301	929
46	Total Revenue Requirement at Equal Return	96,142	-	73,500	4,286	9,612	7,644	1,101
47	Current Miscellaneous Revenue	1,080	-	773	72	133	93	9
48	Total Revenue @ Equal Rates of Return	95,062	-	72,727	4,214	9,479	7,551	1,092
49	Revenue (Deficiency)/Surplus	(9,028)	-	(9,691)	(443)	636	131	339
50	Total Base Revenue as Proposed	44,998	-	29,905	2,484	5,443	6,005	1,161
51	Purchased Power Revenue and GRT	44,166	-	35,791	1,704	5,074	1,337	260
52	USP and EEC Revenue	5,579	-	4,195	38	148	1,189	9
53	Miscellaneous Revenue	1,080	-	773	72	133	93	9
54	Total Revenue as Proposed	95,823	-	70,664	4,297	10,797	8,625	1,440
55	Total Distribution Margin Increase as Proposed	8,709	-	6,855	454	550	850	0
56	Purchased Power Revenue and GRT Change	-	-	-	-	-	-	-
57	USP and EEC Revenue Change	-	-	-	-	-	-	-
58	Miscellaneous Revenues Change	-	-	-	-	-	-	-
59	Total Revenue as Proposed	8,709	-	6,855	454	550	850	0
60	Precent Total Revenue Change	10.00%		10.74%	11.82%	5.37%	10.93%	0.00%
61	Income Prior to Taxes	11,992	-	5,606	661	2,522	2,650	553
62	Income Taxes	2,394	-	1,119	132	504	529	110
63	Operating Income	9,598	-	4,487	529	2,019	2,121	443
64	**Proposed Return**	7.25%		4.94%	7.57%	14.05%	11.83%	19.26%

ALLOCATION OF PRIMARY AND SECONDARY DISTRIBUTION FACILITY COSTS BASED ON MINIMUM SYSTEM ANALYSIS AND AVERAGE OF MONTHLY NON-COINCIDENT PEAK DEMAND FACTORS ADJUSTED TO REFLECT THE PEAK LOAD CARRYING CAPACITY OF THE MINIMUM SYSTEM

Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY		ACCOUNT BALANCE	Total Check	Residential	General Service-1	General Service-4	Large Power	Lighting
				END					
65	Current Relative Rate of Return		1.00		(0.27)	1.16	4.71	3.48	8.17
66	Proposed Relative Rate of Return		1.00		0.68	1.04	1.94	1.63	2.66
67	Current Revenue to Cost Ratio		0.92		0.88	0.91	1.08	1.03	1.32
68	Current Parity Ratio		1.00		0.96	1.00	1.18	1.12	1.44
69	Proposed Revenue to Cost Ratio		1.01		0.97	1.02	1.14	1.14	1.32
70	Proposed Parity Ratio		1.00		0.96	1.01	1.13	1.13	1.31
71	Difference from Parity				1.27	(0.16)	(3.71)	(2.48)	(7.17)
72	Movement Percentage	75%			0.95	(0.12)	(2.78)	(1.86)	(5.38)
73	OCA Target Relative Rate of Return				0.68	1.04	1.93	1.62	2.79

Independent Statistics & Analysis
U.S. Energy Information Administration

February 2021

Cost and Performance Characteristics of New Generating Technologies, *Annual Energy Outlook 2021*

The tables presented below will be incorporated into the Electricity Market Module chapter of the U.S. Energy Information Administration's (EIA) *Annual Energy Outlook 2021* (AEO2021) Assumptions document. Table 1 represents EIA's assessment of the cost to develop and install various generating technologies used in the electric power sector. Generating technologies typically found in end-use applications, such as combined heat and power or roof-top solar photovoltaics (PV), will be described elsewhere in the Assumptions document. The costs shown in Table 1, except as noted below, are the costs for a typical facility for each generating technology before adjusting for regional cost factors. Overnight costs exclude interest accrued during plant construction and development. Technologies with limited commercial experience may include a technological optimism factor to account for the tendency to underestimate the full engineering and development costs for new technologies during technology research and development.

All technologies demonstrate some degree of variability in cost, based on project size, location, and access to key infrastructure (such as grid interconnections, fuel supply, and transportation). For wind and solar PV, in particular, the cost favorability of the lowest-cost regions compound the underlying variability in regional cost and create a significant differential between the unadjusted costs and the capacity-weighted average national costs as observed from recent market experience. To account for this difference, Table 1 shows a weighted average cost for both wind and solar PV, based on the regional cost factors assumed for these technologies in AEO2021 and the actual regional distribution of the builds that occurred in 2019.

Table 2 shows a full listing of the overnight costs for each technology and electricity region, if the resource or technology is available to be built in the given region. The regional costs reflect the impact of locality adjustments, including one to address ambient air conditions for technologies that include a combustion turbine and one to adjust for additional costs associated with accessing remote wind resources. Temperature, humidity, and air pressure can affect the available capacity of a combustion turbine, and EIA's modeling addresses these possible effects through an additional cost multiplier by region. Unlike most other generation technologies where fuel can be transported to the plant, wind generators must be located in areas with the best wind resources. Sites that are located near existing transmission with access to a road network or are located on lower development cost lands are generally built up first, after which additional costs may be incurred to access sites with less favorable characteristics. EIA represents this possibility through a multiplier applied to the wind plant capital costs that increases as the best sites in a region are developed.

Table 1. Cost and performance characteristics of new central station electricity generating technologies

Technology	First available year[1]	Size (MW)	Lead time (years)	Base overnight cost[2] (2020 $/kW)	Techno-logical optimism factor[3]	Total overnight cost[4,5] (2020 $/kW)	Variable O&M[6] (2020 $/MWh)	Fixed O&M (2020$/ kW-yr)	Heat rate[7] (Btu/kWh)
Ultra-supercritical coal (USC)	2024	650	4	3,672	1.00	3,672	4.52	40.79	8,638
USC with 30% carbon capture and sequestration (CCS)	2024	650	4	4,550	1.01	4,595	7.11	54.57	9,751
USC with 90% CCS	2024	650	4	5,861	1.02	5,978	11.03	59.85	12,507
Combined-cycle—single shaft	2023	418	3	1,082	1.00	1,082	2.56	14.17	6,431
Combined-cycle—multi shaft	2023	1,083	3	957	1.00	957	1.88	12.26	6,370
Combined-cycle with 90% CCS	2023	377	3	2,471	1.04	2,570	5.87	27.74	7,124
Internal combustion engine	2022	21	2	1,813	1.00	1,813	5.72	35.34	8,295
Combustion turbine—aeroderivative[8]	2022	105	2	1,169	1.00	1,169	4.72	16.38	9,124
Combustion turbine—industrial frame	2022	237	2	709	1.00	709	4.52	7.04	9,905
Fuel cells	2023	10	3	6,277	1.09	6,866	0.59	30.94	6,469
Nuclear—light water reactor	2026	2,156	6	6,034	1.05	6,336	2.38	122.26	10,455
Nuclear—small modular reactor	2028	600	6	6,183	1.10	6,802	3.02	95.48	10,455
Distributed generation—base	2023	2	3	1,560	1.00	1,560	8.65	19.46	8,935
Distributed generation—peak	2022	1	2	1,874	1.00	1,874	8.65	19.46	9,921
Battery storage	2021	50	1	1,165	1.00	1,165	0.00	24.93	NA
Biomass	2024	50	4	4,077	1.00	4,078	4.85	126.36	13,500
Geothermal[9,10]	2024	50	4	2,772	1.00	2,772	1.17	137.50	8,946
Municipal solid waste—landfill gas	2023	36	3	1,566	1.00	1,566	6.23	20.20	8,513
Conventional hydropower[10]	2024	100	4	2,769	1.00	2,769	1.40	42.01	NA
Wind[5]	2023	200	3	1,846	1.00	1,846	0.00	26.47	NA
Wind offshore[9]	2024	400	4	4,362	1.25	5,453	0.00	110.56	NA
Solar thermal[9]	2023	115	3	7,116	1.00	7,116	0.00	85.82	NA
Solar photovoltaic (PV) with tracking[5,9,11]	2022	150	2	1,248	1.00	1,248	0.00	15.33	NA
Solar PV with storage[9,11]	2022	150	2	1,612	1.00	1,612	0.00	32.33	NA

[1] Represents the first year that a new unit could become operational.
[2] Base cost includes project contingency costs.
[3] The technological optimism factor is applied to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.
[4] Overnight capital cost includes contingency factors and excludes regional multipliers (except as noted for wind and solar PV) and learning effects. Interest charges are also excluded. The capital costs represent current costs for plants that would come online in 2021.
[5] Total overnight cost for ind and solar PV technologies in the table are the average input value across all 25 electricity market regions, as weighted by the respective capacity of that type installed during 2019 in each region to account for the substantial regional variation in wind and solar costs (as shown in Table 4). The input value used for onshore wind in AEO2021 was $1,268 per kilowatt (kW), and for solar PV with tracking it was $1,232/kW, which represents the cost of building a plant excluding regional factors. Region-specific factors contributing to the substantial regional variation in cost include differences in typical project size across regions, accessibility of resources, and variation in labor and other construction costs throughout the country.
[6] O&M = Operations and maintenance.
[7] The nuclear average heat rate is the weighted average tested heat rate for nuclear units as reported on the Form EIA-860, *Annual Electric Generator Report*. No heat rate is reported for battery storage because it is not a primary conversion technology; conversion losses are accounted for when the electricity is first generated; electricity-to-storage losses are accounted for through the additional demand for electricity required to meet load. For hydropower, wind, solar, and geothermal technologies, no heat rate is reported because the power is generated without fuel combustion and no set British thermal unit conversion factors exist. The model calculates the average heat rate for fossil-fuel generation in each year to report primary energy consumption displaced for these resources.
[8] Combustion turbine aeroderivative units can be built by the model before 2022, if necessary, to meet a region's reserve margin.
[9] Capital costs are shown before investment tax credits are applied.
[10] Because geothermal and hydropower cost and performance characteristics are specific for each site, the table entries show the cost of the least expensive plant that could be built in the Northwest region for hydro and Great Basin region for geothermal, where most of the proposed sites are located.
[11] Costs and capacities are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.
Sources: Input costs are primarily based on a report provided by external consultants: Sargent & Lundy, December 2019. Hydropower site costs for non-powered dams were most recently updated for AEO2018 using data from Oak Ridge National Lab

Table 2. Total overnight capital costs of new electricity generating technologies by region

2020 dollars per kilowatt

Technology	1 TRE	2 FRCC	3 MISW	4 MISC	5 MISE	6 MISS	7 ISNE	8 NYCW	9 NYUP	10 PJME	11 PJMW	12 PJMC	13 PJMD
Ultra-supercritical coal (USC)	3,412	3,512	3,838	3,939	3,985	3,531	4,255	NA	4,159	4,293	3,662	4,614	3,952
USC with 30% CCS	4,308	4,422	4,774	4,903	4,942	4,450	5,272	NA	5,167	5,306	4,594	5,640	4,939
USC with 90% CCS	5,642	5,786	6,173	6,381	6,387	5,841	6,764	NA	6,590	6,775	5,956	7,214	6,331
CC—single shaft	977	997	1,112	1,122	1,151	1,006	1,298	1,722	1,301	1,300	1,078	1,302	1,241
CC—multi shaft	851	872	989	1,006	1,032	882	1,134	1,554	1,115	1,140	934	1,196	1,054
CC with 90% CCS	2,410	2,432	2,599	2,605	2,645	2,455	2,729	3,091	2,667	2,707	2,489	2,822	2,593
Internal combustion engine	1,705	1,743	1,862	1,936	1,915	1,766	1,984	2,487	1,909	1,985	1,778	2,164	1,847
CT—aeroderivative	1,034	1,056	1,223	1,226	1,263	1,077	1,315	1,684	1,269	1,308	1,122	1,437	1,190
CT—industrial frame	626	639	742	746	768	653	801	1,033	771	797	680	877	723
Fuel cells	6,589	6,691	6,997	7,299	7,160	6,804	7,428	8,745	7,126	7,364	6,784	7,851	6,993
Nuclear—light water reactor	5,981	6,110	6,450	7,036	6,786	6,309	7,177	NA	6,696	7,013	6,199	7,711	6,451
Nuclear—small modular reactor	6,338	6,486	7,066	7,369	7,366	6,567	7,608	NA	7,246	7,623	6,648	8,506	6,904
Dist. generation—base	1,408	1,437	1,603	1,618	1,659	1,450	1,871	2,482	1,876	1,874	1,554	1,877	1,788
Dist. Generation—peak	1,657	1,692	1,959	1,965	2,024	1,727	2,108	2,698	2,034	2,096	1,798	2,303	1,907
Battery storage	1,165	1,168	1,151	1,207	1,168	1,192	1,201	1,196	1,169	1,173	1,162	1,177	1,173
Biomass	3,784	3,887	4,208	4,348	4,358	3,919	4,842	6,572	4,857	4,942	4,156	4,951	4,736
Geothermal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
MSW—landfill gas	1,476	1,508	1,606	1,673	1,652	1,530	1,713	2,133	1,647	1,711	1,538	1,861	1,596
Conventional hydropower	4,040	4,935	1,963	1,305	2,657	3,932	1,819	NA	3,722	3,866	3,370	NA	3,420
Wind	2,477	NA	1,395	1,268	1,518	1,268	1,680	NA	2,049	1,680	1,268	1,846	1,750
Wind offshore	5,325	6,390	6,304	NA	6,529	NA	6,360	5,486	6,652	6,097	4,985	7,219	5,679
Solar thermal	6,865	6,969	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Solar PV with tracking	1,214	1,191	1,232	1,278	1,264	1,202	1,276	1,501	1,264	1,301	1,229	1,341	1,226
Solar PV with storage	1,561	1,577	1,624	1,677	1,653	1,593	1,687	1,917	1,656	1,690	1,588	1,757	1,643

Technology	14 SRCA	15 SRSE	16 SRCE	17 SPPS	18 SPPC	19 SPPN	20 SRSG	21 CANO	22 CASO	23 NWPP	24 RMRG	25 BASN
Ultra-supercritical coal (USC)	3,533	3,586	3,634	3,557	3,779	3,597	3,748	NA	NA	3,971	3,712	3,873
USC with 30% CCS	4,454	4,496	4,563	4,466	4,713	4,508	4,703	NA	NA	4,942	4,653	4,828
USC with 90% CCS	5,852	5,904	5,974	5,821	6,117	5,863	6,098	NA	NA	6,398	6,008	6,287
CC—single shaft	993	1,005	1,036	1,004	1,066	995	978	1,432	1,399	1,138	922	996
CC—multi shaft	872	883	915	882	947	874	842	1,259	1,225	987	793	889
CC with 90% CCS	2,424	2,437	2,492	2,428	2,509	2,391	2,212	2,774	2,743	2,559	2,080	2,336
Internal combustion engine	1,776	1,781	1,812	1,763	1,858	1,781	1,798	2,155	2,116	1,916	1,775	1,900
CT—aeroderivative	1,071	1,081	1,121	1,079	1,155	1,087	981	1,381	1,347	1,211	949	1,082
CT— industrial frame	649	655	680	654	701	658	594	844	822	737	575	657
Fuel cells	6,853	6,848	6,942	6,728	7,010	6,789	6,884	7,887	7,796	7,209	6,751	7,191
Nuclear—light water reactor	6,390	6,340	6,546	6,135	6,487	6,133	6,361	NA	NA	6,885	6,162	6,893
Nuclear—small modular reactor	6,600	6,651	6,802	6,584	6,993	6,640	6,728	NA	NA	7,285	6,656	7,235
Dist. Generation—base	1,432	1,449	1,493	1,448	1,536	1,434	1,409	2,064	2,017	1,641	1,328	1,436
Dist. Generation—peak	1,717	1,732	1,797	1,729	1,852	1,741	1,572	2,213	2,158	1,941	1,521	1,734
Battery storage	1,203	1,186	1,201	1,159	1,167	1,153	1,180	1,213	1,216	1,193	1,155	1,201
Biomass	3,934	3,963	4,016	3,937	4,183	4,020	4,305	5,515	5,390	4,451	4,265	4,265
Geothermal	NA	NA	NA	NA	NA	NA	2,825	2,802	2,269	2,742	NA	2,772
MSW—landfill gas	1,539	1,541	1,568	1,525	1,605	1,539	1,555	1,857	1,825	1,655	1,534	1,642
Conventional hydropower	1,904	4,130	2,135	4,086	1,722	1,619	3,282	3,473	3,344	2,769	3,306	3,613
Wind	1,512	1,713	1,268	1,395	1,395	1,395	1,395	2,799	2,418	1,848	1,395	1,395
Wind offshore	4,907	NA	NA	NA	NA	NA	NA	8,224	8,628	6,170	NA	NA
Solar thermal	NA	NA	NA	6,934	7,203	6,864	7,193	8,473	8,367	7,656	6,912	7,671
Solar PV with tracking	1,251	1,188	1,228	1,190	1,237	1,199	1,211	1,348	1,341	1,241	1,225	1,236
Solar PV with storage	1,604	1,588	1,607	1,577	1,628	1,594	1,602	1,756	1,751	1,656	1,595	1,653

NA = not available; plant type cannot be built in the region because of a lack of resources, sites, or specific state legislation.

USC = ultra-supercritical, CCS = carbon capture and sequestration, CC = combined cycle, CT = combustion turbine, PV = photovoltaic, MSW = municipal solid waste

Electricity Market Module region map

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis

Notes: Costs include contingency factors, regional cost, and ambient conditions multipliers. Interest charges are excluded. The costs are shown before investment tax credits are applied.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3023618
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Jerome D. Mierzwa, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement 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).

DATED: June 10, 2021
*310227

Signature: Jerome D. Mierzwa
Jerome D. Mierzwa

Consultant Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044-3575

OCA Statement No. 4-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2021-3023618
UGI Utilities – Electric Division	:	

Surrebuttal Testimony of
Roger D. Colton

On Behalf of:
Office of Consumer Advocate
Statement No. 4-SR

June 10, 2021

Table of Contents

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, MA.

Q. ARE YOU THE SAME ROGER COLTON WHO PREVIOUSLY PREPARED 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 to respond to the Rebuttal Testimony of:

- Company witness Christopher Brown (UGI Electric St. 1-R);
- Company witness Daniel Adamo (UGI Electric St. 10-R); and
- Company witness John Taylor (UGI Electric St. 8-R).

Part 1. Response to Christopher Brown.

Q. TO WHAT PART OF MR. BROWN'S REBUTTAL TESTIMONY DO YOU RESPOND?

A. UGI Electric witness Brown acknowledges that in my Direct Testimony, I propose to defer consideration of the allocation of universal service costs for UGI Utilities (including UGI Gas and UGI Electric) to the next UGI Gas base rate proceeding. He agrees with the proposal not to consider the issue in this proceeding. (UGI Electric St. 1-R, at 13). He states, however, that "such a change in reallocation of universal service costs would mark a major policy shift that would affect all electric utilities in

Pennsylvania. Therefore, this issue should only be considered by the Commission in a statewide proceeding." (Id.). The fallacy of that statement lies in the fact that the Commission ***did*** consider the issue in a statewide proceeding involving all Pennsylvania utilities and every stakeholder who wished to participate. (Docket M-2019-3012599).[1] The Commission stated in its Final Order in that Docket (hereafter, Final Order) that "the Commission finds it appropriate to consider recovery of the costs of CAP costs from all ratepayer classes. Utilities and stakeholders are advised to be prepared to address CAP cost recovery ***in utility-specific rate cases*** consistent with the understanding that the Commission will no longer routinely exempt non-residential classes from universal service obligations. . ." (Id., at 99, notes omitted). While the PUC did not say that the issue should necessarily be addressed in the ***next*** base rate case, it did explicitly reject the proposal advanced by Mr. Brown in his Rebuttal Testimony.

Mr. Brown's testimony is related to similar testimony advanced by UGI Electric witness Adamo, which testimony on this specific issue only I will address here (rather than below where I respond to Mr. Adamo's remaining Rebuttal Testimony). Mr. Adamo states that "I want to make clear that to the extent Mr. Colton's testimony is, or could be, construed as a proposal to reallocate universal service costs as a part of this proceeding, that the Company opposes this proposal."(UGI Electric St. 10-R, at 35). My Direct Testimony seemed to be clear. I stated: "I do not present the issue of the allocation of universal service costs in this proceeding, but reserve this issue for a future proceeding." (OCA St. 5, at 52). I stated further that "I do not propose that the PUC consider a reallocation in

[1] http://www.puc.pa.gov/about_puc/consolidated_case_view.aspx?Docket=M-2019-3012599 (November 5, 2019) (last accessed June 3, 2021).

this proceeding." (OCA St. 5, at 48). There is no proposal in my Direct Testimony for the Company to "oppose" in this proceeding.

Part 2. Response to Daniel Adamo.

Q. WHAT IS THE FIRST ISSUE RAISED IN MR. ADAMO'S REBUTTAL TESTIMONY TO WHICH YOU WISH TO RESPOND?

A. Mr. Adamo's responds to my Direct Testimony regarding the relationship between low-income status and electricity consumption in his Rebuttal Testimony. His Rebuttal Testimony is consistently based on a flawed analysis and should not be relied upon as a basis for decision making in this proceeding.

For example, Mr. Adamo responds to my testimony that 22.6% of the population in UGI Electric's service territory has income less than 150% of Poverty Level. He asserts, however, that my analysis "speaks nothing to the source of energy in the home and is otherwise not subject to verification." (UGI Electric St. 10-R, at 24). He does not suggest what energy source would be a potential replacement for electricity in the home.[2] He offers no data indicating that any household, let alone any substantial number of households, use a "source of energy" in lieu of electricity. Mr. Adamo further asserts that the number of "estimated" low-income customers should not be considered in this proceeding. He does not acknowledge that the number of "estimated" low-income customers is a metric prescribed and defined by the Commission.

[2] The question is not who heats with electricity. The question is what percentage of the total population uses electricity in the UGI Electric service territory.

Mr. Adamo finally asserts that my quantification of the increased bill level imposed on low-income customers by the Company's proposed increase in its fixed customer charge "does not account for the numerous customer protections. . .(as a result of COVID-19), the company's ability to place customers on CAP (in accordance with its USECP plan) and the offsetting provisions that these customers may receive if they are able to enroll in CAP, especially on a PIP plan." (UGI Electric St. 10-R at 24 – 25). He does not attempt to rebut the fact, as I document in my Direct Testimony, that UGI Electric has confirmed the low-income status of only a fraction of its total low-income population, and that it enrolls only a fraction of that fraction of Confirmed Low-Income customers in CAP. Overall, four-of-five of UGI Electric's low-income customers are neither affected by the "numerous customer protections" nor protected by the Company's CAP.

Mr. Adamo disagrees with my conclusion that the increased customer charge will have the same adverse impact on low-income customers as eliminating LIHEAP benefits to the Company's low-income customers. His entire explanation is as follows: "Q. Do you agree with Mr. Colton's conclusion. . .? Q. No." (UGI Electric St. 10-R, at 25). The fact remains that LIHEAP provided $436,996 in cash grants to UGI Electric customers in the 2019-2020 LIHEAP program year. The Company proposes to increase low-income bills by $822,204 simply through the increase in the customer charge. The total amount of LIHEAP benefits flowing to UGI Electric low-income customers will be offset by nearly two times the dollar amount simply by UGI Electric's proposed increase in its unavoidable fixed customer charge.

Q. PLEASE RESPOND TO MR. ADAMO'S REBUTTAL TESTIMONY REGARDING THE IMPACT OF INCREASING THE CUSTOMER CHARGE ON LOW-INCOME PAYMENT DIFFICULTIES.

A. Mr. Adamo disagrees with my data analysis leading to the conclusion that increasing bills through an increased customer charge to low-income customers will result in increased low-income payment difficulties. (UGI Electric St. 10-R, at 26 – 30). He states that "Mr. Colton's claim ignores the impacts of the Company's CAP. . ." (UGI Electric St. 10-R, at 26). Mr. Adamo asserts that "this issue should be addressed in the way low-income programs are designed and not in the context of a base rate proceeding." (UGI Electric St. 10-R, at 28). The failure of this argument lies, as noted above, in Mr. Adamo's failure to acknowledge that the Company's CAP fails to serve 80% (four-of-five) of the Company's low-income customer base. While Mr. Adamo asserts that "UGI Electric is not purposefully under-enrolling customers in its CAP program as Mr. Colton insinuates,"[3] that statement is a red herring. It does not matter <u>*why*</u> UGI Electric serves only one-of-five of its low-income customers through CAP. The conclusion remains that for the other four-of-five low-income customers, CAP does not serve to protect those low-income customers from the harms of the proposed increase in the residential customer charge.

Q. PLEASE RESPOND TO MR. ADAMO'S REBUTTAL TESTIMONY REGARDING THE RELATIONSHIP BETWEEN INCOME AND ELECTRICITY USE.

[3] He does not cite any specific basis for his claim that I "insinuated" UGI Electric was "purposefully under-enrolling customers in its CAP" and no such conclusion can reasonably be found in my Direct Testimony.

A. Mr. Adamo disagrees with my conclusion that low-income customers are disproportionately likely to be low-use customers. (UGI Electric St. 10-R, at 25, 32-33). He states that "the Company's own data indicates that low-income customers are generally high-use customers." (UGI Electric St. 10-R, at 25). He asserts that the Company's own data "supports the findings that the Company's low-income customers do have a higher average use per customer." (UGI Electric St. 10-R, at 32).

Mr. Adamo does not respond to my observation that my Direct Testimony "is not to say that all low-income customers are low-use customers, nor that all low-use customers are low-income. It can hardly be questioned, however, that in the UGI-Electric service territory, low-income customers will disproportionately be low-use customers." In reviewing the data presented by Mr. Adamo, remember that due to the very nature of UGI Electric's CAP (as a percentage of income program), CAP participants will be higher users. This is true because if a low-income customer was not a high user, the percentage of income payment imposed through the CAP would be higher than the actual bill incurred by the customer and the customer would not participate in CAP. By design, UGI Electric's CAP is intended to reduce the bill burdens (i.e., bills as a percentage of income) imposed by higher usage to a more affordable level. Under its existing CAP (remember that the petition to adopt the reduced CAP burdens has not yet been approved by the Commission), for example, if a low-income customer's bill is 6% of income, the customer would be better off by not participating in PIP. PIP is, by design, directed toward higher use customers.

Q. DOESN'T TABLE 8 IN UGI ELECTRIC STATEMENT 10-R DEMONSTRATE THAT LOW-INCOME CUSTOMERS ON AVERAGE HAVE HIGHER CONSUMPTION THAN RESIDENTIAL CUSTOMERS AS A WHOLE?

A. No. For the reasons I explain above, CAP participants will, by design, have higher usage than low-income customers who are not CAP participants. That observation is reflected in Table 8 (page 33) of Mr. Adamo's Rebuttal Testimony. One can see how CAP usage drives Mr. Adamo's "low-income" usage by the fact that the increased CAP usage (from 1217 in FY 20 to 1355 in FY21 YTD) has the effect of driving the "low-income" usage up by a corresponding amount.

It is interesting, however, that while Mr. Adamo presents a bar graph of "non-CAP/non-low income," he does *not* present a bar graph of "non-CAP/low-income." We know that CAP participants represent 66% of the total Confirmed Low-Income customer base, and 20% of the total estimated low-income customer base. By simple arithmetic, we can remove the CAP usage from either or both of those populations. For example, if we remove the high CAP usage from the Confirmed Low-Income customer base, the Company's data would show average annual consumption of: (1) 558 kWh (FY9); (2) 597 kWh (FY20); and (3) 591 kWh (FY21 YTD).

In sum, Mr. Adamo's Table 8 proves my initial observation rather than disproving it. All Mr. Adamo's Table 8 does is to add in a small percentage of high use low-income customers (given that CAP involves high use customers by design) to achieve a higher "average" low-income consumption. If one recognizes the disproportionate impact on the “average” that that small number of CAP customers will have –remember UGI Electric enrolls fewer than 20% of its low-income customers in CAP-- the conclusion in my Direct Testimony that low-income customers (as a whole) will disproportionately be low use customers is supported rather than rebutted by Mr. Adamo’s own data.

Q. PLEASE RESPOND TO MR. ADAMO’S REBUTTAL TESTIMONY REGARDING THE NEED FOR A COMPANY-SPONSORED COVID-19 RELIEF PROGRAM.

A. Mr. Adamo opposes any financial relief provided from UGI Electric through an Emergency Relief Program (ERP) to its customers adversely economically affected by COVID-19. He argues that there has been “continuous improvement in the economic conditions of households in Pennsylvania. (UGI Electric St. 10-R, at 14). He notes that the percentage of households finding it “very difficult” to pay their usual household expenses has fallen to 7.3% in Week 29 of the Survey.

What Mr. Adamo does *not* reveal is that he included all income levels in that figure. The population of households with income exceeding $200,000 finding it “very difficult,” for example, has fallen to 0%, while the population of households with income between $150,000 and $200,000 finding it “very difficult” has fallen to 1.4%. The population of households with income between $100,000 and $150,000 finding it “very difficult” to pay their usual household expenses has fallen to 1.9%. These populations represent more than 30% of the populations reporting. They are not the populations to whom an Emergency Relief Program (ERP) would be directed.

What Mr. Adamo did *not* reveal is that the percentage of households with income less than $25,000 finding it "very difficult" to pay household expenses remained above 20% in Week 29 (i.e., the week he reported), and increased to nearly 30% in Week 30. If one excludes these three populations with income exceeding $100,000, Mr. Adamo's conclusion that there is "continuous improvement" is simply wrong.

The Table below presents the PULSE Survey results starting with the last week I used in my Direct Testimony and extending it to the most recent PULSE Survey results available as of the date of this Surrebuttal Testimony (Week 30: data released June 2, 2021).

Table 1. Percent of Households (PA) Having "Very Difficult" Time Paying Usual Household Expenses in COVID-19 Pandemic (Households with Income < $50,000) (Census PULSE Survey)

	Week of PULSE Survey			
Income Range	27[4]	28	29[5]	30[6]
< $25,000	26.9%	34.0%	21.4%	28.6%
$25,000 - $34,999	6.9%	16.6%	19.0%	20.5%
$35,000 - $49,999	5.0%	2.6%	15.3%	17.1%

As can be seen, rather than the "continuous improvement" reported by Mr. Adamo:

- The percentage of households with income below $25,000 having a "very difficult" time was 28.6% in Week 30, compared to 26.9% in Week 27.

[4] This was the most recent week used in my Direct Testimony, the most recent Census PULSE Survey available at the time that testimony was written.

[5] This is the week used in Mr. Adamo's Rebuttal Testimony.

[6] This is the week that, at the time this Surrebuttal Testimony is written, is the most recent PULSE Survey available.

- The percentage of households with income between $25,000 and $35,000 having a “very difficult” time was 20.5% in Week 30, compared to 6.9% in Week 27.
- The percentage of households with income between $35,000 and $50,000 having a “very difficult” time was 17.1% in Week 30, compared to 5.0% in Week 27.

If you exclude those households who are well-off, difficulties have increased in the weeks since my Direct Testimony, not “continuously improved” as claimed by Mr. Adamo.

Mr. Adamo’s reference to an increase in savings as a percentage of personal income is similarly flawed in not considering incomes. One thing we all know as common knowledge is that during COVID-19, the economy was largely shutdown. Eating establishments were closed. Ballgames, concerts and theatres were shuttered. Vacations were abandoned. A considerable amount of money that would normally have been spent, by those having the money to do the spending, was placed into savings instead. Table 2 below begins to show the impact of this decrease as reported by the U.S. Bureau of Labor Statistics Consumer Expenditures (CEX) Survey. I note that this only *begins* to capture the reduced spending attributable to COVID-19. The CEX survey for the full year of 2020 is not yet publicly available. The data below is reported for mid-year (i.e., from July 2019 through June 2020). While the spending of lower income households had not been substantially affected, even by June 2020, the spending on higher income households had been. Through the first four months of the pandemic (March through June 2020), spending by households earning $200,000 or more had been reduced by nearly $12,000; spending by households earning $150,000 to $200,000 had been reduced by nearly $9,000. The data below shows that reductions in spending, by those who had money to spend, occurred in sectors where we might have expected: for example, entertainment; food away from home; fees and admissions.

Table 2. Change in Expenditures by Income (2018=2019 vs. 2019-2020) (mid-year)
(U.S. Bureau of Labor Statistics, Consumer Expenditures Survey)

	All consumer units	**Less than $15,000**	**$15,000 to $29,999**	**$30,000 to $39,999**	**$40,000 to $49,999**	**$50,000 to $69,999**	**$70,000 to $99,999**	**$100,000 to $149,999**	**$150,000 to $199,999**	**$200,000 and more**
					Mean annual expenditures					
2018-2019	$62,438	$25,947	$33,480	$41,323	$46,771	$54,382	$65,863	$85,206	$110,180	$162,660
2019-2020	$61,749	$26,065	$32,709	$40,691	$45,821	$51,335	$65,192	$83,800	$101,313	$150,838
					Food Away from Home					
2018-2019	$3,434	$1,440	$1,655	$2,245	$2,550	$2,961	$3,551	$4,786	$6,176	$9,074
2019-2020	$2,994	$1,158	$1,463	$2,041	$2,548	$2,536	$3,158	$4,027	$4,905	$6,785
					Entertainment					
2018-2019	$3,185	$1,163	$1,503	$1,856	$2,094	$2,501	$3,257	$4,317	$5,979	$10,222
2019-2020	$2,864	$974	$1,385	$2,175	$2,028	$2,034	$2,776	$4,370	$5,312	$6,883
					Fees and Admissions					
2018-2019	$891	$254	$175	$299	$339	$456	$756	$1,048	$1,755	$5,262
2019-2020	$623	$98	$145	$226	$256	$383	$520	$919	$1,559	$2,509

All Mr. Adamo's data on personal savings indicates is that people who were well-off before the pandemic remained well-off, and the shutdown of the economy restricted their ability to engage in their typical spending. It provides no insights whatsoever into the need for an ongoing Emergency Relief Program for those who were hard hit economically, with a resulting difficulty in paying their normal household expenses.

Q. PLEASE RESPOND TO MR. ADAMO'S DISCUSSION OF AVAILABLE FEDERAL AND UGI ELECTRIC PROGRAMS.

A. Mr. Adamo asserts that there is no need for additional financial assistance provided by UGI Electric through an ERP because there is federal financial relief that has been made available. (UGI Electric St. 10-R, at 8 – 11). He acknowledges, however, that that federal financial relief has reached a total of 31 customers (Id., at 9), out of the nearly 6,000 residential customers who were more than 90 days in arrears. The federal program has provided roughly $22,000 of assistance (Id., at 9), while arrearages greater than 90-days old remained in excess of $6 million. To respond to those customers 90-days older (or older), owing in excess of $6 million, UGI Electric has committed to increase its donations to its hardship fund by $20,000 (from $60,500 to $80,500). (Id., at 11),

The reduction of CAP percentage of income burdens, of course, has nothing to do with COVID-19 relief. That reduction in percentage of income burdens was recommended by the Commission in its Revised CAP Policy Statement in 2019, adopted months before anyone had ever heard the words "coronavirus" or "COVID-19." Moreover, as I have discussed in detail elsewhere, the Company's outreach for CAP has resulted in fewer than one-of-five eligible customers being enrolled in the program.

In sum, nothing that Mr. Adamo discusses in his Rebuttal Testimony demonstrates that the economic crisis created by COVID-19 can be expected to be resolved in the foreseeable future. Federal resources that have been provided come nowhere close to being adequate to address the nonpayment situations facing UGI Electric customers (both low-income and near-low-income). UGI Electric resources that have been committed are extraordinarily limited. To address the continuing economic crisis facing UGI Electric customers, an Emergency Relief Program, with clear limitations (e.g., arrears exceeding $200), and extensive cost control mechanisms as I recommended in my Direct Testimony, is merited.

Q. PLEASE RESPOND TO MR. ADAMO'S REBUTTAL TESTIMONY REGARDING YOUR RECOMMENDED LOW-INCOME OUTREACH.

A. Mr. Adamo's Rebuttal Testimony asserts that there is no need for UGI Electric to make any changes in its outreach to, and identification of, low-income customers. Identifying low-income customers is important not only for purposes of enrolling customers in CAP, but for purposes of extending a variety of customer service protections directed specifically toward Confirmed Low-Income customers.

Mr. Adamo asserts that there is no need to change the way UGI Electric identifies low-income customers because, he asserts, UGI Electric "follows the BCS's direction in confirming low-income residential customers. . .” (UGI Electric St. 10-R, at 37). Moreover, he asserts, there is no need for UGI Electric to adopt a Public Partnership Outreach Plan (PPOP) because it held eight WARM events and maintains a Universal Service Advisory Committee (USAC). (UGI Electric St. 10-R, at 38 – 40). Mr. Adamo asserts that my recommendations “would not only duplicate the Company’s efforts, but also duplicate the costs of such programs that are already reflected in the Company’s rates.” (UGI Electric St. 10-R, at 40).

My recommendations, however, demonstrate the need to expand the Company’s efforts, not merely to duplicate what it is already doing. Mr. Adamo, for example, does not rebut the data and analysis presented in my Direct Testimony demonstrating that UGI Electric’s current efforts are “missing” more than four-of-five low-income customers in its service territory. Mr. Adamo does not acknowledge, let alone rebut, that if UGI Electric were to enroll CAP customers simply at the rate that the federal Food Stamp program was enrolled, it would enroll nearly 5,100 more CAP participants. Mr. Adamo does not acknowledge, let alone rebut, the fact that if UGI Electric were to engage in targeted low-income outreach simply in the five school districts which had between 40% and 90% of their students eligible for the national school meal program (which would make those households eligible for CAP), it would have enrolled more than 2,300 additional CAP participants if they enrolled at the same rate as households enroll in Food Stamps (SNAP).

The conclusion in my Direct Testimony was that: "It would be unreasonable for UGI Electric to assume that a household would be sufficiently in need of, and sufficiently interested in, assistance to the point that they would apply for both Food Stamps for their family and subsidized school meals for their children, but would actively decline to apply for, and participate in, the UGI Electric energy assistance program if given the opportunity to do so. Substantial partnerships exist for UGI Electric to pursue, which it is not pursuing at this point, to make CAP participation more widely available in its service territory." (OCA St. 5, at 58).

It is not, however, simply my conclusion that is important. The data and analysis I presented in my Direct Testimony supports the same conclusions that the Commission previously reached in reviewing utility CAP outreach efforts. In its Final Order adopting the Revised CAP Policy Statement in 2019, the PUC stated quite explicitly that:

> While utilities have flexibility as to the contents of their plans, the plans should reflect focused consumer education and outreach efforts, tailored to the demographics of their individual service territories, spanning the duration of the universal service plan period. *In particular, these plans should identify efforts to educate and enroll eligible and interested customers at or below 50% of the FPIG.*

(Final Order, at 79) (emphasis added). Mr. Adamo's rebuttal testimony, which asserts that what UGI Electric is doing is completely adequate, ignores the PUC's findings that:

- "While there is no specific regulatory mandate that each utility must enroll a certain percentage of low-income households in CAP, the near uniform disparity between the total number of potential income-qualified households and those actually receiving assistance *calls into question the overall adequacy of consumer education and outreach*." (Final Order, supra, at 78) (emphasis added).

- ➢ "This fact pattern *does not convince us that needs are being met*, but rather it illuminates the *need for increased awareness*. We have noted in various USECP proceedings the *necessity for utilities to develop more robust efforts to reach customers*, particularly the very marginal, for enrollment in universal service programs." (Id.) (emphasis added).

The Commission has, in other words, specifically found that the existing performance of utilities "calls into question the adequacy" of outreach; that existing performance "does not convince us that needs are being met"; and that existing performance demonstrates "the necessity for utilities to develop more robust efforts to reach customers." The data I presented in my Direct Testimony supports the conclusion that these Commission findings apply to UGI Electric. Mr. Adamo provides no rebuttal indicating that UGI Electric has responded to the previously expressed Commission's concerns, as supported by my Direct Testimony, but instead insists that what UGI Electric is doing is just fine.

Q. PLEASE RESPOND TO MR. ADAMO'S TESTIMONY REGARDING YOUR RECOMMENDATIONS REGARDING THE TARIFF PROVISION SETTING FORTH INCOME VERIFICATION FOR WINTER SHUTOFF PROTECTIONS.

A. Mr. Adamo opposes my recommended changes to the UGI Tariff setting forth required income verification to establish eligibility for the Pennsylvania PUC's winter shutoff protections. Mr. Adamo's opposition did not even acknowledge the accuracy of my assertion that the UGI Electric tariff was "out-of-date" even though the tariff language refers to a state agency that no longer exists (DPW). (UGI Electric St. 10-R, at 43).

Mr. Adamo further asserts that UGI Electric's practices do not follow the language of the UGI Electric tariff. For example, Mr. Adamo states that "UGI Electric accepts verbal confirmations that customers' household incomes are at/below 250% of the federal poverty level to avoid winter termination" even though verbal verifications are not permitted under the terms of the UGI Electric tariff. He states that "income documentation also is not required to prevent shut off during winter moratorium (sic) for those verbally declaring low-income status." (UGI Electric St. 10-R, at 45). Verbal declarations, however, are not provided for pursuant to the UGI Electric tariff.

Mr. Adamo's rebuttal testimony supports rather than rebuts the need to modify the existing UGI Tariff. Particularly when actual practices do not reflect the tariff language, there is a need for a change in the tariff language. When the tariff requires income documentation from a state agency that no longer exists, there is a need for a change in the tariff language. The recommendation I made with respect to the tariff language regarding the income documentation needed to establish eligibility for winter shutoff protections should be adopted.

Q. PLEASE RESPOND TO MR. ADAMO'S TESTIMONY RESPONDING TO YOUR RECOMMENDATION CONCERNING CHANGES TO THE UGI ELECTRIC TARIFF PROVISION REGARDING CHANGES IN CUSTOMER DEPOSITS ATTRIBUTABLE TO MATERIAL CHANGES IN THE CHARACTER OR DEGREE OF USAGE.

A. Mr. Adamo opposes my recommendation that UGI Electric modify its tariff provision regarding setting the level of a cash security deposit to implement Section 56.51 of the PUC's customer service regulations. That regulation provides that the level of a customer's cash security deposit "may be adjusted at the request of the customer or the public utility whenever the character or degree of the usage of the customer has materially changed or when it is clearly established that the character or degree of service will materially change in the immediate future."

Mr. Adamo's only basis for opposing my recommendation is his assertion that "at the time customers qualify for LIURP, a security deposit is not required and if one is currently being held, it is refunded to the customer." (UGI Electric St. 10-R, at 48). He thus concludes that my proposal is not necessary.

Mr. Adamo's conclusion may be well-founded if the only usage reduction investments directed toward low-income customers came through LIURP. My Direct Testimony, however, anticipated that observation and specifically noted: "It is not merely LIURP that would deliver usage reduction services to low-income customers." (OCA St. 5, at 73). My Direct Testimony went on to discuss the various public programs through which low-income usage reduction investments were delivered outside the confines of the LIURP program. Accordingly, Mr. Adamo's rebuttal should not serve as a basis for rejecting my recommendation.

Part 3. Response to John Taylor.

Q. PLEASE RESPOND TO MR. TAYLOR'S REBUTAL TESTIMONY REGARDING USAGE AND INCOME.

A. Mr. Taylor asserts in his Rebuttal Testimony that the Commission should not rely on the Zip Code data I consider in my Direct Testimony "rather than UGI Electric's own data that provides insights into the Company's actual customer usages." (See, e.g., UGI Electric St. 6-R, at 37, 38). His reference, however, is to "Company data" presented by UGI Electric rebuttal witness Mr. Adamo. As I demonstrate above, however, Mr. Adamo's "actual data" only documents that CAP customers have higher consumption, a conclusion that I have freely conceded. By design, CAP participants will have higher consumption. If they had lower consumption, and the lower energy bills/burdens that are associated with that lower consumption, they would not be participating in CAP since their bills at standard residential rates would be lower than their bills would be at the CAP percentage of income. This population of high usage CAP customers, however, is a small percentage of UGI Electric low-income customers. UGI Electric enrolls less than one-in-five of its low-income customers in CAP.

Using Mr. Adamo's own data, if one subtracts out this small population of low-income customers who participate in CAP, the remaining, much larger, low-income non-CAP population has a usage that is substantially lower than the usage identified by Mr. Adamo as being associated with non-CAP, non-low-income customers. Rather than contradicting my Direct Testimony, the "actual data" presented by Mr. Adamo is entirely consistent with my analysis of the association between incomes and the factors that are associated with low usage (e.g., size of housing unit, type of housing unit [e.g., 1-family home vs. apartment], tenure of household [e.g., owner vs. renter], etc.). Moreover, Mr. Adamo's data is entirely consistent with the U.S. Energy Information Administration's (EIA) data on the relationships between various factors and lower usage.

Mr. Taylor seeks to limit my testimony when he states in his rebuttal that my conclusion is simply "that low-income customers use less electricity because they live in smaller housing units." (UGI Electric St. 6-R, at 37). In fact, my conclusions were far broader than that. The EIA identified multiple factors associated with lower electricity consumption, including housing size, housing type, tenure status, and income, amongst others. Using data specific to the UGI Electric service territory, I found that each of these factors is disproportionately associated with low-income status in the UGI Electric service territory, thus supporting the conclusion –confirmed by the data presented by Mr. Adamo-- that low-income customers will disproportionately also be lower usage customers.

Mr. Taylor again advances the same unsupported argument that Mr. Adamo does in asserting that using Census data is not appropriate because I don't identify how many households in the Zip Codes comprising the UGI Electric service territory actually use electricity. (UGI Electric St. 6-R, at 37). Like Mr. Adamo, he does not suggest what alternative to the use of electricity might be used by these households.

Q. PLEASE RESPOND TO MR. TAYLOR'S REBUTTAL TESTIMONY REGARDING THE VARIOUS FACTORS ASSOCIATED WITH DETERMINING ELECTRICITY USAGE.

A. Mr. Taylor presents an extended discussion of various factors that result in what he calls "convoluted connections" between income and usage. Not once, however, does he present any data on the extent of these various factors apply to the UGI Electric service territory. Consider, for example:[7]

- He raises the notion that there may be "college students who live in apartments [who] would be considered low-income, but may not pay their own utility bills." (UGI Electric St. 6-R, at 38). Census data indicates that the number of college students living in the UGI Electric service territory is relatively miniscule (ACS, Table B14004, Sex by College or Graduate School Enrollment by Type of School by Age for the Population 15 Years and Over), let alone adding the pure speculation by Mr. Taylor about those who live in their own apartments, let alone the further speculation about those who are considered low-income, let alone the final speculation about those who are considered low-income but may not pay their own utility bill.

- He raises the notion that there may be some "some large families supporting a grandparent." (UGI Electric St. 6-R, at 38). Census data indicates that the number of children living with grandparents in the UGI Electric service territory is relatively miniscule (ACS, Table B10051, Grandparents Living with Own Grandchildren under 18 Years by Responsibility for Own Grandchildren by Presence of Parent of Grandchildren and Age of Grandparent). The notion that families living with grandparents substantially affect electricity usage in the UGI Electric service territory simply cannot be credibly asserted.

- He raises the notion that "household size and age distribution of occupants also impacts use," (UGI Electric St. 6-R, at 38-39), without indicating how those two factors would affect use. In fact, Census data indicates that, in the UGI Electric service territory, lower income households (i.e., those below Poverty) tend to have smaller household sizes than higher income households (ACS, Table B17012, Poverty Status in the Past 12 Months of Families by Household Type by Number of Related children Under 18 Years), with smaller household sizes associated with lower electricity usage.

Finally, Mr. Taylor asserts, without any substantiation, that "detailed analysis of the relationship between income and usage typically finds weak or no correlation between

[7] American Community Survey (ACS) tables are available at https://data.census.gov/cedsci/advanced (last accessed on June 4, 2021).

income and usage." (UGI Electric St. 6-R, at 39). He makes that assertion without presenting such a "detailed analysis." Indeed, he makes that assertion while having not undertaken any such "detailed analysis." Remember, that UGI Electric has not studied any of these connections, let alone any of these connections in its own service territory. When specifically asked to "provide all studies, reports, evaluations, or other written document of any nature, in the custody or control of the Company, whether or not prepared for the Company, prepared on or subsequent to January 1, 2015, that assesses, studies, or otherwise discusses the relationship, if any, between income and consumption," UGI Electric cited a 2017 document that contained no such analysis. (OCA-IV-47) The "analysis" presented by that 2017 document, cited as the only UGI Electric analysis undertaken of the relationship between income and usage, stated, *in its entirety*, as follows:

> In short, the position taken by Mr. Colton fails to take into account a number of nuances and, rather than provide details on each, I will simply summarize a few. Income and usage data is often misleading because of convoluted connections between income and usage. For example, college students who live in apartments would be considered low income, but may not pay their own utility bills from that income. There is a similar disconnect for wealthy people who choose to live in smaller homes. Further, the interconnection between income, household size, and ability to pay is not taken into account, as some large users may have difficulty affording their electric bill even at relatively higher incomes, *e.g.*, $50,000 a year income with four children. The simple data presented by the EIA survey ignores the difference in urban and rural poverty on electric use. The analysis also fails to reflect the impact of energy efficiency on use by low-income customers. Even though they may have fewer appliances, the appliances are typically older and less efficient. Similarly, the thermal envelope of low-income dwellings is typically much less energy efficient. This data does not account for the effect of household size and age distribution of occupants that also impacts use (*e.g.*, retired and wealthy part time Pennsylvania resident). The bottom line is that detailed analysis of the relationship between income and usage typically finds weak or no correlation between income and usage.

("Rebuttal Testimony of John D. Taylor to the testimony of Office of Consumer Advocate witness Roger D. Colton, dated May 25, 2018, in the UGI Electric Base Rate Proceeding at Docket No. R-2017-2640058," as cited in OCA-IV-47). As can be seen, the document referenced as being the only "analysis" performed by UGI Electric is nearly word-for-word the same rebuttal testimony Mr. Taylor presented in this proceeding.

Moreover, when specifically asked to provide all studies undertaken by, or on behalf of, the Company within the past ten years of residential usage by housing type, or of residential usage by housing size, UGI Electric responded that "the Company has not undertaken such studies." (OCA-IV-57).

Q. DO YOU HAVE ANY FINAL RESPONSE TO MR. TAYLOR'S REBUTTAL ON THE IMPACT ON LOW-INCOME CUSTOMERS OF UGI ELECTRIC'S PROPOSED INCREASE IN ITS RESIDENTIAL CUSTOMER CHARGE?

A. Mr. Taylor finally asserts in his Rebuttal Testimony that "it is far more efficient to address the issues of low-income customers directly through programs and assistance, such as the Company's CAP." (UGI Electric St. 6-R, at 42). This statement does not acknowledge the fact that UGI Electric's CAP reaches only one-in-five of the Company's low-income population. To adopt the reasoning propounded by Mr. Taylor is to accept the fact that the adverse low-income impacts associated with increasing the residential customer charge will not be addressed at all for eight-of-ten of UGI Electric's low-income population.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

310502

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3023618
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement 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).

DATED: June 10, 2021
*310228

Signature: ______________________
Roger D. Colton

Consultant Address: Fisher, Sheehan, & Colton
34 Warwick Road
Belmont, MA 02478

OCA STATEMENT NO. 5-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3023618
	:	
UGI Utilities, Inc. – Electric Division	:	

SURREBUTTAL TESTIMONY
OF
MORGAN N. DEANGELO

ON BEHALF OF
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JUNE 10, 2021

Introduction:

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

A. My name is Morgan N. DeAngelo. My business address is 555 Walnut Street, Forum Place, 5th Floor, Harrisburg, Pennsylvania 17101. I am currently employed as a Regulatory Analyst by the Pennsylvania Office of Consumer Advocate (OCA).

Q. Have you previously provided testimony in this case?

A. Yes. I provided direct testimony in this case on May 3, 2021 in OCA Statement 5.

Q. What is the purpose of your surrebuttal testimony?

A. In my surrebuttal testimony, I will comment on the rebuttal testimony of UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company") witness Daniel V. Adamo (UGI Electric Rebuttal Testimony Statement No. 10-R), which responds to issues discussed in my direct testimony.

Q. Please summarize your direct testimony.

A. My direct testimony discusses details in regards to the impacts the ongoing COVID-19 Pandemic has had, and continues to have on Pennsylvania, and how it is important to balance the interests of consumers and shareholders. Pennsylvania residents and small businesses in the retail and restaurant / food service industry are facing long-term impacts as unemployment and loss of income numbers still remain significantly higher than before the Pandemic.

Response to UGI Electric's Rebuttal Testimony:

Q. Please summarize Mr. Adamo's rebuttal testimony regarding your direct testimony.

A. Mr. Adamo states in his rebuttal testimony that he does not dispute the observations of the various impacts the COVID-19 Pandemic has had on UGI Electric's customers, Pennsylvania residents and Pennsylvania businesses. However, he states that I do not take into account (1) the numerous state and federal assistance programs available to UGI Electric's customers, (2) information and data that suggests the impacts of the Pandemic are less severe than claimed in my direct testimony, and (3) the numerous steps UGI Electric has already taken to mitigate the impacts of the COVID-19 Pandemic on its customers. He then provides graphs displaying the Company's Low Income Home Energy Assistance Program ("LIHEAP") dollars received and results of the Company's Operation Share Program, and UGI Electric's Residential Customer Arrears. He does not believe the conclusions made in my testimony should be given any weight, regarding the appropriate balance that should be struck in this proceeding.[1]

Q. Do you agree with Mr. Adamo that your direct testimony should be given no weight in this proceeding?

A. No. In my direct testimony I provided valuable data and statistics as to the ongoing impacts of the COVID-19 pandemic on Pennsylvania's economy and on the citizens of Pennsylvania. The Commission should thoroughly consider this information as well as the testimony of OCA witness Roger Colton when making its final determinations as to the appropriate balance that should be struck between the interests of the Company's shareholders and its customers.

Q. As to Mr. Adamo's first point that you have not taken into account the numerous state and federal assistance programs available to UGI Electric's customers, how do you respond?

A. According to the monthly reporting of at-risk customer accounts received April 13, 2021, a total of 6,278 Electric customers were at risk for Termination. Of these customers, 30.1% are listed as Residential Customer Assistance Program (CAP) customers, while 34.1% are listed as Residential Low Income Customers and 35.8% of at risk customers are not classified as low income or CAP customers.[2] It appears that although there are

[1] UGI Electric Statement No. 10-R at p. 17-20.
[2] Docket No. M-2020-3019244

numerous assistance programs, there are a significant number of customers that are still at risk for termination.

Q. Mr. Adamo's second point states you do not take into account information and data that suggests the impacts of the Pandemic are less severe than claimed in your testimony, how to you respond?

A. Although the data in graphs 3 and 4[3] provided in Mr. Adamo's testimony show favorable trends, residential debt still remains significantly higher than it was at the start of the Pandemic. The Total Aggregate Dollars of Arrears as of 3/31/21 remains 36% higher than the amount as of 3/31/20.[4]

Q. Mr. Adamo's third point states you do not take into account the numerous steps UGI Electric has already taken to mitigate the impact of the COVID-19 Pandemic on its customers, how do you respond?

A. While UGI Electric has taken steps to mitigate COVID-19 impacts on its customers, these impacts are still being faced throughout all of Pennsylvania, including UGI Electric's service territory. The unemployment rate for Pennsylvania in April 2021, remains higher than the United States' unemployment rate[5], at 7.4%.[6] Additionally, UGI Electric provides service in Luzerne County, which has an unemployment rate of 8.5%,[7] and Wyoming County, which has an unemployment rate of 6.5%.[8] The U.S. Bureau of Labor Statistics (BLS) released an article in December 2020, "Employment Recovery in the Wake of the COVID-19 Pandemic"[9] where it states that employment may not fully recover until the Pandemic subsides. However, we do not know when that will be. A more recent article, also released by the BLS, in February 2021, "Employment

[3] UGI Electric Statement No. 10-R at p.19-20.

[4] Docket No. M-2020-3019244

[5] Current U.S. Unemployment Rate is 6.1% https://www.bls.gov/cps/

[6] https://www.bls.gov/eag/eag.pa.htm

[7] https://www.workstats.dli.pa.gov/Documents/County%20Profiles/Luzerne%20County.pdf

[8] https://www.workstats.dli.pa.gov/Documents/County%20Profiles/Wyoming%20County.pdf

[9] https://www.bls.gov/opub/mlr/2020/article/employment-recovery.htm

Projections in a Pandemic Environment"[10] shares in light of the still-evolving health crisis, there is a lot of uncertainty over the next decade as a result of the Pandemic. Although steps are being taken to mitigate the impacts of the COVID-19 Pandemic, we can assume UGI Electric customers are still experiencing negative impacts the Pandemic continues to bring forth.

Conclusion:

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

A. Yes, it does. I reserve the right to modify or supplement my testimony if necessary.

310503

10 https://www.bls.gov/opub/mlr/2021/article/employment-projections-in-a-pandemic-environment.htm

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3023618
	:	
UGI Utilities, Inc. – Electric Division	:	

VERIFICATION

I, Morgan N. DeAngelo, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 5-SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) 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).

DATED: June 10, 2021
*307974

Signature: Morgan N. DeAngelo
Morgan N. DeAngelo

Consultant Address: Office of Consumer Advocate
555 Walnut Street
5^{th} Floor, Forum Place
Harrisburg, PA 17101-1923