BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan for the Period of June 1, 2021 through May 31, 2025	: : : :	**Docket No. P-2020-3019907**

OFFICE OF SMALL BUSINESS ADVOCATE
LIST OF EVIDENCE TO BE ADMITTED INTO THE RECORD

- Direct Testimony and Exhibits of Robert D. Knecht, labeled OSBA Statement No.1
- Rebuttal Testimony and Exhibits of Robert D. Knecht, labeled OSBA Statement No.1-R
- Surrebuttal Testimony and Exhibit of Robert D. Knecht, labeled OSBA Statement No.1-S

DATE: 12/09/20

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

COMMONWEALTH OF PENNSYLVANIA

August 6, 2020

The Honorable Dennis J. Buckley
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

Re: Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan for the Period of June 1, 2021through May 31, 2025 / Docket No. P-2020-3019907

Dear Judge Buckley:

Enclosed please find the Direct Testimony and Exhibits of Robert D. Knecht, labeled OSBA Statement No. 1, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceedings.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

Enclosures
cc: PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Robert D. Knecht
Parties of Record

OSBA Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. - Electric Division For Approval of a Default Service Plan (DSP IV) for the Period June 1, 2021 Through May 31, 2025	:	**Docket No. P-2020-3019907**

Direct Testimony and Exhibit of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Default Service

Date Served: August 6, 2020

Date Submitted for the Record: October 2, 2020

DIRECT TESTIMONY OF ROBERT D. KNECHT

1. Introduction

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I am a Principal of Industrial Economics, Incorporated ("IEc"), an economics and policy consulting firm located at 2067 Massachusetts Avenue, Cambridge, MA 02140. My consulting practice currently consists primarily of the preparation of analyses and expert testimony in the field of regulatory economics. I obtained a B.S. degree in Economics from the Massachusetts Institute of Technology in 1978, and a M.S. degree in Management from the Sloan School of Management at M.I.T. in 1982, with concentrations in applied economics and finance. I am appearing in this proceeding on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA"). My résumé and a listing of the expert testimony that I have filed in utility regulatory proceedings during the past five years are attached in Exhibit IEc-1. My experience with UGI Utilities, Inc. – Electric Division ("UGI Electric" or "the Company") includes the submission of testimony in the Company's default service proceedings at Docket No. P-2013-2357013 ("DSP II") and Docket No. P-2016-2543523 ("DSP III"), as well as participation in a variety of base rates, energy efficiency and long-term planning/DSIC proceedings dating back to 1994.

Q. Please describe your assignment in this matter.

A. The OSBA requested that I review and evaluate the Company's proposed default service plan for June 2021 through May 2025 ("DSP IV"), to determine whether small business customers are being treated reasonably and equitably.

Q. Please detail the salient features of UGI Electric's DSP IV as they affect small business customers.

A. The Company's proposed DSP IV has much in common with DSP III. The key features of the plan are listed below. Except as noted, the provisions are similar or identical to those of DSP III.

- The proposed term for the DSP IV Plan is four years, June 2021 to May 2025.
- The Company proposes to retain two default service rate class groups, GSR-1 and GSR-2. GSR-1 includes residential and non-residential customers with maximum peak demand up to 100 kW. GSR-2 includes non-residential customers with maximum demand above 100 kW.
- The 100-kW demarcation would be a one-time determination, remaining in effect for the four-year plan, based on maximum billing demand in the 12 months prior to September 30, 2020.[1]
- The Company proposes to apply a migration charge/credit to customers transitioning from GSR-1 to GSR-2, to require departing GSR-1 customers to continue to pay (or be credited for) their share of the reconciliation balance in the GSR-1 rate at the time of transition. No parallel exemption from the reconciliation charge is proposed for customers transitioning from GSR-2 to GSR-1, although the Company has expressed a willingness to consider it.[2]
- GSR-2 default service customers with load in excess of 100 kW will be supplied through hourly spot market purchases, supplemented by capacity, ancillary service, other transmission and AEPS credit purchases.[3]
- Default service purchases for the GSR-1 class are based 50 percent on a "block-and-spot" approach and 50 percent on a full-requirements load-following ("FRLF") approach. Over the past seven years, the block-and-spot approach has consistently shown a materially lower average cost than the FRLF approach.

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[1] See OSBA-I-5(a-c). UGI Electric agrees to correct its proposed tariff language to clarify this proposal.

[2] See OSBA-I-5(g).

[3] "AEPS credits" refers to electricity supplier requirements under the Alternative Energy Portfolio Standards Act, primarily with respect to the purchase of Tier I, Tier II and Solar alternative energy credits ("AECs") for specified percentages of the load served.

- FRLF procurements will be based on laddered 12-month terms, with half the FRLF load procured in the spring (June to May supply) and half in the fall (December to November supply). FRLF suppliers are responsible for matching a specific percentage of the default service energy requirements, as well as providing the associated capacity, transmission, ancillary services and AEPS credits.

- The block-and-spot approach involves the purchase of 6-month 7x24 and 5x16 energy block contracts twice per year based on forecast GSR-1 load, supplemented by Company procurement of the necessary capacity, transmission, ancillary services and AEPS requirements. Energy variances between actual loads and the block supplies are met by spot market purchases and sales.

- Should a FRLF contract procurement fail, UGI Electric would, if feasible, adopt a "block-and-spot" procurement approach for GSR-1 energy supplies as a contingency, supplemented by purchases of capacity, transmission, ancillary services and AEPSA credits. If a block-and-spot approach is not feasible, the Company will use spot market purchases to serve the load.[4]

- GSR-1 rates for residential and non-residential customers will be the same on a per-kWh basis. In effect, electricity supply costs are allocated between the classes based on energy consumption.

- GSR-1 rates include a forecast cost component ("EC") and a reconciliation component ("ECA"). UGI Electric reports that rates will generally be reconciled on a quarterly basis, with a two-month lag. For example, the balance in the revenue-cost variance account as of March 31 will be recovered in rates in the June 1 to August 31 period. However, if the variance would result in a more than 5 percent change on a total bill basis, the recovery period will be

[4] The latter portion of this contingency plan represents a minor change from DSP III. Petition at 14. It is a reasonable modification.

extended up to a maximum of 12 months. Nevertheless, the actual result of this mechanism in the DSP III period has produced ECA charges/credits that typically remain in effect for at least six months. Given the relative stability of historical shopping patterns for GSR-1 customers and recognizing that the procurements are based on six-month intervals, the Company should consider whether formally adopting a six-month reconciliation period would be simpler and would improve rate stability.[5]

- The Company's tariff defines the price-to-compare ("PTC") for residential and smaller non-residential customers to *". . . include the Energy Charge ("EC"), the Energy Cost Adjustment ("ECA"), the Alternative Energy Cost Charge ("AECC") and the applicable base transmission rate contained in UGI's tariff. The Price-To-Compare shall also include the State Tax Surcharge in Rider A."* However, the AECC ended June 1, 2014 and separate transmission charges were eliminated in the Company's last base rates proceeding. It is my understanding that the current PTC is simply the EC and ECA components of the GSR-1 plus STAS.[6]

- UGI Electric is obligated to purchase excess supplies from its net metered customers as part of its default service portfolio. Thus far, such purchases have had a *de minimis* impact on default service costs.

- Certain administrative costs are included in default service charges, forecast at about $258,000 per year.[7] The major administrative cost items are load research costs, the cost of a monitoring firm for the procurements, weather forecasting and GSR-2 customer hourly meter reading and billing.[8]

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[5] See ECA rate pattern in the attachment to OSBA-I-1.

[6] As neither "AECC" nor "base transmission rate" is mentioned elsewhere in the Company's tariff, this excess verbiage should probably be excised.

[7] Exhibit SFA-2.

[8] In DSP III, the Company indicated that it ". . . plans to automate Hourly Billing [for GSR-2 customers] in the future." Exhibit SFA-1, Docket No. P-2016-2543523. It does not appear that this plan has yet come to fruition.

Administrative costs are allocated between the two default service rate class groups based on either direct assignment or kWh load.

- New and relocating customers are informed about retail choice opportunities by referral to the Commission's PA Power Switch website.

- Although the Company operates a Standard Offer Program to which customers may be referred, no electric generation suppliers ("EGSs") currently participate in the program. UGI Electric indicates that it is developing marketing materials related to the program. At present, however, the costs would appear to be prohibitive.[9]

Q. Please describe the current state of shopping for the smaller UGI Electric customers.

A. Residential shopping remains minimal, at approximately 1 percent of overall residential load. Historical shopping rates for commercial customers are shown in Figure IEc-1 below and in more detail in RDK WP1.[10] As shown, commercial customer shopping rates have been reasonably stable for eight years. Shopping rates measured as percentage of load are far higher than percentage of customers, since larger commercial customers are more inclined to shop. Only about 10 percent of commercial customers shop, but they represent nearly 50 percent of the commercial load. If anything, commercial shopping has declined modestly during DSP III.

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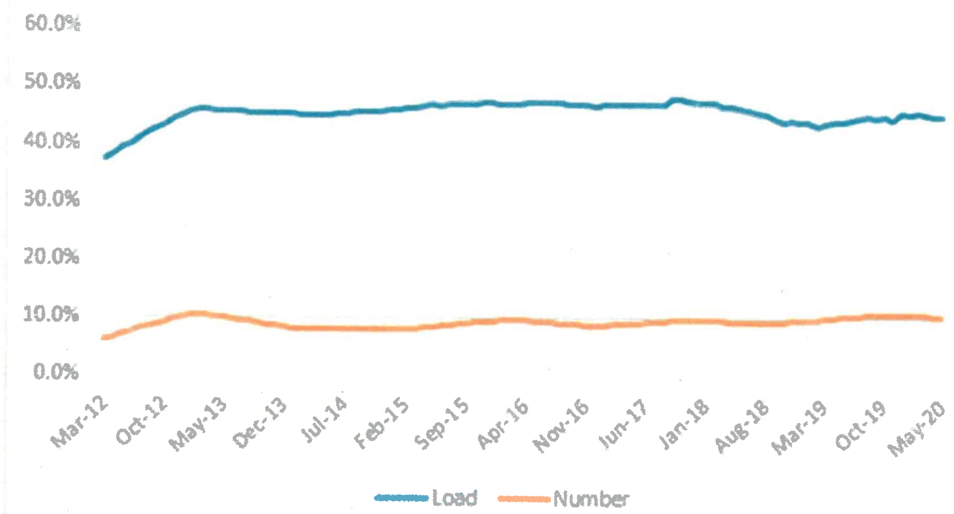
[9] OSBA-I-11 indicates supplier participation could be as high as $12,000 per month.

[10] In OSBA-I-2, OSBA requested shopping versus non-shopping data by tariff rate class segregated between GSR-1 and GSR-2 components. Unfortunately, the attachment to the Company's response provided data split only into residential/commercial/industrial categories split between heat and non-heat customers. I am therefore unable to evaluate shopping trends by rate class, or even between GSR-1 and GSR-2 customers.

Figure IEc-1
UGI Electric Commercial Shopping Rate
12-Month Moving Average



Q. What issues do you address in this testimony?

A. This testimony addresses:

- Whether the 50/50 split of "block-and-spot" and FRLF procurements is reasonable for GSR-1 default service customers;
- Whether the combined procurement for residential and non-residential customers below 100 kW remains reasonable, and, if so, whether an energy-based allocation of costs is reasonable;

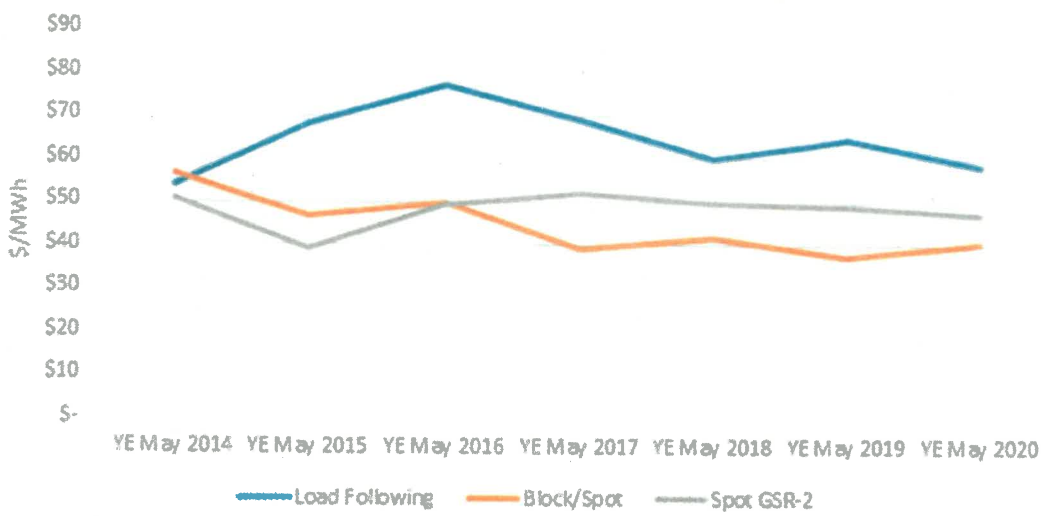
These issues are addressed sequentially in sections 2 and 3 below. To the extent that I have not addressed an issue, it should not be concluded that I approve of the Company's proposal.

2. <u>Procurement Approach for GSR-1</u>

Q. What analysis have you undertaken regarding the Company's proposal to use a 50/50 split of block-and-spot and full requirements procurement methods?

A. In RDK WP2, I attempted to estimate the relative costs of the two approaches over the past seven years. In OSBA-I-3, the Company provided its procurement costs for each year, split between GSR-1 and GSR-2, with separate costs for FRLF contracts and for all other purchases. A summary of my results is shown in Figure IEc-2 below.[11]

Figure IEc-2
UGI Electric Default Service Purchase Costs



As shown, the actual costs incurred by the Company for this period under the block-and-spot approach have represented the lowest supply costs, not only relative to the FRLF contracts but also relative to the spot market approach for the GSR-2 load (which would likely involve a lower cost-to-serve load shape). The differences are quite significant, with the block-and-spot approach outperforming the FRLF approach by an average of over $16 per MWh or about 25 percent over the seven years.

Past performance, of course, is no guarantee of future performance. The FRLF approach should generally provide greater rate stability, as well as some price protection in the event that market price fluctuations cause a significant shift in shopping percentages.[12]

[11] Note that the block-and-spot values shown in the figure include a relatively small amount of low-cost legacy New York Public Authority purchases, an even smaller amount of relatively high-cost net metered purchases, and the spot market effects of both buying and selling spot supplies to balance the load with the block purchases.

[12] If market prices spike, shopping customers may opt to return to default service. Under the block-and-spot approach, the Company would essentially be required to purchase supplies for those customers at the high market spot prices, thereby losing price protection for the remaining customers. Similarly, if market prices fall well below the default service price, more customers may choose to shop, which would require the Company to sell its block supplies at the low market prices, putting upward pressure on default service rates.

Nevertheless, the historical price advantage of the block-and-spot approach combined with the relative stability of shopping rates indicates that the Company should seriously evaluate expanding the share of supplies purchased with that method.

3. Residential versus Non-Residential GSR-1 Rates

Q. Please provide the background to default service rates for smaller customers.

A. As a general rule, Pennsylvania electric distribution companies ("EDCs") serving as default service providers purchase default service supplies separately for their residential and small/medium non-residential customers. While there are certain administrative costs that apply to both customer groups, the rates for each group are effectively set based on the actual cost of providing service to that group. As such, the assignment of costs between classes is more precise than any arbitrary cost allocation method would produce. Based on my experience, I observe that default service rates for the non-residential customer groups tend to be modestly lower than the rates for residential customers, but there is considerable variability, particularly when reconciliation effects are factored in.[13]

However, because of the relatively small size of UGI Electric, it is generally believed that the cost for separate procurements would be significant and would outweigh the benefits of better cost assignment. Thus, supplies for the combined group of residential and smaller non-residential customers have been procured together, and the rates have been set to be equal on a per-MWh basis for all customers within the combined group.

In the settlement of the DSP III proceeding, the parties agreed,

> *"To facilitate the evaluation of the continued combined grouping of residential and small commercial and industrial customers with peak loads less than 100 kw, the Company will provide load research data for June 1, 2017 through December 31, 2019 in the Company's 2020 DSP IV default electric service filing. The Company also shall have its independent market monitor PACE provide an annual cost estimate for load-following service for C&I customers with peak loads less than 100kw for years 1*

[13] I have not prepared a formal comparison of EDC residential and non-residential default service rates for this testimony.

through 3 of the 4-year DSP III. PACE'S C&I customer bid estimates shall be included with the DSP IV filing."

Q. How did the Company determine that combined procurement for residential and non-residential GSR-1 supplies was reasonable?

A. Pursuant to the settlement of the DSP III matter, the Company's consultant Pace Global ("Pace") prepared range estimates of the costs for full requirements contracts for separate procurement of full requirements contracts for residential and non-residential customer groups, for each of the seven DSP III procurements. Pace also provided a comparable range estimate for the cost of a combined procurement. The results of that analysis are provided in the attachment to OSBA-I-13, which are included in my RDK WP4.

Using that analysis, the Company determined that the overall cost to customers of undertaking a combined procurement was materially lower than undertaking separate procurements (even before the administrative cost effects), and it therefore proposes to retain the combined approach.

Q. Did you review Pace's analysis?

A. No. UGI Electric indicates that the Pace analysis is proprietary and not available to the Company.[14] As such, the Company's analytical basis for continuing combined procurements is based on a black-box model, which neither the Company nor the other participants to this proceeding can evaluate. Unless the Company can demonstrate that the results from this black box are reasonable and credible, I am advised that the OSBA reserves its right to make a legal argument that supplies should be separately procured for residential and non-residential customers.

Q. What are the implications of Pace's analysis for the relative cost to serve non-residential customers?

A. Pace's analysis indicates that the UGI Electric non-residential customers are substantially less costly to serve than residential customers, as well as being less costly than serving the combined load. Based on the mid-points of the Pace range estimates, the non-residential

[14] OSBA-I-12

load procurement cost would average 28 percent below the procurement cost for stand-alone residential, and 15 percent below the procurement cost for serving the combined load.[15]

Q. Are the Pace results reasonable?

A. Without being able to review the underlying detail, I cannot respond with any certainty. Nevertheless, these results are surprising to me, for two reasons. First, as I indicated earlier, while non-residential default service rates for smaller customers are often modestly lower than residential rates, the 28 percent difference implied by the Pace analysis is quite large. While I have not attempted to prepare a statistical comparison, my experience suggests that actual differences at other EDCs are much more modest.

Second, as a test, I undertook an analysis of the load research information provided by the Company in OSBA-I-14. This analysis is shown in RDK WP3. In that analysis, I applied PJM locational marginal prices ("LMPs") to the hourly class loads developed by the Company from its load research, and calculated the implied average energy prices for 2017, 2018 and January-September 2019.[16] That analysis implied that the average energy rate for the non-residential load was indeed lower than that for the residential load, but by roughly $1 to $3 per MWh, rather than the $20 per MWh implied in the Pace analysis. Of course, the Pace difference may relate to capacity, ancillary services and transmission cost impacts. Even so, the load factor differences between the two customer groups are relatively modest, with the non-residential load factor at about 53 percent and the residential load factor at 46 percent.[17]

As such, I have analytical concerns regarding the reliability of the Pace estimates.

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[15] See RDK WP4 for average calculations.

[16] In so doing, I used the PPL Zone LMPs, and limited the non-residential loads to small and medium customers, using the UGI Electric strata 5-9.

[17] These are class annual non-coincident peak load factors for 2017/2018. The residential class tends to peak during the winter in the early evening, although there are also fairly high peaks during summer late afternoon. The non-residential class generally peaks in the summer in early afternoon.

Q. If the Company can demonstrate that the Pace estimates are reasonable, what are the implications of that analysis?

A. The Pace analysis implies that non-residential default service customers are materially harmed by the combined procurement, since independent procurement would result in lower rates for non-residential customers. Thus, based on the Pace analysis, not only do all the benefits of combined procurement flow to residential customers, there are additional cross-subsidies from non-residential customers to residential customers.[18]

This inequity can potentially be resolved two ways. First, the Company could adopt separate procurements for residential and non-residential loads. However, I expect that this approach would be administratively costly, as well as having an overall higher procurement cost, as suggested in the Pace analysis.

The second approach would be to establish separate GSR-1 rates for residential and non-residential customers. In effect, this approach would implicitly allocate electric supply costs to residential and non-residential customers differently than the energy-based allocation method that is currently used. The Company has expressed a willingness to consider such an approach, but it chose not to make any affirmative proposal to address this obvious inequity.[19]

A simple and reasonable approach to making this adjustment would be to set the non-residential GSR-1 rate equal to the average GSR-1 rate multiplied by the Pace-estimated historical ratio of standalone non-residential costs to combined procurement costs. This approach is "conservative," in that it implicitly assigns the full benefit of the combined procurement to the residential customers, and sets the non-residential price at the standalone cost. As shown in RDK WP4, this ratio ranges from 0.793 (Pace low-end estimates) to 0.898 (Pace high-end estimates), with a Pace mid-point of 0.850.

Thus, this approach would imply that the non-residential GSR-1 rate should be set at 85 percent of the average GSR-1 per-MWh cost, with the residential rate being set at the level

[18] Setting rates in excess of standalone cost meets the economist's textbook definition of a cross-subsidy.

[19] OSBA-I-15.

needed to recover the balance of the GSR-1 costs. While I do not have specific data regarding residential versus non-residential GSR-1 default service loads, I estimate that the residential rate would need to be about 105 percent of the average GSR-1 per-MWh procurement cost in order to achieve full cost recovery.[20] However, as I indicated earlier, adopting this approach would need to be predicated on a demonstration that the Pace approach for estimating residential, non-residential and combined procurement costs is reasonable.

Q. Does this conclude your direct testimony?

A. Yes, it does.

[20] The attachment to OSBA-I-2 indicates that the residential class represents at least 75 percent of the default service load. Thus, the 105 percent estimate is based on 0.25 * 0.85 + 0.75 * 1.05 = 1.00.

EXHIBIT IEc-1

RÉSUMÉ AND EXPERT TESTIMONY LIST

FOR

ROBERT D. KNECHT

ROBERT D. KNECHT — PRINCIPAL

Overview

Mr. Knecht has more than 35 years of practical economic consulting experience, focusing on the energy, utility, metals and mining industries. For the past 25 years, Mr. Knecht's practice has primarily involved providing analysis, consulting support and expert testimony in regulatory matters, primarily involving electric and natural gas utilities. Mr. Knecht's work includes many aspects of utility regulation, including industry restructuring, cost unbundling, cost allocation, rate design, rate of return, customer contributions, energy efficiency programs, smart metering programs, treatment of stranded costs and utility revenue requirement issues. He has worked for state advocacy agencies, industrial customer groups, law firms, regulatory agencies, government agencies and utilities, in both the United States and Canada. He has provided expert testimony in more than one hundred separate utility proceedings.

In addition to his work with regulated utilities, Mr. Knecht has consulted on international industry restructuring studies, prepared economic policy analyses, participated in a variety of litigation matters involving economic damages, and developed energy industry forecasting models.

Education

Master of Science, Management (Applied Economics and Finance), Sloan School of Management, M.I.T.

Bachelor of Science, Economics, Massachusetts Institute of Technology

Select Project Experience

For more than twenty years, Mr. Knecht has provided consulting services, analysis and expert testimony before the Pennsylvania Public Utility Commission on all manner of regulatory proceedings to the **Pennsylvania Office of Small Business Advocate**. In addition to expert testimony, Mr. Knecht has assisted OSBA with the development of public policy positions, litigation strategy, and longer term strategy.

For the **Industrial Gas Users Association**, Mr. Knecht provided consulting and expert witness services in a generic cost allocation proceeding involving Gaz Métro before the Régie de l'énergie in Québec.

For the **New Brunswick Public Intervener**, Mr. Knecht provides consulting and expert witness services in a variety of regulatory proceeding before the New Brunswick Energy and Utilities Board involving New Brunswick Power, Enbridge Gas New Brunswick, and petroleum products. Mr. Knecht has addressed issues of load forecasting, costs forecasting, cost of capital, allocation of corporate overhead costs, utility cost allocation, revenue allocation, market-based rate design, cost-based rate design, and rate decoupling.

For **L'Association québécoise des consommateurs industriels d'électricité (AQCIE) and le Conseil de l'industrie forestière du Québec (CIFQ)**, Mr. Knecht provided analysis, consulting advice and expert testimony before the Régie de l'énergie in regulatory matters involving Hydro Québec Distribution and TransÉnergie. This work includes revenue requirement, power purchasing, cost allocation, treatment of cross-subsidies, and rate design.

For the **Independent Power Producers Society of Alberta**, Mr. Knecht provided consulting advice, analysis and expert testimony before the Alberta Energy and Utilities Board in a series of proceedings involving the restructuring of the electric utility industry, the unbundling of rates, and the development of transmission rates.

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2016-2580030	Pennsylvania Public Utility Commission	UGI Penn Natural Gas	April 2017	Pennsylvania Office of Small Business Advocate	Test year, load forecast, O&M expenses, rate base, rate of return, cost allocation, rate design, EE&C program, capacity assignment
Matter 336	New Brunswick Energy & Utilities Board	New Brunswick Power	January 2017	New Brunswick Public Intervener	Financial forecast, equity requirement, depreciation life, variance mechanisms, cost allocation, rate design
Matter 338	New Brunswick Energy & Utilities Board	Generic	December 2016	New Brunswick Public Intervener	Retail petroleum margins
Matter 330	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	September 2016	New Brunswick Public Intervener	Revenue requirement, investment test, customer retention initiatives, cost allocation, rate design
R-2016-2537359	Pennsylvania Public Utility Commission	West Penn Power Company	July 2016	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design.
R-2016-2537355	Pennsylvania Public Utility Commission	Pennsylvania Power Company	July 2016	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design.
P-2016-2537609, 2537594	Pennsylvania Public Utility Commission	UGI Central Penn Gas, UGI Penn Natural Gas	July 2016	Pennsylvania Office of Small Business Advocate	Waiver of DSIC cap.
P-2016-2543523	Pennsylvania Public Utility Commission	UGI Utilities, Inc., Electric Division	July 2016	Pennsylvania Office of Small Business Advocate	Default service procurement.
R-2016-2529660	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania, Inc.	June 2016	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design.
R-2015-2469275	Pennsylvania Public Utility Commission	PPL Electric Utilities Corporation	May 2016	Pennsylvania Office of Small Business Advocate	Default service procurement plan.
R-2015-2518438	Pennsylvania Public Utility Commission	UGI Utilities, Inc., Gas Division	April 2016	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design, energy efficiency and conservation program.

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
P-2016-2521993	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania, Inc.	April 2016	Pennsylvania Office of Small Business Advocate	Waiver of DSIC cap.
M-2015-2477174	Pennsylvania Public Utility Commission	UGI Utilities, Inc., Electric Division	February 2016	Pennsylvania Office of Small Business Advocate	Energy efficiency and conservation plan review and development.
Matter No. 306	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	February 2016	New Brunswick Public Intervenor	Financial review, investment prudence, revenue requirement, cost allocation, rate design, market-based pricing.
P-2015-2511333, 2511351, 2511355, 2511356	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Pennsylvania Power, West Penn Power	January 2016	Pennsylvania Office of Small Business Advocate	Default service procurement plans, purchase of receivables.
P-2015-2501500	Pennsylvania Public Utility Commission	Philadelphia Gas Works	October 2015	Pennsylvania Office of Small Business Advocate	DSIC rate design under cash flow regulation, capital structure
P-2014-2459362	Pennsylvania Public Utility Commission	Philadelphia Gas Works	June 2015	Pennsylvania Office of Small Business Advocate	Demand side management programs, rate decoupling mechanism, incentive mechanism, cost-benefit analysis.
R-2015-2469275	Pennsylvania Public Utility Commission	PPL Electric Utilities	June 2015	Pennsylvania Office of Small Business Advocate	Misc. revenue requirement issues, cost allocation, rate design
R-2015-2468056	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2015	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design, customer contribution policy
R-2015-2461373	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	April 2015	Pennsylvania Office of Small Business Advocate	Load balancing rates, reconciliation
R-2014-2456648	Pennsylvania Public Utility Commission	Peoples TWP LLP	March 2015	Pennsylvania Office of Small Business Advocate	Load balancing rates, reconciliation
R-3867-2013	Régie de l'énergie, Québec	Société en commandite Gaz Métro	February 2015	l'Association des Consommateurs de Gaz	Distribution cost allocation

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-3888-2014	Régie de l'énergie, Québec	Hydro Québec TransÉnergie	December 2014	AQCIE/CIFQ	Transmission customer contribution policy
R-2014-2428744 R-2014-2428742	Pennsylvania Public Utility Commission	Pennsylvania Power Company, West Penn Power Company	November 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
M-2014-2430781	Pennsylvania Public Utility Commission	PPL Electric Utilities	October 2014	Pennsylvania Office of Small Business Advocate	Smart meter procurement, rate design
Matter No. 253	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	September 2014	New Brunswick Public Intervenor	Financial review, investment prudence, revenue requirement, cost allocation, rate design, market-based pricing.
P-2014-2417907	Pennsylvania Public Utility Commission	PPL Electric Utilities	July 2014	Pennsylvania Office of Small Business Advocate	Default service procurement, class eligibility, reconciliation
R-2014-2406274	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2014-2407345	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2014	Pennsylvania Office of Small Business Advocate	Customer contribution policy, alternative financing mechanism
R-2014-2408268	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2014	Pennsylvania Office of Small Business Advocate	Gas procurement sharing mechanism, cost allocation
R-2014-2397237	Pennsylvania Public Utility Commission	Pike County Light & Power (Electric)	April 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2014-2397353	Pennsylvania Public Utility Commission	Pike County Light & Power (Gas)	April 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation
R-2014-2399598	Pennsylvania Public Utility Commission	Peoples TW Phillips	March 2014	Pennsylvania Office of Small Business Advocate	Gas procurement, design day demand, cost allocation rate design, retainage
P-2013-2389572 (Remand)	Pennsylvania Public Utility Commission	PPL Electric Utilities	February 2014	Pennsylvania Office of Small Business Advocate	Time of use rates, net metering rates

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
Matter 225	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	January 2014	New Brunswick Public Intervenor	Financial review, investment prudence, revenue requirement, cost allocation, rate design, market-based pricing.
P-2013-2391368, P-2013-2391372, P-2013-2391375, P-2013-2391378	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Pennsylvania Power, West Penn Power	January 2014	Pennsylvania Office of Small Business Advocate	Default service procurement, cost allocation, rate design
Matter No. 214	New Brunswick Energy & Utilities Board	Generic	November 2013	New Brunswick Public Intervenor	Maximum retail margins for motor fuel and residential heating oil.
Matter No. 171	New Brunswick Energy & Utilities Board	New Brunswick Power	September 2013	New Brunswick Public Intervenor	Amortization method for deferral costs associated with refurbishing Point Lepreau Generating Station
C-2013-2367475	Pennsylvania Public Utility Commission	PPL Electric Utilities	August 2013	Pennsylvania Office of Small Business Advocate	Forecasting and reconciliation of default service electric costs and revenues.
P-2011-2277868, I-2012-2320323	Pennsylvania Public Utility Commission	Generic	August 2013	Pennsylvania Office of Small Business Advocate	Ratemaking treatment for customers in overlapping NGDC service territories ("gas-on-gas").
P-2013-2356232	Pennsylvania Public Utility Commission	UGI Central Penn Gas, UGI Penn Natural Gas, UGI Utilities (Gas Division)	July 2013	Pennsylvania Office of Small Business Advocate	Program design, cost recovery and rate design for alternative system expansion financing pilot program ("GET Gas")
R-2013-2355886	Pennsylvania Public Utility Commission	Peoples TWP LLC	July 2013	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2013-2361764, R-2013-2361763, R-2013-2361771	Pennsylvania Public Utility Commission	UGI Central Penn Gas, UGI Penn Natural Gas, UGI Utilities (Gas Division)	July 2013	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas.

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
Matter No. 178	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	July 2012	NB Public Intervenor	System expansion economic test, test year revenue requirement, cost allocation, rate design, treatment of stranded costs.
R-2012-2290597	Pennsylvania Public Utility Commission	PPL Electric Utilities	June 2012	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2012-2293303	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2012	Pennsylvania Office of Small Business Advocate	Treatment of pipeline credits
AUC ID #1633	Alberta Utilities Commission	Alberta Electric System Operator	April 2012	Powerex, Northpoint Energy Solutions, Cargill	Economic efficiency issues for allocation of constrained transmission capacity.
R-2012-2286447	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2012	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas retainage, reconciliation
R-2012-2281465	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2012	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas retainage, gas price procurement and hedging
R-2011-2273539	Pennsylvania Public Utility Commission	Peoples TWP	March 2012	Pennsylvania Office of Small Business Advocate	Design day demand methodology
P-2011-2273650 P-2011-2273668 P-2011-2273669 P-2011-2273670	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Penn Power, West Penn Power	February 2012	Pennsylvania Office of Small Business Advocate	Default service procurement, retail market enhancement, rate design.
R-2011-2264771	Pennsylvania Public Utility Commission	PPL Electric Utilities	January 2012	Pennsylvania Office of Small Business Advocate	TOU Rates

Note: Dates shown reflect submission date for direct testimony.

Industrial Economics, Incorporated
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Cambridge, MA 02140 USA
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EXHIBIT IEc-2

REFERENCED INTERROGATORY RESPONSES

OSBA-I-1

OSBA-I-2

OSBA-I-3

OSBA-I-5

OSBA-I-11

OSBA-I-12

OSBA-I-13

OSBA-I-14

OSBA-I-15

The electronic attachments to these interrogatories are incorporated by reference.

UGI Utilities, Inc. - Electric Division
Docket No. P-2020-3019907
UGI Electric Default Service Plan
Responses to OSBA Set I (1 thru 16)
Delivered on July 8, 2020

OSBA-I-1

Request:

In MS Excel electronic format, please provide a quarterly history of UGI Electric's default service charges for each default service rate class group from January 2013 through the present, segregated between C-Factor (EC) and E-Factor (ECA including interest) components. Please also provide the base per-kWh transmission charges for each rate class for each quarter.

Response:

Please see Attachment OSBA-I-1.

Prepared by or under the supervision of: Stephen F. Anzaldo

OSBA-I-2

Request:

In MS Excel electronic format, please provide a quarterly (or monthly) database from January 2010 to the present of the number of customers and MWh consumption, segregated between shopping and default service load, and differentiated by tariff rate class (R, GS-1, GS-4, GS-5, LP, etc.). Please segregate customers between below and above 100 kW in the GS-4 and LP classes, to the extent available.

Response:

Please see Attachment OSBA-I-2.

Prepared by or under the supervision of: Stephen F. Anzaldo

UGI Utilities, Inc. - Electric Division
Docket No. P-2020-3019907
UGI Electric Default Service Plan
Responses to OSBA Set I (1 thru 16)
Delivered on July 8, 2020

OSBA-I-3

Request:

For each plan year ending May 31 for 2014 through 2020, please provide total default service costs and MWh purchased, split between the full requirements load-following ("FRLF") contracts and the block-and-spot procurements (inclusive of all related costs, including AEPS). (That is, please update the Company's response to OSBA-I-9(c) from the last default service proceeding at Docket No. P-2016-2543523.)

Response:

Please see Attachment OSBA-I-3.

Prepared by or under the supervision of: Angelina M. Borelli

UGI Utilities, Inc. - Electric Division
Total Default Service Costs and MWh Purchased

	12 Months Ending May 2014									
	GSR-1R		GSR-1C		GSR-2		GSR-3		Total	
	MWh	Cost	MWh	Cost	MWh	Cost	MWh	Cost	MWh	Cost
Blocks	357,574	$20,099,168			0	$0	0	$0	357,574	$20,099,168
NYPA	2,537	$64,861			0	$0	0	$0	2,537	$64,861
Load Following	139,473	$6,903,506	91,460	$5,685,037			0	$0	230,933	$12,588,543
Load Following - Reconciliation	0	$579,112	0	$655,062			0	$0	0	$1,234,174
Spot Purchase	149,550	$7,690,939	71,166	$3,238,853			44,588	$2,225,089	265,304	$13,154,881
Spot Sale	(24,505)	($827,421)			23,984	$1,200,138	0	$0	(521)	$372,717
Net Metering Purchases	45	$3,019							45	$3,019
AEPS Costs										$442,141
Total	624,673	$34,513,186	162,626	$9,578,952	23,984	$1,200,138	44,588	$2,225,089	855,871	$47,959,506

	12 Months Ending May 2015							
	GSR-1R		GSR-1C		GSR-2		Total	
	MWh	Cost	MWh	Cost	MWh	Cost	MWh	Cost
Blocks	344,395	$15,290,820	0	$0	0	$0	344,395	$15,290,820
NYPA	3,205	$83,302	0	$0	0	$0	3,205	$83,302
Load Following	351,594	$23,276,061	0	$0	0	$0	351,594	$23,276,061
Load Following - Reconciliation	0	$736,101	0	($19,040)	0	$0	0	$717,061
Spot Purchase	71,730	$2,781,151	0	$0	80,150	$3,150,119	151,880	$5,931,270
Spot Sale	(57,022)	($1,568,117)	0	$0	0	$0	(57,022)	($1,568,117)
Net Metering Purchases	41	$3,560	0	$0	0	$0	41	$3,560
AEPS Costs								$351,536
Total	713,943	$40,602,879	0	($19,040)	80,150	$3,150,119	794,093	$44,085,493

Effective June 2014, Groups GSR-1R and GSR-1C were combined into GSR-1.

UGI Utilities, Inc. - Electric Division
Total Default Service Costs and MWh Purchased

Effective June 2014, Groups GSR-2 and GSR-3 were combined into GSR-2.

	12 Months Ending May 2016					
	GSR-1		GSR-2		Total	
	MWh	Cost	MWh	Cost	MWh	Cost
Blocks	528,470	$21,533,095	0	$0	528,470	$21,533,095
NYPA	2,739	$65,457	0	$0	2,739	$65,457
Load Following	174,797	$12,713,508	0	$0	174,797	$12,713,508
Load Following - Reconciliation	0	($157,269)	0	$0	0	($157,269)
Spot Purchase	52,682	$1,591,055	77,311	$2,212,588	129,994	$3,803,643
Spot Sale	(97,420)	($1,927,863)	0	$0	(97,420)	($1,927,863)
Net Metering Purchases	48	$4,038	0	$0	48	$4,038
AEPS Costs						$496,403
Total	661,317	$33,822,021	77,311	$2,212,588	738,628	$36,531,011

	12 Months Ending May 2017					
	GSR-1		GSR-2		Total	
	MWh	Cost	MWh	Cost	MWh	Cost
Blocks	353,755	$13,203,419	0	$0	353,755	$13,203,419
NYPA	2,430	$66,771	0	$0	2,430	$66,771
Load Following	353,429	$22,990,941	0	$0	353,429	$22,990,941
Load Following - Reconciliation	0	$1,459,702	0	$0	0	$1,459,702
Spot Purchase	48,926	$1,056,521	77,098	$2,327,437	126,025	$3,383,958
Spot Sale	(61,208)	($1,148,289)	0	$0	(61,208)	($1,148,289)
Net Metering Purchases	58	$4,220	0	$0	58	$4,220
AEPS Costs						$355,780
Total	697,390	$37,633,284	77,098	$2,327,437	774,488	$40,316,501

UGI Utilities, Inc. - Electric Division
Total Default Service Costs and MWh Purchased

	12 Months Ending May 2018					
	GSR-1		GSR-2		Total	
	MWh	Cost	MWh	Cost	MWh	Cost
Blocks	355,515	$12,310,046	0	$0	355,515	$12,310,046
NYPA	3,000	$77,695	0	$0	3,000	$77,695
Load Following	359,234	$22,048,462	0	$0	359,234	$22,048,462
Load Following - Reconciliation	0	($479,251)	0	$0	0	($479,251)
Spot Purchase	57,151	$3,433,467	86,077	$3,435,172	143,229	$6,868,639
Spot Sale	(50,091)	($843,230)	0	$0	(50,091)	($843,230)
Net Metering Purchases	78	$5,321	0	$0	78	$5,321
AEPS Costs						$283,602
Total	724,887	$36,552,510	86,077	$3,435,172	810,964	$40,271,284

	12 Months Ending May 2019					
	GSR-1		GSR-2		Total	
	MWh	Cost	MWh	Cost	MWh	Cost
Blocks	366,635	$13,167,638	0	$0	366,635	$13,167,638
NYPA	2,772	$70,477	0	$0	2,772	$70,477
Load Following	357,815	$22,271,991	0	$0	357,815	$22,271,991
Load Following - Reconciliation	0	$755,224	0	$0	0	$755,224
Spot Purchase	47,613	$942,551	77,122	$2,423,973	124,734	$3,366,523
Spot Sale	(57,576)	($1,064,633)	0	$0	(57,576)	($1,064,633)
Net Metering Purchases	110	$7,069	0	$0	110	$7,069
AEPS Costs						$244,775
Total	717,368	$36,150,316	77,122	$2,423,973	794,490	$38,819,064

UGI Utilities, Inc. - Electric Division
Total Default Service Costs and MWh Purchased

	12 Months Ending May 2020					
	GSR-1		GSR-2		Total	
	MWh	Cost	MWh	Cost	MWh	Cost
Blocks	365,915	$12,593,258	0	$0	365,915	$12,593,258
NYPA	2,313	$57,432	0	$0	2,313	$57,432
Load Following	359,742	$21,614,091	0	$0	359,742	$21,614,091
Load Following - Reconciliation	0	($633,778)	0	$0	0	($633,778)
Spot Purchase	29,156	$777,314	76,806	$1,767,730	105,961	$2,545,043
Spot Sale	(83,219)	($1,026,008)	0	$0	(83,219)	($1,026,008)
Net Metering Purchases 1/			0	$0	0	$0
AEPS Costs						$264,782
Total	673,907	$33,382,309	76,806	$1,767,730	750,713	$35,414,821

1/ Net Metering Purchases for the 12 months ending May 2020 have not been determined.

OSBA-I-5

Request:

Reference proposed Rider B. The Company appears to propose that the 100 kW demarcation limit between GSR-1 and GSR-2 be re-evaluated annually, rather than being set once for the four-year term of the plan.

a. Please describe the reasons for the change.

b. When will the affected customers be notified that their default service status will change?

c. Will both shopping and non-shopping customers be notified of a change? Please explain any negative response.

d. If the demand is evaluated as of September 30, when will the change in status take place?

e. Please provide a sample of the communication to customers who will experience a shift from GSR-1 to GSR-2 status, differentiated as necessary by whether the customers are shopping at the time of the transition.

f. Please provide a sample of the communication to customers who will experience a shift from GSR-2 to GSR-1 status, differentiated as necessary by whether the customers are shopping at the time of the transition.

g. Please provide the Company's rationale for imposing a migration charge/credit on customers who are recategorized from GSR-1 to GSR-2.

h. Please provide a quantitative example showing how the migration charge for customers who are recategorized from GSR-1 to GSR-2.

i. Will customers who transition from GSR-2 to GSR-1 be similarly exempt from the variance charges/credits for twelve months? If not, please explain why not.

OSBA-I-5 (Continued)

Response:

a. - c. The Company is not proposing that the 100 kW demarcation be re-evaluated annually. The tariff language included in the Company's Petition inadvertently excluded the full date by which the customer's highest billing demand would be determined. Accordingly, the Company will revise the tariff (at the appropriate time) to state that the Customer's highest billing demand in the twelve-month period ending September 30, 2020 shall be the annual peak load determinant for purposes of applying the GSR.

d. Per the Company's ProForma tariff, changes will become effective with the new default service plan on June 1, 2021.

e. - f. The Company does not have sample communications at this time.

g. The Company believes it is appropriate that the migrating customers pay their portion of the ECA charges.

h. Please see Attachment OSBA-I-5, which provides the calculation used in DSP III.

i. No, as filed in the Company's proforma tariff, the ECA charge will apply to customers moving from GSR-2 to GSR-1. The Company is willing to reconsider this approach as part of this proceeding.

Prepared by or under the supervision of: Stephen F. Anzaldo

UGI UTILITIES, INC. - ELECTRIC DIVISION

Allocation of (Over)/Under

Ln 1	Total Sales for GSR-1 for 12-Months Ended May 31, 2017		658,636,937	Annual Reconciliation, Page 1
Ln 2	Sales for GSR-1 Customers Migrating to GSR-2		3,717,704	
Ln 3	Sales for Customers Migrating to GSR-2 as % of Total		0.6%	= Ln 3 / Ln 1
Ln 4	Cumulative (Over)/Under through May 2017 1/	$	(275,541)	Schedule C, Page 1
Ln 5	(Over)/Under to Carry to GSR-2	$	(1,555)	= Ln 4 * Ln 3

OSBA-I-11

Request:

Regarding the standard offer program, UGI Electric Statement No. 1 at Section VIII:

a. Please describe the Company's efforts with EGSs to engender participation in the standard offer program.

b. Please provide any analysis or research conducted by the Company which explains the lack of supplier participation in the standard offer program.

c. Please provide the Company's judgment as to why EGSs do not participate in the standard offer program.

Response:

a. The Company has not developed marketing material to engender participation in the standard offer program but will develop and provide information about the program on the Company's Energy Management Website by the end of 2020.

b. The Company has not conducted research to explain the lack of supplier participation in the standard offer program.

c. The Company is not aware why EGSs do not participate in the standard offer program however the cost if only one supplier would participate would be $12,000 per month.

Prepared by or under the supervision of: Angelina M. Borelli

OSBA-I-12

Request:

Reference UGI Electric Statement No. 1 at Section IX, table at page 25:

a. Please describe the methodology used to develop the values shown in the referenced table.

b. Please provide all assumptions and supporting workpapers for the referenced table, in MS Excel electronic format as appropriate.

Response:

a. The values shown in the referenced table are developed by Pace Global. Pace uses a proprietary model which takes into account various factors such as the forward price of energy at the PJM Western Hub, capacity, transmission, ancillary services, ARR value, and AEPS when developing price estimates.

b. UGI does not have access to the workpapers used to develop the forecasts in the referenced table.

Prepared by or under the supervision of: Angelina M. Borelli

UGI Utilities, Inc. - Electric Division
Docket No. P-2020-3019907
UGI Electric Default Service Plan
Responses to OSBA Set I (1 thru 16)
Delivered on July 8, 2020

OSBA-I-13

Request:

Reference UGI Electric Statement No. 1 at Section IX, table at page 26:

a. Please describe the methodology used to develop the values shown in the referenced table.

b. Please provide all assumptions and supporting workpapers for the referenced table, in MS Excel electronic format as appropriate.

Response:

a. The values are found by taking the pricing estimates provided by Pace multiplied by the volume estimates developed during UGI's RFP procurement process. Please see the response to OSBA-I-12 for an explanation on Pace's price estimates.

b. Please see Attachment OSBA-I-13(b), which will be provided electronically in Excel format. The prices for the Fall 2019 and Spring 2020 "Separate Procurement - High Range" shown in the UGI Electric Statement No. 1 at Section IX, page 26 were inaccurate for Fall 2019 and Spring 2020 and have been updated from the table provided in Section IX page 26 to correctly reflect the estimates provided by Pace.

Prepared by or under the supervision of: Angelina M. Borelli

OSBA-I-14

Request:

Reference UGI Electric Statement No. 1 at pages 27-28:

a. Please describe the sampling of data supporting the load forecast.

b. Please provide the underlying data and analysis supporting the development of the load forecast, in MS Excel electronic format as available.

Response:

a. UGI has installed load research meters on 1,621 of its residential, commercial and industrial customers which provide average hourly kilowatt usage per customer by strata. The data gathered from the load research meters along with the number of customers by strata was used to estimate the historical split between residential and commercial/industrial load.

b. Please see Attachment OSBA-I-14(b), which will be provided electronically in Excel format.

Prepared by or under the supervision of: Angelina M. Borelli

OSBA-I-15

Request:

Reference UGI Electric Statement No. 1 at Section IX:

a. In light of the material differences between estimated standalone costs for residential and small commercial procurements, please explain why the Company has not proposed an alternative cost allocation method for developing separate residential and commercial GSR-1 charges that would better reflect the cost-to-serve differences.

Response:

The Company is willing to discuss options for allocating costs between residential and commercial customers with the parties during settlement discussions.

Prepared by or under the supervision of: Angelina M. Borelli

EXHIBIT IEc-3

ELECTRONIC WORKPAPERS

OF ROBERT D. KNECHT

RDK WP1:	Shopping Rates
RDK WP2:	Purchase Cost Comparison by Method
RDK WP3:	Load Research/Energy Prices
RDK WP4:	Pace Procurement Estimates
RDK WP5:	Load Research Backup

Workpapers RDK WP1 – RDK WP4 are being circulated to parties with the testimony. RDK WP5 exceeds the capacity of OSBA e-mail but is available from Mr. Knecht upon request, with the approval of OSBA.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. - Electric Division For Approval of a Default Service Plan (DSP IV) for the Period June 1, 2021 Through May 31, 2025	:	**Docket No. P-2020-3019907**

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Direct Testimony labelled OSBA Statement No. 1 and associated Exhibits IEc-1, IEc-2 and IEc-3 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 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: August 6, 2020

Robert D. Knecht

BEFORE THE PENNSYLVANIA
PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan for the Period of June 1, 2021 through May 31, 2025	:	**Docket No. P-2020-3019907**

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email and/or First-Class mail (*unless otherwise noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

The Honorable Dennis J. Buckley
Administrative Law Judge
Pennsylvania Public Utility Commission
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Harrisburg, PA 17120
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/s/ Steven C. Gray

DATE: August 6, 2020

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

COMMONWEALTH OF PENNSYLVANIA

August 31, 2020

The Honorable Dennis J. Buckley
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

Re: Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan for the Period of June 1, 2021through May 31, 2025 / Docket No. P-2020-3019907

Dear Judge Buckley:

Enclosed please find the Rebuttal Testimony and Exhibits of Robert D. Knecht, labeled OSBA Statement No. 1-R, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceedings.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

Enclosures

cc: PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Robert D. Knecht
Parties of Record

Office of Small Business Advocate
Forum Place | 555 Walnut Street, 1st Floor | Harrisburg, PA 17101 | 717.783.2525 | Fax 717.783.2831 | www.osba.pa.gov

OSBA Statement No. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. - Electric Division For Approval of a Default Service Plan (DSP IV) for the Period June 1, 2021 Through May 31, 2025	:	**Docket No. P-2020-3019907**

Rebuttal Testimony and Exhibits of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Default Service

Date Served: August 31, 2020

Date Submitted for the Record: October 2, 2020

REBUTTAL TESTIMONY OF ROBERT D. KNECHT

1. <u>Introduction</u>

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Bob Knecht. I submitted direct testimony and associated exhibits earlier in this proceeding, and my qualifications were presented therein.

Q. Please describe the purpose of this rebuttal testimony.

A. The OSBA requested that I review and evaluate the direct testimony of Dr. Serhan Ogur, representing the Pennsylvania Office of Consumer Advocate ("OCA") for consistency with sound economics and regulatory principles. As detailed below, I have little in the way of theoretical disagreements with Dr. Ogur's analysis. Moreover, Dr. Ogur uncovered a significant error in the Company's response to an OSBA interrogatory, which has a material impact on the analysis in my direct testimony. I update my analysis and conclusions accordingly in this rebuttal testimony.

In addition, the Company belatedly submitted some additional detail from the Pace Study, which it used in its filing to justify its proposal to continue to procure default supplies for residential and smaller commercial customers on a combined basis. This testimony includes my initial observations regarding the new information.

Q. Please summarize the different recommendation with respect to the procurement of default service supplies for the GSR-1 customer group that includes residential and small/medium general service customers.

A. The Company proposes to retain its existing approach, in which half of the supplies are purchased in 12-month layered, fixed-price, full-requirements load-following ("FRLF" or "FPFR") contracts, and half are purchased using a "block-and-spot" approach.[1]

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[1] UGI Electric's block-and-spot approach includes purchases of 6-month around-the-clock (7x24) and peak-period (5x16) power supply blocks, using spot market purchases and sales to balance differences between the actual load and the block supplies. This approach also requires UGI Electric to purchase generation capacity, transmission capacity and alternative energy credits associated with that load.

In my direct testimony, I recommended that the Company continue to use that approach, but also to evaluate expanding the share of supplies met through the block-and-spot approach.

Dr. Ogur recommends that the Company abandon the block-and-spot approach and replace that half of the default supply requirements with 24-month FRLF supplies.

Q. Why do you reach a different conclusion from Dr. Ogur?

A. Dr. Ogur presents his rationale for full reliance on FRLF contracts at pages 11 to 12 of his direct testimony. His reasoning is that the FRLF approach will result in more stable rates, reduced administration costs, reduced ratepayer price and volume risk, and the practices of other Pennsylvania default service providers. All those arguments are reasonable and credible. In fact, I employed most of those arguments in the early days of electric industry rate unbundling in Pennsylvania in support of the adoption of the FRLF approach.[2]

In my direct testimony, I advocated for continued and potentially expanded use of the block-and-spot approach, based on information from the Company that indicated that the block-and-spot approach resulted in materially lower costs than the FRLF method. I should have been more skeptical, as the UGI Electric data imply patently unrealistic purchase costs. Despite OSBA asking the Company to provide all costs incurred for default supplies, split between the FRLF and block-and-spot approaches, the Company's response to OSBA-I-3 excluded PJM generation capacity, PJM transmission network integration transmission service ("NITS"), PJM transmission enhancement charges ("TEC"); and other PJM costs.[3] I therefore updated my cost comparison analysis to reflect the additional data provided by the Company. I then produced the updated of Figure IEc-2 from my

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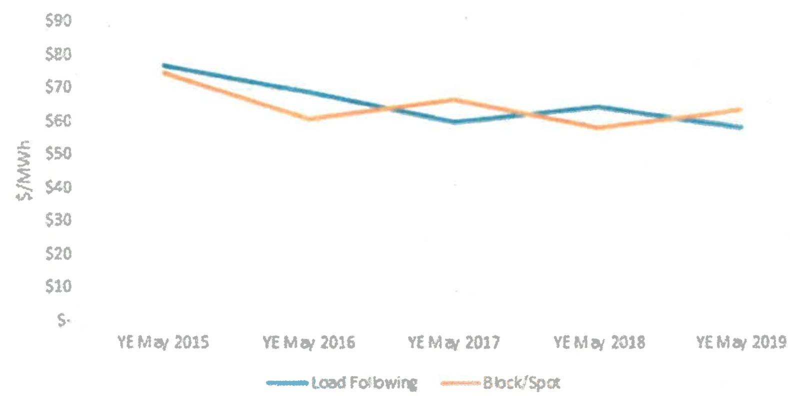
[2] Ironically, those proceedings often involved an expert for OCA advocating for the block-and-spot approach.

[3] See OCA-I-4, attached in Exhibit IEc-R2.

direct testimony as shown below, with updated analysis in my RDK WPR2 electronic workpaper.[4]

Figure IEc-2 Updated
UGI Electric Default Service Purchase Costs



As shown in the updated Figure IEc-2, the revised analysis indicates that the two methods produce roughly the same supply cost, with neither method being obviously superior.

Q. Dr. Ogur opines that the block-and-spot approach will produce results that are less stable than the FRLF approach. Do you agree?

A. As a theoretical or conceptual matter, I do. However, to test that hypothesis, I compared the net UGI Electric GSR-1 supply rate to the PPL Electric price to compare for both Residential and Small C&I customers in RDK WP5. PPL Electric purchases a significant majority of its Residential supplies and all of its Small C&I supplies using FRLF contracts.

The results show that the UGI Electric approach, based half on block-and-spot approach, produced an overall lower supply rate than the PPL Electric approach over the 2014 to mid-2020 period, at 7.0 cents per kWh compared to 8.0 and 7.5 cents per kWh (Residential/Small C&I). Using the ratio of standard deviation to mean as a measure of

[4] In so doing, I assumed that the PJM costs reported by UGI Electric in the responses to OCA-I-1-4 related only to GSR-1 supplies, as that is the data requested by OCA. However, the Company's responses indicate that those are "total" costs, and it is possible that some of those costs are related to GSR-2 supplies.

volatility, the UGI Electric GSR-1 history (12.8%) shows more volatility than PPL Electric Residential (10.3%) but less than the PPL Electric Small C&I (15.1%).

Thus, while it would be logical to expect that the block-and-spot approach would materially increase rate volatility, the impact, at least relative to PPL Electric, is relatively modest.

Q. Please comment on Dr. Ogur's proposed reconciliation mechanism.

A. Dr. Ogur observes that the GSR-1 reconciliation charge (denoted the "ECA") has been relatively high, averaging 8 percent of the GSR-1 cost rate (denoted the "EC"). He proposes that, in conjunction with a shift to all FRLF purchases, that a "6-month/12-month" approach be adopted for reconciliation. In Dr. Ogur's recommended approach, the revenue-cost variance would be evaluated every six months, but each variance would be amortized over a 12-month period. Thus, at any time, the ECA would consist of two components, based on the prior two variance evaluations.

Again, I have no conceptual disagreement with Dr. Ogur. I do note, however, that it is difficult to read too much into the actual UGI Electric ECA history, due to certain unusual features of the Company's approach.

- First, the Company has historically and inappropriately used the ECA as a dumping ground for variances resulting from program-end variances in its energy efficiency and conservation ("EE&C") program. Although that policy was eliminated in early 2019, its impacts have not yet been fully phased out.[5]

- Second, the Company's amortization period for variances is not fixed, in that the Company generally uses a 3-month period, but it uses a longer period if the overall impact on the GSR-1 rate is more than 5 percent. As shown in RDK WPR5, a longer period was used 9 times in the past 24 quarters. Moreover, it is unclear how the Company chooses the length for the longer amortization period.

[5] See Joint Petition for Approval of Settlement, Docket No. M-2018-3004144, paragraph 32. Also, as shown in RDK WPR5, the Company's most recent GSR reconciliation filing continues to include an EE&C adjustment factor in the ECA.

- **Third, the Company also makes no change to either the EC rate or the ECA rate in a quarterly filing if the overall GSR-1 rate change is less than 2 percent. This approach can allow variance levels to build up, simply because cost effects offset the changes in variances.**

As a result of these three factors, the volatility in the ECA is substantially affected by factors unaffected by basic revenue-cost differences.

Rather than trying to analyze ECA patterns with all this complexity, I compiled the Company's actual monthly revenue-cost differences from mid-2014 to mid-2020, and I calculated the implied volatility of the ECA under several different amortization approaches. (See RDK WPR5.) The 3-month/3-month approach (variances compiled quarterly and amortized quarterly) produced the highest ECA volatility, while a 3-month/12-month approach produced the lowest volatility. The 6-month/6-month and 6-month/12-month approaches (the latter recommended by Dr. Ogur) produced variances that were much lower than the 3-month/3-month approach, and only a little higher than the 3-month/12-month approach. Thus, a longer amortization period would improve rate stability relative to a pure 3-month approach under the existing procurement method. It is difficult to evaluate it compared to the Company's present method, due to the complexities and flexibilities in UGI Electric's current approach discussed above.

In preparing this analysis, I also observed that the highest variances occurred in winter periods, particularly 2017-18 and 2014-15. Both of these winters involved abnormal cold periods related to the "polar vortex."[6] Thus, it is likely that the block-and-spot approach substantially increases UGI Electric GSR-1 ratepayer risk related to weather events, particular cold weather events.

Q. Do you have any concerns regarding Dr. Ogur's proposal to use 24-month FRLF contracts for half the GSR-1 default service supply?

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[6] See, e.g., https://en.wikipedia.org/wiki/February_2015_North_American_cold_wave#:~:text=Like%20most%20normal%20cold%20waves,much%20of%20the%20entire%20month and https://en.wikipedia.org/wiki/2017%E2%80%9318_North_American_cold_wave

A. As a general rule, longer-term FRLF contracts would be expected to have higher risk premiums, since the wholesale supplier, in making a fixed price bid for a fixed percentage of the load, absorbs all volume risks related to weather, economic activity and changes in shopping rates. The longer-term contracts, of course, provide for greater rate stability for default service ratepayers because some risks are shifted to the wholesale supplier. Basic financial (option pricing) theory indicates that the longer the term, the higher the risk (all other factors being equal). Thus, longer-term contracts will likely be priced higher than shorter-term contracts, all other factors being equal.

However, given the extremely low level of shopping for the Residential portion of the GSR-1 load for a long time (see RDK WP1R), and the fact that Residential load represents a significant majority of GSR-1 load, the shopping risk is relatively low. Thus, while two-year contracts may result in modestly higher risk premiums built into the wholesaler bids, these are offset by rate stability benefits. Moreover, the use of 24-month FLRF contracts is not unusual for default supply procurement. As such, I conclude the additional risk is not unreasonable.

Q. What, then, do you conclude regarding Dr. Ogur's recommendations for a procurement method and reconciliation?

A. At the end of the day, there is little evidence that the Company's existing method is superior to the approach laid out in Dr. Ogur's recommendations. I therefore conclude that adopting Dr. Ogur's recommendations would not be unreasonable.

Q. Please address Dr. Ogur's testimony regarding the Pace Study and its implications for the relative cost to serve Residential and smaller commercial customers.

A. Dr. Ogur and I are similarly frustrated that the Company has declined to provide the details of the Pace analysis. I expressed a concern that the differences were larger than I observed at other Pennsylvania EDCs where separate procurement is used. Dr. Ogur hypothesizes that the Pace Study may have neglected to include two factors in the analysis of the relative cost of procurement.

First, Dr. Ogur concludes that customer migration risk is higher for commercial customers than for residential customers, as commercial shopping rates are higher and more variable.

He hypothesizes that the Pace Study failed to consider this factor. As a conceptual matter, I agree with Dr. Ogur. However, in practice, default-service-volume-risks result from a variety of weather, economic and shopping factors. In RDK WPR1 I measured the month-to-month volatility of non-shopping customer loads, over the past nine years and over the past five years. As shown, the volatility for residential non-shopping load is about twice as high as that for commercial loads, over both periods evaluated. Thus, when all volume risks are considered, the commercial non-shopping load has significantly lower overall volatility and thus should be less costly to serve.

Second, Dr. Ogur suggests that the Pace Study may not have considered the relative size of the commercial load, and that the load size may be too small to be attractive to wholesale suppliers. As shown in the Company's load research analysis, the peak load for the commercial default service customers is about 40 MW. This is a little less than one-quarter of the overall UGI Electric default service GSR-1 load, and thus it is about the same size as the 25 percent tranche that UGI Electric proposes to use for its FRLF procurements (which it has used in the past). It is also only modestly lower than the 50 MW tranche size target that has been used by FirstEnergy and PPL Electric for their default service procurements. Thus, the 40 MW commercial load level would imply that a separate procurement approach for the smaller commercial customers would likely involve only one contract for any one time, reducing the rate stability benefits of layering contracts. Nevertheless, there would not be any additional risk to the wholesale supplier associated with a smaller size for the commercial tranche. As such, it is not clear that consideration of this factor would have had a material impact on the Pace Study results.

Q. Has the Company subsequently provided any additional details regarding the Pace Study?

A. The Company circulated additional detail regarding the Pace Study in a supplemental response to OSBA-I-12 after the close of business on Friday, August 28, 2020. The additional detail that was provided is included in RDK WPR6, attached to this testimony, with some averaging calculations that I added. While I have not had the opportunity to study this update in detail, I note the following:

First, the Pace Study indicates that the energy prices as measured at PJM West are similar for residential and commercial customers, generally showing a wider range and a slightly higher average for the commercial group. The analysis in my direct testimony suggested that the residential energy prices should be slightly higher than commercial, based on recent PJM energy prices in the PPL Electric zone.

Second, the Pace Study concludes that the generation capacity and transmission costs for the residential class would be more than two or even three times higher on a per-MWh basis than those for commercial customers. At this writing, I do not understand how Pace obtains that result. As I indicated in my direct testimony, the load factor for commercial customers from the Company's load research would suggest a modestly lower per-MWh cost for commercial, but not nearly of the magnitude shown in the Pace Study results.

Absent a clearer explanation of the factors contributing to the low capacity and transmission costs, I retain my concerns about the validity of the Pace Study estimates.

Q. **Does this complete your rebuttal testimony?**

A. Yes, it does.

EXHIBIT IEc-R1

ELECTRONIC WORKPAPERS

OF ROBERT D. KNECHT

RDK WPR1: Shopping rate calculations

RDK WPR2: Updated analysis of relative supply cost methods

RDK WPR5: Analysis of UGI Electric ECA (Reconciliation Charge)

RDK WPR6: Updated Pace Study detail from supplemental response to OSBA-I-12.

Workpapers will be transmitted via separate e-mail attachment simultaneous to e-mail service of this document

EXHIBIT IEc-R2

REFERENCED INTERROGATORY RESPONSES

OCA-I-1

OCA-I-2

OCA-I-3

OCA-I-4

OCA-I-1

Request:

1. For each of the seven tables ("12 Months Ending May 2014" – "12 Months Ending May 2020") in Attachment OSBA-I-3,

    a. Please state total PJM capacity costs that have been incurred directly by UGI for the portion of the GSR-1 default service load not served by load following contracts.

    b. Please explain how these capacity costs have been recovered by UGI from GSR-1 default service customers.

    c. Please state in which line item in each table UGI included these capacity costs.

Response:

a. Please see Attachment OCA-I-1(a).

b. The capacity costs are recovered in accordance with Rider B to UGI Electric Pa. P.U.C. No. 6. In addition, these costs are shown on the quarterly GSR filings on Schedule E.

c. These capacity costs were not included in the tables in Attachment OSBA-I-3.

Prepared by or under the supervision of: Angelina M. Borelli

UGI Utilities, Inc. - Electric Division
Total PJM Capacity Costs

	12 Months Ending May 2014	12 Months Ending May 2015	12 Months Ending May 2016	12 Months Ending May 2017	12 Months Ending May 2018	12 Months Ending May 2019	12 Months Ending May 2020
Total PJM Capacity Costs	$ 10,116,821.11	$ 3,830,126.18	$ 6,638,627.93	$ 4,545,131.01	$ 4,308,308.99	$ 4,506,999.87	$ 2,869,620.40

UGI Utilities, Inc. - Electric Division
Docket No. P-2020-3019907
UGI Electric Default Service Plan
Responses to OCA Set I (1 thru 4)
Delivered on August 27, 2020

OCA-I-2

Request:

2. For each of the seven tables ("12 Months Ending May 2014" – "12 Months Ending May 2020") in Attachment OSBA-I-3,

   a. Please state total PJM Network Integration Transmission Service ("NITS") costs that have been incurred directly by UGI for the portion of the GSR-1 default service load not served by load following contracts.

   b. Please explain how these NITS costs have been recovered by UGI from GSR-1 default service customers.

   c. Please state in which line item in each table UGI included these NITS costs.

Response:

a. Please see Attachment OCA-I-2(a).

b. The PJM Network Integration Transmission Service costs are recovered in accordance with Rider B to UGI Electric Pa. P.U.C. No. 6. In addition, these PJM Network Integration Transmission Service costs are shown on the quarterly GSR filings on Schedule E.

c. These NITS costs were not included in the tables in Attachment OSBA-I-3.

Prepared by or under the supervision of: Angelina M. Borelli

UGI Utilities, Inc. - Electric Division
Total PJM Network Integration Transmission Service (NITS) Costs

	12 Months Ending May 2014	12 Months Ending May 2015	12 Months Ending May 2016	12 Months Ending May 2017	12 Months Ending May 2018	12 Months Ending May 2019	12 Months Ending May 2020
Total PJM NITS Costs	$ 3,882,463.45	$ 2,938,639.45	$ 4,197,505.43	$ 3,058,373.91	$ 4,214,329.34	$ 4,450,145.08	$ 5,379,611.81

OCA-I-3

Request:

3. For each of the seven tables ("12 Months Ending May 2014" – "12 Months Ending May 2020") in Attachment OSBA-I-3,

   a. Please state total PJM Transmission Enhancement Charges ("TEC") costs that have been incurred directly by UGI for the portion of the GSR-1 default service load not served by load following contracts.

   b. Please explain how these TEC costs have been recovered by UGI from GSR-1 default service customers.

   c. Please state in which line item in each table UGI included these TEC costs.

Response:

a. Please see Attachment OCA-I-3(a).

b. The PJM Transmission Enhancement Charges are recovered in accordance with Rider B to UGI Electric Pa. P.U.C. No. 6. In addition, these PJM Transmission Enhancement Charges costs are shown on the quarterly GSR filings on Schedule E.

c. These TEC costs were not included in the tables in Attachment OSBA-I-3.

Prepared by or under the supervision of: Angelina M. Borelli

UGI Utilities, Inc. - Electric Division
Total PJM Transmission Enhancement Charges (TEC) Costs

	12 Months Ending May 2014	12 Months Ending May 2015	12 Months Ending May 2016	12 Months Ending May 2017	12 Months Ending May 2018	12 Months Ending May 2019	12 Months Ending May 2020
Total PJM TEC Costs	$ 438,924.51	$ 350,111.39	$ 597,444.67	$ 358,477.82	$ 335,835.48	$ (350,195.78)	$ 167,669.41

OCA-I-4

Request:

4. For each of the seven tables ("12 Months Ending May 2014" – "12 Months Ending May 2020") in Attachment OSBA-I-3,

    a. Please state total other PJM costs (e.g. regulation, synchronized reserve, day-ahead and balancing operating reserve, PJM scheduling, system control and dispatch) that have been incurred directly by UGI for the portion of the GSR-1 default service load not served by load following contracts.

    b. Please explain how these other PJM costs have been recovered by UGI from GSR-1 default service customers.

    c. Please state in which line item in each table UGI included these other PJM costs.

Response:

a. Please see Attachment OCA-I-4(a).

b. Other PJM costs are recovered in accordance with Rider B to UGI Electric Pa. P.U.C. No. 6. In addition, these other PJM costs (e.g. regulation, synchronized reserve, day-ahead and balancing operating reserve, PJM scheduling, system control and dispatch) are shown on the quarterly GSR filings on Schedule E.

c. These other PJM costs were not included in the tables in Attachment OSBA-I-3.

Prepared by or under the supervision of: Angelina M. Borelli

UGI Utilities, Inc. - Electric Division
Total Other PJM Costs

	12 Months Ending May 2014	12 Months Ending May 2015	12 Months Ending May 2016	12 Months Ending May 2017	12 Months Ending May 2018	12 Months Ending May 2019	12 Months Ending May 2020
Non Firm Transmission Service Credit	$ (8,027.87)	$ (5,491.17)	$ (5,864.49)	$ (4,486.15)	$ (8,197.87)	$ (6,685.86)	$ (3,965.74)
Reactive Supply / Voltage Control	$ 362,569.57	$ 180,702.89	$ 274,546.84	$ 246,962.47	$ 182,944.21	$ 307,716.86	$ 318,273.73
Black Start Service	$ 2,894.94	$ 1,831.17	$ 12,065.68	$ 11,008.38	$ 11,239.55	$ 11,205.69	$ 14,285.29
Regulation and Frequency Response	$ 182,541.86	$ 91,968.53	$ 75,307.49	$ 31,841.17	$ 43,538.24	$ 42,844.01	$ 37,901.09
Ramapo	$ -	$ 3,304.13	$ 14,797.07	$ 1,472.06	$ 11,060.69	$ -	$ -
Operating Reserves	$ 1,534,363.89	$ 280,850.02	$ 235,987.08	$ 136,806.78	$ 214,897.33	$ 57,442.39	$ 73,537.02
PJM Office Expense	$ 142,933.45	$ 111,370.01	$ 158,884.14	$ 108,099.04	$ 122,987.75	$ 149,043.53	$ 130,777.82
PJM Membership	$ -	$ 4,513.85	$ -	$ -	$ -	$ -	$ -
TO Office Expense	$ 30,492.54	$ 22,783.72	$ 31,819.27	$ 20,863.45	$ 22,314.59	$ 20,028.79	$ 21,563.30
Expansion Cost Recovery	$ 3,377.49	$ 2,077.09	$ -	$ -	$ -	$ -	$ -
GATS	$ 2,719.55	$ 3,206.63	$ 3,294.41	$ 2,983.49	$ 2,650.06	$ 1,328.38	$ 2,732.84
NERC/RFC	$ 13,834.21	$ 11,486.09	$ 17,779.95	$ 12,113.66	$ 13,746.74	$ 15,786.09	$ 14,639.27
Load Response Charges	$ 562,626.34	$ 3,628.83	$ (644.82)	$ (181.47)	$ 897.00	$ (576.22)	$ 1,576.64
Meter Correction Charges	$ (5,446.31)	$ (9,057.12)	$ (8,520.49)	$ (4,596.06)	$ (7,937.72)	$ (9,961.06)	$ (10,091.44)
Congestion/Credits	$ 1,556,298.51	$ 448,326.02	$ (671,314.75)	$ (690,257.69)	$ (13,898.63)	$ (1,345,740.35)	$ (1,461,121.93)
Marginal Loss Expense/Credits	$ 230,313.71	$ 49,738.75	$ (201,878.37)	$ (83,100.30)	$ (116,554.99)	$ (369,613.10)	$ (295,420.32)
FTR Auction Charges	$ (17,695.49)	$ 224,642.90	$ (160,983.27)	$ (420,144.20)	$ (158,848.00)	$ -	$ -
FTR Auction Credits	$ (88,187.36)	$ -	$ (115,635.87)	$ -	$ -	$ -	$ -
ARR Revenues	$ (139,467.41)	$ (196,970.79)	$ (260,234.16)	$ 64,112.17	$ (13,320.54)	$ 63,539.23	$ 125,471.34

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. - Electric Division For Approval of a Default Service Plan (DSP IV) for the Period June 1, 2021 Through May 31, 2025	:	**Docket No. P-2020-3019907**

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Direct Testimony labelled OSBA Statement No. R-1 and associated Exhibits IEc-R1 and IEc-R2 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 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: August 31, 2020

Robert D. Knecht

BEFORE THE PENNSYLVANIA
PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan for the Period of June 1, 2021 through May 31, 2025	:	**Docket No. P-2020-3019907**

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless otherwise noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

The Honorable Dennis J. Buckley
Administrative Law Judge
Pennsylvania Public Utility Commission
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Harrisburg, PA 17120
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DATE: August 31, 2020

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

COMMONWEALTH OF PENNSYLVANIA

September 30, 2020

The Honorable Dennis J. Buckley
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

Re: Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan for the Period of June 1, 2021through May 31, 2025 / Docket No. P-2020-3019907

Dear Judge Buckley:

Enclosed please find the Surrebuttal Testimony and Exhibit of Robert D. Knecht, labeled OSBA Statement No. 1-S, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

Enclosures
cc: PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Robert D. Knecht
Parties of Record

OSBA Statement No. 1-S

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. - Electric Division For Approval of a Default Service Plan (DSP IV) for the Period June 1, 2021 Through May 31, 2025	: : : : :	Docket No. P-2020-3019907

Surrebuttal Testimony and Exhibit of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Default Service

Date Served: September 30, 2020

Date Submitted for the Record: October 2, 2020

SURREBUTTAL TESTIMONY OF ROBERT D. KNECHT

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Bob Knecht. I submitted direct testimony, rebuttal testimony and associated exhibits earlier in this proceeding, and my qualifications were presented therein.

Q. Please describe the purpose of this surrebuttal testimony.

A. This testimony updates my direct testimony analysis of the implications of certain analysis prepared for UGI Utilities, Inc. – Electric Division ("UGI Electric" or "the Company") by Pace Global ("Pace"). Pursuant to the settlement in the Company's last default service proceeding, the Pace analysis addressed the relative costs of independently procuring default service supplies for GSR-1 residential and GSR-1 non-residential (generally called "commercial" by the Company) and the joint procurement method.[1] As detailed further herein, this update of my direct testimony is necessary because the Company has identified material errors in the originally-filed Pace analysis, and it has since submitted a revised analysis. This testimony also responds to the rebuttal testimony of Ms. Angelina M. Borelli for the Company regarding this analysis.

Q. Please summarize the evidence regarding the Pace study.

A. As I explained in my direct testimony, the Company submitted summary results in its filing (May 26) of an analysis prepared by Pace showing the estimated standalone procurement costs for GSR-1 residential and GSR-1 commercial customers, compared to the cost for combined procurement. I am advised by counsel that OSBA's understanding of that settlement provision was that it would inform the decision as to whether residential and non-residential default service supplies should be separately procured, and would help assess whether the combined procurement resulted in reasonable rates for both residential and commercial customers.

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[1] GSR-1 applies to smaller customers with maximum demand below 100 kW. GSR-2 applies to customers with demand above 100 kW and is an hourly priced service.

Pace prepared its estimates at half-year intervals, for seven periods running from spring 2017 to spring 2020. The original Pace analysis showed (a) on an overall cost basis, it was materially less expensive for UGI Electric to procure supplies on a combined basis than on an individual basis, and (b) it was substantially (39% to 59%) more expensive to procure residential supplies independently than to procure commercial supplies. Pace concluded that the average per-MWh cost to independently procure small commercial supplies was well below the average cost for combined procurement. The Pace study summary was presented on a "black-box" basis, and parties to the proceeding were denied access to the underlying data and analysis.[2]

In my direct testimony (distributed on August 6), I expressed some surprise at the magnitude of the difference between the stand-alone procurement costs for the two GSR-1 sub-classes in the Pace study, based in part on observed results from standalone procurements at other Pennsylvania electric distribution companies ("EDCs"). As a check, I prepared an analysis of the relative energy costs for residential and commercial customers using the Company's load research analysis and reported PPL Zone locational marginal prices and concluded that, for energy costs, commercial customers were only modestly less expensive to serve. I also reviewed the relative peak demands and load factors for the two customer groups from the Company's load research. While load factors were modestly higher for commercial customers, I concluded that this difference did not appear to justify the substantial standalone cost differentials in the Pace analysis.[3] However, I also opined that if these estimates did indeed prove to be accurate, that the Company should consider setting separate GSR-1 rates for residential and non-residential customers based on the Pace estimates, in order to reduce the cross-subsidization within the current GSR-1 tariff. Based on my analysis of the time, even granting all of the benefits of combined

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[2] In her rebuttal testimony, UGI Electric witness Ms. Borelli asserts that the settlement agreement only required UGI Electric to provide the estimates, and it did not require the Company to provide supporting analysis or methods. (UGI Electric Statement No 1-R at 20.) While I cannot comment on the legal aspects of Ms. Borelli's position, it is my experience in Pennsylvania that (a) this type of legalistic interpretation of a settlement provision is not the norm for Pennsylvania utilities in regulatory proceedings, and (b) this approach is likely to discourage future settlements.

[3] Unlike the Company's proprietary Pace analysis, my analysis was available to all parties.

procurement to the residential class, the GSR-1 residential rate would be set at 1.05 times the average cost, while GSR-1 commercial would be set at 1.15 times the average cost.

In direct testimony, Dr. Serhan Ogur representing the Pennsylvania Office of Consumer Advocate ("OCA") also expressed concern regarding the Pace study results, and he offered two potential explanations for the wide discrepancy in unit costs for the two sub-classes.

Just prior to the due date for rebuttal testimony (August 31), the Company circulated some additional detail among the parties in support of the Pace analysis, although that information remained far from complete. The additional detail demonstrated that Pace had concluded that there were only small differences in market energy costs for residential and commercial loads, but that there were very substantial differences in peak-demand related costs, namely generation capacity and transmission capacity costs. No changes to the analysis were presented at that time.

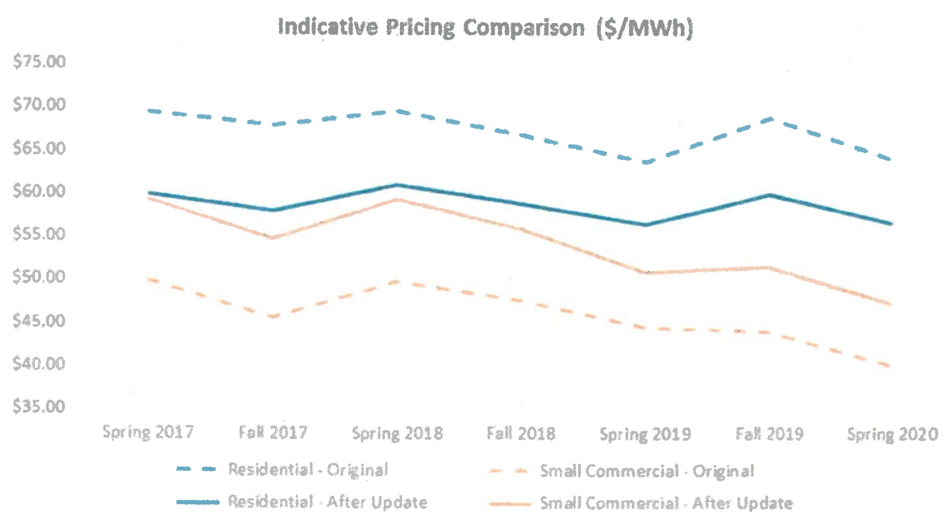
In rebuttal testimony, I reiterated my concern that the Pace analysis of demand costs did not appear to be consistent with my review of the Company's load research data, and I again expressed doubt about the validity of the analysis. Dr. Ogur's rebuttal testimony indicated that he generally agreed with the results of the analysis in my direct testimony, and he reached similar conclusions to my own regarding the updated Pace study information.

In the Company's rebuttal, Ms. Borelli expressed strong support for the accuracy of the Pace analysis, based on Pace's performance history with the Company, and she concluded that " . . . I have no reason to believe that Pace's methodology is inaccurate."[4] However, Ms. Borelli also opined that my proposal to establish separate rates for residential and commercial GSR-1 customers based on the Pace analysis was not reasonable, because my analysis indicated that the cost differences appeared only be relatively modest.[5] Ms. Borelli did not attempt to reconcile those two positions, which do not appear to be consistent.

[4] UGI Electric Statement No. 1-R at 19-20.

[5] *Id.* at 21-22.

On September 9, the Company's counsel advised parties that there were errors in the Pace analysis relating to class load factors, and that revised results would be forthcoming. On September 16, the Company circulated a spreadsheet described as the "revised Pace estimate," and on September 17 it circulated responses to Set II of interrogatories from OCA regarding this topic, generally referring to the revised Pace analysis. This updated analysis generally showed that the standalone procurement costs for residential and commercial supplies were of similar magnitude in the spring of 2017, but widened considerably by the spring of 2020, with residential cost being about 20 percent higher than commercial cost for the most recent estimate. The analysis confirms that there is little difference in energy costs for the two classes, and that the shift from the original filing is due to changes in relative class load factors over the three years. Overall, the results show that the residential cost premium is much less than that in the earlier analysis, but is still significant, particularly using more recent load and market information. In particular, the revised Pace analysis shows that the cost to serve residential customers was nearly 20 percent higher than the cost to serve commercial customers in the spring of 2020. The Company's comparison chart is copied below:



On September 17, I submitted some follow-up "informal discovery" questions to the Company regarding the updated Pace analysis, to which the Company responded on September 22. The essence of these responses was:

- The updated Pace analysis was further updated to include an estimate of the combined cost for procuring GSR-1 load, in addition to the standalone analysis. The combined analysis continued to show that, overall, a combined procurement was less expensive than standalone procurement, when averaged over the seven periods analyzed by Pace. However, in the new analysis, the overall savings fell from 8 percent in the original filing to 1 percent with the update. Moreover, the updated results implied that combined procurement would result in a higher average cost than separate procurement in the three most recent periods.

- Per-MWh generation capacity costs for commercial customers were materially lower than those for residential customers, particularly in the more recent periods, due to a higher Unforced Capacity ("UCAP") load factor for commercial. UCAP is a measure of capacity used by PJM to measure the generating capacity obligation needed to serve a customer. Pace reports that UCAP values were provided by the Company.

- Per-MWh transmission capacity costs for commercial customers were also materially lower than those for residential customers, due to a higher Network Service Peak Load ("NSPL") load factor. NSPL is the measure of peak demand used by PJM for assigning transmission capacity costs. Pace again reports that NSPL demands were provided by UGI Electric. On a relative basis, the ratio of commercial load factor to residential load factor for NSPL is materially higher than it is for UCAP. Thus, for example, Pace's "indicative" transmission cost for residential customers is $17.22 per MWh for Spring 2020, while the transmission cost for commercial is $10.25 per MWh.

Q. Does the updated Pace analysis resolve all the concerns that you expressed in preparing your earlier testimony?

A. The reduction in the spread between estimated residential and commercial cost is directionally reasonable. In addition, the Company has provided more clarity with respect to how energy and demand costs are developed for the respective rate class groups. However, the following anomalies remain:

- As I indicated earlier, combined procurement for all GSR-1 loads is more costly than separate procurements for three periods, Spring 2019 and 2020 and Fall 2019. I do not understand how that would happen.

- The updated Pace analysis graphically depicts UCAP load factors for residential and small commercial customers. For some periods, the relative UCAP load factors do not appear to be consistent with the reported per-MWh costs for residential and commercial customer groups. For other periods, the values are consistent.

- The load factor spreads between residential and commercial rate class groups, particularly for NSPL demand, are higher than I would have expected based on my review of the Company's load research data.

Nevertheless, these results have presumably been scrutinized both by Pace and by the Company, and thus represent the best estimate regarding the relative cost to serve residential and commercial customers on record in this proceeding. Thus, the Company has demonstrated that the cost to serve commercial customers is significantly lower than the cost to serve residential customers. As a result, the current combined procurement approach (with uniform rates for residential and commercial customers) requires that commercial customers subsidize residential customers.

Q. What options are available for addressing the cost subsidy issue?

A. I see three generic options:

- Procure residential and commercial default supplies separately (the "separate procurement" approach);

- Procure residential and commercial default supplies together, but allocate costs based on cost causation principles (the "cost allocation" approach);

- Continue the existing method while the anomalies in the Pace analysis are resolved and alternative ratemaking approaches are more fully developed (the "business-as-usual" approach).

Q. Should residential and commercial GSR-1 default service loads be separately procured?

A. Although the updated Pace analysis shows little overall cost benefit for combined procurement, I do not recommend separate procurements at this time, for three reasons. First, separate procurements would increase administrative costs to the detriment of ratepayers. Second, UGI Electric's historical experience with separate procurements argues against a return to that approach. In its initial default service plan, the Company relied on separate procurements for residential and non-residential default service customers, with the non-residential group including customers with loads up to 500 kW.[6] The Company attempted to procure full requirements load following ("FRLF") supplies for the non-residential group, but most of the procurements were rejected by the Commission. While it is possible that these earlier procurement efforts failed because larger customers (maximum demand from 100 kW to 500 kW) with a higher propensity to shop were included in the non-residential category, there is no evidence or analysis on record in this proceeding that would ensure this problem would not recur. Third, if a separate procurement approach were adopted, it would be necessary to revisit the overall procurement approach for both residential and commercial load. As Dr. Ogur notes in his direct testimony, and as I discuss in my rebuttal testimony, the overall load size for commercial customers is relatively small, and the complex mix of contracts envisioned by the Company would not be appropriate for this rate class group. Unfortunately, due to the Company's errors and delays, parties were not aware until late in the proceeding that the Company's analysis shows there is little overall ratepayer benefit to combined procurement. This delay precludes the ability of parties to develop a reasonable procurement strategy for any independent procurement approach in this proceeding.

Q. How would a cost allocation approach work for developing differentiated rates?

A. If a cost allocation framework is adopted, I propose the following. Overall, the approach would be conceptually similar to how Pace builds up its standalone cost estimates, but it relies on information provided by the Company. In my proposal, default service costs

[6] See Docket No. P-2013-2357013, OSBA Statement No. 1, June 20, 2013, at 5-15.

would be segregated into three "buckets." These buckets would be costs related to MWh energy consumption, costs related to UCAP demand, and costs related to NSPL demand. Energy costs would include all cost items that Pace treats as energy-related, including all "energy" costs plus ARR, ancillary services, AEPS and margin. UCAP costs would be the "capacity" costs in the Pace analysis, while NSPL costs would be the "transmission" costs. In cost allocation parlance, default service costs would be "classified" into these three categories. Costs would then be allocated based on class contribution to each of these parameters, namely MWh consumption, UCAP demand and NSPL demand.

Q. Why do you propose using overall MWh consumption for energy related costs, since energy costs vary by hour and the residential and commercial customer groups have different load profiles?

A. Theoretically, energy-related costs should reflect class-specific load profiles and the related hourly energy costs. However, in this proceeding, the Pace analysis suggests that the per-MWh energy-related costs are slightly higher for the commercial sub-class, while my analysis indicated that energy-related costs are slightly higher for the residential class. Thus, based on the evidence on the record, I conclude that a MWh allocation approach for energy-related costs is reasonable for this utility at this time. This approach, however, would need to be re-evaluated periodically.

Q. How would the UCAP and NSPL demand allocation factors be derived in your proposal?

A. As I indicated earlier, the Company provided Pace with historical UCAP and NSPL demand levels split between residential and commercial rate class groups for default service load. I propose that the Company calculate a historical average load factor for each demand type (UCAP and NSPL) and apply that average load factor to the forecast MWh loads to derive the respective demand allocation factors.

Q. As a practical matter, how would you propose to set GSR-1 rates for the residential and commercial sub-classes?

A. As I suggested in my direct testimony, I believe a simple and reasonable approach would be to apply a multiplier to the calculated GSR-1 rate. In effect, UGI Electric would calculate the GSR-1 overall cost rate in exactly the same way it currently does, and then apply separate multipliers for resident and commercial to that value. To keep the calculations as simple and as consistent with current practice as possible, the multiplier would apply to both the forecast cost component ("C-Factor") and the reconciliation component ("E-Factor") of the GSR-1 rate.

Q. What information would be necessary for developing the multipliers?

A. To derive the multipliers, the Company would need to (a) forecast energy use (or share of energy use) for residential and commercial, (b) compile historical UCAP and NSPL load factors for residential and commercial sub-classes, and (c) forecast procurement costs in each of the three "buckets," namely energy, UCAP and NSPL costs.

Q. Does this require an unusual amount of cost forecasting?

A. No. All cost allocation studies in a test year regulatory environment require a forecast of classified costs as well as the development of demand and energy allocation factors. While my proposed approach would necessarily be somewhat more complicated than those that apply to utilities large enough for separate procurements (where very little cost allocation is needed), it is no more complicated than normal cost allocation practice in Pennsylvania. For example, PPL Electric already separates its generation and transmission costs for default service ratemaking. Differentiated rates for generation costs are derived by separate procurements. Differentiated default service rates for transmission costs are derived using traditional cost allocation methods, notably an allocation based on peak demands.

Q. How often should the multipliers be updated?

A. I propose that the multipliers be updated annually. Because the load factors are based on a historical average, the annual changes in relative demand allocators will likely be relatively small. However, the cost mix parameters will change with electricity market changes, and the relative load size for residential and commercial customers will change with both load growth and shopping rates. As such, I do not recommend that the multipliers be locked in for the entire four-year DSP period.

Q. Have you derived the current value for these multipliers using this method?

A. Yes, RDK WPS6 contains this analysis, which I prepared both for the Pace "indicative" scenario and the Pace "high" scenario. The indicative scenario is based on the following parameters:

- MWh load mix is based on the Spring 2020 mix from the Pace report, at 74.2% residential and 25.8% commercial;
- Unfortunately, historical load factors are not available from the Pace analysis. However, as a matter of arithmetic, the ratio of the per-MWh capacity and transmission costs for the two classes should equal the inverse of the ratio of the class load factors, if costs are assigned on a demand basis as reported by Pace. Thus, the average historical residential to commercial ratio of load factors for the seven periods evaluated by Pace is 0.857 for UCAP, and 0.738 for NSPL. With a little arithmetic, these values can be used to derive demand allocation factors.[7]
- The mix of default service costs is based on the Spring 2020 mix from the Pace report, at 55.6% energy, 15.9% UCAP and 28.5% NSPL.

Using these parameters, the ratio of the commercial GSR-1 rate to the residential GSR-1 rate is 0.90, with an implied residential multiplier of 1.027 and a commercial multiplier of .923. This is shown in Table IEc-S1 below. Note that this analysis is all prepared based on percentages of overall costs. Substituting an actual cost forecast would not change the multipliers or the ratios in this analysis.

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[7] Let "LFR" be the ratio of residential to commercial load factors, equal to $(E_R/D_R)/(E_C/D_C)$., where E is MWh energy, D is demand (UCAP or NSPL, as appropriate), R is residential, C is commercial. Re-arranging terms: $D_C/D_R = LFR * E_C/E_D$. Adding unity to both sides: $(D_C + D_R)/D_R = 1+LFR * E_C/E_D$. Since the residential demand allocator is $D_R/(D_C+D_R)$, that equals $1/(1+LFR * E_C/E_D)$.

Table IEc-S1 UGI Electric Default Service GSR-1 Cost Allocation Analysis: Indicative Case				
	Energy	**UCAP Demand**	**NSPL Demand**	**Total**
Cost Mix	55.6%	15.9%	28.5%	100.0%
Residential Allocator	74.2%	77.0%	79.6%	76.2%
Commercial Allocator	25.8%	23.0%	20.4%	23.8%
Residential Cost	41.3%	12.3%	22.6%	76.2%
Commercial Cost	14.4%	3.6%	5.8%	23.8%
Residential Unit Cost				102.7%
Commercial Unit Cost				92.3%
C/R Price Ratio				0.899
Note: Cost values are calculated as the cost mix value multiplied by the respective allocation factor. Unit cost values equal the cost values divided by energy shares. Source: RDK WPS6.				

My analysis of the "high" scenario produces similar results, with multipliers of 1.025 and 0.929 for residential and commercial respectively.

Q. Are these the specific parameters that you recommend adopting for default service rates if the cost allocation method is adopted?

A. No. I propose that, prior to setting the default rates, the Company recalculate the rate ratios based on its most recent cost forecasts and based on average historical class load factors that incorporate any updated load research information and UCAP/NSPL reassessments. As noted earlier, I recommend that these ratios be updated annually.

Q. Please describe the "business and usual" approach to this problem.

A. As I explained, the Pace analysis of the standalone cost of providing default service to residential and non-residential GSR-1 customers indicates that the per-MWh cost to serve residential customers is materially higher than that to serve non-residential customers, based on current class load profiles and market costs. It also indicates that there is only a very small overall cost benefit to combined procurement. While it is the best evidence on record in this proceeding, there are credibility problems with the analysis as discussed above.

Thus, the "business-as-usual" approach would be one in which the current combined procurement method with uniform rates is retained until a credible evaluation of independent procurement and cost allocation methods is prepared. Allowing this situation to fester for the full four years of the default service plan, however, would be inequitable if the most recent Pace analysis proves to be accurate. However, if the Pace analysis is inaccurate and combined procurement remains the best option, it should not be necessary to shorten the DSP-IV term.

To pursue this approach, I recommend that before December 31, 2021 the Company be required to file a study of the relative cost of default service supplies for GSR-1 residential and non-residential customers. The filing will include all workpapers and assumptions used in the analysis, subject to reasonable confidentiality restrictions as necessary. The study will evaluate both block-and-spot and full requirements procurement methods. This study is not intended to rely solely on information derived in DSP-IV but should also rely on prior period information. In effect, I recommend that a more careful, thorough, and transparent version of the Pace analysis be prepared and filed with the Commission.

At that time, the Company would make a recommendation as to whether the combined procurement detailed in Paragraph 2 should be retained, or whether an alternative plan with differentiated rates should be adopted following the completion of the first two years of DSP IV. The Company would evaluate both separate procurement and cost allocation methods for rate differentiation.

Procedurally, all parties would retain their rights to challenge the Company's recommendation at that time.

If the Commission determines that differentiated rates are justified, the second half of DSP IV, with differentiated rates, would go into effect in June 2023.

Q. Would adopting this approach require any modifications to the proposed procurement schedule?

A. The procurement schedule would need only be modified if the Commission determines that differentiated rates should go into effect in Year 3 (June 2023 – May 2024). If the

Commission does so, all procurement contracts would need to terminate at the end of May 2023. Under the Company's proposed procurement plan (Petition pages 23-24), the 12-month full requirements procurement in the Fall of 2022 would need to be replaced with a 6-month procurement.[8] By completing the analysis in 2021, this schedule would allow for a Commission decision prior to the Fall 2022 procurement date, and thus modifying the schedule would be necessary only if an alternative approach is adopted.

Q. Does this complete your surrebuttal testimony?

A. Yes, it does.

[8] If Dr. Ogur's procurement approach is adopted, I believe this schedule can be accommodated while retaining much of the essence of Dr. Ogur's proposal. I would recommend modifying Dr. Ogur's Table 1 to (a) procure 2 tranches of 24-month supply and 1 tranche of 12-month supply in the Spring of 2021, (b) procure 2 tranches of 12-month supply in the Spring of 2022, and (c) modify the Fall 2022 12-month procurement to a 6-month contract. The last change would only be needed if differentiated rates are established for the second half of DSP-IV.

EXHIBIT IEc-S1

ELECTRONIC WORKPAPERS

OF ROBERT D. KNECHT

RDK WPS6: Updated Pace Analysis with Illustrative Cost Allocation Results

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. - Electric Division For Approval of a Default Service Plan (DSP IV) for the Period June 1, 2021 Through May 31, 2025	:	**Docket No. P-2020-3019907**

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Surrebuttal Testimony labelled OSBA Statement No. S-1 and associated Exhibit IEc-S1 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 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: September 30, 2020

Robert D. Knecht

BEFORE THE PENNSYLVANIA
PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. – Electric Division for Approval of a Default Service Plan for the Period of June 1, 2021 through May 31, 2025	:	**Docket No. P-2020-3019907**

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless otherwise noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

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/s/ Steven C. Gray

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BEFORE THE PENNSYLVANIA
PUBLIC UTILITY COMMISSION

Petition of UGI Utilities, Inc. – Electric	**:**	
Division for Approval of a Default Service	**:**	
Plan for the Period of June 1, 2021	**:**	**Docket No. P-2020-3019907**
through May 31, 2025	**:**	

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DATE: December 9, 2020

/s/ Steven C. Gray

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