COMMONWEALTH OF PENNSYLVANIA

March 25, 2021

E-FILED

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

Re: Pennsylvania Public Utility Commission, v. Pike County Light & Power Company (Electric) / Docket No. R-2020-3022135

Dear Secretary Chiavetta:

The Pennsylvania Public Utility Commission's Implementation Order at *Electronic Access to Pre-Served Testimony*, Docket No. M-2012-2331973, requires that all testimony furnished to the court reporter during a proceeding must subsequently be provided to the Secretary's Bureau.

As such, this letter will confirm that the Office of Small Business Advocate ("OSBA") per ALJ Long's Interim Order dated March 15, 2021 has filed the Direct Testimony of Robert Knecht, labeled OSBA Statement No. 1, the Rebuttal Testimony of Robert Knecht, labeled OSBA Statement 1-R and the Surrebuttal Testimony of Robert Knecht labeled OSBA Statement No. 1-S on behalf of the OSBA, in the above-captioned proceeding.

All known parties were previously served with the aforementioned Testimony. If you have any questions, please contact me.

Sincerely,

/s/ Sharon E. Webb

Sharon E. Webb
Assistant Small Business Advocate
Attorney ID No. 73995

Enclosures

cc: Robert D. Knecht
Parties of Record (Cover Letter and Certificate of Service Only)

COMMONWEALTH OF PENNSYLVANIA

February 2, 2021

The Honorable Mary D. Long
Pennsylvania Public Utility Commission
Piatt Place
301 5th Avenue, Suite 2020
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission, v. Pike County Light & Power Company (Electric) / Docket No. R-2020-3022135

Dear Judge Long:

Enclosed please find the Direct Testimony of Robert D. Knecht, labeled OSBA Statement No. 1, 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/ Sharon E. Webb

Sharon E. Webb
Assistant Small Business Advocate
Attorney ID No. 73995

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

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2020-3022135**
PIKE COUNTY LIGHT & POWER COMPANY (Electric Division)	:	

Direct Testimony and Exhibit of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation
Rate Design

Date Served: February 2, 2021

Date Submitted for the Record: March 15, 2021

DIRECT 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 Robert D. Knecht. I am a Principal of Industrial Economics, Incorporated ("IEc"), a consulting firm located at 2067 Massachusetts Avenue, Cambridge, MA 02140. As part of my consulting practice, I have prepared analyses and expert testimony in the field of regulatory economics on a variety of topics. 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 recent expert testimony that I have filed in utility regulatory proceedings are attached in Exhibit IEc-1. I have represented OSBA in a number of proceedings before the Pennsylvania Public Utility Commission ("Commission") over the past twenty-five years, including electric utility base rates proceedings for Pike County Light & Power Company in 2008 and 2014.[1]

Q. Please describe the purpose of this testimony.

A. OSBA requested that I review the filing of Pike County Light & Power Company Electric Division ("the Company" or "PCL&P") regarding cost allocation, revenue allocation and rate design for its electric distribution service, and to evaluate whether small business customers are being treated equitably.

Q. Please summarize the Company's proposed rate increase in this proceeding.

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[1] Full disclosure: This testimony borrows liberally from the exposition in my direct testimony in the 2013 base rate proceeding.

A. PCL&P proposes to increase its annual electric distribution revenues by approximately $1.92 million or 36.9 percent for the forecast test year ending June 2021.[2] This increase is proposed to achieve a target return on equity of 9.75 percent and a weighted average return on rate base of 7.09 percent.

The proposed increase would be achieved by assigning the increases among the major rate classes as shown in Table IEc-1 below.

Table IEc-1 PCL&P Electric Proposed FTY Rate Increases		
	Amount ($000)	**Percent**
SC1: Residential	$ 659	31.0%
SC1: Res. Space/Water Htg.	$ 171	30.7%
SC2-S: C&I Secondary	$ 931	45.2%
SC2-P: C&I Primary	$ 116	33.0%
SC3: Municipal Lighting	$ 33	37.7%
SC4: Private Area Lighting	$ 11	37.7%
Total	**$1,920**	**36.9%**
Sources: RDK WP1, "PoR FTY"		

Q. Please summarize your conclusions.

A. My conclusions are as follows:

- The Company's cost allocation method as filed contains certain acknowledged technical errors that have a material impact on the results. The Company's method also relies on methodologies that are, on balance, inappropriately biased against small business customers. I therefore developed two alternative versions of the cost allocation study. The first simply corrects the Company's electric

[2] The Company measures its rate increase by comparing the revenues at present rates for the historical test year ("HTY") ending June 2020 to the revenues at proposed rates for the future test year ("FTY") ending June 2021. As such, the Company's reported increase includes the effects of changes in both billing determinants and tariff charges. Consistent with Pennsylvania practice, I consistently measure rate increases based on the FTY, which avoids the distortive effects of changing billing determinants.

class cost of service study ("ECOSS") for the acknowledged errors. The second modifies that corrected study based on principles that are more consistent with cost causation and recent Commission precedent. In this analysis, I made reasonably "conservative" adjustments to the Company's cost allocation analysis, such that my cost analysis continues to overstate the cost to serve small business customers.

- PCL&P's proposed revenue allocation for assigning the rate increase among the various rate classes is not fully consistent with its own ECOSS, even without correcting for the admitted technical errors.

- I developed two alternative revenue allocation proposal, based on (a) the Company's cost allocation methodology as corrected for the acknowledged errors and (b) my proposed cost allocation methodology. Both proposals are based on the principle of moving rates more into line with allocated cost, subject to rate gradualism considerations.

- PCL&P's tariff for non-residential secondary voltage customers (SC2-S) is a relatively complicated affair, with a customer charge, a three-tiered declining-block load-factor energy charge (with little rate differentiation), a two-tiered inclining-block demand charge, an energy-only charge for non-demand-metered customers, and an option for customers to pay a discounted energy-only charge for electric space heating service. I recommend the following:

    - The relative importance of peak demand in the tariff should be increased, either by increasing rate differentials within the load-factor tariff or by increasing the demand charge, to better align rates and allocated costs.

    - The differential in the blocked demand charge should be reduced, also to better align rates and allocated costs.

    - The Company's proposed increase in the customer charge is not unreasonable at the full proposed revenue requirement; if the Company's overall revenue requirement is reduced, the increase in the SC2-S customer charge should be scaled back proportionately.

- The energy-only electric space heating charge should be phased out.

2. <u>Cost Allocation</u>

Q. What is a utility cost allocation study?

A. A utility cost allocation study, in this case the Company's ECOSS, is an analytical tool that assigns the utility's test year total costs (i.e., the "revenue requirement") among the various utility rate classes. Pennsylvania electric and gas utilities typically use an "embedded cost" approach to cost allocation, in which accounting book costs are directly assigned among the rate classes, rather than a marginal cost approach. Cost allocation analysts generally agree that costs should, to the extent practicable, be assigned among rate classes based on "cost causation," such that costs caused by a particular class of customers are assigned to that class. A cost allocation study usually involves a three step process, in which costs are (a) segregated by function ("functionalization"), (b) further segregated by cost causation factor, notably throughput, peak demand, "excess" demand, and customer count ("classification"), and (c) allocated among the rate classes based on each class' contribution to the cost causation factor ("allocation").

Q. What purpose does the ECOSS serve in a utility rate proceeding?

A. The ECOSS informs both the assignment of the rate increase among customer classes ("revenue allocation") and the design of rates to recover the assigned revenues. Revenue allocation is often used to move rate revenue more into line with allocated costs from the ECOSS. For rate design, classified costs, such as customer-related and demand-related costs, inform the development of specific rate charges, such as monthly customer and demand charges.

Q. Please describe the Company's filing with respect to cost allocation in this proceeding.

A. The Company's cost allocation analysis was filed in Exhibits E-6 and E-7 and was provided in electronic version in I&E-RS-2D. These analyses are based on the full allocation of embedded book costs, using the Company's ECOSS.

Consistent with the settlement of the Company's base rates proceeding at Docket No. R-2008-2046520, the cost allocation analysis is performed for the historical test year ("HTY") ending June 2020, rather than for the future test year ("FTY") as is normal electric utility practice in Pennsylvania. However, the Company has also roughed out the implications of a FTY ECOSS, by taking the HTY allocated costs and then reallocating all of the changes in revenues and costs between the FTY and HTY. This approach is far from perfect, as it (a) lumps together many of the year-to-year revenue and cost changes into aggregate accounts, and (b) fails to correctly reflect changes in forecast loads, demands and number of customers.[3] In effect, for the FTY, the Company allocates 2021 costs with 2020 allocation factors.[4]

In addition, most of the key classification and allocation factors used in this year's ECOSS are either identical to those used in the Company's 2013 base rates case or are updated simply for changes in use per customer. These include the sub-functionalization analysis between primary and secondary system costs, the classification factors for primary and secondary distribution equipment, the transmission, primary and secondary peak demand factors, and the services plant allocator. As these allocation factors are unchanged from that proceeding, my testimony relating to those factors is generally also unchanged.[5]

The Company has four basic rate classes: Residential (SC1), Small Commercial and Industrial ("Small C&I") (SC2), Municipal Street Lighting (SC3) and Private Area Lighting (SC4). For both cost allocation and rate design, the Company segregates the SC2 class into primary and secondary ("SC2-P" and "SC2-S" respectively) voltage categories.

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[3] The Company acknowledges the latter problem in OSBA-I-29(d).

[4] As I understand it, the Company undertakes a similar exercise in its response to I&E-RS-9-D and I&E-RS-10-D, where it provides electronic versions of what is reported to be a FTY 2021 cost of service study. These versions, like the original filed version, also suffer from the basic problem that FTY costs are being allocated with HTY allocators.

[5] See page 10 and 11 of the Rate Panel testimony and OSBA-I-17(a) regarding sub-functionalization, OSBA-I-16(b) relating to classification factors, "Electric Demands 6-30-20.xlsx" from OSBA-I-18 for demand and services allocation factors. Note that the Company did update its allocation method for meters costs, discussed further below, OSBA-I-20(b).

For cost allocation purposes, the Company segregates SC1 into "residential" and "space/water heating" categories, but the same tariff charges apply to both sub-categories.

Q. How have you addressed these problems with the Company's ECOSS?

A. I constructed an alternative electronic version of the Company's ECOSS that replicates the Company's results for the HTY and for the adjustments to estimate the FTY. This analysis is provided in RDK WP1.[6] I then developed an alternative version of the ECOSS based on correcting the specific errors acknowledged by the Company. This model is provided in RDK WP2. Finally, based on my analysis and recommendations regarding the Company's methodology as detailed below, I developed an "RDK ECOSS" for this proceeding, which is provided in RDK WP3.

As I indicated earlier, I develop two alternative revenue allocation proposals based on the corrected PCL&P ECOSS (RDK WP2) and the RDK ECOSS (RDK WP3).

Q. Has the Company acknowledged technical errors in the filed ECOSS?

A. Yes. The Company acknowledged the following errors:

- The Company inadvertently used a primary voltage demand allocation factor to allocate secondary demand-related costs.[7] In so doing, the Company incorrectly allocates secondary plant costs to the SC2-P class.

- The Company inadvertently used the meters plant allocator rather than the meter reading allocator to allocate meter reading costs in developing its labor cost allocation factor.[8] This error serves to overstate meter reading costs for the non-residential classes in that allocator. That error is then passed on to a variety of costs that are allocated based on the labor allocation factor.

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[6] My electronic workpapers in executable MS Excel format are circulated with this testimony.

[7] OSBA-I-14.

[8] OSBA-I-15. Note that the Company correctly applies the meter reading allocator to O&M costs, but it uses the incorrect allocator for deriving the general labor cost allocation factor. The labor cost allocation factor is used to allocate general plant and certain administrative and general ("A&G") costs.

These errors are corrected in RDK WP2.

Q. Do these errors have a material impact on the results of the ECOSS?

A. Yes. Table IEc-2 below shows the HTY class rate of return at present rates for the Company's filed version and my corrected version. It also shows the rate increase necessary to achieve cost-based rates for the FTY under both ECOSS simulations.

Table IEc-2
ECOSS Impact of Acknowledged Errors

	HTY Class Rate of Return at Current Rates		FTY Increase to Cost-Based Rates	
	PCL&P	Corrected	PCL&P	Corrected
SC1: Residential	5.4%	3.7%	33.9%	46.8%
SC1: Res. Space/Water Htg.	8.4%	6.8%	24.3%	33.9%
SC1: Residential Total	*6.0%*	*4.3%*	*31.9%*	*44.1%*
SC2-S: C&I Secondary	3.1%	4.7%	43.7%	31.4%
SC2-P: C&I Primary	4.2%	7.4%	31.9%	10.8%
SC3: Municipal Lighting	4.9%	4.9%	40.2%	40.2%
SC4: Private Area Lighting	3.1%	3.1%	59.5%	59.6%
Total	**4.6%**	**4.6%**	**36.9%**	**36.9%**

Sources: RDK WP1, RDK WP2

As shown, the corrections result in a significant shift in costs from the SC2 classes to the SC1 classes. This is particularly true for the SC2-P class, because PCL&P incorrectly assigned significant secondary voltage system costs to this class. However, the SC2-S class also exhibits a material reduction in costs, due to the change in the labor allocation factor. Because the labor allocator relies on a relatively small amount of labor costs, and because it affects the allocation of a significant amount of general plant and A&G costs, the change to the meter reading costs has a significant impact.

Q. Beyond the acknowledged errors, what specific aspects of PCL&P's cost allocation methodology do you address in this proceeding?

A. This testimony addresses the following methodological issues:

- Classification and allocation of primary and secondary distribution plant;
- Allocation of services plant;
- Allocation of meters plant;
- Implications of limited accounting system detail for O&M and labor costs;
- Allocation of customer service and sales O&M costs; and
- Allocation of working capital costs.

Q. What issue is most debated with respect to electric utility distribution company ("EDC") cost allocation?

A. The most contentious issue regarding EDC cost allocation usually revolves around the "classification" and "allocation" of joint use distribution plant costs, including substations, poles, overhead and underground lines, and transformers. This debate arises for several reasons.

- First, this plant represents a substantial portion of the overall distribution plant, making the issue of critical importance to the overall allocation of rate base. Moreover, because O&M costs are generally allocated in proportion to the allocation of plant, the allocation of plant has a large impact on the allocation of O&M costs.

- Second, unlike meters and service line plant, this plant represents "joint use" costs, meaning that multiple rate classes rely on the same plant. These costs therefore generally cannot be directly assigned to the specific rate class which uses the plant but must be allocated using some reasonable factors.

- Third, the economics literature provides little theoretical support for the allocation of such costs, other than to state that the allocated costs should lie somewhere between the short-run marginal cost of providing service and the standalone cost of serving a particular class. These guidelines leave considerable leeway for allocating electric distribution plant costs.

- Fourth, the various methodologies offered by cost allocation analysts produce a wide range of cost allocation outcomes.

The debate for allocating joint use distribution plant costs generally revolves around which factors best reflect "cost causation." These factors typically fall into three categories: peak demand, annual energy usage (or its arithmetic equivalent, average demand), and number of customers. These three "classification" factors are generally abbreviated as "demand," "energy" and "customer."

Q. Please describe the issues involved in the classification and allocation of distribution plant costs.

A. An electric distribution system must be designed to meet two objectives. First, the poles, wires and transformers must be large enough to be able to deliver power from the transmission grid to customer premises at the time when the load on each component of the system is the highest. Second, the system must be designed to interconnect all the EDC's customers.

A two-step process is generally used to recognize how these system design considerations cause costs to be incurred and to assign costs to rate classes. First, distribution plant costs are *classified* into demand-related and customer-related components, to reflect both the peak demand and size of system design considerations. Second, each component of the classified costs is *allocated* among the various rate classes. Customer-related costs are generally allocated on the basis of the number of customers.[9] Demand-related costs are allocated on the basis of some measure of customer peak demand.

Figure IEc-1 below depicts this two-step process schematically, and identifies the primary methodologies used by cost allocation analysts for each step. In my experience, all of these methods are in general use, although experts disagree about which method best reflects cost causation.

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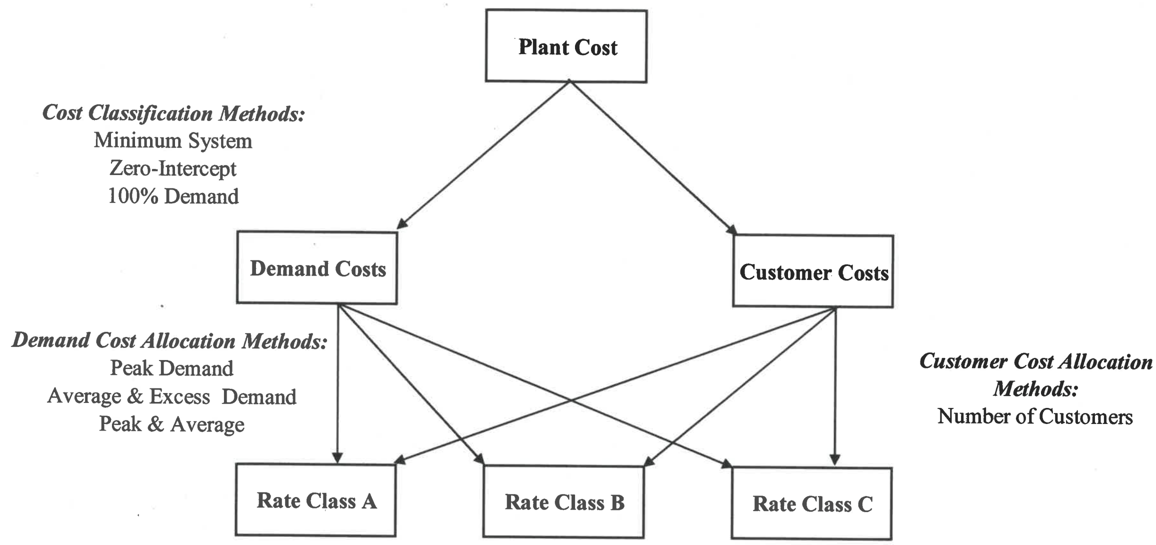
[9] Depending on the utility's accounting records, some costs can be directly assigned, such as meters and services. In the alternative, a weighted customer allocator can be used to reflect estimated cost differences between classes for customer-related assets.

Figure IEc-1

Classification and Allocation of Electric Distribution Plant Costs: Summary of Methodologies



Q. Please briefly discuss the electric distribution plant cost *classification* methods shown in Figure IEc-1.

A. The "minimum system" approach is based on the idea that the customer-related component of costs should represent those costs that would be incurred to meet minimal demand levels. It is calculated by determining what the cost of the electric distribution system would be if only minimum-sized poles, wires and transformers were installed. The ratio of the cost of this minimum system to the cost of the actual system is deemed to be the percentage of the cost of the actual system that is customer-related. All costs incurred in excess of the minimum system are considered demand-related.

The minimum system approach is often criticized for failing to recognize that a minimum system has some load carrying capability, and therefore overstates the customer-related component of costs. This critique is addressed by some analysts using a "zero-intercept" methodology. In a zero-intercept approach, the minimum system is based not on the cost of the actual minimum-sized plant, but on the implicit cost of plant with zero load carrying capability. The cost of a zero-capacity transformer, for example, is determined using statistical methods, which show a mathematical relationship between the cost of a transformer and its capacity.

A second criticism of both the minimum system and zero-intercept methods is that it is not clear that the customer portion of costs, as measured in this method, does in fact vary over the longer term with number of customers. There is conceptual appeal in the argument that it costs less per unit of demand to attach one customer with a 100 kW load than to attach 20 customers with 5 kW loads. However, neither the minimum system nor the zero-intercept method attempts to measure these scale economies that are related to system topology.

Finally, the "100% demand" approach assumes that all distribution costs are demand-related, and that there is no customer component at all. This method simply assumes that there are no economies of scale related to serving larger customers on the distribution system, and that all customers have the same cost per unit of peak demand.

Q. Please address the issues relating to the *allocation* of distribution plant costs.

A. The most common methods for allocating the demand component of electric distribution plant costs are either a peak demand method or the average-and-excess ("A&E") demand method. Under the peak demand method, costs are allocated based on each class's contribution to peak demand. Peak demand methods include coincident peak ("CP"), non-coincident peak ("NCP") and individual customer maximum demand ("ICMD") methods. Under the CP method, costs are allocated based on each class's contribution to a measure of the diversified system peak. For NCP, costs are generally allocated based on the diversified sum of peak demands within each class. For ICMD, costs are allocated based on the undiversified sum of each individual customer's peak demand within each class.[10] For electric utilities, generation and transmission demand-related costs are more commonly

[10] Load diversity refers to the fact that not all customers experience their peak demand at the same time. Thus, for example, it is not necessary to build electric generation capacity sufficient to meet the sum of the individual peak demands of every single customer on the grid. These "benefits of diversity" necessarily decrease as the electric plant in service gets closer to the individual customers. While generation capacity can reflect the benefits of diversity, local transformers and service drops must be sized to meet individual customer peaks.

allocated using a diversified CP method, whereas distribution costs are more commonly allocated using NCP and ICMD methods.[11]

The A&E method allocates demand costs based on a weighted average of "average demand," which is proportional to annual energy consumption, and "excess demand," which is the difference between peak demand and average demand.

In addition, in Pennsylvania and elsewhere, some experts advocate the use of a peak-and-average ("P&A") allocation method for demand costs. In this method, costs are allocated based on a weighted average of average demands and peak demands.

Q. What approaches has PCL&P taken with respect to electric distribution plant cost classification and allocation?

A. PCL&P proposes to classify all primary voltage distribution plant as 100 percent demand-related. For secondary voltage distribution plant, PCL&P uses a minimum system approach for cost classification.

For allocating primary system costs, PCL&P uses a class NCP allocator. For its secondary distribution plant demand-related costs, PCL&P uses a weighted average of the class NCP demand and the sum of individual customer demands.[12]

Q. Do you agree with PCL&P's methods for joint-use distribution plant allocation?

A. I agree that distribution plant costs, particularly secondary voltage distribution plant, should have both a customer and a demand component, for the cost causation reasons discussed earlier, and based on Commission precedent. However, both traditional industry practice and relatively recent Commission decisions imply that primary system costs should also include both a customer component and a demand component.[13]

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[11] For distribution system costs, some analysts argue that distribution costs related to peak periods should be allocated using multiple on-peak hours, and that there should be geographic differences in when these high usage hours occur. As smart meters become more prevalent, this approach becomes more technically feasible. However, because PCL&P does not have smart meters, this approach is moot for this proceeding.

[12] See 2013 Pike Electric Selected Allocation Factors.xlsx, from OSBA-I-18(b).

[13] Regarding Commission precedent, the example of PPL Electric is discussed in detail below.

As a conceptual matter, I prefer the use of a zero-intercept approach to PCL&P's minimum system approach for distribution plant cost classification, because the zero-intercept approach addresses the problem of the load-carrying capability of the minimum system. However, because the zero-intercept approach for an EDC is much more complicated and more data intensive than a minimum system analysis, it would not be cost effective for a small EDC like PCL&P. Moreover, Commission precedent supports use of the minimum system method. Thus, I do not object to the use of a minimum system method in this proceeding.

I also agree with PCL&P's use of a peak demand method for allocating the demand-related portion of distribution plant costs. An electric distribution system must be sized to meet peak demands, or customers will see their electric use constrained during peak periods. PCL&P's use of the class NCP allocator for primary system distribution costs is consistent with industry practice, and it reflects a measure of the load diversity that the electric distribution system experiences at primary voltage. In addition, at the secondary voltage level, there are few benefits of load diversity for poles, conductors and transformers. These assets must generally be sized to meet the peak demands of a very few customers within a narrow geographic area. Thus, PCL&P's use of a mix of class NCP and individual customer peak demands is a reasonable approach.

Q. Are PCL&P's cost classification methods consistent with the practices of other Pennsylvania EDCs and industry practice?

A. While the Company's methods are not outside the range of industry practice, a reasonable case can be made that some component of primary system plant should be classified as customer-related, rather than classifying all primary system plant as demand-related.

For many years, PPL Electric used an approach that is conceptually similar to that offered by the Company in this proceeding, in that it used 100 percent demand classification for its primary system and a minimum system approach for secondary distribution plant. However, PPL Electric modified its method to include a customer component for its primary distribution system (excluding substations). The Commission explicitly approved the revised method in December 2012.[14]

In addition, the FirstEnergy EDCs use a minimum system methodology for distribution plant cost classification (excluding substations), applying the analysis to both primary and secondary systems.[15]

Moreover, the NARUC manual for electric cost allocation specifies that distribution plant costs have both a demand and a customer component, and it identifies the minimum system approach as one of the standard methods. It indicates that the minimum system should be applied to both primary and secondary distribution plant (excluding substations). The manual further supports the use of NCP and individual customer demands as allocation factors for distribution demand-related costs.[16]

Q. What do you conclude from this methodological review of PCL&P's electric distribution plant cost classification and allocation methods?

A. Because industry practice would generally support the use of a customer component for primary distribution plant, I included such a provision in the RDK ECOSS (RDK WP3). At this time, I do not have sufficient information to develop a minimum system value for primary system plant. I have therefore used a 30 percent factor for customer-related costs.[17] By way of contrast, PPL Electric's average customer component for primary system plant was 51 percent in the cost allocation study approved by the Commission. My workpapers from the most recent FirstEnergy base rates proceeding (four EDCs) show that minimum system method at the four EDCs classified poles as 73-82 percent customer related, overhead lines as 82-92 percent customer-related, underground lines as 82-90 percent

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[14] Opinion and Order, Pennsylvania Public Utility Commission, Docket No. R-2012-2290597, Order Entered December 28, 2012, pages 105- 113.

[15] OSBA Statement No. 1, Docket No. R-2016-2537349 et al., pages 9-15.

[16] "Electric Utility Cost Allocation Manual," National Association of Regulatory Utility Commissioners, January 1992, pages 86-92, and 96-97.

[17] I acknowledge that this value is based on my judgment, as well as the practices of other utilities. However, it is no more judgmental than the Company's approach of simply assuming that the costs are entirely demand-related.

customer-related and transformers as 52-71 percent customer-related, for the combined primary and secondary systems. As such, my proposed modification to PCL&P's primary system classification assumption is conservative, and likely understates the minimum system customer component of costs (and therefore overstates costs caused by business customers).

Q. Let's move to a different cost allocation topic. Please comment on PCL&P's allocation of service lines costs.

A. Electric service lines (or "drops") run from the distribution system into customers' premises and can be either overhead or underground. Because lighting customers have no service drops, services costs apply only to the SC-1, SC-2 secondary and SC-2 primary rate classes.

As PCL&P recognizes, services costs are normally considered to relate to the number of customers on the system, and they are therefore classified as "customer-related" in cost allocation study. In some cases, services costs are simply allocated on a per-customer basis. However, in other cases, EDCs recognize that the per-customer services cost for larger customers may be higher than for smaller customers. This cost difference can be recognized in cost allocation analyses by one of two approaches. First, if plant records are sufficiently detailed, the cost of services may be directly assigned to customer classes. Second, services costs may be split into demand and customer components using a minimum system or zero intercept method, similar to the treatment of electric distribution plant costs. Third, services costs may be allocated using a weighted customer allocator, where the weights reflect modestly higher service costs for larger customers.

Unfortunately, PCL&P takes none of these approaches. For allocation purposes, PCL&P deems that services have no customer component at all, and it therefore allocates all services costs on the basis of primary voltage class non-coincident peak demands, but excluding SC2-P. [18] In this proceeding, the Company has modified its methodology from

[18] OSBA-I-18(e) states that services costs are allocated using the sum of individual customer peak demands (the "ICMD" approach described above), but that does not appear to be correct, according to the Company's Electric Demand 6-30-20.xlsx workpaper. Also, it is unclear why the Company would want to use primary voltage demands to allocate secondary system services costs.

2013 to exclude the services costs that were formerly allocated to primary voltage customers, because the Company indicates that it does not install services for these customers.[19]

The Company's method fails to recognize the economies of scale in services costs. While services costs may very well increase with the capacity of the service, they do not do so proportionally. PCL&P's cost information from earlier proceedings confirms this observation. Although PCL&P reported in 2013 that it did not have embedded cost information relating to its services costs, its estimates of the costs for new services generally indicated that service costs increase less than proportionately with capacity. For example, doubling the capacity of an underground service line increased costs by only about 30 percent.[20] Therefore, PCL&P's methodology will over-assign services costs to larger customers and under-assign costs to smaller customers. Because both SC-2 primary and SC-2 secondary customers are, on average, larger than SC-1 customers, PCL&P's methodology will over-assign costs to both SC-2 customer classes.

Q. You raised this issue regarding service plant costs in the Company's last two base rates proceeding. Has PCL&P made an effort to correct this bias?

A. No. As noted earlier, the Company generally has not attempted to update any of its analyses regarding key cost allocation factors. The only changes have been (a) to set allocation of service costs for SC2-P costs to zero to correct an error in the earlier studies, and (b) to update the demand allocation factor to reflect usage changes.

Q. Have you adjusted PCL&P's cost allocation analysis for this bias?

A. Yes. For the purpose of this proceeding, I use an approximation that services plant costs are 70 percent customer-related and 30 percent demand-related.[21] By way of contrast, PPL Electric's most recent cost allocation study classifies services as 98.8 percent customer-related and 1.2 percent demand-related. The FirstEnergy EDCs simply allocate services

[19] See OSBA-I-22(d). It appears that the 2013 study erroneously allocated services costs to SC2-P.

[20] This conclusion is based on the Company's response to OSBA-I-24 in the previous base rates proceeding.

[21] The demand component uses secondary voltage demands, not the primary demands proposed by the Company.

costs based on the number of secondary voltage customers, implying that services are 100 percent customer-related. Thus, my adjustment is conservative, and likely understates the customer component of services costs.

Q. Please describe the Company's method for allocating meters costs.

A. The Company has updated the method for allocating meters plant from its last base rates proceeding, as shown in the attachment to OSBA-I-20. This change has resulted in a substantial increase in the costs assigned to the SC2 classes. In the 2013 ECOSS, the relative meter cost for an SC2-S customer was 2.9 times the cost for an SC1 meter; in the current filing that ratio is 8.4 times. The comparable values for SC2-P are 10.1 and 67.0 times.[22] The Company indicates that the change occurs because it has modified how installation costs are allocated.[23]

The Company begins with an estimate for the physical cost of a meter in each class, which is $130 for SC1, $390 for SC2-S and $12,500 for SC2-P. No basis is provided for these values. By way of contrast, the meters plant cost values in 2013, including installation costs, were $61, $146, and $617 for the three classes respectively. Thus, the Company has used much higher physical meter costs than in the last proceeding, with the 20-fold increase in the unit cost for an SC2-P meter being particularly surprising.[24]

To that, PCL&P adds estimated installation costs, based on an assumed number of hours for installation and a labor rate with overhead.

The labor hour estimates are 0.5 hours for a SC1 (residential) meter, 6 hours for SC2-S and 16 hours for SC2-P. No basis is provided for these estimates. These estimates are not terribly credible, at a minimum because the installation labor cost should reasonably include travel time to and from the job site, which the SC1 value apparently does not.

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[22] These values are derived from Copy of #10 Meter Services Installation Costs 6-30-2020 for Pike–updated.xlsx and PIKE 2013 Electric ECOS Study for Distribution.xls, provided in response to OSBA-I-20.

[23] OSBA-I-20.

[24] In the last case, the Company's *installed* meters cost for the SC1 class was $130, which matches the physical cost used in this proceeding. This may be coincidental.

Finally, in deriving installation costs, the Company uses an hourly labor rate with overhead, of $293 per hour. This is not reasonable and may result from double-counting overhead in both the regular labor rate and the overhead factor.[25]

Pending clarification from the Company in rebuttal testimony, I modified the Company's meter allocation calculations as follows:

- The physical meters cost from 2013 are used rather than the updated values, as that appears to be the Company's intent as stated in OSBA-I-20;
- An hour of travel time per installer is added to the labor cost estimates for each installation;
- The fully loaded labor rate is limited to the Company's labor rate of $122 per hour.

The end result of these changes is that the meter cost multiplier for SC2-S is 4.6 times the residential rate (compared to the 2.9 factor in 2013) and is 12.5 times for SC2-P (compared to 8.4 times in 2013). Thus, my alternative calculations reflect the Company's determination that meters costs are relatively higher for non-residential customers when installation costs are factored in, but I use more reasonable assumptions for those installation costs. These calculations are shown in RDK WP3 on the "Meters" tab, and the alternative allocator is reflected in the cost allocation model.

Q. Turning to the allocation of O&M costs, does PCL&P maintain detailed records for its distribution O&M costs?

A. No. The Company records its distribution O&M costs in only three accounts: overhead conductors, underground conductors, or miscellaneous. In effect, for cost allocation

[25] As noted elsewhere, the Company does not capitalize employee benefits. As such, zero benefits overhead should be included in meters capital cost. Note also that the Company uses a much more reasonable hourly labor cost in its comparable evaluation of meters cost for the gas utility.

purposes, PCL&P implicitly assumes that O&M costs related to its substation, services plant, lighting plant, meters plant and transformers are zero.[26]

This is particularly problematic for developing the labor cost allocation factor. It is relatively common practice for cost allocation analysts to use a "labor" allocation factor to assign general plant and administrative and general ("A&G") costs among the rate classes, on the theory that these overhead costs exist to support utility labor.[27] For PCL&P with its limited O&M cost differentiation however, that assumption is not reasonable. The Company's cost allocation study essentially uses the allocation of about $125,000 in labor costs, which are recorded in only a few separate operating accounts, to distribute some $3.3 million in general plant and $1.4 million in A&G costs.[28] The Company is letting the tail wag the dog.

Q. How do you address this concern?

A. I modified the Company's allocation method in two ways.

First, regarding the large pool of A&G costs, there are certain components that can be allocated in a way that is more consistent with the associated functions. Specifically, the A&G costs include a relatively large amount related to customer service, and I therefore allocate those using the customer service allocator (discussed below). A&G costs include postage costs, which are more accurately allocated using the customer bills allocator, as the magnitude of the cost item implies these are related to billing.[29] Within the outside services A&G account, I deemed that the legal, financial and regulatory services were more related to supporting the overall operation than just supporting labor, so these costs were

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[26] OSBA-I-26.

[27] As the Company in fact does in OSBA-I-23(a).

[28] Note also that the Company capitalizes a significant share of its labor, and that amount is not used in developing the labor allocator. However, the Company does not capitalize the associated employee benefits costs, thereby resulting in a large implied burden on the direct labor costs. See OSBA-I-23(c).

[29] OSBA-I-27.

allocated based on overall class revenue requirement. Also, the energy services costs within the outside services category were allocated based on energy.

Second, for general plant, I use total distribution plant as the allocation factor.[30] The Company keeps more detailed records for its plant accounts than for the labor accounts, and thus these are likely to better reflect the assets that are supported by general plant..

These modifications are shown in my proposed ECOSS in RDK WP3.

Q. What is your concern regarding the allocation of customer services and sales O&M costs?

A. The FERC customer service accounts include costs in three general categories: providing information to customers, customer assistance programs, and informational/instructional advertising expenses.[31] In general, costs for providing information to customers are usually deemed to be customer related. Costs related to customer information systems and call centers are the same for smaller customers as they are for larger customers. (In fact, smaller customers may disproportionately use the call centers.) These costs should therefore be allocated based on customer count. Similarly, informational advertising typically takes the form of bill inserts, which are also customer-related costs.

Regarding sales costs, in my experience, sales efforts are primarily targeted at smaller customers, and it is common for these costs to be allocated entirely based on customer count. There is little need to target sales efforts at larger electricity users. Thus, based on the limited information available, I conclude that the large majority of customer service and sales costs should be classified as customer-related and allocated using a customer allocator.

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[30] General plant primarily consists of the Company's Operating Center which includes the materials & supplies storeroom, and computer equipment. It is not unreasonable to conclude that these facilities support all distribution functions.

[31] See http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=054f2bfd518f9926aac4b73489f11c67&rgn=div5&view=text&node=18:1.0.1.3.34&idno=18 .

The Company's 50/50 approach has the effect, at present rates, of imposing customer services costs on secondary commercial customers that are more than double (per customer) than those for residential customers. Larger commercial customers are assigned customer service costs that are more than 55 times that of the average residential customer. I do not believe this is reasonable.

Regarding sales costs, in my experience, sales costs are primarily targeted at smaller customers, and it is common for these costs to be allocated entirely based on customer count. There is little need to target sales efforts at larger electricity users. Thus, based on the limited information available, I conclude that the large majority of customer service and sales O&M costs should be classified as customer-related and allocated using a customer allocator. Absent a more detailed assessment of cost causation for these costs, I conclude that the Company's allocation method substantially overstates the "revenue-related" portion of these costs, and therefore over-assigns costs to larger customers.

Q. **Have you made any adjustment in your cost allocation analysis for this bias?**

A. Based on judgment, I use an allocator that is weighted 80 percent to customer and 20 percent to energy use. This allocator applies to the Company's costs recorded in accounts 906 to 917, as well as to the customer service costs embedded in the A&G accounts. As utilities often allocate all of these costs based on customer count, this adjustment is conservative.

Q. **Please comment on PCL&P's allocation of working capital costs.**

A. One component of working capital costs is the lag between when PCL&P provides service to its customers and when it receives payment from the customers. This component of working capital costs is therefore causally related to two separate factors: the amount billed (company revenues) and the duration of the time lag from service to payment.

PCL&P allocates working capital costs on the basis of O&M costs (excluding purchased power). In so doing, PCL&P implicitly assumes that the lag from service to payment is the same for all rate classes. In my testimony in the Company's last two base rates cases, I relied on information from the Company showing that the payment lag for commercial customers was far shorter than that for residential customers.[32] The evidence provided in this proceeding indicates the payment lags are similar among rate classes.[33] Thus, the Company's proposed allocation method does not appear to be unreasonable, and I therefore make no adjustment for this concern that I voiced in earlier proceedings.

Q. Have you made any other changes to the RDK ECOSS in RDK WP3?

A. I have included the following adjustments:

- Other power supply costs reflect O&M transmission costs. I therefore allocated these using the primary system peak demand allocator rather than energy allocator used by the Company, as transmission must generally be sized to meet peak demands;[34]

- I allocate late payment charge revenues based on actual historical late payment levels rather than Company's approach of using the uncollectibles cost allocator;[35]

- Sales expense is added into the O&MXPP allocator -- the Company appears to have inadvertently excluded it.

Q. How do the results of your modified cost allocation study compare with the Company's results?

A. Table IEc-3 below compares the class rate of return at present rates under the two approaches.

[32] This conclusion is based on the Company's response to OSBA-I-6 at Docket No. R-2008-2046518. At the time, the billing-to-collection lag for residential customers is 33.3 days, compared to 22.1 days for commercial and 22.9 days for municipal. The longer lag for residential customers s likely due to the longer payment term provided to residential customers in the tariff (20 days for SC-1 and SC-4, versus 15 days for SC-2 and SC-3), as well as more restrictive rules for terminating service for residential customers. Updated information is not available at this writing.

[33] OSBA-I-1. I have no information regarding why the payment lag changed so substantially.

[34] These costs benefit both default service and shopping customers, and therefore need not be unbundled. See OSBA-I-9(b).

[35] OSBA-I-4.

Table IEc-3 Comparative HTY Class Rates of Return at Current Rates			
	PCL&P ECOSS	**PCL&P ECOSS Corrected***	**RDK ECOSS**
Residential	5.4%	3.7%	2.3%
Residential Heating	8.4%	6.8%	5.7%
Sub-Total Residential (SC1)	*6.0%*	*4.3%*	*2.9%*
Small C&I Secondary (SC2-S)	3.1%	4.7%	7.2%
Small C&I Primary (SC2-P)	4.2%	7.4%	10.0%
Municipal Lighting (SC3)	4.9%	4.9%	4.5%
Private Area Lighting (SC4)	3.1%	3.1%	-0.5%
Total	**4.6%**	**4.6%**	**4.6%**

* Replicated PCL&P ECOSS adjusted for acknowledged errors.
Sources: RDK WP1, RDK WP2, RDK WP3

Overall, the net effect of my proposed changes to the Company's method is to reduce costs assigned to the SC2 classes and increase costs assigned to the other rate classes. As I indicated however, some of my proposed changes have the reverse effect.

3. Revenue Allocation

Q. What are the primary regulatory criteria for revenue allocation?

A. The primary criterion used by most regulators for revenue allocation is cost of service. The primary objective of most regulators is to move class revenues into line with allocated class costs, subject to any constraints associated with the other criteria. In Pennsylvania, the Commonwealth Court has confirmed that cost of service should be the "polestar" criterion for revenue allocation.[36]

The secondary criteria most often used are "value of service" and "rate gradualism."

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[36] Lloyd v. Pennsylvania Public Utility Commission, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006).

The value of service criterion may be used to temper rate increases to customers or customer classes who are perceived to give lower value to the utility service, generally because they have a high price elasticity of demand. A high price elasticity typically results when a customer has ready economic alternatives (such as alternative fuel, bypass, relocation) or when a customer is in financial distress and cannot afford an increase.

Rate gradualism, or avoidance of rate shock, is a general principle that rates for one rate class or one group of customers should not rise substantially faster than rates for other customers or classes. Applying this criterion often takes the form of putting a limit on the increase for any rate class to be no more than, say, 1.5 or 2.0 times the system average rate increase.

Q. How does PCL&P propose to allocate revenues in this proceeding?

A. The Company's rate panel does not directly explain how it assigns the rate increase among the various rate classes, other than to indicate that it considers allocated costs. However, the specific calculations underpinning the Company's revenue allocation are provided in the "Revenue Allocation" tab in the Pike Electric Rate Design 10-07-20.xlsx worksheet, submitted in response to OSBA-I-33. Based on those calculations, the Company's method appears to be:

- Set the Residential class increase at 32.0 percent, compared to a system average of 37.7 percent, presumably to reflect the above-average class rate of return in the Company's ECOSS.
- Set the increase for the SC3 and SC4 lighting classes at the system average increase of 37.7 percent.
- Apply the balance of the required increase to the SC2-S and SC2-P rate classes. This remaining increase is split between the SC2-S and SC2-P classes based on the relative increase necessary to achieve cost-based rates.

This approach results in the revenue allocation shown in Table IEc-4 below:

Table IEc-4 PCL&P Proposed Revenue Allocation Using PCL&P Filed ECOSS				
	PCL&P Current R/C Ratio	Increase ($000)	Increase (%)	PCL&P Proposed R/C Ratio
Residential	102%	$659.1	31.0%	98%
Residential Heating	110%	$170.6	30.7%	105%
Sub-Total Residential (SC1)	104%	$829.7	30.9%	101%
Small C&I Secondary (SC2-S)	95%	$931.1	45.2%	101%
Small C&I Primary (SC2-P)	105%	$115.6	33.0%	101%
Municipal Lighting (SC3)	99%	$32.5	37.7%	98%
Private Area Lighting (SC4)	87%	$11.0	37.7%	86%
Total	**100%**	**$1,919.9**	**37.7%**	**100%**
Sources: RDK WP1				

Q. Do you agree with this approach?

A. While the Company does not explain how it derived the proposed increase for the Residential class, the Company's proposal generally moves rates substantially more into line with the Company's ECOSS results. Moreover, the individual class increases are well within the usual "rule of thumb" for rate gradualism, namely that no class increase be more than 1.5 or 2.0 times system average.

The exception is that the Company proposes a system average increase for the SC4 class, despite the class revenue/cost ratio being well below that of any other class.

However, while the Company's approach is mostly consistent with its ECOSS, the Company's ECOSS is not reasonable (in part by its own admission), for the reasons discussed above in Section 3. As such, an alternative revenue allocation is required.

Q. Please provide your revenue allocation proposal in the event the Commission approves the corrected version of the Company's ECOSS but does not approve your other proposed changes.

A. In that event, I propose that revenues be allocated to move rates into line with allocated costs for all rate classes, subject to a 1.5 times system average limit on the increase for the SC4 rate class. For the Residential class, I developed the revenue allocation to move the combined class to a 100 percent revenue/cost ratio, and then assigned the same average increase to the two sub-classes.[37] I allocate this small shortfall back among the other rate classes based on each class' revenue requirement. The details supporting this revenue allocation are shown in RDK WP2 and summarized in Table IEc-5 below.

Table IEc-5

RDK Revenue Allocation Using Corrected PCL&P ECOSS

	Current R/C Ratio	Increase ($000)	Increase (%)	Proposed R/C Ratio
Residential	93%	$ 938.7	44.1%	98%
Residential Heating	102%	$ 245.6	44.1%	108%
Sub-Total Residential (SC1)	95%	$1,184.3	44.1%	100%
Small C&I Secondary (SC2-S)	104%	$ 647.0	31.4%	100%
Small C&I Primary (SC2-P)	125%	$ 37.8	10.8%	100%
Municipal Lighting (SC3)	99%	$ 34.7	40.3%	100%
Private Area Lighting (SC4)	87%	$ 16.1	55.3%	97%
Total	**100%**	**$1,919.1**	**36.9%**	**100%**

Sources: RDK WP2

Q. Please provide your revenue allocation proposal based on the RDK ECOSS

A. Under this scenario, I adopt a revenue allocation method that is consistent with that used above. However, in addition to capping the maximum increase at 1.5 times system average, I set the rate increase for the SC2-P class at zero based on judgment, instead of adopting the rate reduction implied by the RDK ECOSS. With those constraints, the SC1 (Residential) and SC4 classes are assigned the capped maximum increase, the SC2-P class

[37] In practice, the relative magnitude of the increase within the Residential class will depend on rate design for that class, an issue I do not address in this testimony.

increase is set at zero, and the balance is assigned to the SC2-S and SC3 classes. This results in revenues for both the SC-2 and SC3 classes being modestly above allocated costs. The details supporting this revenue allocation are shown in RDK WP3 and summarized in Table IEc-6 below.

Table IEc-6
RDK Revenue Allocation Using RDK ECOSS

	Current R/C Ratio	Increase ($000)	Increase (%)	Proposed R/C Ratio
Residential	85%	$1,175.6	55.3%	96%
Residential Heating	97%	$ 307.5	55.3%	109%
Sub-Total Residential (SC1)	87%	$1,483.2	55.3%	98%
Small C&I Secondary (SC2-S)	119%	$ 375.5	18.2%	104%
Small C&I Primary (SC2-P)	141%	$ 0.0	0.0%	103%
Municipal Lighting (SC3)	95%	$ 45.3	52.5%	104%
Private Area Lighting (SC4)	64%	$ 16.1	55.3%	71%
Total	**100%**	**$1,952.5**	**37.7%**	**100%**

Sources: RDK WP3

4. Rate Design for SC2-S

Q. Please describe the current SC2-S class rate design.

A. In the last base rates proceeding, the Company substantially simplified the tariff structure for SC2-S class. Nevertheless, it remains relatively complicated, in that it includes a customer charge, three levels of declining-block load-factor ("Wright") energy charges, two levels of *inclining* block demand charges, a separate energy charge for non-demand metered customers, and a separate energy charge for space heating loads (minimum 10 kW installed equipment) for customers who opt to have that service separately billed.[38]

[38] The space heating service is presumably separately metered, although the tariff does not so specify, nor does there appear to be a separate customer charge for the additional meter.

Approximately 75 percent of the SC2-S revenues at current rates are produced from the load-factor energy charges. The customer charge accounts for about 8 percent, and the blocked demand charges 14 percent. The balance comes from an energy charge for customers with no demand meters, and a special space heating energy rate.

Q. Please describe the Company's proposed changes to Rate SC2-S.

A. The Company proposes to retain its current basic rate design, but it proposes to apply a modestly higher rate increase to the load-factor energy charges than to the customer and demand charges. Overall, this produces a relatively narrow range of increases within the class, from about 41.1 percent for small low load factor customers to 46.3 percent for large high load factor customers.[39] The specific proposed changes are shown in Table IEc-7 below.

Table IEc-7

PCL&P Proposed Rate Design: Rate SC2-S

	Current	Proposed	Percent
Customer Charge ($/mo.)	$13.60	$18.73	37.7%
First 100 kWh/kW (cents/kWh)	5.7964	8.5328	47.2%
Next 100 kWh/kW (cents/kWh)	4.7998	7.0657	47.2%
Over 200 kWh/kW (cents/kWh)	4.7100	6.9335	47.2%
Demand First 5 kW ($/kW)	$0.95	$1.31	37.9%
Demand Over 5 kW ($/kW)	$3.69	$5.09	37.9%
FTY Class Average (cents/kWh)	**6.5097**	**9.4518**	**45.2%**

Note: The energy charges for non-demand metered customers and space heating would also increase by 47.2 percent.

Source: RDK WP3 "PoR FTY" worksheet.

Q. How does this tariff design compare to the tariff designs of other Pennsylvania EDCs for small/medium commercial customers?

[39] See RDK WP3 "SC2 RD" worksheet.

A. It is generally more complex. Table IEc-8 below compares the basic distribution tariff components of Pennsylvania EDCs. The values in each cell represent the number of blocks in the tariff.

Table IEc-8

Pennsylvania EDC Small/Medium Commercial Tariff Design Components

	Customer Charge	Energy Charge	Demand Charge	Load Factor
PCL&P SC2-S	1	--	2	3
PPL Electric GS-1	1	--	1	--
PPL Electric GS-3	1	--	1	--
FirstEnergy GS-Small	1	1	--	--
FirstEnergy GS-Medium	1 or 2[1]	--	1	--
West Penn Rate 20	1	1	--	--
West Penn Rate 30	1	1	1	--
PECO Rate GS	3[2]	--	1	--
Duquesne Light GS/GM & GMH	1	1	1[3]	--
UGI Electric GS-1	1	1	--	--
UGI Electric GS-4	1	--	2	3
Citizens Electric GLP-1	1	1	1	--
Citizens Electric GLP-3	1	--	1	2
Wellsboro Electric No. 4	1	1	1	--
Wellsboro Electric No. 5	1	1	--	2

Notes:

FirstEnergy includes Metropolitan Edison, Pennsylvania Electric and Penn Power.

Like PCL&P, utilities with demand charges generally have an energy charge for non-demand-metered customers.

[1] Differentiated 1-phase v. 3-phase, except Penn Power

[2] Differentiated by phase and demand versus non-demand meter

[3] Over 5 kW only

Sources: Pennsylvania EDC tariffs

As shown, all of the Pennsylvania EDCs have a simpler tariff design than PCL&P except for UGI Electric (which has had but one base rates proceeding in the base 25 years). For good or for ill, most Pennsylvania EDCs are moving away from the load-factor Wright tariffs for small and medium general service customers.

Q. Starting with the easy aspect, do you agree with the Company's proposed increase to the customer charge, from $13.60 to $18.73 per month?

A. I conclude that the Company's proposed increase at the full revenue requirement is not unreasonable.

On a cost basis, I calculate a customer-related cost for the SC2-S class at around $50 per month, and between $35 and $40 per month for smaller customers within the class. As such, a $18.73 charge is not unreasonable on a cost basis.

I also reviewed the customer charge rates for small C&I classes at other Pennsylvania EDCs. These vary widely, with the low end at West Penn and UGI Electric's GS-1 charge of $9.52 and $9.83 respectively, to $22.00 for PPL Electric's GS-1, $21.88 for Metropolitan Edison's GS-Small and $24.89 for the Penn Power GS-Small class. PCL&P's proposed rate is not obviously unreasonable in that context.

Finally, as I discuss further below, the Company has a very low demand charge for the first 5kW, which benefits the low-usage customers. Some utilities who have a zero or minimal demand charge for the first few kW often try to use the customer charge to recover some of the demand costs related to that block. This is not the case for PCL&P.

Thus, I conclude the Company's proposal for the SC2-S customer charge is not unreasonable. I recommend only that if the SC2-S rate class increase is scaled back, that the Company's proposed customer charge increase be similarly scaled back.

Q. Please describe generally the purpose of the demand charge and the load-factor "Wright" tariff charges.

A. The demand charge, as its name implies, is generally designed to recover costs that are classified as peak-demand related. However, the peak demand costs in the ECOSS are based on non-coincident peak class demand, which recognizes some load diversity, whereas demand charges are based on the customer's individual peak billing demand. Thus, there is some mismatch between cost causation recognized in the ECOSS and the demand charge.

The demand charge, of course, provides a strong economic incentive for customers to avoid peak demands and to levelize their load. For any particular demand charge, the cost per kWh for a customer with a 25% load factor is three times higher than it is for a customer with a 75% load factor.[40]

However, as I explained earlier, the mismatch between billing demand and ECOSS demand often causes utilities to recover demand-related costs using a combination of the demand charge, based on individual customer peak demands, and an energy charge. In the alternative, the utility may use the load-factor ("Wright") tariff that implicitly incorporates both customer peak demand and energy usage factors. The idea of including an energy component in the tariff is an attempt to recognize that the customer's peak demand may not coincide with the more diversified system demands that cause costs to be incurred (and allocated to the class in the ECOSS). Some utilities have gone to a 100 percent demand charge approach for small and medium C&I customers, as shown in Table IEc-8 above.

Q. Please address the Company's blocked demand charges.

A. The Company has two demand charge blocks. The first 5 kW of billing demand are currently charged a minimal rate of $0.95 per kW, which would amount to only about 0.3 cents per kWh for a 40 percent load factor customer. Billing demand over 5 kW is charged $3.69 per kW, or about 1.3 cents per kWh for a 40 percent load factor customer. As I indicated earlier, the demand charge recovers only a relatively small share of SC-2 costs, about 14 percent.

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[40] Load factor refers to the ratio of average demand to peak demand. A customer who consumes 1500 kWh in a 30-day month has an average demand of 2.08 kW (1500/30/24). If that customer has a peak billing demand in that month of 8 kW, the load factor is 26%. If the customer could simply shift load around (or use battery storage) to reduce the peak load to 4 kW, the load factor would be 52%, and the cost per kWh related to the demand charge would be cut in half.

At this writing, it is not clear why the Company the Company has a low demand charge for the first 5 kW, since it is not recovering those costs in the customer charge. The Company may be trying to keep per-kWh rates down for the smallest customers, although there is no cost basis for doing so.

Also, it is not clear why the Company recovers such a small portion of its distribution costs with the demand charge, particularly in light of the relatively flat structure of the load factor tariff block charges, as discussed below.

Q. Please address the Company's load factor block energy charges.

A. The Company has three load factor blocks split at up to 100 kWh/kW (a 14 percent load factor), 100 to 200 kWh/kW (14 percent to 29 percent load factor) and over 200 kWh/kW. Since the per-kWh charge declines at higher kWh per kW levels, higher load factor customers pay an average per-kWh charge than lower load factor customers. In that way, the Wright tariff is conceptually similar to a tariff with both demand and energy charges, but it tends to have less extreme impacts for customers with very low load factors. Moreover, the relative impact of peak demand average unit rates is dependent on how steep the decline is for the energy charges. Steeper steps down in energy charges implicitly increase the importance of peak demand in the tariff.

PCL&P's current (and proposed) SC2-S tariff charges are relatively flat, which implies that the tariff is more tilted toward an energy charge than toward a demand charge. In the Company's tariff, a 90 percent load factor customer would pay only about 16 percent less per kWh than a 10 percent load factor customer. By way of contrast, under a demand charge approach, the 90 percent load factor customer would pay 89 percent per kWh less than the 10 percent load factor customer.[41] As also shown in RDK WP3, the approximate implicit demand charge in the Company's tariff is only about $0.76 per kW at current rates and $1.12 per kW at proposed rates. Thus, the Company's load factor tariff is primarily a per-kWh energy charge.

[41] Supporting calculations are shown in RDK WP1, "SC2 RD" page.

Overall, the Company's SC-2 base rate tariff recovers more than 70 percent of distribution costs with an energy charge, despite the fact that energy-related costs represent only a small fraction of distribution base rates costs. Therefore, I conclude that the Company should be moving to increase the relative importance of peak demands in its tariff design for this class.

Q. How should the Company go about increasing the importance of demand in the SC2-S tariff charges?

A. If the Company desires to retain both demand and Wright tariff charges, I recommend that (a) the spread between the first block and tail block demand charges be gradually reduced, since demand costs are not lower per kW for small customers than larger customers, and (b) the spread between Wright energy tariff rates should be gradually increased, to reflect the fact that the costs being recovered are primarily related to peak demands.

If the Company desires to move to a simpler tariff structure for SC2-S like other Pennsylvania EDCs, I recommend that (a) an above average increase be applied to the demand charge, (b) reduce the relative importance of the load-factor energy block charges, and (c) phase out the block differentials for both.

I developed illustrative examples for both scenarios, that produce the identical SC2-S class revenues to the Company's proposal. The details are provided in RDK WP3 "PoR FTY" sheet and summarized in Table IEc-9 below. A bill impact review analysis is also presented in RDK WP3, in the "SC2 RD" worksheets.

Table IEc-9 Alternative Proposed Rate Designs: Rate SC2-S				
	Current	**PCL&P**	**RDK 1**	**RDK 2**
Customer Charge ($/mo.)	$13.60	$18.73	$18.73	$18.73
First 100 kWh/kW (cents/kWh)	5.7964	8.5328	9.8604	6.6660
Next 100 kWh/kW (cents/kWh)	4.7998	7.0657	7.1997	6.3837
Over 200 kWh/kW (cents/kWh)	4.7100	6.9335	6.1230	6.2643
Demand First 5 kW ($/kW)	$0.95	$1.31	$1.50	$5.00
Demand Over 5 kW ($/kW)	$3.69	$5.09	$4.50	$8.00
FTY Class Average (cents/kWh)	**6.5097**	**9.4518**	**9.4518**	**9.4517**
Source: RDK WP3 "PoR FTY" worksheet.				

Q. Please evaluate the Company's SC2-S charge for non-demand-metered customers.

A. SC2-S customers without demand meters currently pay the regular customer charge plus a flat per-kWh energy charge. That charge is currently set at 6.9431 cents per kWh, which is moderately higher than the average paid by demand-metered customers (6.01 cents per kWh), but it is lower than the rates paid by small low-load-factor SC2-S customers. The Company proposes to impose a 47.2 percent increase to that charge, equal to the proposed increases for the load factor energy charges.

This tariff applied to 109 customers in June 2020, with average load of 213 kWh per month, well below the load for a typical residential customer, with a pronounced winter-peaking pattern. These are very small customers, and it is likely that demand-metering is not cost-effective. The non-demand-metered rate is lower than the regular rate only for larger customers (say 30 kW demand) with load factors below 25 to 30 percent, and smaller customers with load factors below 20 percent.

I therefore conclude that the Company's proposal to apply a modestly above-average increase to these customers is not unreasonable.

Q. Please evaluate the Company's special space heating charge rate.

A. For electric space heating, the Company offers a special rate for SC2-S customers with at least 10 kW of electric space heating equipment. The charge also applies to air conditioning load where the equipment provides both heating and cooling. The tariff is not clear as to whether this load is separately metered, although the proof of revenue analysis indicates that it is.[42]

As of June 2020, there were 11 customers served on this rate, with 436 MWh of load, or about 3300 kWh per customer per month.[43] The current base distribution rate is 4.8913 cents per kWh, and the Company proposes to apply the 47.2 percent increase it proposes for all SC2-S energy charges. At both current and proposed rates, the space heating charge is lower for any customer than the regular tariff rates, including 100 percent load factor customers. Moreover, it is unclear whether a separate customer charge applies to this load to recover the cost of the extra meter, meter reading, billing and administration, or whether these costs are embedded in the energy charge.

To my knowledge, the Company does not explain why this special rate exists, or why it should be retained. I confess that I did not request an explanation. Thus, my recommendation is tentative, pending an explanation from the Company.

My hypothesis is that this special rate is an anachronism from the era of bundled rates, based on an effort to try to attract new loads that more than recover the incremental cost. As such, it should be phased out.

I recommend that the increase to this charge be set at 1.5 times the average increase for the SC2-S class, to begin phasing out this option. I included this proposal in my alternative rate design recommendations.

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[42] Exhibit E-8, page 13 of 30.

[43] See OSBA-I-12(b). .

Q. Does this conclude your direct testimony?
A. Yes, it does.

EXHIBIT IEc-1

RÉSUMÉ AND EXPERT TESTIMONY LIST

FOR

ROBERT D. KNECHT

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.

IEc

INDUSTRIAL ECONOMICS, INCORPORATED

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.

May 2017

EXHIBIT IEc-2

REFERENCED INTERROGATORY RESPONSES

I&E-RS-2-D

OSBA-I-1

OSBA-I-4

OSBA-I-9

OSBA-I-12

OSBA-I-14

OSBA-I-16

OSBA-I-17

OSBA-I-18

OSBA-I-20

OSBA-I-22

OSBA-I-24

OSBA-I-26

OSBA-I-27

OSBA-I-29

OSBA-I-33

OSBA-I-6 at Docket No. R-2008-2046518

Associated attachments to the above-referenced interrogatory responses are available on Pike County Light and Power Company's (Electric) Citrix website. If you encounter any difficulty accessing them, please contact the OSBA @ swebb@pa.gov

**PIKE COUNTY LIGHT & POWER COMPANY (ELECTRIC)
RESPONSES TO BUREAU OF INVESTIGATION AND ENFORCEMENT'S
DATA REQUESTS, SET RS-1-D TO RS-8-D**

I&E-RS-2-D Provide a working excel copy of Pike County Power and Light (Electric) Exhibits E-6, E-7, and E-8 showing the cost of service studies, the proof of revenue and the bill comparisons.

RESPONSE: A working copy of Exhibits E-6 and E-7 are provided in the attached file "Pike ECOS 10-07-20.xlsm". A working copy of Exhibit E-8 is provided in the attached files "Pike Electric Rate Design 10-07-20.xlsx" and "Pike Electric Bill Comparison 10-07-20.xls".

PROVIDED BY: Paul Normand, Debbie Gajewski (Cost of Service / Rate Panel)

DATE: November 24, 2020

The column labeled Dollar Days was calculated by multiplying Billed Revenues by the Average Lag Days for each rate class. The 16.7 overall day lag was calculated by dividing the total Dollar Days of $11,704,019.25 by the total amount billed of $6,609,534.09.

b. The SC2 average lag of 18.03 days shown on the lead lag study is for **SC2 gas commercial customers**. It is not the average for electric SC2 – Primary and SC2 – Secondary Customers. The average lag for electric SC2 – Primary and SC2 – Secondary Customers would be 17.09 days. Please note, all residential customers whether they are gas customers or electric are classified as SC1. The SC1 data used in the lead lag study did not differentiate between electric and gas customers, since all SC1 gas customers are also SC1 electric customers. SC3 – Municipal Street Lighting and SC4 – Lighting classes are electric only.

c. Currently 77% (3,974 / 5,186) of the Company's meters are read remotely. Please refer to the Company's response to question 21 for the breakdown by revenue class of the AMR meters. All residential and commercial customers are scheduled to have their meters read on monthly billing cycle.
Assuming a customer's consumption is uniform throughout a billing cycle, their usage for the first day of the cycle would be outstanding for approximately 30 days before the meter is read and their usage for the last day of the month would be outstanding for 1 day before the meter is read. On average a customer's usage would be outstanding for half the month before the meter is read. The 15.2 days was calculated by dividing 365 days by 12 months and dividing the resulting average number of 30.4 days in a month (i.e., 365/12) by 2 to calculate the average number of days that a customer's consumption is outstanding before the meter is read in a given month. The average billing lag of 1.9 days takes into account the time it takes after all meter readings are transmitted to the customer billing system to calculate the customer invoices, print, and then mail them.

d. The lead / lag study accounted for all billed revenues and expenses recorded in the revenue requirement under the Company's existing rate structure. The Company's base rates have not been unbundled to move the working capital requirement associated electric supply to the default service charge. The Company has no objection to moving the Working Capital requirement associated with electric supply to the default service charge, but would note that in the Company's lead / lag working capital calculation the revenue requirement associated with electric supply is relatively small (i.e., approximately $2,400).

PROVIDED BY: Charles A. Lenns, Richard A. Kane (Accounting Panel)

DATE: December 1, 2020

PENNSYLVANIA PUBLIC UTILITY COMMISSION v. PIKE COUNTY LIGHT AND POWER COMPANY (ELECTRIC); DOCKET NO. R-2020-3022135

PIKE COUNTY LIGHT AND POWER COMPANY'S RESPONSES TO OFFICE OF SMALL BUSINESS ADVOCATE, SET I

4. Reference Accounting Panel Testimony (Statement No. 2) at 33:

   a. Please provide late payment charge ("LPC") revenues and the LPC factor by rate class for each of the past three years.

RESPONSE: The table below shows the Late Payment Charge ("LPC") Revenues and average LPC factors for the last three years for electric and gas recorded on the Company's books and records for the Twelve Months Ended June 30th.

Fiscal Year	LPC Revenues	Electric Billed Revenues	LPC Rate
July 2017 - June 2018	$ 9,125	$ 8,072,225	0.11%
July 2018 - June 2019	9,887	8,536,672	0.12%
July 2019 - June 2020	7,530	6,609,534	0.11%
Electric Total	$ 17,418	$ 15,146,206	0.11%

Fiscal Year	LPC Revenues	Gas Billed Revenues	LPC Rate
July 2017 - June 2018	$ 872	$ 1,545,811	0.06%
July 2018 - June 2019	2,969	1,788,959	0.17%
July 2019 - June 2020	2,498	1,448,169	0.17%
Gas Total	$ 6,339	$ 4,782,938	0.13%

The attachment entitled "Pike LPC by Rate Code Oct17 to Sept20.xlsx" shows the LPC revenues for the most recent three years. Please note that the data in this report is reflects adjustments that have been made to customer records (e.g., cancellations and rebills). As a result, the monthly activity on the report may vary from amounts recorded in a given month on the Company's General Ledger.

PROVIDED BY: Charles A. Lenns, Richard A. Kane (Accounting Panel)

DATE: December 1, 2020

PENNSYLVANIA PUBLIC UTILITY COMMISSION v. PIKE COUNTY LIGHT AND POWER COMPANY (ELECTRIC); DOCKET NO. R-2020-3022135

PIKE COUNTY LIGHT AND POWER COMPANY'S RESPONSES TO OFFICE OF SMALL BUSINESS ADVOCATE, SET I

9. Reference Exhibit E-4, Schedule 3:

   a. Please describe the specific types of costs included in the Other Power Supply Expense category, and the approximate magnitude for each.

   b. Please explain why Other Power Supply Costs do not appear to be recovered in the default service charge.

RESPONSE:

a. The Other Power Supply Expense category reflects the carrying cost for Orange and Rockland Utilities' ("ORU") transmission facilities that are used to deliver energy from the ISO to Pike. Pike does not have any direct ties to either the PJM or NYISO systems.

b. Pike's last base rate case was settled in 2014, when it was still owned and operated by Orange and Rockland Utilities, Inc. (ORU). ORU had a FERC tariff in place (i.e., "Power Supply Agreement") that allowed it to bill Pike for its prorated share of carrying costs of O&R's internal transmission system. The base rates that were established in Docket No. 2013-2397237 did not unbundle ORU's Other Power Supply Expenses.

   This is the first base rate case Pike has filed since it was acquired from ORU. The Company has no objection and agrees that it is appropriate to unbundle the Other Power Supply Transmission expenses and include them in the default service charge as long as retail access providers also pay their proportionate share of this expense. The Company calculated that the revenue requirement associated with Other Power Supply expense of $672,200 shown in Exhibit E-4, Summary is approximately $727,300. The revenue requirement is made up of the Other Power Supply Expense of $672,200 plus the associated Gross Receipt Tax of approximately $42,900, Uncollectible expense of $11,100 and the working capital requirement of $1,100.

   If the PaPUC unbundles Other Power Supply expenses, then it would also be appropriate to unbundle uncollectible expense associated with energy supply. To the extent the uncollectibles are not unbundled, it will be necessary to recalculate the Company's uncollectible factor to account for items removed from base rates.

PROVIDED BY: Charles A. Lenns, Richard A. Kane (Accounting Panel)

DATE: December 1, 2020

PENNSYLVANIA PUBLIC UTILITY COMMISSION v. PIKE COUNTY LIGHT AND POWER COMPANY (ELECTRIC); DOCKET NO. R-2020-3022135

PIKE COUNTY LIGHT AND POWER COMPANY'S RESPONSES TO OFFICE OF SMALL BUSINESS ADVOCATE, SET I

12. Reference Exhibit E-5 Schedule 6 and Exhibit E-8 page 1:

a. Please reconcile the FTY market energy revenues in E-5 S6 (columns 7 and 8) with the future electric supply revenues in E8 page 1.

b. Please provide kWh energy usage for the HTY (ending June 30, 2020) and FTY (ending June 30, 2021) by rate class as defined in the class cost of service study, split between POLR and ESCO supplies.

RESPONSE:

a. The future test year energy revenues shown on Exhibit E-5, Schedule 6 (columns 7 and 8) include Pennsylvania Gross Receipts Taxes of 5.9%. The future test year energy revenues shown on Exhibit E8 page 1 do not included the Gross Receipts Tax. Below is the reconciliation.

	Market Supplly	Adjustment Charge	Total
Exhibit E-5, Sched 6	$2,829,000	$ (853,600)	$1,975,400
Less GRT (5.9%)			116,549
Energy Rev. (excl. GRT)			1,858,851
Exhibit E-8, Sched 1			1,858,851
Variation			$ -

b. Please see attachment "OSBA Data Request 12b.xlsx". The schedules show the historic and forecast sales and revenues by rate class as defined in the class cost of service study, split between POLR and ESCO supplies. Please note that for the Future Test Year all energy revenues (POLR and ESCO supplies) were forecast at the Company's current default service rates.

PROVIDED BY: Charles A. Lenns, Richard A. Kane (Accounting Panel)

DATE: December 1, 2020

PENNSYLVANIA PUBLIC UTILITY COMMISSION v. PIKE COUNTY LIGHT AND POWER COMPANY (ELECTRIC); DOCKET NO. R-2020-3022135

PIKE COUNTY LIGHT AND POWER COMPANY'S RESPONSES TO OFFICE OF SMALL BUSINESS ADVOCATE, SET I

14. Reference Exhibit E-6, Schedule ERP-6-E page 2 and Schedule ERP-4-E page 14:

    a. Please explain why the secondary voltage demand allocators (DDISTPOL and DDISTPUL as defined in Schedule ERP-6-E) are numerically the same as the primary voltage demand allocator (DDISPHT) in Schedule ERP-4-E.

RESPONSE:

a. The secondary voltage demand allocators for accounts 364-367 should be the same as the Secondary Demand allocator used in account 368.

PROVIDED BY: Paul Normand, Debbie Gajewski (Cost of Service / Rate Panel)

DATE: December 1, 2020

PENNSYLVANIA PUBLIC UTILITY COMMISSION v. PIKE COUNTY LIGHT AND POWER COMPANY (ELECTRIC); DOCKET NO. R-2020-3022135

PIKE COUNTY LIGHT AND POWER COMPANY'S RESPONSES TO OFFICE OF SMALL BUSINESS ADVOCATE, SET I

16. Reference Exhibit E-6, Schedule ERP-4-E, page 3, Accounts 364 and 365; Electric Rate Panel Testimony at page 13:

  a. Please describe how costs were sub-functionalized between primary and secondary voltage levels for these accounts and provide supporting workpapers as necessary.

  b. Please explain why primary costs are not classified into demand and customer components.

  c. Please provide the Company's minimum size analysis for the secondary plant costs for these accounts. Please include an explanation for any deviation from the methodology specified in the 1992 NARUC Electric Utility Cost Allocation Manual.

  d. To the extent available, please provide the Company minimum size analysis for the primary plant costs in these accounts.

RESPONSE:

  a. The costs for Accounts 364 and 365 were sub-functionalized consistent with the last filing in which Primary HT was considered to be primary demand and the secondary portion was classified as customer and demand based on a minimum system analysis. See page 10 and 11 of the Direct Testimony of the Rate Panel.

  b. Primary costs were classified as demand consistent with the last filing.

  c. The Company's minimum size analysis for the primary and secondary plant is provided in the attached file, "2013 Pike Electric Minimum System Calculations for 365 & 367.xlsx".

  d. See response OSBA No. 16 c. The minimum size methodology specified in the NARUC Electric Utility Cost Allocation Manual classifies primary as demand and customer. The 2020 cost of service study classified primary as demand consistent with the 2013 filed cost of service study.

PROVIDED BY: Paul Normand, Debbie Gajewski (Cost of Service / Rate Panel)

DATE: December 1, 2020

PENNSYLVANIA PUBLIC UTILITY COMMISSION v. PIKE COUNTY LIGHT AND POWER COMPANY (ELECTRIC); DOCKET NO. R-2020-3022135

PIKE COUNTY LIGHT AND POWER COMPANY'S RESPONSES TO OFFICE OF SMALL BUSINESS ADVOCATE, SET I

17. Reference Exhibit E-6, Schedule ERP-4-E, page 3, Accounts 366, 367 and 368; Electric Rate Panel Testimony at page 13:

    a. Please provide the workpapers for the sub-functionalization of costs between primary and secondary voltage for Accounts 366 and 367.

    b. Please provide the Company's minimum size analysis for the secondary plant costs in these accounts. Please include an explanation for any deviation from the methodology specified in the NARUC Electric Utility Cost Allocation Manual.

RESPONSE:

a. The costs for Accounts 366 and 367 were sub-functionalized consistent with the last filing in which Primary HT was considered to be primary demand and the secondary portion was classified as customer and demand based on a minimum system analysis. See page 10 and 11 of the Direct Testimony of the Rate Panel.

b. See response OSBA No. 16 c.

PROVIDED BY: Paul Normand, Debbie Gajewski (Cost of Service / Rate Panel)

DATE: December 1, 2020

18. Reference Exhibit E-6, Schedule ERP-4-E, page 14, demand allocators:

    a. Please describe how the primary, secondary and transformer level demand allocators were developed.

    b. Please provide supporting workpapers for the development of the demand allocators, including but not limited to load research or load profiles relied upon, in executable electronic format.

    c. Please identify dates, times and peak demands for the system coincident peak and each rate class non-coincident peak.

    d. Please explain why the transformer level demand for the residential classes is substantially higher than the primary demand for those classes.

    e. Please provide the Company's assessment of the sum of individual customer peaks for each rate class, if available.

RESPONSE:

a. Pike County electric does not maintain current load data by customer class. The primary, secondary and transformer level demand allocators were developed using the load data from the prior 2013 cost of service study. The demands per customers for each class were computed for the test period based on the prior study load data and then adjusted for the change in sales per customer. See the attached worksheet "Electric Demands 6-30-20.xlsx."

b. See the file provided in the response above for the test period demand allocators and the attached worksheet "2013 Pike Electric Selected Allocation Factors.xlsx" for the load research data.

c. The system coincident peak demands from the 2013 study were based on the highest five day, four hour averages for the summer period. The 2013 non-coincident peaks were based on the class non-coincident maximum high tension class demand at generating stations. The dates and times of the system coincident peaks and each rate class non-coincident peaks are in the attached file "Pike_2013_System_Class_Peak _Times.xlsx".

d. The primary customers are served at the primary voltage level and were not allocated secondary line transformers. The residential customers are served at the secondary voltage level and are allocated secondary line transformers.

e. The sum of individual customer peaks was developed in the same manner as the primary, secondary and transformer level demand allocators as described in a.

above. This allocator was classified as customer related and used to allocate Services to the Residential and Small Commercial secondary customer classes.

PROVIDED BY: Paul Normand, Debbie Gajewski (Cost of Service / Rate Panel)

DATE: December 1, 2020

20. Reference Exhibit E-6 Schedules ERP-4-E page 15 and ERP-6-E page 3:

    a. Please explain how the CUSTMTR allocator is derived and provide supporting workpapers.

    b. Please explain the reasons for the substantial increase in the relative cost of meters for the SC2-S class relative to the Company's 2013 cost allocation study, as it appears that class' share of meters costs increases from approximately 42 percent of meters plant in 2013 to 61 percent of meters plant in the current filing.

RESPONSE:

a. The CUSTMTR allocator was developed by calculating the estimated current typical meter cost for each customer class. This included meter cost, installation costs and overhead costs. The total current cost per meter for each class was then multiplied by the number of meters in each rate class and then used to allocate the book cost (allocator CUSTMTR). See the attached worksheet "Copy of #10 Meter Services Installation Costs 6-30-2020 for Pike–updated.xlsx" in the "Pike Electric" tab.

b. The major reason for the increase in the allocation of meter costs to the SC-2 secondary rate class is that in the 2013 study, total installation costs were allocated to the rate classes based on the allocated meter cost. In the current study, the installation costs were estimated for each rate class and not allocated. See the attached worksheet "PIKE 2013 Electric ECOS Study for Distribution.xls" "AFC" tab, starting on line 181, column 7 which shows the allocation of installation costs in the 2013 study.

PROVIDED BY: Paul Normand, Debbie Gajewski (Cost of Service / Rate Panel)

DATE: December 1, 2020

PENNSYLVANIA PUBLIC UTILITY COMMISSION v. PIKE COUNTY LIGHT AND POWER COMPANY (ELECTRIC); DOCKET NO. R-2020-3022135

PIKE COUNTY LIGHT AND POWER COMPANY'S RESPONSES TO OFFICE OF SMALL BUSINESS ADVOCATE, SET I

22. Reference Exhibit E-6 ERP-4-E page 15 and ERP-6-E page 3:

a. Please explain how the CUSTSERV allocator is derived and provide supporting workpapers.

b. Please identify the specific number of service lines for each rate class.

c. Please explain generally why the services cost per kWh is higher for SC-2 customers than for residential

d. Please explain why the services allocator for SC2-P is zero, as compared to the non-zero value used in the Company's 2013 class cost of service study.

RESPONSE:

a. This allocator was based on the prior 2013 study and is the sum of the non-coincident maximum demands. The workpaper supporting this calculation, "Electric Demands 6-30-20.xlsx," is provided in Response 18, part a.

b. Pike County does not maintain data for the number of services by rate class.

c. The load factors for the SC-2 secondary customer class are lower than the residential, and this would account for the higher allocation of service costs to the SC-2 customers.

d. Pike County does not install services for primary customers, and therefore, no service cost was allocated to this customer class.

PROVIDED BY: Paul Normand, Debbie Gajewski (Cost of Service / Rate Panel)

DATE: December 1, 2020

PENNSYLVANIA PUBLIC UTILITY COMMISSION v. PIKE COUNTY LIGHT AND POWER COMPANY (ELECTRIC); DOCKET NO. R-2020-3022135

PIKE COUNTY LIGHT AND POWER COMPANY'S RESPONSES TO OFFICE OF SMALL BUSINESS ADVOCATE, SET I

24. Reference Exhibit E-6, Schedule ERP-4-E page 4, general plant:

a. Please detail the specific land and land rights assets (Account 389) included in the general plant account and identify the functional purpose for each.

b. Please detail the specific structures and improvements plant (Account 390) included in the general plant account and identify the functional purpose for each.

RESPONSE:

a. The Company does not have any land or land rights recorded in Account 389. Lines 3 through 11 of Exhibit E-6, Schedule ERP-4E, page 4, general plant had the plant balances on the wrong lines. This correction does not impact the cost study results since all accounts were allocated on the same allocator. Each plant balance should have been reflected on the line below. Please see the table below for the revised amounts:

Line			Allocation	Total Electric Company (Column C)		
No.		Description	Factor	As Filed	Corrected	Change
3	389-	Land and Land Rights	Labor	$ 2,001,978	$ -	$ (2,001,978)
4	390-	Structures & Improvements 100%	Labor	1,016,335	2,001,978	985,643
5	391-	Office Furniture & Equipment 85%	Labor	182,254	1,016,335	834,081
6	392-	Transportation 85%	Labor	-	182,254	182,254
7	393-	Store Equipment	Labor	84,376	-	(84,376)
8	394-	Tools, Shop & Garage Equip 100%	Labor	-	84,376	84,376
9	395-	Laboratory Equipment	Labor	122,927	-	(122,927)
10	397-	Communications Equipment 85%	Labor	77,724	122,927	45,203
11	398-	Miscellaneous Equipment 85%	Labor	-	77,724	77,724
12		Total		$ 3,485,594	$ 3,485,594	$ -

b. The Company's Operating Center is recorded in FERC Account 390 - Structures and Improvement and makes up the entire $2 million balance. Pike employees work out of this facility and the building includes the Material & Supplies Storeroom. Computer equipment and software accounts for approximately $837,750 of the $1 million balance in account 391 – Office Furniture and Equipment.

PROVIDED BY: Part a. - Paul Normand, Debbie Gajewski (Cost of Service / Rate Panel)
Part b. - Charles A. Lenns, Richard A. Kane (Accounting Panel)

DATE: December 1, 2020

PENNSYLVANIA PUBLIC UTILITY COMMISSION v. PIKE COUNTY LIGHT AND POWER COMPANY (ELECTRIC); DOCKET NO. R-2020-3022135

PIKE COUNTY LIGHT AND POWER COMPANY'S RESPONSES TO OFFICE OF SMALL BUSINESS ADVOCATE, SET I

26. Reference Exhibit E-6, Schedule ERP-4-E, page 7, O&M costs:

a. Please indicate where O&M costs related to each of the following distribution plant are reflected in the reported O&M costs: substation, line transformers, meters, service lines, street lighting.

RESPONSE:

a. The Company did not charge any O&M costs to FERC Accounts 592 – Station Equipment, 595 - Transformers, 596 – Street Lights, or 597 - Meters during the historic Test Period ended June 30, 2020. All electric distribution maintenance costs were charged to FERC Account 593 – Overhead Lines, 594 – Underground Lines, and 598 – Miscellaneous Maintenance Expense.

As a result, the O&M costs associated with substations, line transformers, meters, service lines, and street lighting would be in Accounts 593- Maintenance Overhead Lines, 594 – Maintenance Underground Lines and 598 – Miscellaneous Maintenance Expense.

PROVIDED BY: Charles Lenns, Richard A. Kane (Accounting Panel)

DATE: December 1, 2020

PENNSYLVANIA PUBLIC UTILITY COMMISSION v. PIKE COUNTY LIGHT AND POWER COMPANY (ELECTRIC); DOCKET NO. R-2020-3022135

PIKE COUNTY LIGHT AND POWER COMPANY'S RESPONSES TO OFFICE OF SMALL BUSINESS ADVOCATE, SET I

27. Reference Exhibit E-6, Schedule ERP-4-E, page 8, A&G costs:

a. Please provide a quantitative breakdown of administrative salaries costs (Account 920) by employee function (e.g., executive, legal, accounting, etc.)

b. Please identify the specific types and relative magnitudes of costs included in Account 921.

c. Please detail the specific outside services included in Account 923, and the cost magnitude for each.

RESPONSE:

a. Please refer to the first tab in the attachment entitled "OSBA Data Request 27.xlsx" for the breakdown by function of salaries and wages.

b. Please refer to the second tab in the attachment entitled "OSBA Data Request 27.xlsx" for the breakdown of costs included in this account.

c. Please refer to the third tab in the attachment entitled "OSBA Data Request 27.xlsx" for the breakdown of costs included in this account.

PROVIDED BY: Charles Lenns, Richard A. Kane (Accounting Panel)

DATE: December 1, 2020

PENNSYLVANIA PUBLIC UTILITY COMMISSION v. PIKE COUNTY LIGHT AND POWER COMPANY (ELECTRIC); DOCKET NO. R-2020-3022135

PIKE COUNTY LIGHT AND POWER COMPANY'S RESPONSES TO OFFICE OF SMALL BUSINESS ADVOCATE, SET I

29. Reference Exhibit E-7:

a. Please provide an executable electronic version of Exhibit E-7, preferably in MS Excel electronic format.

b. Please provide copies of all workpapers supporting Exhibit E-7 in executable electronic format.

c. To the extent available, please provide a full class cost of service study for the FTY, in executable electronic format. To the extent it is not available, please explain why a FTY cost allocation study was not prepared.

d. Please explain how changes in customer count, energy consumption and peak demands between the HTY and FTY are reflected in Exhibit E-7.

e. Please explain why the change in state and federal income tax are allocated using a revenue allocation factor.

RESPONSE:

a. Exhibit E-7, FTY, can be found within the HTY cost of service study provided in response to OSBA No. 13. Page 2 of the HTY cost of service study shows the future test year 12 months ended June 30, 2020.

b. Workpapers supporting Exhibit E-7 are provided in response to OSBA No. 13.

c. A full class cost of service study for the FTY was not prepared since the detail to perform the study was not available.

d. Changes in customer count, energy consumption and peak demands are not reflected in Exhibit E-7.

e. A state and federal income tax calculation by rate class was not available since a full class cost of service study for the FTY was not prepared. A claimed revenue allocation factor was used to allocate the change in state and federal income taxes. The use of the claimed revenue allocator enables each class to contribute revenue for the change in income taxes in proportion to the revenues in each class at the claimed rate of return which should closely track the actual cost responsibility from a cost of service study.

PROVIDED BY: Paul Normand, Debbie Gajewski (Cost of Service / Rate Panel)

DATE: December 1, 2020

PENNSYLVANIA PUBLIC UTILITY COMMISSION v. PIKE COUNTY LIGHT AND POWER COMPANY (ELECTRIC); DOCKET NO. R-2020-3022135

PIKE COUNTY LIGHT AND POWER COMPANY'S RESPONSES TO OFFICE OF SMALL BUSINESS ADVOCATE, SET I

33. Reference "Attachment Section IV A. 1 & 2 - MAC Sales and Revenue by Charge with Rate Table" and Exhibit E-8 Rev:

    a. Please provide versions of these tables in executable electronic format, preferably MS Excel.

RESPONSE:

a. The following MS Excel files are being provided in response to the above request:
   1. "MAC Sales and Revenue by Charge with Rate Table"
   2. "Pike Electric Rate Design 10-07-20.xlsx" – Rate Design portion of Exhibit E-8 Rev.
   3. "Pike Bill Comparison 10-28-20.xls" – Bill Comparison portion of Exhibit E-8 Rev.

PROVIDED BY: Paul Normand, Debbie Gajewski (Cost of Service / Rate Panel)

DATE: December 1, 2020

Company Name: PCL&PC
Case Description: PCL&PC Electric Base Rate Case
Case: R-2008-2046518-Elec

Response to OSBA Interrogatories – Set OSBA1
Responding Witness: Accounting Panel

Question No.: 6
Reference Accounting Panel evidence, page 18, lines 6 to 8.

a. Please provide the lag in bill payments for each "revenue class of billing," and the weighted average calculation supporting the 26.9 day overall lag.

RESPONSE:

a. Please refer to the attached for the computation of the lag in bill payments for each "revenue class of billing," and the weighted average calculation supporting the 26.9 day overall lag.

PIKE COUNTY LIGHT & POWER
CALCULATION OF LAG DAYS ON REVENUE RECOVERY
LAG TIME FROM SERVICE TO COLLECTION
FOR 12 MONTHS ENDING 12/31/07

		AMOUNT	LAG DAYS	DOLLAR DAYS
Service Period To Billing:				
Service Period to Meter Reading Date				
Billed Monthly Revenue	(365/12)/2	$ 4,125,439.14 *	15.2	$ 62,741,053.59
Meter Reading to Date of Billing			1.5 (1)	
Total Service Period to Billing Lag			16.7	
Billing to Collection Date:				
Sales of Electricity -				
Residential		1,767,020.90 *	33.3 (2)	58,871,436.78
Commercial		2,316,340.31 *	22.1 (2)	51,139,114.63
Municipal		43,077.93 *	22.9 (2)	987,871.66
		4,125,439.14		110,998,423.07
Total Billing to Collection Lag			26.9	
Total Service to Collection Lag			43.6 DAYS	

*** COMPLETE REPORT SCHEDULE 6B-2 PAGE 2 OF 2**
SEE SCHEDULES 1 & 2

SCHEDULE 2

PIKE COUNTY LIGHT & POWER
AVERAGE LAG DAYS
FROM BILLING TO COLLECTION DATE
12 MONTHS ENDING DECEMBER 31, 2007

Jan-07

Company	Type	[illegible]	[illegible] Billed	Jan 07 Avg Days
Overall	[illegible]	[illegible]	[illegible]	[illegible]
Pike County	Commercial	941	673,537	21.8
Pike County	Company Use	2	0	1.0
Pike County	Municipal	5	5,165	33.8
Pike County	Residential	3,653	593,615	32.5
		4,601		

Apr-07

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Pike County	Commercial	946	666,780	23.0
Pike County	Company Use	2	0	1.0
Pike County	Municipal	5	4,699	20.6
Pike County	Residential	3,639	582,923	36.1
		4,592		

Jul-07

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Pike County	Commercial	944	727,517	21.6
Pike County	Company Use	2	0	1.0
Pike County	Municipal	5	4,524	18.5
Pike County	Residential	3,656	509,354	31.5
		4,607		

Oct-07

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Pike County	Commercial	1,311	905,026	21.9
Pike County	Company Use	2	0	1.0
Pike County	Municipal	5	4,929	18.8
Pike County	Residential	5,084	657,183	33.2
		6,402		

		TOTAL	AVERAGE
Average lag Days	RESIDENTIAL	133.3	33.3
	COMMERCIAL	88.35	22.1
	MUNICIPAL	91.73	22.9

Source:
Supplied by the CIMS Depatment
A sample of 4 months from the year (January, April, July & October)

EXHIBIT IEc-3

RDK ELECTRONIC WORKPAPERS

RDK WP1: Replication of PCL&P ECOSS

RDK WP2: PCL&P ECOSS Corrected for Acknowledged Errors

RDK WP3: RDK ECOSS

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

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**Docket No. R-2020-3022135**
	:	
PIKE COUNTY LIGHT & POWER COMPANY (Electric Division)	:	
	:	

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 through 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: February 2, 2021

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2020-3022135**
	:	
PIKE COUNTY LIGHT AND POWER COMPANY (ELECTRIC)	:	

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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The Honorable Mary D. Long
Pennsylvania Public Utility Commission
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Harrisburg, PA 17120
malong@pa.gov

DATE: February 2, 2021

/s/ Sharon E. Webb

Sharon E. Webb
Assistant Small Business Advocate
Attorney ID No. 73995

OSBA STATEMENT NO. 1-R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2020-3022135**
PIKE COUNTY LIGHT & POWER COMPANY (Electric Division)	:	

Rebuttal Testimony of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation

Date Served: February 22, 2021

Date Submitted for the Record: March 15, 2021

REBUTTAL TESTIMONY OF ROBERT D. KNECHT

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

A. My name is Robert D. Knecht. I submitted direct testimony and associated exhibits earlier in this proceeding and my qualifications were detailed therein.

Q. Please describe the purpose of this testimony.

A. OSBA requested that I evaluate the direct testimony submitted by Karl Richard Pavlovic, PhD., on behalf of the Pennsylvania Office of Consumer Advocate, and Witness Esyan A. Sakaya, representing the Commission's Bureau of Investigation and Enforcement ("I&E") on matters relating to cost allocation and revenue allocation.

Acronyms and initialisms defined in my direct testimony are used in this rebuttal with the same meaning.

Q. Please summarize the positions of the I&E and OCA witnesses regarding cost allocation and revenue allocation.

A. Witness Sakaya relies on the Company's ECOSS model that was submitted in response to I&E-RS-11-D, rather than the Company's filed ECOSS. Witness Sakaya indicates that this ECOSS ". . . reflects data for the FTY ending June 30, 2021." Based on this ECOSS, Witness Sakaya offers no changes to the Company's proposed revenue allocation at the full increase but offers a scaleback mechanism to retain progress toward cost-based rates in the event the Commission reduces the Company's proposed revenue requirement.

Dr. Pavlovic opines that the Company's ECOSS should be modified such that (a) all joint-use distribution plant is classified as 100 percent demand related, replacing the Company's use of the minimum-size classification approach, and (b) all joint use distribution plant costs should be allocated using a single coincident peak ("1CP") allocation factor, rather than the non-coincident-peak ("NCP") and sum of customer peaks approach advocated by the Company. Based on his simulation of the Company's ECOSS with those modifications, he offers an alternative revenue allocation.

Q. Please evaluate Dr. Sakaya's proposals.

A. Witness Sakaya and I use a different starting point for our evaluation of the Company's ECOSS. I relied on the Company's HTY ECOSS as filed, with the adjustments to the FTY revenue requirement, because that was the approach taken by the Company. Witness Sakaya uses the "FTY" ECOSS as submitted by the Company in an interrogatory response. Witness Sakaya's approach is not unreasonable, although as I explained in my direct testimony, that ECOSS reflects cost data for the FTY, but relies on volumetric, demand and customer allocators for the HTY. Neither approach is particularly accurate. To avoid this problem in the future, the Company should be required to file a FTY ECOSS with FTY costs and FTY allocation factors in future base rates proceedings, which is normal practice in Pennsylvania.

More importantly, the "FTY" ECOSS relied upon by Witness Sakaya contains the same problems as the Company's HTY ECOSS that I identified in my direct testimony. These problems include the inadvertent but significant programming errors acknowledged by the Company regarding the application of a primary demand allocator to secondary demand costs and the Company's failure to use the meter reading allocator for meter reading labor costs. On that basis, Witness Sakaya's reliance on the Company's ECOSS is not reasonable. Moreover, for the reasons detailed in my direct testimony, the Company's ECOSS uses a primary system distribution plant classification methodology that is not consistent with Commission precedent, and it contains other features that should be modified to better allocate costs.

Because the ECOSS relied upon by Witness Sakaya is known to be inaccurate, Witness Sakaya's specific revenue allocation proposals are not (as yet) relevant to this proceeding.

Nevertheless, I commend Witness Sakaya for offering an alternative scaleback proposal that maintains progress toward cost-based rates, in the event that the Commission reduces the Company's revenue requirement. Table IEc-R1 below shows Witness Sakaya's scaleback proposal, as compared to the traditional "proportional scaleback" method.

Table IEc-R1 I&E Scaleback Proposal						
	Full Increase		**Prop. Scaleback 50%**		**I&E Scaleback 50%**	
	$	**%**	**$**	**%**	**$**	**%**
SC1: Residential Total	$826,176	30.8%	$413,088	15.4%	$331,097	12.3%
SC2-S: C&I Secondary	$941,176	45.7%	$470,588	22.8%	$550,676	26.7%
SC2-P: C&I Primary	$116,279	33.2%	$58,140	16.6%	$61,279	17.5%
SC3: Muni. Lighting	$32,528	37.7%	$16,264	18.9%	$20,528	28.8%
SC4: Pvt Area Lighting	$11,002	37.7%	$5,501	18.9%	--	0.0%
Total	**$1,927,161**	**37.0%**	**$963,581**	**18.5%**	**$963,580**	**18.5%**
Sources: I&E Exhibit 3, Schedule 7, RDK Calculations						

It is a well-known (but often-ignored) problem with the traditional proportional scaleback method that it reduces the progress toward cost-based rates that is built into the full requirements revenue allocation. Witness Sakaya's proposal accurately depicts that problem. In order to retain the progress toward cost-based rates in the Company's full requirements proposal, Witness Sakaya must propose a rate increase for the SC2-S class that is more than proportional to the original proposal, and he similarly must scale back the relative rate increase for the SC1 Residential class. Thus, as shown in Table IEc-R1, the ratio of SC2-S increase to system average increases from 1.23 in a proportional scaleback (22.8%/18.5%) to 1.44 in the alternative approach (26.7%/18.5%). Similarly, the SC-1 rate increase relative to system average ratio falls from 0.83 to 0.67. In short, to maintain progress toward cost-based rates in a scaleback, the benefits of the scaleback must be disproportionately assigned to the classes with below average rate increases.

One trusts that Witness Sakaya will retain this revenue allocation philosophy and the proposed scaleback methodology when a corrected ECOSS is applied, and the resulting cost differences indicate a need for a disproportionately large increase for the SC1 Residential class.[1]

Q. Turning to Dr. Pavlovic's cost allocation recommendations, he asserts that joint-use electric distribution equipment costs ". . . do not and cannot vary with the number of customers connected to the distribution system." Do you agree?

A. Of course not. Dr. Pavlovic's assertion would only be reasonable if (a) the distribution system never expands to new areas to serve new customers, and (b) the existing distribution system that was expanded to interconnect new customers never needs to be replaced. Obviously, if the electric distribution system expands into new areas, it will incur additional poles, conductors and transformer costs, some of which are related to the increased demand and some of which are related to the need to interconnect the new customers. Moreover, since much of the existing distribution system was once expanded in a similar manner, i.e. to meet new load and connect new customers, the cost of replacing those assets are similarly related to both demand and customers.

In addition, Dr. Pavlovic's assertion does not recognize a second rationale for including a customer component in distribution costs, namely that it is generally less costly per unit of demand to provide service to larger commercial and industrial customers who are often located in narrower geographic areas (i.e., commercial-zoned districts) than it is to provide service to geographically dispersed residential customers. In a densely populated urban area where many residential customers are packed closely together with commercial customers, a demand-only allocation approach may be reasonable. Outside of such a dense urban area, namely in the outer reaches of cities, suburbs, exurbs and rural areas, the cost associated with interconnecting additional customers is significant.

Q. Dr. Pavlovic indicates that the minimum size approach to classifying joint-use distribution plant is not in wide use. Is that true in Pennsylvania?

A. No. As I indicated in my direct testimony, the use of a minimum system approach is common in Pennsylvania, and the Commission not only approved the minimum system

[1] As shown in my simulation of the Company's ECOSS correcting only the acknowledged errors, provided in RDK WP2, the SC1 Residential class rate of return at present rates is well below system average.

approach for classification of secondary system costs, but affirmatively approved the extension of the minimum system method from secondary voltage systems to primary voltage systems.[2] The Commission has also recently affirmed that position in the 2018 UGI Electric base rates proceeding.[3]

Q. Dr. Pavlovic cites to Professor Bonbright's treatise Principles of Public Utility Rates in support of his assertion that there should be no customer component to distribution costs. Was evidence regarding Professor Bonbright's dim view of the minimum system approach offered to the Commission in the PPL Electric and UGI Electric matters?

A. Yes. Repeatedly. It is apparent that the Commission has not in the past been swayed by Professor Bonbright's views regarding minimum system cost allocation methods, or by his views regarding embedded cost allocation studies in general. [4]

Q. At page 3, Dr. Pavlovic cites to the cost allocation treatise published by the Regulatory Assistance Project ("RAP") in support of setting the customer component of joint-use distribution costs to zero as an "updated revision of its electric cost manual." Is this document an update to the NARUC Electric Utility Cost Allocation Manual?

A. No, it is not. While the document has much to recommend it, the authors have long served as advocates for smaller residential customers in regulated utility cost allocation proceedings. The document does not represent a consensus of view of cost allocation analysts. The credits for the document appear to include few if any utility representatives who participated in the project or who agree with the findings. Regarding distribution embedded cost allocation studies, the authors offer little or no statistical evidence that there are no distribution economies of scale associated with serving geographically more

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[2] Opinion and Order, Pennsylvania Public Utility Commission, Docket No. R-2012-2290597, Order Entered December 28, 2012, pages 105- 113.

[3] "Opinion and Order," Pennsylvania Public Utility Commission, Docket No. R-2017-2640058, Order entered October 25, 2018, pages 159-160.

[4] Professor Bonbright also takes a dim view of embedded cost allocation studies in general. His 1988 text approvingly notes, "Many economists would like to see the fully distributed cost concept dispatched to the museum of antiquated and irrelevant ideas." To my knowledge, fully distributed cost studies have been used in Pennsylvania electric and gas utility rate cases every year since 1988.

concentrated larger commercial customers than for serving geographically diverse smaller residential customers. In short, the referenced document is not a manual but an advocacy piece, albeit a lengthy and detailed one.

Q. Dr. Pavlovic opposes the use of class NCP demands for allocating distribution demand costs in favor of a 1CP approach. Is his argument credible?

A. The use of a 1CP demand allocation factor is appropriate when the size of a particular distribution asset is determined by the maximum diversified sum of individual customer loads. Thus, for example, suppose a distribution system has 10,000 customers each with a maximum demand of 5 kW, implying a sum of customer peak demands of 50 MW. But because the customers do not peak at the same time, the system coincident peak maximum demand is 35 MW, meaning that there are benefits of load diversity, at least for those assets which serve the entire 35 MW load. Those assets are reasonably allocated using a 1CP allocator.

For PCL&P, where the entire system load is served through two substations, Dr. Pavlovic may make a credible case that a coincident peak allocator is appropriate for Account 362, substations. However, the Company only owns one of those substations which serves a minority of the load, while the majority of the Company's load comes directly from an Orange and Rockland Utilities' substation.[5] Thus, even the Company's substation costs do not benefit from all of the diversity in customer load, and thus a 1CP allocator overstates the benefits of diversity for those costs.

For most other distribution system assets, fully diversified system single coincident peak demand is not the driver for cost causation. Generally, cost causation should reflect that the further the asset is from the individual customer and the deeper the asset is in the electrical systems, e.g., substations and transmission assets, the greater is the importance is a diversified coincident peak for cost allocation. The more local the assets, the greater the importance of undiversified individual customer demands and individual customer count. The poles, conductors and transformers on a residential street must be sized to meet

[5] OSBA-I-6 and PCL&P Statement No. 3 at 2-3.

the maximum demands of the customers on that street, and they must be extended to interconnect all the customers on the street. A line transformer is likely to serve only a few residential customers or a single moderate-size commercial customer, and it must be sized to meet the undiversified maximum loads of those customers. The size of these assets does not benefit from diversity in load from customers in the neighboring town.

Dr. Pavlovic appears to base his reliance on a CP allocator at least in part on the argument that PCL&P is so small that there is little load diversity. Since the absence of diversity means that there is zero difference between a NCP and a CP allocator, Dr. Pavlovic's argument is moot. If there is no load diversity, the CP, NCP and sum of individual customer peaks allocators all produce the same arithmetic result, and there is no need to choose among the allocators.

While I cited concerns about the accuracy and timeliness of the Company's analysis of various peak demand allocators in my direct testimony, I do not agree with Dr. Pavlovic that there is no diversity of demand. Moreover, pretending that load diversity reduces costs across the entire distribution system from pole transformer to substation is not consistent with common sense or cost causation principles.

I observe also that all lighting customers are assigned zero joint-use distribution plant costs in Dr. Pavlovic's ECOSS. Because the system coincident peak is deemed to occur during daytime hours, the lighting customers do not contribute to that peak. Thus, Dr. Pavlovic would exempt those classes from paying for the poles, conductors and transformers necessary to interconnect them with the rest of the distribution system simply because they do not use the distribution system during the single coincident peak hour. This result also defies common sense and is inconsistent with the principle of cost causation.

Q. Did Dr. Pavlovic correct for the errors acknowledged by the Company in his alternative ECOSS?

A. While Dr. Pavlovic did not circulate an electronic version of his ECOSS simulation with his testimony, the partial output that he provided in the attachments to his testimony appears to indicate that he did not correct the Company's error of allocating secondary system plant costs to both primary and secondary system customers. In fact, by eliminating the customer component of joint-use distribution assets, Dr. Pavlovic allocates a large share of the secondary distribution plant equipment to the SC-2 primary class, thereby exacerbating the Company's admitted error.

Regarding the labor allocation factor error, because Dr. Pavlovic does not mention the correction in the text of his testimony, I assume that he similarly did not make that correction.

Q. Do you agree with Dr. Pavlovic's revenue allocation proposal?

A. While Dr. Pavlovic did not provide any supporting workpapers, it appears that his revenue allocation proposal is directionally consistent with the results of his ECOSS, and he appears to have limited the maximum increase to no more than two times system average (which is about the increase he assigns to the SC2-P class). However, because I conclude that Dr. Pavlovic's ECOSS (a) is not consistent with cost causation, (b) fails to correct for acknowledged errors, and (c) is not consistent with recent Commission precedent, Dr. Pavlovic's revenue allocation proposal is not appropriate for this proceeding.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2020-3022135**
PIKE COUNTY LIGHT & POWER COMPANY (Electric Division)	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Rebuttal Testimony labelled OSBA Statement No. 1-R 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: February 22, 2021

Robert D. Knecht

COMMONWEALTH OF PENNSYLVANIA

March 4, 2021

The Honorable Mary D. Long
Pennsylvania Public Utility Commission
Piatt Place
301 5th Avenue, Suite 2020
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission, v. Pike County Light & Power Company (Electric) / Docket No. R-2020-3022135

Dear Judge Long:

Enclosed please find the Surrebuttal Testimony 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/ Sharon E. Webb

Sharon E. Webb
Assistant Small Business Advocate
Attorney ID No. 73995

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

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2020-3022135**
PIKE COUNTY LIGHT & POWER COMPANY (Electric Division)	:	

Surrebuttal Testimony of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation

Date Served: March 4, 2021 Date

Submitted for the Record: March 15, 2021

SURREBUTTAL TESTIMONY OF ROBERT D. KNECHT

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

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

Q. Please describe the purpose of this testimony.

A. This surrebuttal testimony responds to the rebuttal testimony of (a) Rate Panel representing Pike County Light & Power Company (Electric Division) ("PCL&P" or "the Company"), and Dr. Karl Richard Pavlovic, representing the Pennsylvania Office of Consumer Advocate ("OCA").

Acronyms and initialisms defined in my direct testimony are used in this surrebuttal with the same meaning.

Q. In your direct testimony, you indicated that the Company had acknowledged certain technical errors in its electric class cost of service study ("ECOSS") that would have a material impact on the allocated cost results. Has the Company corrected those errors in its ECOSS?

A. Yes. The Company submitted a revised ECOSS with its rebuttal testimony. The results of the Company's revised ECOSS are virtually identical to the cost allocation analysis presented in my direct testimony in RDK WP2.

Q. In your direct testimony, you concluded that the Company had not classified its primary voltage distribution system into customer and demand components, consistent with Commission precedent. Did the Company correct its error?

A. No. The Company merely argued that my placeholder suggestion was erroneous and not supported by any analysis of the Company's costs. The problem with this argument is that the Company failed to undertake the necessary analysis to comply with Commission precedent. (As I indicated in my direct testimony, the Company did not even update any of its key cost classification factors since its last base rates case seven years ago.) Thus, the failure belongs to the Company, not to me. Thus, it is the Company's assumption that there is a zero customer component to primary voltage system costs is "grossly in error," since it represents the Company's failure to comply with Commission policy and it is inconsistent with the practices of other Pennsylvania EDCs.

Q. At page 9 the Rate Panel indicates that you misunderstand the class assignment of service laterals and meters to customer classes. Let's start with service lines. The Company indicates that the "... service lateral ... costs assignment to each class were calculated based on typical costs from the company records ..." and that "the use of a demand allocation factor would incorrectly shift costs among the rate classes." Please respond.

A. The Company's rebuttal testimony is consistent with neither the Company's direct testimony nor its filed ECOSS. As the Company explicitly states in response to OSBA-I-22, the allocator for service lines "... was based on the prior 2013 study and is the sum of the non-coincident maximum demands." Based on my records from the last base rates case, this statement appears to be correct. Even Dr. Pavlovic recognizes that the Company allocates service line costs based on peak demand.[1]

Thus, the Company's rebuttal assertion that services are allocated based on "typical costs from service records" is simply wrong as a factual matter. The Company relies on a 100 percent demand allocator.

Moreover, I agree with the Company's assertion that the use of a demand allocator is inappropriate. However, the Company's argument is a critique of its own allocation methodology, and it in fact supports my recommendation.

Q. Turning to the meters plant allocator, the Rate Panel makes the same argument, namely that "... meter plant costs assignment to each class were calculated based on typical costs from the company records ..." and that "the use of a demand allocation factor would incorrectly shift costs among the rate classes." Please respond.

A. The Company's rebuttal fails to address the concerns that I raised in my direct testimony.

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[1] OCA Statement No. 2R, page 6.

For meters cost, the Company does indeed attempt to calculate a typical cost for a new meter for each rate class, based on assumptions regarding the cost of the meter and the labor involved in installation. In my direct testimony, I highlighted certain non-credible assumptions in the Company's calculations supporting the development of a typical installed meters cost, not the least of which was the assumption that the labor cost was $293 per hour. Moreover, neither I nor the Company proposed that meters plant be allocated based on a demand allocation factor. The Company's rebuttal fails to address the specific concerns that I raised regarding the derivation of installed meters cost, implying that the Rate Panel believes that $293 per hour is a reasonable labor cost assumption for meter installation personnel. I therefore retain my view that my adjusted estimate for installed meters cost is more credible than the Company's calculations.

Q. **In your direct testimony, you offered alternative methods for the Company's allocation of customer service and sales O&M costs, the O&M transmission costs, late payment revenues and the development of the overall O&M allocation factor. Did the Company address any of these issues in rebuttal?**

A. No.

Q. **Having corrected its ECOSS for the acknowledged errors, did the Company modify its revenue allocation and rate design proposals?**

A. No.

Q. **Did the Company provide any rebuttal to your revenue allocation recommendation that was based on the version of the Company's ECOSS corrected only for the acknowledged errors?**

A. No.

Q. **Is the Company's revenue allocation from its filed case consistent with its corrected ECOSS?**

A. No. Table IEc-S1 below shows the impacts of the Company's proposed revenue allocation, using the Company's corrected ECOSS methodology:

Table IEc-S1 Impact of PCL&P Rebuttal Revenue Allocation Proposal				
	Rate of Return	Proposed	Revenue-Cost Ratio	
	Present Rates	Increase %	Present	Proposed
SC1: Residential Total	4.30%	32.00%	94.9%	90.8%
SC2-S: C&I Secondary	4.68%	44.63%	104.0%	110.5%
SC2-P: C&I Primary	7.44%	32.40%	124.5%	120.0%
SC3: Muni. Lighting	4.92%	37.14%	99.4%	97.2%
SC4: Pvt Area Lighting	3.11%	37.14%	87.2%	86.3%
Total	**4.62%**	**37.14%**	**100.0%**	**100.0%**
Sources: Exhibit E-6 Rev, Schedule ERP-3-E, RDK calculations				

As shown, the Company's proposed revenue allocation is almost entirely wrong-headed. As the Rate Panel states, the purpose of having a ECOSS is to serve as a guide for cost allocation.[2] This implies that classes with rates of return at present rates that are below system average should get above-average rate increases, and vice versa. In that respect, PCL&P's policy fails. The SC1 Residential class, with a rate of return modestly below system average, is assigned a below-average increase. Conversely, the SC2-S class, which exhibits a rate of return above system average, is assigned an above-average increase.

This bizarre revenue allocation proposal has the effect one would expect, namely that cross-subsidies increase.

A cost-based revenue allocation should show that revenue-cost ratios move closer to 100 percent, moving from current rates to proposed rates. Under PCL&P's proposal, the reverse is generally true.

As shown in Table IEc-S1, the SC1 Residential class exhibits revenues at 94.9 percent of allocated costs at present rates, which falls to 90.8 percent at proposed rates. In effect, the subsidy to that class increases from a little over 5 percent to more than 9 percent. Similarly,

[2] Rate Panel Statement No. 1-R, page 3.

the SC2-S class shows revenue-cost ratios moving further away from 100 percent, going from 104.0 to 110.5 percent. And even for the SC2-P class, where the adjustment from the revenue allocation is directionally correct, the progress toward cost-based rates is minimal, falling only from a 124.5 percent level to 120.0 percent. This leaves the SC2-P class still heavily burdened by other class' costs.

Thus, the Company's revenue allocation proposal should be rejected.

Q. Can you address the Company's rebuttal regarding the structure of the SC2-S tariff charges?

A. The Company appears to argue that the current structure of the SC2-S tariff, with its customer charge, three-tiered declining block Wright tariffs and its two-tiered inclining block tariff better aligns intraclass rates and costs. A worthy goal, I agree. However, the Company has not provided any information about how costs vary within the class by size of customer. Thus, whether this complicated tariff is more accurate than a simpler tariff in matching rates and costs in unknown.

Moreover, the Rate Panel argues that a distribution tariff rate should not have any pure kWh-based tariff charges, because distribution costs do not vary with energy consumption. I agree. Unfortunately, as I demonstrated in my direct testimony, the Company's Wright tariff charges are structured in such a way that the charges are almost a pure energy charge. My recommendations were consistent with the Company's rebuttal testimony, namely that there should be a reduced emphasis on the energy charge in the SC2-S tariff. Thus, once again, the Company's rebuttal applies to its own proposal, and not to the recommendations in my direct testimony.

Q. Does the Company's rebuttal testimony cause you to reconsider any of the recommendations in your direct testimony?

A. No. The Company's rebuttal testimony either fails to address my concerns or actually provides further support for my recommendations.

Q. Turning to Dr. Pavlovic's rebuttal testimony, has Dr. Pavlovic corrected his cost allocation study for the technical errors acknowledged by the Company and corrected in the Company's rebuttal testimony?

A. No he has not. He refers to these errors as "purported." I disagree. These errors are not purported; they are obvious, and they are admitted. In his direct testimony, Dr. Pavlovic failed to observe that secondary system distribution costs were incorrectly being allocated to primary system customers, and that the labor cost allocator was developed using the wrong meters reading allocator. He then failed to correct those errors in rebuttal. Thus, Dr. Pavlovic's cost allocation analysis cannot be used as a guide for revenue allocation or rate design in this proceeding.

Q. Dr. Pavlovic addresses your proposal to include a customer component in the classification of primary distribution system joint-use plant. Can you respond to his rebuttal testimony?

A. Dr. Pavlovic opposes my classification proposal for primary system plant, based on the same arguments that he uses to oppose the Company's classification of secondary plant costs. I addressed those arguments in my rebuttal testimony and need not repeat them here. He also indicates that peak demand is a reasonable proxy for service line costs, for which he offers no evidence. This position is also contradicted by service line cost allocation in other Pennsylvania EDCs, as well as being contradicted by the Company's Rate Panel rebuttal testimony.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2020-3022135**
PIKE COUNTY LIGHT & POWER COMPANY (Electric Division)	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Surrebuttal Testimony labelled OSBA Statement No. 1-S 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: March 4, 2021

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2020-3022135**
	:	
PIKE COUNTY LIGHT AND POWER COMPANY (ELECTRIC)	:	

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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DATE: March 25 2021

/s/ Sharon E. Webb

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