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June 29, 2022

VIA ELECTRONIC FILING
Rosemary Chiavetta
Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor North
P.O. Box 3265
Harrisburg, PA 17105-3265

Re: 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 Nos. P-2020-3019907 and G-2020-3019908

Dear Secretary Chiavetta:

Attached please find for filing a Procurement Study, titled *Study of the Relative Cost of Default Service Supply for Residential and Non-Residential GSR-1 Customers* dated June 24, 2022, which UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company") prepared in accordance with a requirement set forth in an Order of the Pennsylvania Public Utility Commission (Order entered January 14, 2021) in the above-referenced dockets. The Company hired the NorthBridge Group to perform the Procurement Study for UGI Electric, enclosed herewith as Attachment A. Due to its voluminous nature, the Procurement Study's supporting work papers and assumptions will be made accessible to the parties on the certificate of service by way of electronic mail containing a SharePoint site link to the documentation.

I. BACKGROUND

On May 26, 2020, UGI Electric filed its *Petition of UGI Utilities, Inc., - Electric Division for Approval of a Default Service Plan (DSP IV) for the Period of June 1, 2021 through May 31, 2025* at Docket Nos. P-2020-3019907 and G-2020-3019908 ("DSP IV Petition"). On October 23, 2020, the parties filed a Joint Petition for Settlement ("Settlement"), which, in part, stated that the Company would conduct a Procurement Study comparing the relative cost of default service supplies for GSR-1 residential and non-residential customers. Settlement at 7. The Procurement Study would be filed before June 30, 2022 with all workpapers and assumptions. Id.

The study would review data from DSP III and DSP IV through at least the Fall of 2021. Id. Finally, the study would "evaluate the relative costs to GSR-1 residential and non-residential customers associated with: (1) both block-and-spot and full requirements procurements methods; and (2) both separate procurements and cost allocations being made to the residential and non-residential customer groups under a combined procurement." Id. at 7-8. Concurrent with the Procurement Study, the Company would recommend "whether to: (1) continue its existing combined procurement methodology for residential and non-residential customers under the single GSR-1 rate; (2) propose separate procurements for residential and non-residential GSR-1 customers; or (3) maintain combined procurements with differentiated rates for residential and non-residential GSR-1 customers." Id. at 8.

II. GSR-1 PROCUREMENT COSTS BY CUSTOMER GROUP

The Procurement Study identified the individual cost components associated with default service supply for UGI Electric's residential and non-residential GSR-1 customers under both block-and-spot and fixed-price, full requirements ("FPFR") product procurement methods. The cost components reviewed include Energy, Capacity, Network Integration Transmission Service ("NITS"), and Other Costs. Procurement Study at 3-13. With this data, the Study developed a relative comparison of the total costs to procure supply needed to serve the GSR-1 load for residential and commercial customers between June 2022 and May 2025. The costs (measured in dollars-per-megawatt-hour) of UGI Electric's residential and non-residential GSR-1 default service supply were approximately 2% higher and 6%-7% lower, respectively over the three year period, as compared to the composite GSR-1 default service supply cost. Id.

III. RECOMMENDATION

As the Study finds, separate procurements would likely entail unnecessary cost-related risks (e.g., lack of competitive bid responses), and an estimated $25,000 annual increase in administrative costs. Therefore, the Company's recommendation aligns with a rate allocation methodology posed in the Study. Specifically, to more appropriately assign the expected procurement costs to the relative customer groups, Relative Cost Factors could be developed (similar to the tables on page 14 of the Study) for DSP V and applied to the Energy Cost ("EC") value in the GSR-1 Rate. Page 19 of the Study prepared examples, spanning the period of June 2022-May 2025, showing how to calculate the Relevant Cost Factors. It estimated Relevant Cost Factors of 1.02 for Residential GSR-1 customers and between 0.93 – 0.94 for Non-Residential GSR-1 customers (during that period). The Company intends to propose implementing Relevant Cost factors in its DSP V filing.

Sincerely,

/s/ Michael S. Swerling
Michael S. Swerling

Enclosures: Supporting Information
Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that I have, this 29th day of June, 2022, served a true and correct copy of the foregoing document upon the following persons, in the manner indicated, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

VIA E-FILE & ELECTRONIC MAIL

<u>E-FILE</u>:

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Date: June 29, 2022

/s/ Michael S. Swerling
Michael S. Swerling

Attachment A

Study of the Relative Cost of Default Service Supply for Residential and Non-Residential GSR-1 Customers

Prepared for UGI Utilities, Inc.

Scott G. Fisher
David C. Coleman
The NorthBridge Group

June 24, 2022

THE NORTHBRIDGE GROUP
ECONOMIC & STRATEGIC CONSULTING

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I. Executive Summary

In an Order entered January 14, 2021,[1] the Pennsylvania Public Utility Commission ("Commission") approved and adopted without modification the rates, terms and conditions of service contained in the Joint Petition for Settlement of UGI Utilities, Inc. – Electric Division ("UGI") in the proceedings pertaining to UGI's fourth default service plan ("DSP IV").[2] As a part of the DSP IV Settlement, UGI agreed to file a study:

> *Before June 30, 2022, the Company will file a study of the relative cost of default service supplies for GSR-1 residential and non-residential customers. The Company may select a consultant of its choosing to perform the study. The filing will include all workpapers and assumptions used in the analysis, subject to reasonable confidentiality restrictions as necessary. The study will rely on data from DSP III, DSP IV and actual data through at least the Fall of 2021. The study will evaluate the relative costs to GSR-1 residential and non-residential customers associated with: (1) both block-and-spot and full requirements procurements methods; and (2) both separate procurements and cost allocations being made to the residential and non-residential customer groups under a combined procurement.*[3]

This document constitutes that study. Specifically, in fulfillment of the charge of the DSP IV Order, this study:

- Identifies the cost components associated with default service supply for UGI's residential and non-residential GSR-1 customers under both block-and-spot and fixed-price, full requirements ("FPFR") product procurement methods and presents an analysis of the relative cost for each of these two customer groups.
- Presents information and draws conclusions regarding the relative merits of combined versus separate default service supply procurements/products for UGI's residential and non-residential GSR-1 customers.
- Outlines a cost allocation approach that could be applied to translate the cost on a dollars per megawatt-hour basis for combined supply for UGI's residential and non-residential GSR-1 customers into rates that reflect the relative costs for each of these two customer groups.

The main conclusions of our study are as follows:

- Default Service Supply Relative Cost Analysis: Our analysis indicates the costs (measured in dollars-per-megawatt-hour) of UGI's residential and non-residential GSR-1 default service supply are about 2% higher and 6%-7% lower, respectively, as compared to the composite GSR-1 default service supply cost:

[1] Order, *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 Nos. P-2020-3019907, G-2020-3019908, Order entered January 14, 2021. ("DSP IV Order")

[2] Joint Petition for Settlement, *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 Nos. P-2020-3019907, G-2020-3019908, October 23, 2020. ("DSP IV Settlement")

[3] DSP IV Settlement, pp. 7-8.

	Residential vs. Composite GSR-1	Non-Residential GSR-1 vs. Composite GSR-1	Residential vs. Non-Residential GSR-1
June 2022 – May 2023	+2%	-6%	+8%
June 2023 – May 2024	+2%	-6%	+8%
June 2024 – May 2025	+2%	-7%	+9%

- Evaluation of Combined versus Separate Procurements: There is insufficient data to quantify, with a useful confidence level, the expected overall difference in supply cost between an approach in which the default service supply for UGI's GSR-1 group is procured through separate products for residential supply and non-residential GSR-1 supply versus an approach in which the default service supply is procured for the combined GSR-1 group. However, empirical evidence and analysis indicate that splitting the GSR-1 customer group into separate residential and non-residential groups for supply procurement purposes would entail unnecessary cost-related risks.

- Possible Cost Allocation Approach to Reflect Relative Cost Differences in Rates: If the Commission desires to set residential and non-residential GSR-1 default service supply rates in a way that reflects these customer groups' expected relative costs, a reasonable approach would entail applying factors to the combined default service supply cost on a dollars per megawatt-hour basis. For illustrative purposes, consistent with the findings of this study, the factors would be as follows:
  - For June 2022 through May 2023, a factor of 1.02 would be applied to calculate the residential default service supply rates, and a factor of 0.94 would be applied to calculate the non-residential GSR-1 default service supply rates.
  - For June 2023 through May 2024, a factor of 1.02 would be applied to calculate the residential default service supply rates, and a factor of 0.94 would be applied to calculate the non-residential GSR-1 default service supply rates.
  - For June 2024 through May 2025, a factor of 1.02 would be applied to calculate the residential default service supply rates, and a factor of 0.93 would be applied to calculate the non-residential GSR-1 default service supply rates.

  If this cost allocation approach were adopted, factors could be established for a multi-year period, or they could be updated on an annual basis or on another reasonable basis to reflect changes in market conditions, including changes in residential and non-residential shares of the GSR-1 default service load and changes in forward energy or capacity prices. The existing reconciliation mechanism across the GSR-1 customer group would continue to be utilized to ensure that all default service supply costs are recovered.

II. Default Service Supply Relative Cost Analysis

A. Overview

This section identifies the cost components associated with default service supply for UGI's residential and non-residential GSR-1 customers under both block-and-spot and fixed-price, full requirements ("FPFR") product procurement methods, and it presents an analysis of the relative cost for each of these two customer groups.

Regardless of whether default service supply is procured through a block-and-spot approach,[4] a FPFR product approach,[5] or a hybrid of the two, the supply itself consists of the same basic components. As a result, an evaluation of the relative supply cost for two different customer groups is dependent upon the costs of these components. These components consist of the following:

- Energy – Energy refers to the three-phase, 60-cycle alternating current electric energy, expressed in units of megawatt-hours. PJM operates wholesale markets for energy within its geographic footprint, which includes the UGI service area. Hourly energy prices ("Locational Marginal Price" or "LMP") result from these markets. UGI's default service supply contracts include energy, so it is reasonable to conclude that default service suppliers' bid prices are based on the suppliers' expectations about future wholesale energy prices.
- Capacity – Capacity refers to the commitment of resources to deliver electricity or limit electricity demand when they are needed. PJM operates a wholesale capacity market to ensure resource adequacy within its geographic footprint. Load Serving Entities ("LSEs") in PJM are assessed capacity charges each day based on the prevailing $/MW-day capacity price, which is reset on June 1 of each year, and the LSE's allocation of the overall capacity needed to ensure that annual peak system demands are met. As an LSE, UGI directly incurs capacity costs from PJM for the portion of its default service supply that is not provided by a FPFR product supplier. UGI's FPFR default service supply contracts shift to the FPFR product supplier the responsibility to cover the cost of capacity for the applicable portion of the default service load. So, it is reasonable to conclude that FPFR default service suppliers' bid prices are based on the suppliers' expectations about future PJM capacity prices.
- Network Integration Transmission Service ("NITS") – NITS costs are assessed by PJM to compensate transmission owners within the PJM footprint for the costs of their transmission system. These costs are allocated to LSEs based on their customers' network service peak load values ("NSPLs"). UGI's FPFR default service supply contracts shift to the FPFR product supplier the responsibility to cover the cost of transmission for the applicable portion of the default service load. So, it is reasonable to

[4] A block-and-spot approach involves managing an energy supply portfolio consisting of fixed-quantity, fixed-price block energy products supplemented with spot market transactions to cover the mismatch between the fixed quantities of fixed-price energy supply purchased and actual load requirements. Other supply components, such as capacity, ancillary services, etc., are generally purchased directly from the PJM Interconnection LLC ("PJM"). Currently, a 25% cross section of the default service supply for UGI's GSR-1 group is secured through a block-and-spot approach.

[5] A FPFR product approach involves procuring FPFR products on a competitive basis to satisfy the default service supply needs. Each FPFR product obligates the seller of the product to satisfy a specified percentage of all the applicable default service customers' supply requirements in every hour of the delivery period, regardless of the default service customers' instantaneous changes in energy consumption, regardless of how frequently customers switch to or from default service, and regardless of how the seller's cost to satisfy its supply obligation may change. The seller is paid a predetermined price per megawatt-hour for this service. Currently, a 75% cross section of the default service supply for UGI's GSR-1 group is secured through a FPFR product approach.

conclude that FPFR default service suppliers' bid prices are based on the suppliers' expectations about these costs.

- Other Costs – Energy, capacity, and transmission costs in aggregate generally represent the vast majority of the overall cost of default service supply. However, there are other costs. These include the costs of ancillary services and other PJM services that are billed directly by PJM.[6] They also include the costs of Alternative Energy Credits.[7] Furthermore, there are costs that result from the risks associated with default service supply. Such risks are often associated with customer migration and its effect on the default service volumes to be supplied, usage and wholesale market price uncertainty, potential changes in laws and regulations that could impact costs, and credit-related costs. Under the FPFR product approach, the costs associated with these risks are embedded in the dollar-per-megawatt-hour price of the FPFR product. The FPFR product supplier guarantees fixed prices regardless of how the actual load and wholesale market price levels change from hour to hour, so the supplier assumes the financial impacts of these risks. UGI holds open solicitations for its FPFR products, helping to ensure the achievement of competitive prices for the FPFR product suppliers to assume these risks. Under the block-and-spot approach, the same price guarantees are not provided to customers, so more of these risks are borne by the customers themselves in the form of potential increases in rates. Consequently, neither the FPFR product approach nor the block-and-spot approach avoids these risks, but instead the choice of approach simply determines who bears the risks, and the costs associated with these risks can be estimated from the prices achieved in open solicitations for FPFR products.

The analysis of the relative cost of default service supply for UGI's residential and non-residential GSR-1 customers is forward looking in that it utilizes market prices for future periods, as of May 31, 2022.[8] However, the analysis also relies on relevant data stretching back to early 2017, the beginning of the UGI DSP III period. Furthermore, for some parts of the analysis in which additional data would be relevant and useful, data is used from as early as 2011. The data and methodologies used in the analysis are described below, and all workpapers supporting this analysis accompany this study.

The relative cost analysis of residential versus non-residential GSR-1 default service supply requires forecasting the energy cost, capacity cost, NITS cost, and other costs (as described above) on a dollars-per-megawatt-hour basis for each of the two customer groups, summing the component costs, and comparing the sums. This comparison can be illustrated graphically, as shown below.

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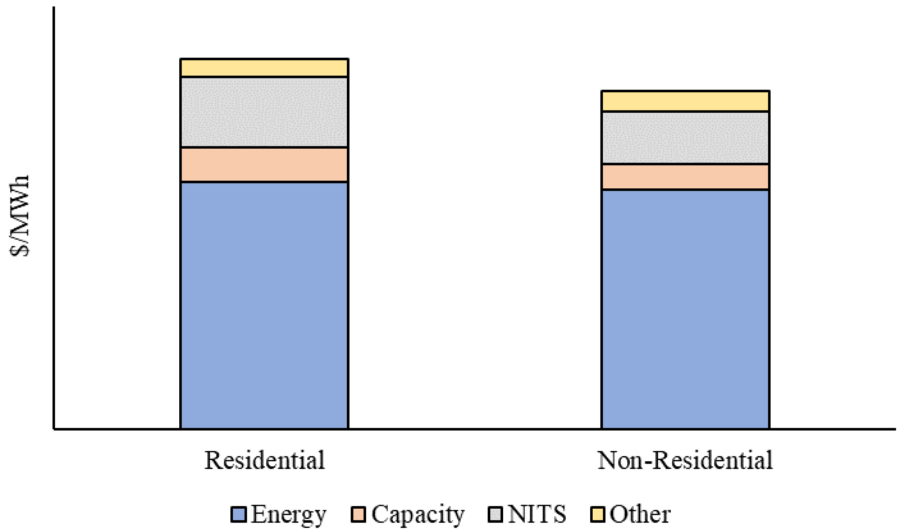
[6] Some of these costs are credits, such as marginal loss credits (monetary amounts that PJM allocates to Load Serving Entities that are reflective of overcollections of line loss costs embedded in wholesale hourly energy prices) and auction revenue rights credits (monetary amounts that PJM allocates to Load Serving Entities and that reflect the revenues in PJM's auctions of Financial Transmission Rights).

[7] The Alternative Energy Portfolio Standards Act of 2004, P.L. 1672, No. 213 ("AEPS Act") requires LSEs to include specific percentages of electricity over time from alternative energy resources in the electricity that they sell to Pennsylvania customers. LSEs meet this requirement by utilizing AECs generated by qualified alternative energy sources to demonstrate compliance with the AEPS Act.

[8] For the delivery periods, June 2023 to May 2025, we used the applicable June 2023 – May 2024 capacity price published by PJM on June 21, 2022.

Illustrative Default Service Supply Cost Build-Up



The first three cost components illustrated above (i.e., energy, capacity, and NITS) are directly estimated based on forward-looking prices, load forecasts, and actual historical hourly price and customer usage patterns. For example, with respect to energy, forward market prices for block energy reflect the expected levels of energy prices, and historical hourly price and load patterns are used to capture differences between the costs of supplying block energy and the costs of supplying load-following energy. With respect to capacity, PJM's Reliability Pricing Model ("RPM") capacity market provides information in advance about capacity prices and volumes. NITS costs are based on NITS tariff rates. The fourth cost component, "other costs," is estimated by studying the actual prices obtained in solicitations for FPFR products that were held during a period of approximately five years, and subtracting the associated estimates of energy, capacity, and NITS, as applicable, to isolate the aggregate market-based cost of this "other costs" component.

The following subsections describe the methodology and data sources used to estimate each of the four cost components. Furthermore, the Appendix provides a table of the main sources of data.

B. Energy Cost Estimation

Several steps are involved in the development of estimates of the load-following energy cost for each applicable customer group.[9] The remainder of this subsection describes in detail the estimation process.

[9] These estimates may not reflect all the risk-related costs of load-following energy supply. For example, costs can arise due to the uncertainty about overall wholesale energy price levels, the uncertainty about overall load levels, and the correlations between them. Furthermore, there may be risk-related costs associated with the possibility that overall average wholesale energy price levels do not match the values implied by forward prices. These risk-related costs are captured in the "other costs" component.

Step #1: Assemble the PJM Western Hub block energy forward prices for the applicable monthly on-peak and off-peak periods.

PJM Western Hub block energy forward prices with a trade date of May 31, 2022, for the applicable monthly on-peak and off-peak periods, are collected. Forward prices are provided by S&P Global Platts M2MS-Power North American Electricity forward price product.

Step #2: Calculate differences in marginal losses between PJM Western Hub and UGI.

Average hourly differences in marginal losses between PJM Western Hub and UGI are measured separately for the on-peak period and the off-peak period, across the 24 historical months ending with the month immediately preceding the trade date associated with the PJM Western Hub forward prices collected in Step #1. Day-ahead marginal loss data is used, and each average difference is recorded as a percentage of the associated average PJM Western Hub day-ahead LMP.

Step #3: Calculate differences in congestion between PJM Western Hub and UGI.

Differences in congestion between PJM Western Hub and UGI are based on the results of PJM's Financial Transmission Rights ("FTR") auctions. The results of these auctions reflect market-based expectations of forward-looking differences in congestion between delivery locations. For a given delivery period, data from the most recent FTR annual and long-term auctions (as of the trade date associated with the PJM Western Hub forward prices collected in Step #1) is used. The delivery periods in these auctions correspond with entire June through May periods, with separate delivery periods for on-peak versus off-peak periods. The congestion difference for a given delivery period is recorded as a percentage of the associated average PJM Western Hub forward price for that delivery period, as of the trade date associated with the bid due date of the respective FTR auction.

Step #4: Apply the basis differentials in Steps #2 and #3 to estimate the UGI block energy forward prices for the applicable monthly on-peak and off-peak periods.

To estimate the UGI monthly on-peak and off-peak block energy forward prices, the marginal loss and congestion differences calculated in Steps #2 and #3 are applied to the respective monthly on-peak or off-peak PJM Western Hub block energy forward prices from Step #1. For each monthly on-peak or off-peak delivery period, this can be expressed algebraically as follows:

$$P_{UGI} = P_{PJMWesternHub} * \left[1 + \left(Marginal\ Loss\%_{UGI\ Minus\ PJMWesternHub}\right) + \left(Congestion\%_{UGI\ Minus\ PJMWesternHub}\right)\right]$$

Step #5: Calculate preliminary energy costs based on historical hourly energy prices and hourly loads.

The dollars-per-megawatt-hour cost of supplying the load-following energy consumed by residential or non-residential customers differs from block energy prices. Customers' hourly loads vary from hour to hour, whereas block energy refers to a constant volume delivered in each hour. Wholesale spot energy prices also vary by hour. Consequently, hourly differences between customer loads and block energy volumes must be met with spot purchases or sales of varying quantities and prices. Furthermore, there tends to be a positive correlation between hourly customer loads and hourly energy prices. Energy prices tend to be higher during periods of higher customer loads.

To capture differences between the dollars-per-megawatt-hour cost of supplying block energy quantities and supplying load-following energy quantities for a given customer group, historical hourly customer loads for the applicable customer group and historical hourly real-time LMPs are analyzed.[10] Specifically, for a given customer group, for a given on-peak or off-peak period of a given month of the year, the historical real-time UGI LMPs and hourly loads from the same month and on-peak or off-peak period of a previous year are gathered, and the associated overall energy cost is calculated. This is repeated using price data from multiple previous years to capture different possibilities of hourly loads and prices, all of which are reflective of actual market data.

<u>Step #6: Scale the preliminary energy costs to forward-looking market price levels.</u>

In Step #5, a preliminary overall energy cost for each given on-peak or off-peak period of a given month of the year is calculated, for each of multiple historical years. Next, each of these values is scaled up or down by the ratio of the applicable UGI forward block energy price (calculated in Step #4) to the straight average of the historical real-time LMPs during the given historical monthly on-peak or off-peak period, so the resulting cost value is consistent with the market price level associated with the applicable UGI forward block energy price. The applicable resulting monthly on-peak and off-peak cost values for each given historical year are then summed and divided by the sum of the associated monthly on-peak and off-peak historical loads, to determine a load-weighted energy cost using data from each given historical year on a dollars-per-megawatt-hour basis.[11] These values are then averaged to develop a final estimate of the cost of supplying load-following energy. The result is therefore consistent both with the forward energy prices and with actual hourly price and load patterns. The following table shows an illustrative, example calculation for the July 2022 on-peak period.

[10] UGI load data is limited to load values through July 2021 because residential versus non-residential GSR-1 load data was provided through that date. Subject to that constraint for UGI load data, for the purposes of analysis of default service supply solicitations used to calculate "other costs," it is assumed that load data through the preceding November is available for any spring solicitation and it is assumed that load data through the preceding May is available for any fall solicitation.

[11] An additional adjustment, specific to the calculation of UGI energy cost estimates, is also made. UGI has stated that the payments made to its FPFR default service suppliers reflect the contracted winning bid prices applied to the load values before deration factors are applied, as opposed to applying the prices to the derated load values. However, hourly LMPs apply to derated loads. Consequently, an adjustment, based on historical deration factors, is made to the UGI energy cost estimates to make these energy cost estimates applicable to load values before deration factors are applied. Such adjustments are not needed elsewhere in the overall analysis because the reported UGI loads used in this study are the loads before deration factors are applied.

Illustrative Example Calculation of Estimated July 2022 On-Peak Energy Cost

Estimated July 2022 On-Peak Energy Cost as of May 31, 2022, for the Residential Customer Group						
Historical Month	**Historical Load (GWh)**	**Historical Average Hourly LMP ($/MWh)**	**Historical Supply Cost ($)**	**Forward Block Price ($/MWh)**	**Scaled Supply Cost ($)**	**Scaled Supply Cost ($/MWh)**
	[A]	[B]	[C]	[D]	[E]=[C] * [D] / [B]	[F] =[E] / [A]
Jul-11	22,089	$86.50	$2,151,654	$142.65	$3,548,473	$160.64
Jul-12	24,508	$60.43	$1,646,485	$142.65	$3,886,531	$158.58
Jul-13	26,217	$59.91	$1,766,137	$142.65	$4,205,463	$160.41
Jul-14	22,278	$45.63	$1,102,550	$142.65	$3,446,983	$154.72
Jul-15	24,673	$33.23	$908,784	$142.65	$3,901,053	$158.11
Jul-16	24,452	$36.74	$934,293	$142.65	$3,627,117	$148.34
Jul-17	21,442	$34.28	$787,786	$142.65	$3,277,892	$152.87
Jul-18	24,290	$35.67	$914,557	$142.65	$3,657,734	$150.59
Jul-19	24,868	$27.44	$714,993	$142.65	$3,717,316	$149.48
Jul-20	30,683	$24.13	$770,304	$142.65	$4,554,409	$148.43
Jul-21	25,646	$35.94	$946,201	$142.65	$3,755,151	$146.43
Average Estimate of July ‘22				**$142.65**		**$153.51**

In the example above, historical hourly loads and LMPs are used to calculate the historical energy supply cost [C]. Because of the hourly load and price patterns and the correlations between them, the energy cost [C] is greater than the product of the total load [A] and the average hourly LMP [B]. However, the historical cost [C] is not a reasonable estimate of the future cost because expected future overall market price levels differ from historical outcomes. To account for the difference in market conditions, the historical energy supply cost [C] is scaled by the ratio of the forward block energy price [D] to the historical average hourly LMP [B], resulting in the scaled energy cost [E]. This value is then divided by the sum of the hourly loads to determine the load-weighted energy cost estimate on a dollars-per-megawatt-hour basis [F].[12] The result reflects both expected overall market price levels and actual hourly price-load relationships observed in the market.

C. Capacity Cost Estimation

The estimated cost of capacity is based largely on two factors: the capacity price in dollars-per-megawatt-day, and the megawatt amount of the unforced capacity (“UCAP”) obligation associated with the load and applicable to the capacity price. The capacity price is published by PJM for each period for which an RPM auction has cleared, and it is assumed that the capacity price remains constant for periods beyond the last period for which an RPM auction has cleared. PJM publishes an estimated zonal UCAP obligation for each period for which an RPM auction has cleared, and the zonal UCAP obligation forms the basis of the estimated default service UCAP obligation. Specifically, recent Peak Load Contribution (“PLC”) values for the zone and for the applicable class load are gathered. The default service PLC is calculated by multiplying

[12] For illustrative purposes of showing values only for this specific period, the division by the sum of the hourly loads is performed only for this specific period.

the class PLC by the ratio of default service load to class load in the most recent historical month available corresponding to the same calendar month. The default service UCAP obligation is calculated as the product of the zonal UCAP obligation and the ratio of the default service PLC to the zonal PLC. The estimated default service capacity cost on total dollar basis is then calculated as the product of the applicable capacity price, the number of days in the month, and the applicable default service UCAP obligation. The capacity cost on a dollars-per-megawatt-hour basis is then calculated as the sum of estimated capacity costs across the applicable periods, divided by the sum of the forecasted megawatt-hour loads across the applicable periods.

The forecasted megawatt-hour load is based on PJM's most recent zonal load forecast and historical relationships between the applicable customer group's load and the zonal load. On or around January of each year, PJM publishes a forecast of monthly zonal loads.
Two steps are taken to convert the zonal load forecast to the default service load forecast for the applicable customer group. First, the applicable customer group's forecasted total (default service and choice, in aggregate) load is calculated. For each given calendar month, the average of the three fractions of the applicable customer group's load divided by zonal load for the given calendar month in three historical years is calculated, and that value is applied to the forecasted zonal load for the same calendar month in the future. For example, the fractions for three recent months of May are averaged, and that value is applied to the forecasted zonal load for future May periods. The second step involves calculating and applying the fractions of the applicable customer group's total load that is retained as default service. For a given calendar month's forecasted load, the fraction is based on the applicable customer group's total load and default service load pertaining to the same calendar month during the most recent twelve months for which load data is available. The overall calculation of the forecasted default service load for the applicable customer group is expressed as follows:

$$
\begin{aligned}
&Forecast\ Load_{DefaultServiceGroup} \\
&\qquad = ZonalForecast * HistoricalClassFraction_{TotalGroup/Zonal} \\
&\qquad * Historical\ RetainedFraction_{DefaultServiceGroup/TotalGroup}
\end{aligned}
$$

D. Network Integration Transmission Service Cost Estimation

The cost of NITS in each delivery month is calculated by multiplying the estimated NITS tariff rate denominated in dollars-per-megawatt-day by the default service NSPL obligation and the number of days in the month.[13] The default service NSPL obligation is calculated by multiplying the class NSPL by the ratio of default service load to class load in the most recent historical month available corresponding to the same calendar month. The NITS cost on a dollars-per-megawatt-hour basis is then calculated as the sum of estimated NITS costs across the applicable periods, divided by the sum of the forecasted megawatt-hour loads across the

[13] For the NITS cost projection as of May 31, 2022, estimated future NITS rates are assumed to be the published NITS rates applicable starting June 1, 2022. For the purposes of analysis of default service supply solicitations used to calculate "other costs," for any spring solicitation it is assumed that estimated NITS rates for all dates on or after the upcoming June 1 are the published NITS rates applicable starting the upcoming June 1. For the purposes of analysis of default service supply solicitations used to calculate "other costs," for any fall solicitation it is assumed that estimated NITS rates for all dates are the current NITS rates.

applicable periods. The process for determining the forecasted megawatt-hour loads is described previously.

E. "Other Costs" Estimation

As noted previously, the fourth cost component, "other costs," is estimated by studying the results of actual prices obtained in solicitations for FPFR products that were held during a period of approximately five years, and subtracting the associated estimates of energy, capacity, NITS, etc., as applicable, to isolate the aggregate market-based cost of this "other costs" component.

UGI's FPFR product solicitations do not provide information about the relative levels of "other costs" for residential versus non-residential GSR-1 default service supply because these two groups are aggregated together for the purpose of procuring default service supply. However, PECO, a nearby Pennsylvania utility, conducts separate FPFR product solicitations to supply its residential ("PECO Residential Group") default service load and the default service load of its non-residential customers with peak demands less than or equal to 100 kW ("PECO Small Commercial Group"). These two PECO customer groups are aligned with the two UGI customer groups relevant to this study, as the relevant UGI customer groups are defined as the residential group and the non-residential group of customers with peak loads less than 100 kW. By analyzing the results of the PECO FPFR product solicitations for both the PECO Residential Group and the PECO Small Commercial Group, and the results of the UGI GSR-1 FPFR product solicitations, reasonable estimates of the "other costs" associated with UGI's residential default service supply and the "other costs" associated with UGI's non-residential GSR-1 default service supply can be developed.

As the first step, the results of each solicitation for PECO Residential Customer Group FPFR default service supply products and PECO Small Commercial Customer Group FPFR default service supply products since early 2017 are analyzed. For a given FPFR default service supply product procured in a solicitation for a PECO customer group, the reported winning bid price for the FPFR product solicited is recorded. Next, estimates of the applicable cost of energy and cost of capacity, both expressed in terms of dollars-per-megawatt-hour, are subtracted from the winning bid price. These two costs are estimated using a calculation methodology that is consistent with the methodology described above to estimate UGI's energy and capacity costs. For the analysis of the PECO solicitations, data pertaining to the applicable PECO customer groups is used, the data is limited to that available as of the time of the respective PECO solicitation being analyzed, and the data used is that applicable to the delivery period of the given FPFR product being analyzed. Unlike UGI's FPFR products, which require the winning bidders to cover the cost of NITS, PECO's FPFR products do not require the winning bidders to cover the cost of NITS. Consequently, in the analyses of the PECO FPFR product solicitations, the difference, after subtracting the energy and capacity cost estimates from the winning bid price, represents the estimate of "other costs" for the given applicable FPFR default service supply product procured in the given solicitation for the given PECO customer group.

Next, the estimated "other costs" pertaining to the PECO supply solicitations for the PECO Residential Customer Group are averaged to develop an estimate of this group's "other costs" of

$5.05/MWh, and the estimated "other costs" pertaining to the PECO supply solicitations for the PECO Small Commercial Customer Group are averaged to develop an estimate of this group's "other costs" of $5.85/MWh. A load-weighted average of these two values is then calculated by weighting the two values by the forecasted default service loads associated with their counterpart UGI customer groups, which are the residential customer group and the non-residential GSR-1 customer group, respectively, to develop a UGI-load-weighted average of the two PECO "other costs" estimates. This load-weighted average value is $5.25/MWh.

The results of each solicitation for UGI GSR-1 FPFR default service supply products since early 2017 are then analyzed. For a given applicable FPFR default service supply product procured in a given solicitation, the reported winning bid price for the FPFR product solicited is recorded. Next, estimates of the applicable cost of energy, cost of capacity, and cost of NITS, all expressed in terms of dollars-per-megawatt-hour, are subtracted from the winning bid price. These three costs are estimated using a calculation methodology that is consistent with the methodology described above to estimate UGI's energy, capacity, and NITS costs. For the analysis of the UGI solicitations, the data is limited to that available as of the time of the respective UGI solicitation being analyzed, and the data used is that applicable to the delivery period of the given FPFR product being analyzed. The difference, after subtracting the energy, capacity, and NITS cost estimates from the winning bid price, is then recorded for the given applicable FPFR default service supply product procured in the given solicitation. The differences, across all the UGI FPFR default service supply products procured in the UGI solicitations, are then averaged, resulting in an estimate of the UGI GSR-1 "other costs" of $5.98/MWh.

The next steps of the analysis combine the results of the analysis of the PECO Residential Customer Group supply solicitations, the PECO Small Commercial Customer Group supply solicitations, and the UGI GSR-1 supply solicitations. First, $0.42/MWh, which is the historical dollars-per-megawatt-hour cost of certain PJM charges which UGI FPFR product suppliers must cover, but that PECO FPFR product suppliers are not required to cover, is subtracted from the estimate of the UGI GSR-1 "other costs" of $5.98/MWh, to calculate a $5.56/MWh value for UGI GSR-1 "other costs" that is effectively comparable to the $5.25/MWh value identified above for the PECO "other costs" for a comparable default service load mix. Since the value of $5.56/MWh calculated from the analysis of the UGI solicitations is higher by a factor of 1.061 than the $5.25/MWh composite value calculated from the analysis of the PECO solicitations, the individual customer group values for PECO of $5.05/MWh for the PECO Residential Customer Group and $5.85/MWh for the PECO Small Commercial Customer Group are scaled by a factor of 1.061 to develop values for UGI of $5.36/MWh for the residential customer group and $6.21/MWh for the non-residential GSR-1 customer group. Finally, the $0.42/MWh value, which again is the historical dollars-per-megawatt-hour cost of certain PJM charges which UGI FPFR product suppliers must cover, is added back to calculate estimated "other cost" values of $5.78/MWh for the UGI residential customer group and $6.63/MWh for the UGI non-residential GSR-1 customer group.

In sum, the "other costs" estimates for the UGI residential customer group and the UGI non-residential GSR-1 customer group represent the default service supply costs that are not captured in the energy, capacity, and NITS cost estimates, including costs that result from the risks associated with default service supply. Furthermore, these estimates are based on solicitation results for 58 FPFR default service supply products procured in 22 solicitations over approximately the past five years.

UGI GSR-1 Solicitations and Products Analyzed

Default Service Plan	Solicitation	Bid Due Date	Delivery Period	# of Months	Products Analyzed
III	Spring 2017	4/11/2017	Jun 17 – Nov 17	6	Combined Residential and Non-Residential GSR-1
	Spring 2017	4/11/2017	Jun 17 – May 18	12	
	Fall 2017	10/10/2017	Dec 17 – Nov 18	12	
	Spring 2018	4/24/2018	Jun 18 – May 19	12	
	Fall 2018	10/16/2018	Dec 18 – Nov 19	12	
	Spring 2019	4/16/2019	Jun 19 - May 20	12	
	Fall 2019	10/15/2019	Dec 19 - Nov 20	12	
	Spring 2020	4/21/2020	Jun 20 - May 21	12	
	Fall 2020	10/13/2020	Dec 20 - May 21	6	
IV	Spring 2021	4/20/2021	Jun 21 - Nov 21	6	
	Spring 2021	4/20/2021	Jun 21 - May 22	12	
	Spring 2021	4/20/2021	Jun 21 - May 23	24	
	Fall 2021	10/12/2021	Dec 21 - Nov 22	12	
	Spring 2022	4/20/2022	Jun 22 – May 23	12	

PECO Residential and Small Commercial Solicitations and Products Analyzed

Default Service Plan	Solicitation	Bid Due Date	Delivery Period	# of Months	Products Analyzed
IV	Spring 2017	3/15/2017	Jun 2017–May 2018	12	Product #1: Residential Product #2: Small Commercial
	Spring 2017	3/15/2017	Jun 2017–May 2019	24	
	Fall 2017	9/26/2017	Dec 2017– Nov 2018	12	
	Fall 2017	9/26/2017	Dec 2017– Nov 2019	24	
	Spring 2018	3/13/2018	Jun 2018–May 2019	12	
	Spring 2018	3/13/2018	Jun 2018–May 2020	24	
	Fall 2018	9/25/2018	Dec 2018–Nov 2019	12	
	Fall 2018	9/25/2018	Dec 2018–Nov 2020	24	
	Spring 2019	3/12/2019	Jun 2019–May 2020	12	
	Spring 2019	3/12/2019	Jun 2019–May 2021	24	
	Fall 2019	9/24/2019	Dec 2019–Nov 2020	12	
	Fall 2019	9/24/2019	Dec 2019–Nov 2021	24	
	Spring 2020	3/10/2020	Jun 2020–May 2021	12	
	Spring 2020	3/10/2020	Jun 2020–May 2022	24	
	Fall 2020	9/29/2020	Dec 2020 – Nov 2021	12	
	Fall 2020	9/29/2020	Dec 2020 – Nov 2022	24	
V	Spring 2021	3/2/2021	Jun 2021–May 2022	12	
	Spring 2021	3/2/2021	Jun 2021–May 2023	24	
	Fall 2021	9/28/2021	Dec 2021 – Nov 2022	12	
	Fall 2021	9/28/2021	Dec 2021 – Nov 2023	24	
	Spring 2022	3/15/2022	Jun 2022–May 2023	12	
	Spring 2022	3/15/2022	Jun 2022–May 2024	24	

F. Development of Relative Costs by Customer Group

Once all the component cost estimates are calculated on a dollars-per-megawatt-hour basis as described above, the respective residential cost estimates are summed, and the respective non-residential GSR-1 cost estimates are summed. The two resulting total cost estimates are then weighted by each customer group's default service load to develop a composite GSR-1 total cost estimate. By comparing each customer group's total cost estimate to the composite GSR-1 total cost estimate, the estimated relative costs by customer group, expressed as a factor of the composite GSR-1 cost, are determined. The following tables depict the results for each of the three June through May periods remaining during UGI's DSP IV period.

Relative Cost Analysis: June 2022 – May 2023

	Residential	**Non-Residential GSR-1**	**Composite GSR-1**
Energy ($/MWh)	$108.06	$104.34	
Capacity ($/MWh)	$8.85	$6.51	
NITS ($/MWh)	$20.63	$15.27	
Other Costs ($/MWh)	$5.78	$6.63	
Total ($/MWh)	$143.33	$132.74	$140.75
Load (MWh)	530,279	170,711	700,990
Relative Cost Factor	**1.02**	**0.94**	**1.00**

Relative Cost Analysis: June 2023 – May 2024

	Residential	**Non-Residential GSR-1**	**Composite GSR-1**
Energy ($/MWh)	$65.37	$63.15	
Capacity ($/MWh)	$4.57	$3.36	
NITS ($/MWh)	$20.70	$15.33	
Other Costs ($/MWh)	$5.78	$6.63	
Total ($/MWh)	$96.41	$88.47	$94.48
Load (MWh)	529,951	170,476	700,427
Relative Cost Factor	**1.02**	**0.94**	**1.00**

Relative Cost Analysis: June 2024 – May 2025

	Residential	**Non-Residential GSR-1**	**Composite GSR-1**
Energy ($/MWh)	$55.69	$53.46	
Capacity ($/MWh)	$4.59	$3.37	
NITS ($/MWh)	$20.80	$15.41	
Other Costs ($/MWh)	$5.78	$6.63	
Total ($/MWh)	$86.86	$78.87	$84.92
Load (MWh)	525,870	169,145	695,015
Relative Cost Factor	**1.02**	**0.93**	**1.00**

The following table provides a summary of the relative costs across the three periods.

Percentage Differences in Estimated Dollars-Per-Megawatt-Hour Supply Costs

	Residential vs. Composite GSR-1	**Non-Residential GSR-1 vs. Composite GSR-1**	**Residential vs. Non-Residential GSR-1**
June 2022 – May 2023	+2%	-6%	+8%
June 2023 – May 2024	+2%	-6%	+8%
June 2024 – May 2025	+2%	-7%	+9%

III. Evaluation of Combined Versus Separate Procurements

The Commission-approved DSP IV Settlement states that the relative cost evaluation should address "both separate procurements and cost allocations being made to the residential and non-residential customer groups under a combined procurement."[14] This section of the study addresses costs and risks associated with procuring GSR-1 default service supply through combined supply products versus through separate supply products for residential versus non-residential GSR-1 customers. The subsequent section of this study presents a possible cost allocation approach under a combined procurement, based on the type of analysis of the relative cost for residential and non-residential GSR-1 customer groups presented in the previous section.

Insights can be drawn about the costs and risks associated with an approach in which the default service supply for UGI's GSR-1 group is procured through separate products for residential supply and non-residential GSR-1 supply versus an approach in which the default service supply is procured for the combined GSR-1 group, but there is insufficient data to quantify the expected overall difference in supply cost between these two approaches with a useful confidence level. UGI's historical default service plans have not entailed procurements of both separate products and combined products, which would facilitate a reasonable quantification of the expected overall difference in UGI supply cost between separate and combined product approaches. Further, even if another service area had a history that offers supply cost data for both separate and combined product approaches, certain aspects of UGI's situation, such as its size, make it potentially materially different from the circumstances in other service areas.

While there is insufficient data to quantify, with a useful confidence level, the expected overall difference in supply cost between the combined and separate product approaches for UGI's GSR-1 default service supply, empirical evidence and analysis indicate that splitting the GSR-1 customer group into separate residential and non-residential groups for supply procurement purposes would entail unnecessary cost-related risks. This is described in the remainder of this section.

UGI is among the smallest electric utilities whose customers are provided a choice regarding their retail Electric Generation Supplier ("EGS"). Further separating its GSR-1 customer group into further subgroups for supply procurement purposes could result in solicited supply amounts for a single customer group that are so small that supplier interest in them would be inadequate to receive competitive bids, or to receive bids at all. Indeed, the administrative costs of formulating bids and managing the resultant contracts, as well as the transactional costs associated with managing supply obligations, may make the proposition of bidding to supply such small amounts for a customer group unattractive to potential bidders.

To help illustrate this point, the following table provides estimates of megawatt-hours of supply solicited in Pennsylvania utilities' default service supply solicitations. Specifically, for each Pennsylvania utility, we studied the utility's default service supply solicitation cycle for each separate customer group for which the utility solicits FPFR products with somewhat comparable

[14] DSP IV Settlement, pp. 7-8.

delivery periods to UGI's delivery periods.[15] For each utility, the smallest estimated aggregate number of megawatt-hours of default service supply solicited (in the form of FPFR supply products with somewhat comparable delivery periods) for a customer group in a single solicitation was then recorded in the following table.[16]

Indicative Analysis of Pennsylvania Utilities' FPFR Default Service Solicitations

Utility	Smallest Estimated Volume for a Single Customer Group in a Single Solicitation (MWh)	Customer Group
Citizens' and Wellsboro	280,064	Residential and Small Commercial
Duquesne Light Company	245,164	Small Commercial & Industrial
PECO	989,460	Small Commercial
PPL	890,438	Small Commercial & Industrial
FirstEnergy – Met-Ed	59,744	Commercial
FirstEnergy – Penelec	67,020	Commercial
FirstEnergy – Penn Power	47,950	Commercial
FirstEnergy – West Penn Power	143,911	Commercial
UGI (if GSR-1 were split)	**42,272**	**GSR-1 Non-Residential**

As shown in the table, separating UGI's GSR-1 customer group into a residential group and a non-residential group for supply procurement purposes would result in the new GSR-1 Non-Residential customer group having the smallest aggregate number of megawatt-hours of default service supply solicited (in the form of FPFR products with somewhat comparable delivery periods) for any single customer group in any single solicitation in all of Pennsylvania. Consequently, prospective suppliers may be inclined not to expend the effort to prepare and submit competitive bids for the chance of being awarded such small volumes. This unnecessary risk could be further compounded by the fact that the overall aggregate volumes of supply solicited in UGI's default service supply solicitations are already relatively small compared to other utilities.[17]

While UGI has held many successful solicitations for default service supply, it has also experienced unsuccessful solicitations for default service supply for smaller customers:

- UGI's March 2012 solicitation for load following default service supply for its non-residential customers with peak loads less than 500 kW was deemed non-competitive

[15] For the purposes of this indicative analysis, "somewhat comparable" delivery periods are identified as delivery periods of six months or more. It was observed that delivery periods that are shorter than six months may have notably less risk of significant changes in market conditions, which suppliers must manage.

[16] Megawatt-hour values are based on actual annual June 2020 – May 2021 default service values from the applicable utility. For example, if the applicable supply solicited is in the form of two-year products comprising (in aggregate) 25% of the default service supply for the applicable customer group, and the overall default service supply for that customer group during June 2020 – May 2021 was 1.5 million megawatt-hours, the applicable value is 2 years x 25% x 1.5 million megawatt-hours per year = 750,000 megawatt-hours.

[17] Along these lines, while values in the table associated with some of FirstEnergy's utilities are not enormously different from the UGI value in the table, FirstEnergy's Pennsylvania utilities procure their default service supply through single solicitations in which all the utilities participate together, significantly increasing the total amount of supply being solicited in a single solicitation.

and its results were rejected.[18]

- UGI's October 2012 solicitation for load following default service supply for its non-residential customers with peak loads less than 500 kW was deemed non-competitive and its results were rejected.[19]
- No bids were received in UGI's October 2014 solicitation for load following default service supply for its GSR-1 customers.[20]

These outcomes are evidence that unsuccessful solicitations are a possibility. Consequently, it may not be preferable to make any change that could decrease prospective suppliers' inclination to bid sufficiently on certain portions of the supply, such as a change that entails breaking the GSR-1 supply group into even smaller groups, as that could entail significant risks of unsuccessful solicitations for portions of the supply.

Separating UGI's GSR-1 customer group into a residential group and a non-residential group for supply procurement purposes would also entail increased administrative costs. Specifically, UGI estimates that this approach would increase the annual administrative costs of the utility or its procurement monitor by almost $25,000 in aggregate, as shown in the following table.

UGI Estimate of the Increased Administrative Costs from Separating GSR-1 into Residential and Non-Residential GSR-1

Category	Estimated Annual Cost Increase	Notes
RFP Monitoring Service	$13.0K	Based on an estimate of $6K-$7K per solicitation, provided by the procurement monitor
Supply Procurement	$8.1K	Estimated increase of 50% of internal time involved to procure, plus eight hours per month for additional data preparation
Allocation of Supply Costs to Groups	$1.7K	Estimated increase of 50% of internal time involved to file with the Commission
Gross Receipts Taxes	$1.4K	GRT rate of 5.9%
TOTAL	**$24.2K**	

In sum, empirical evidence and analysis indicate that splitting the GSR-1 customer group into separate residential and non-residential groups for supply procurement purposes would entail unnecessary cost-related risks. Separate from these risks, UGI also estimates that administrative costs would be higher if the GSR-1 group were split. Furthermore, as explained in the next section, a reasonable cost allocation approach could be applied to the costs that result from the solicitations to supply the combined GSR-1 group, if so desired. Given these considerations, maintaining UGI's combined GSR-1 group may be the more prudent approach.

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[18] Secretarial Letter Re: UGI Utilities, Inc. – Results of Request for Proposals Process Proposals for the March 2012 Group 2 Load Following RFP, Pennsylvania Public Utility Commission, Docket No. P-2009-2135496, March 27, 2012.

[19] Secretarial Letter Re: UGI Utilities, Inc. – Results of Request for Proposals Process Proposals for the October 2012 Group 2 Load Following RFP, Pennsylvania Public Utility Commission, Docket No. P-2009-2135496, October 23, 2012.

[20] Secretarial Letter Re: UGI Utilities, Inc. – Results of Request for Proposals Process Proposals for the October 2014 GSR-1 Load Following/Block RFPs, Pennsylvania Public Utility Commission, Docket No. P-2013-2357013, October 8, 2014.

IV. Possible Cost Allocation Approach to Reflect Relative Cost Differences in Rates

The Commission-approved DSP IV Settlement states that the relative cost evaluation should address "both separate procurements and cost allocations being made to the residential and non-residential customer groups under a combined procurement."[21] In this section, we outline a reasonable cost allocation approach that could be applied to translate the cost on a dollars per megawatt-hour basis for combined supply for UGI's residential and non-residential GSR-1 customers into rates that reflect the relative costs for each of these two customer groups. This cost allocation approach is intended to be simple, it is based on a default service supply cost allocation methodology that is already applied in Pennsylvania, and importantly it is designed to reasonably reflect the difference in cost of providing default service supply to residential customers and non-residential GSR-1 customers.

The cost allocation approach would be implemented through a simple adjustment to the process that UGI currently uses to calculate its GSR-1 Rate. The GSR-1 Rate is the rate by which UGI recovers the default service supply costs for the GSR-1 group, and it is assessed in terms of cents per kilowatt-hour of load. As explained in UGI's Tariff Book,[22] this rate is calculated as the sum of three components that are expressed in terms of cents per kilowatt-hour, and then grossed up for the applicable Pennsylvania Gross Receipts Tax Rate:

- "Energy Costs" or "EC" – Projected direct and indirect purchased power costs incurred by UGI to acquire electric supply for the GSR-1 group.
- "Energy Cost Adjustment" or "ECA" – Net over or under collection of the EC defined above to be refunded/recovered in the GSR-1 group.
- "Interest" or "Int" – Interest on the net over or under collection of the EC defined above to be refunded/recovered in the GSR-1 group.

To implement the cost allocation approach, factors would be applied to the EC value. The factor for residential customers would be different from the factor for non-residential GSR-1 customers. The factors would reflect the difference in expected costs to serve each of these groups, and they could be calculated using a methodology consistent with that described and applied in Section II.

In Section II, it is shown that the default service supply costs (in terms of dollars per megawatt-hour or alternately cents per kilowatt-hour) for residential and non-residential GSR-1 customers are expected to differ from the composite GSR-1 default service supply cost by the percentages in the following table.

[21] DSP IV Settlement, pp. 7-8.
[22] UGI Utilities, Inc. – Electric Division, Electric Service Tariff, issued March 22, 2022, pp. 39-40.

Percentage Differences vs. Composite in Estimated Dollars-Per-Megawatt-Hour Supply Costs

	Residential vs. Composite GSR-1	**Non-Residential GSR-1 vs. Composite GSR-1**
June 2022 – May 2023	+2%	-6%
June 2023 – May 2024	+2%	-6%
June 2024 – May 2025	+2%	-7%

For illustrative purposes, based on these findings, the factors applied to the EC value would be as follows:

- For June 2022 through May 2023, a factor of 1.02 would be applied to calculate the residential default service supply rates, and a factor of 0.94 would be applied to calculate the non-residential GSR-1 default service supply rates.
- For June 2023 through May 2024, a factor of 1.02 would be applied to calculate the residential default service supply rates, and a factor of 0.94 would be applied to calculate the non-residential GSR-1 default service supply rates.
- For June 2024 through May 2025, a factor of 1.02 would be applied to calculate the residential default service supply rates, and a factor of 0.93 would be applied to calculate the non-residential GSR-1 default service supply rates.

If this cost allocation approach were adopted, factors could be established for a multi-year period, or they could be updated on an annual basis or another reasonable basis to reflect changes in market conditions, including changes in residential and non-residential shares of the GSR-1 default service load and changes in forward energy or capacity prices. The existing reconciliation mechanism across the GSR-1 customer group would continue to be utilized to ensure that all default service supply costs are recovered.

This basic factor-based default service cost allocation approach has precedent in Pennsylvania, as it is very similar to a cost allocation approach that has been approved by the Commission and applied in Duquesne Light's service area for almost a decade. Duquesne Light procures default service supply for its residential and lighting customers on a consolidated basis, like UGI does for its residential and non-residential GSR-1 customers. To develop its default service rates, Duquesne Light applies rate factors to its projected direct and indirect purchased power costs (expressed in terms of cents per kilowatt-hour) to acquire electric supply for the combined residential and lighting customer group, and the rate factor for residential customers is different from the factor for lighting customers.[23] This approach is similar to the cost allocation approach described in this section for UGI. Furthermore, Duquesne Light's rate factors are based on market-based cost estimates that incorporate each customer group's energy consumption patterns and capacity requirements.[24] The methodology used to develop those market-based cost estimates is similar to the methodology that is used to develop the expected relative default service supply costs presented in Section II.

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[23] Duquesne Light Company, Schedule of Rates, issued March 1, 2022, pp. 103-104.

[24] Duquesne Light Statement No. 4, Petition Of Duquesne Light Company For Approval Of Default Service Plan For The Period June 1, 2021 Through May 31, 2025, Docket No. P-2020-3019522, April 20, 2020, pp. 4-7.

In sum, the Commission could consider implementing the cost allocation approach outlined in this section. This approach may better reflect the expected relative costs of supplying residential versus non-residential GSR-1 default service customers. It also may be relatively simple to implement, and the basic approach has precedent in Pennsylvania.

V. Appendix

Main Data Sources Used in the Default Service Supply Relative Cost Analysis

Type of Data	Description	Source
Locational Marginal Prices	Hourly energy prices, including congestion and loss components, for PJM nodes 51288 (PJM Western Hub), 51279 (UGI), and 51297 (PECO). Hourly prices are day-ahead	PJM Data Miner 2: http://dataminer2.pjm.com/feed/da_hrl_lmps
Financial Transmission Rights	Historical prices for annual and long-term auctions for PJM nodes 51288 (PJM Western Hub), 51279 (UGI), and 51297 (PECO)	https://www.pjm.com/markets-and-operations/ftr
Block Energy Forward Prices	Historical and contemporary forward prices for on-peak and off-peak block energy delivered at PJM Western Hub	S&P Global Platts M2MS-Power North American Electricity forward price product
UGI Class-Specific Load	Historical hourly load for residential and non-residential GSR-1 customers, both default service and choice customers	Provided by UGI
PECO Class-Specific Load	Historical hourly load for PECO residential and small-commercial customers, including both default service and choice customers	https://www.pecoprocurement.com/
PJM Zonal Load	Historical hourly load for UGI and PECO load zones	http://dataminer2.pjm.com/feed/hrl_load_metered
UGI GRP-1 residential and commercial customer PLC	Actual daily PLC values for UGI residential and commercial customers	Provided by UGI
UGI GRP-1 residential and commercial customer NSPL	Actual daily NSPL values for UGI residential and commercial customers	Provided by UGI
PECO residential and small commercial customer PLC	Actual daily PLC values for PECO residential and non-residential customers, including both default service and choice customers	https://www.pecoprocurement.com/
PJM zonal PLC	Historical PLC values by PJM RPM capacity zone	https://www.pjm.com/markets-and-operations/rpm
Network Integration Transmission Service (NITS) Rates	Rates for NITS service assessed based on NSPL	Rates for periods prior to June 1, 2022 were provided by UGI; Rate beginning June 1, 2022 downloaded from https://www.pjm.com/-/media/markets-ops/settlements/network-integration-trans-service-june-2022.ashx
PJM Load Forecasts	Forecasted annual GWh load for PJM load zones produced annually by PJM for future delivery years	https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process
RPM Prices and UCAP Obligations	Historical PJM RPM zonal capacity prices and UCAP MW obligations by zone for BRA and incremental auctions	https://www.pjm.com/markets-and-operations/rpm
Default Service Solicitation Bid Results	Historical winning bid prices for default service load-following products	Provided by UGI, https://www.pecoprocurement.com/