COMMONWEALTH OF PENNSYLVANIA

December 22, 2020

The Honorable Christopher P. Pell
Administrative Law Judge
Pennsylvania Public Utility Commission
801 Market Street, Suite 4063
Philadelphia, PA 19107

Re: Pennsylvania Public Utility Commission v. PECO Energy Company – Gas Division / Docket No. R-2020-3018929

Dear Judge Pell:

Enclosed please find the **Public Version** of Direct Testimony and Exhibits of Robert D. Knecht, labeled OSBA Statement No. 1, with Exhibits IEc-1 through IEc-3, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

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

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

Sincerely,

/s/ Steven C. Gray

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

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

OSBA Statement No. 1

R-2020-3018929
2/17/21 JK

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2020-3018929**
PECO Energy Company (Gas Division)	:	

Direct Testimony of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

********* PUBLIC VERSION *********

Topics:

Context
Cost Allocation
Revenue Allocation
Rate Design

Date Served: December 22, 2020

Date Submitted for the Record: ____________________________

DIRECT TESTIMONY OF ROBERT D. KNECHT

1. Introduction and Overview

Q. 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. My consulting practice consists primarily of the preparation of analysis and expert testimony in the field of regulatory economics. I obtained a B.S. degree in Economics from the Massachusetts Institute of Technology in 1978, and an 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"). I have represented the OSBA before the Pennsylvania Public Utility Commission in a variety of matters since 1994. My résumé and a listing of the expert testimony that I have filed in utility regulatory proceedings during the past five years are attached in Exhibit IEc-1.

Q. What is the purpose of this testimony?

A. I was retained by the OSBA to review the filing of the PECO Energy Company – Gas Division ("PECO Gas" or "the Company"), to evaluate whether the Company's proposed rate increase and tariff changes are consistent with sound regulatory and economic principles, and treat small business customers equitably.

Despite a long history in Pennsylvania utility regulatory proceedings, this is my first participation in a PECO Gas base rates proceeding. PECO has a relatively complicated set of rate classes and tariff provisions, and I am not familiar with many long-standing policies that have been adopted by the Company and approved by the Commission. This testimony represents my understanding and views at this time. I will update these views as necessary as additional information comes to light.

Q. Please summarize your current conclusions and recommendations.

A. As detailed herein, I conclude the following:

- When evaluating the allowed rate of return in this proceeding, the Commission should carefully consider (a) the economic context for this rate filing, particularly for small businesses (b) the substantial increases in risk premiums awarded by utility regulators across the country over the past two decades while at the same time adopting mechanisms to reduce utility risk, and (c) the fundamental problems associated with excess reliance on the DCF method for determining the cost of equity capital.

- The Company's gas cost of service study ("GCOSS") relies (a) on an allocation method for mains that is not consistent with Commission precedent and (b) on design day demand assumptions that do not reasonably represent class differences in load patterns and the contribution of some interruptible rate classes to distribution system peak demand. The GCOSS also includes other minor inconsistencies and inadvertent errors. I prepared an alternative version of the GCOSS which addresses these issues.

- The Company appears to have failed to meet its commitment from the settlement of its 2008 base rates proceeding to propose to move the Rate GC and L class rates of return to the system average rate of return in this proceeding.

- The Company's revenue allocation is not consistent with its GCOSS. This problem appears to arise due to an initial error in the filed GCOSS. While the GCOSS error was corrected, the Company did not update its revenue allocation proposal to reflect the correction. I prepared an alternative revenue allocation proposal that is consistent with my version of the GCOSS. While this revenue allocation proposal fails to move rates fully into line with allocated costs, it makes substantial progress to that end without violating rate gradualism rules of thumb.

- The Company has not reasonably justified most of its negotiated rates arrangements with customers in Rate NGS. Rate increases that are assigned to the TS-F and TS-I classes should therefore include the effects of the revenue shortfall from these customers.

- The Company has little cost justification for its proposed tariff charge structure for Rate GC. Based on my cost analysis, rate design for the GC class should include a zero increase for the customer charge and a narrowing of the block differential for the commodity charges.

- The Company has not prepared a cost justification for the large volumetric rate differentials in Rates TS-F and TS-I between large and smaller customers, and it declined to provide the cost information necessary for me to prepare that evaluation. Based on the available information, I recommend that those differentials be narrowed in this proceeding, and that the Company prepare a more detailed evaluation in the future.

- The Company's disproportionate allocation of DSIC costs to Rate GC customers is not consistent with cost causation or the principle of rate equity. DSIC revenues should be allocated among rate classes based on all distribution revenues and not only the volumetric charges.

- Pending additional information from the Company, I tentatively recommend that the Company eliminate its legacy interruptible, bundled, flex rate classes, namely MV-I, IS and TCS. At a minimum, revenues in excess of PGC costs related to the IS class should serve to offset base rates for other classes. It is not reasonable for those margins to be credited to either the PGC or shareholder pockets.

- The Company's requirement that the delivery charge for standby service volumes for transportation customers be based on regular firm service tariff rates is unduly discriminatory and unduly complicated. Standby gas supply service should be based on the Company's cost of providing that gas supply. Delivery of those volumes should be priced at the same cost as if those supplies were provided by the customer.

Q. How is your testimony organized?

A. Section 2 provides some context for this proceeding, notably with respect to the Company's claimed cost of capital. Sections 3 through 5 cover cost allocation, revenue allocation, and rate design respectively. Exhibit IEc-2 presents a listing of the Company's responses to interrogatories to which I make reference in this testimony. I am advised by counsel that due to the voluminous and electronic nature of those responses, OSBA will move those responses into the record at a future time. Exhibit IEc-3 lists my electronic workpapers. Executable MS Excel versions of those workpapers are being circulated with this testimony.

2. Context

Q. Please summarize the Company's filing.

A. The Company proposes what it describes as an increase in annual base rate operating revenues of $68.7 million, for the fully projected future test year ("FPFTY") ending June 30, 2022. The Company's two most recent base rate cases occurred in 2008 and 2010, although the Company was able to increase base rates through the Distribution System Improvement Charge ("DSIC") mechanism. The DSIC has allowed it to increase base rates by 5 percent without explicit Commission approval. The $68.7 million increase is on top of the DSIC and Tax Cut and Jobs Act ("TCJA") charges that would otherwise be in place for the FPFTY.[1]

In this proceeding, the Company filed a GCOSS which assigns the Company's embedded-cost revenue requirement at present rates to nine rate classes, and also calculates the

[1] There are a few clarifications to the Company's overall increase figure. First, but for the base rate increase, the DSIC and TCJA mechanisms would generate approximately $17.0 million and $4.4 million in revenue respectively. Since the DSIC gets zeroed out with the implementation of new base rates, and the TCJA effects are rolled into base rates, the Company's proposed increase in base rates must add in that $21.4 million to the other increases to base rates charges. Second, the $68.7 million includes FPFTY revenues that the Company will earn from its merchant function charge ("MFC"), gas procurement charge ("GPC") and discounts on its purchases of receivables, totaling some $1.9 million, leaving a net base rate increase of $66.8 million. Since revenues from those charges are actually declining, the $68.7 million modestly overstates the rate increase required from ratepayers. Finally, the Company's proposed rate increase includes a small amount of additional revenues from two of its "flex" rate classes ("MV-I" and "TCS"). Since rates for these classes are set based on market conditions, it is unclear why the Company reports a rate increase for those classes. Please see workpaper RDK WP1 tab "RevPrf" for a full proof of revenue analysis of the Company's proposal.

revenue requirement at proposed rates based on a levelized 7.70 percent average rate of return across classes.

In the Company's 2008 rate proceeding, PECO Gas made the following commitment with respect to assigning the revenue increases among the rate classes:

> PECO agrees that, over the course of its next two gas base rate filings, it will propose to move the Rate GC and L class rates of return to the system average rate of return by moving fifty percent (50%) towards that goal in the next such filing and removing all remaining difference through the following filing. All parties retain their rights, in such future rate proceedings, to challenge that proposal through the use of class rates of return obtained through alternative cost of service studies or other ratemaking principles.[2]

I am advised by OSBA counsel that the Company made substantial progress toward cost-based rates for the Rate GC and Rate L classes in the 2010 base rate proceeding.

However, in this proceeding, while I am not an attorney, it appears that PECO has reneged on this commitment. Company witness Mark Bisti acknowledges that the Company's proposal also considered principles other than moving Rate GC and Rate L class rates of return to system average, which does not appear to be permitted under the settlement.[3] The Company's proposed revenue allocation and resulting class rates of return are shown in Table IEc-1 below. As shown, the Rate GC class exhibits an 8.1 percent class rate of return at present rates, compared to a system average proposed rate of return of 7.7 percent. Rather than proposing a rate decrease as it committed to in the 2008 base rate case, the Company proposes a very substantial increase, which serves to produce a class rate of return of 10.2 percent at proposed rates, well above system average.

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[2] Joint Petition for Settlement of Rate Investigation, Docket No. R-2008-2028394, *et al.*, August 21, 2008, pages 5-6.

[3] PECO Energy Company Statement No. 7 at 4-5.

Table IEc-1
PECO Gas Proposed Revenue Allocation

	Increase $000	Increase %	ROR Current	ROR Proposed
GR	41,720	17.9%	4.7%	6.5%
GC	17,310	17.0%	8.1%	10.2%
L	35	46.0%	-2.1%	-0.9%
MV-F	97	20.5%	12.6%	16.1%
MV-I	1	10.6%	32.2%	35.3%
IS	0	--	-5.6%	-5.6%
TCS	56	8.1%	44.4%	47.4%
TS-F	5,370	32.1%	6.5%	9.7%
TS-I	2,378	25.0%	8.8%	12.0%
Total	**$66,787**	**18.5%**	**5.7%**	**7.7%**

Rate class composition is described in more detail below.
Sources: RDK WP1

Based on my experience in Pennsylvania, I would expect that not meeting settlement commitments will discourage parties from entering into settlements with PECO Gas going forward, particularly where those settlements involve future commitments.[4]

I am advised by counsel that OSBA will address the appropriate remedy for the Company's apparent failure to comply with the provisions of the 2008 settlement in its briefs in this matter.

Q. Please describe the economic context in which this proceeding takes place.

A. All parties are aware of the personal suffering and economic disruption associated with the COVID-19 pandemic. I offer a few summary observations relating to small and medium businesses from the most recent US Census Bureau survey reports: [5]

[4] Having watched settlement dynamics in Pennsylvania for decades, I observe that future commitments often represent important components for addressing parties' concerns and often represent a necessary concession for getting to settlement. If these commitments cannot be relied upon, achieving settlements will likely become considerably more difficult.

[5] https://portal.census.gov/pulse/data/

- Nationwide, a significant majority of businesses have experienced either an overall moderate negative effect (44.4 percent) or a large negative effect (30.7 percent). The worst hit business sectors are accommodation/food services (NAICS 72), education (NAICS 61), arts/entertainment/recreation (NAICS 71).

- By way of contrast, the utility sector (NAICS 22) reports a moderate negative impact of about 40.7 percent, and only 6.3 percent report a large negative effect.

- Pennsylvania businesses are slightly worse than the national average at 45.75 percent moderate negative effect and 32.9 percent large negative effect.

- Some 14.5 percent of Pennsylvania businesses report reductions in employees, also above the national average (12.6 percent).

- 7.7 percent of Pennsylvania businesses believe that their operations will never return to pre-pandemic levels, and over 49 percent believe it will require at least six months to recover, both values above the national average.

In addition, crude oil (WTI) prices plummeted from the $55 to $60 per barrel range in the second half of 2019 to the $35 to $40 range in October, and have rallied modestly to the $45 to $50 per barrel range at present, significantly harming the Pennsylvania economy.[6]

Q. In light of these conditions, what does the Company request as a return on invested capital?

A. The Company requests a 10.95 percent return on equity capital, an equity share of invested capital of 53.4 percent, and an overall average return of 7.70 percent. This is, of course, outrageous. With current 10-year Treasury Bond yields of 0.90 percent, the Company is asking for an equity risk premium of over 1000 basis points.

However, it must be said that utility industry regulators continue to live in a reality that is totally different from the rest of the world when it comes to the cost of equity capital. For example, Duff & Phelps (the successor to the respected Ibbotson Associates and

[6] https://www.eia.gov/dnav/pet/hist/RWTCD.htm

Morningstar entities for tracking cost of capital data) recently lowered its average risk cost of equity capital to 8.0 percent, consisting of a risk-free rate of 2.5 percent and an equity risk premium of 5.5 percent.[7] Since regulated natural gas utilities mostly serve customers who have no credible competitive alternatives and are allowed to pass on costs where they face the highest risk, their relative risk should imply a cost of equity capital well below 8.0 percent.

Q. Does the utility industry acknowledge that risk premiums for allowed returns on equity have been increasing?

A. Yes. I downloaded allowed equity returns and risk-free rate information from the Edison Electric Institute, which reported the pattern shown in Figure IEc-1 below. The figure shows what we all know, namely that US regulators have allowed utility equity returns to reflect a risk premium that has risen from the 400 to 500 basis point range in the 1990s to the 700 to 800 point range over the past decade.

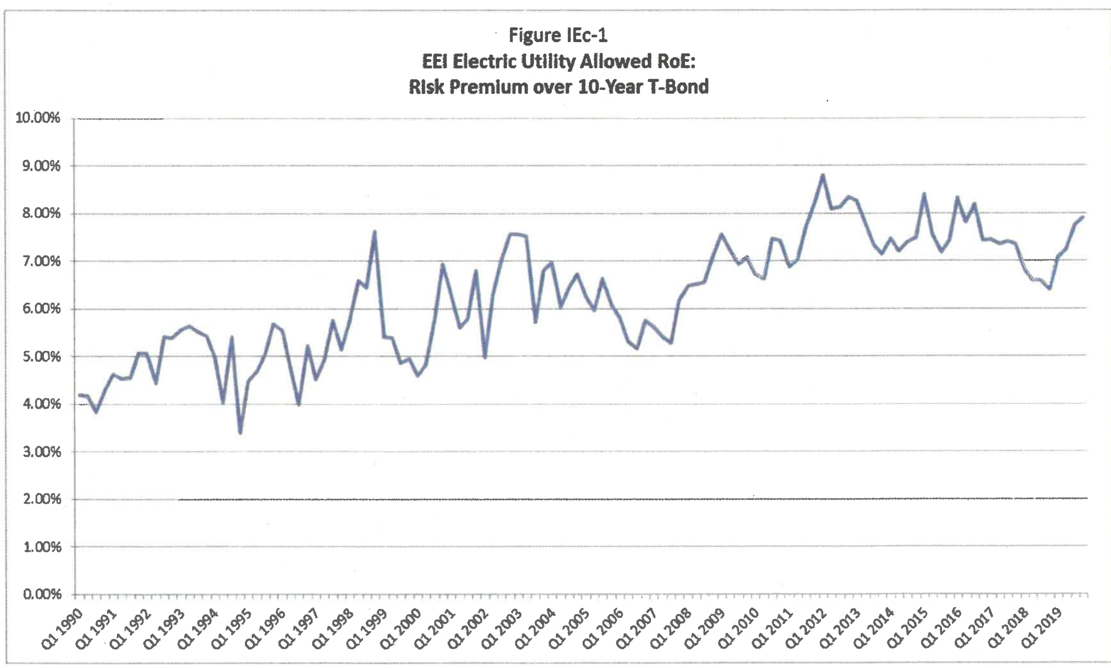

Figure IEc-1
EEI Electric Utility Allowed RoE:
Risk Premium over 10-Year T-Bond

[7] https://www.duffandphelps.com/insights/publications/cost-of-capital?utm_campaign=NN-VS-CT-FA-NN-CO-NOTAV-PNREP2012ELQ%20ERP%20Recommendation&elqid=CDUFF000001308084&utm_medium=email&utm_source=Eloqua

Q. Why have regulatory authorities allowed utility risk premiums to rise in an era when utility business risks appear to be declining?

A. The obvious answer is that ratepayer advocates are simply outspent and outmaneuvered by the utilities. However, the two other explanations that come to mind are (a) regulators have an excessive reliance on the discounted cash flow ("DCF") method, and (b) regulators have entered into an implicit bargain with utilities to achieve non-rate public policy objectives.

Q. Please describe your concerns about excessive reliance on the DCF method for evaluating the cost of equity capital.

A. In responding, I first acknowledge that the DCF model is a well-established technique for deriving the equity cost of capital that is widely used in utility regulation. I also acknowledge that no method is perfect, and all rely on certain heroic assumptions. Nevertheless, relying to a large extent on the DCF model has two significant disadvantages.

The first is circularity. The DCF model requires as inputs (a) the dividend yield and (b) the expected perpetual growth rate for the per-share dividend for a sample of "pure play" natural gas distribution utilities. The dividend yield, of course, is a directly observable market phenomenon, and can be defined with reasonable accuracy (although the selection of the sample is often a matter of dispute). The DCF model has the advantage that the dividend yield input directly reflects one aspect of the market's view of the cost of capital. If, for example, the market determined that the cost of equity capital for a particular utility had declined, the utility's share price would rise and, all other factors being equal, the DCF cost of equity would fall.

However, all other things are not equal. There is a second input to the model that is not directly observable. And worse, that other parameter is directly dependent on market expectations for regulatory return on equity ("RoE") awards.

Specifically, market expectations for per-share dividend growth must necessarily be based on the market's expectation for regulatory RoE awards. Thus, if the market observes that regulators have been following a pattern in which the implied risk premiums for RoE awards have been rising for decades, the market will likely expect those RoE award risk premiums to remain high and perhaps continue to rise until proven otherwise. This, expectation, of course, then keeps the implied equity costs from the DCF model high and provides an excuse for regulators to fail to adjust RoE awards to reflect capital market realities.

If historical trends are used to estimate growth, the expected growth rate is dependent on past regulatory awards. If regulatory awards are excessive, or if capital market conditions have changed, future RoE awards from the DCF method are distorted.

Since regulators, as a matter of human nature, all watch each other and make adjustments to RoE awards only gradually, excessive reliance on the DCF model understates real changes in capital markets, most notably those related to the yields on risk-free (or relatively low-risk) investments.

My second concern about the DCF model is the perpetual nature of the growth assumptions in the model. Practitioners of DCF evaluations must demonstrate that the growth rate used in deriving the cost of equity capital is not the expected growth for the next three or five or even fifty years, but in perpetuity. This is particularly an issue for natural gas distribution. It is unlikely that natural gas will continue to be a major and growing fuel source forever. Even in Pennsylvania, where natural gas is an abundant and economical resource, statewide policies are being adopted that will require reductions in natural gas consumption over the longer term. Natural gas is often seen as a "transition fuel," providing near-term reductions in carbon dioxide emissions relative to other fossil fuels, but gradually giving way to alternative resources.

In the DCF context, however, the difference between a thirty-year or even a fifty-year growth period and a perpetuity is substantial. For example, consider a DCF analysis which concludes that the dividend yield is 3.5 percent and the expected growth rate is 5.0 percent. In a perpetual DCF, those assumptions imply an equity cost of capital of 8.5 percent. However, if the regulated entity is expected to last fifty years rather than forever, and even if the 5.0 percent growth is retained throughout those fifty years, the implied DCF cost of equity capital falls to 7.3 percent. Or, suppose (heroically) that per-share dividend growth will continue forever, but drops from 5.0 percent to 4.2 percent after the first 10 years (matching DOE/EIA's long-term forecast for economic growth), reflecting not a decline but a steady state for natural gas. Even this small change reduces the DCF cost of capital to 7.9 percent. Thus, even using favorable growth assumptions for 10 years and neutral assumptions thereafter moves the DCF cost of equity capital down below the Duff & Phelps cost of equity for an average risk firm. And, of course, assuming continued growth for natural gas utility services with the overall economy is optimistic, since energy economists recognize that energy use as a share of the overall economy has been declining for decades and is likely to continue to do so.

A significant reliance on the DCF model would mean that the Commission must believe that natural gas distribution, a mature business that delivers a finite natural resource whose consumption has a detrimental effect on the planet, will grow forever at a rate that exceeds that of the overall economy. A more reasonable interpretation is that the market expects a lower average growth rate over a shorter time period than that assumed in the "perpetual" traditional DCF, and thus the market likely deems that the cost of equity capital is considerably lower than that offered by traditional DCF calculations.

Q. Please explain what you mean about an implicit bargain between regulators and utilities.

A. It is often observed that a serious problem with industry regulation is that the regulator get too cozy with the regulated entity.[8] In the case of utility regulation, there is some evidence that utilities are increasingly being used by both legislatures and regulators as an arm of the government to implement various social and redistributive policies that would otherwise require taxation and/or legislation. Consider the following policies in Pennsylvania:

- The Commission has recently substantially expanded benefits for lower-income residential customers, which of course must be paid by regular ratepayers. Moreover, the Commission is at least considering abandonment of its long-standing policy of recovering those costs only from the customer class which

[8] This phenomenon is often called "regulatory capture." The issues raised with Boeing's aircraft design flaws fall into this category. See, e.g., https://www.economist.com/business/2019/03/23/regulatory-capture-may-be-responsible-for-boeings-recent-problems. (Reviewed May 21, 2020.)

benefits (based on an insurance model of cost recovery), and effectively imposing broader distribution of the burden (the taxation model).

- The legislature requires that electric distribution utilities ("EDCs") adopt energy efficiency and conservation ("EE&C") programs. While these programs were originally designed (more than thirty years ago) to benefit all ratepayers, the current model requires that regular ratepayers subsidize program participants.[9] The Commission has compounded this redistribution by allowing some natural gas distribution utilities ("NGDCs") to adopt "voluntary" EE&C programs, albeit without the strong performance incentives built into the legislation for EDCs. Moreover, the Commission makes it clear that its economic evaluation of these programs is equivalent to government program evaluation, rather than consideration of the actual costs faced by regular ratepayers. For its evaluation of the cost-effectiveness of EE&C programs, the Commission rejects the use of a cost of capital actually faced by ratepayers, because " . . . Act 129 programs are, in fact, a government policy designed to encourage investments in energy efficiency that would not happen absent policy intervention."[10] In layman's terms, these are "tax and spend" programs.

- The Pennsylvania legislature implicitly imposes environmental taxes on utility rates, both through the renewable portfolio standards ("RPS") and alternative energy certificate ("AEC") mechanisms, and other redistributive mechanisms such as net metering, whereby certain ratepayers with distributed generation can avoid paying for distribution system, energy conservation programs and low-income assistance programs, at the expense of regular ratepayers.

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[9] In the old model, embedded cost rates tended to be below the incremental cost of new service. Since avoided costs exceeded rates, the utility could subsidize conservation to the benefit of all ratepayers, as long as the incremental utility cost was lower than the avoided cost. This principle is reflected in the ratepayer impact measure ("RIM") for EE&C programs, which of course virtually no one pays attention to any longer. Pennsylvania refuses even to consider it.

[10] Final Order, Docket No. M-2019-3006868, order entered December 19, 2019, page 21.

- Perhaps counter-intuitively, the Commission appears to be allowing for substantial cross-subsidization to both encourage the use of natural gas by new customers (at the expense of existing customers) and to prevent the economic abandonment of leak-prone and dangerous gas systems.[11]

Thus, in order to encourage utilities to readily support and implement these public policy programs, regulators may be adopting policies that serve to reduce utility risk and increase shareholder return.

Q. What do you conclude from these observations?

A. In evaluating the Company's revenue requirement filing in this proceeding, particularly with respect to the RoE award, I respectfully request that the Commission consider the following:

- Regulators, including the Commission, have allowed risk premiums in RoE awards to rise substantially above those from thirty years ago, despite reductions in utility risk. The pendulum should begin to swing in the other direction.

- Utilities are substantially protected against economic risks. The same is not remotely true for residential and small business customers in the PECO Gas service territory, particularly in this period of pandemic.

- The Commission should increase its reliance on risk premium methods (including the capital asset pricing model) that reflect long-term historical norms adjusted for the reduced utility risk and reduce its reliance on the DCF method.

- A fundamental policy objective for utility regulation is to prevent abuse of monopoly power, rather than using that power as an opportunity for implied taxation. While achieving various public policy objectives may be desirable, the

[11] See Opinion and Order, Docket Nos. A-2018-3006061 et al., entered January 24, 2020 relating to the full replacement of the "Goodwin-Tombaugh" systems.

Commission should recognize that doing so comes at a significant cost to the "regular" residential and small business ratepayers.

3. Cost Allocation

Q. What is a utility cost allocation study?

A. A utility cost allocation study, in this case the Company's gas class cost of service study ("GCOSS"), 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 generally 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. It is generally agreed 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 generally 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 GCOSS serve in a utility rate proceeding?

A. The GCOSS 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 GCOSS. For rate design, classified costs, such as customer-related and demand-related costs, are used to inform the development of specific rate charges, such as monthly customer and demand charges.

Q. Please describe the various rate classes used in the Company's GCOSS.

A. The Company's GCOSS includes the following rate classes:

Rate GR, General Service Residential: Eligible customers include single-family residences, and multi-family master-metered residences of up to five units. Customers can choose between utility sales service and retail "Gas Choice" transportation service.

Rate GC, General Service Commercial and Industrial: Service is provided to commercial and industrial ("C&I") customers, where "commercial" includes a variety of entities including but not limited to commercial businesses, multi-family master-metered residences (over five units), government entities, institutions and office buildings.[12] For cost and revenue allocation purposes, the Company includes Rate OL Outdoor Lighting Service in the GC class.[13] As described further below, Rate GC includes a small number of transportation customers who purchase backup gas supplies through "Standby Sales Service, " and some negotiated rate service under Rate NGS.[14] GC customers can take utility sales or Gas Choice supply service. This is an extremely diverse class. The Company forecasts that there are 44,450 customers in the FPFTY. Of these, about 3,700 customers have annual load below 85 mcf (the average residential usage) while nearly 2,900 customers have annual load above 18,000 mcf (which is the Company's cutoff for the highest volume rate class).[15]

Rate L, Large High Load Factor Service: This tariff category appears to have been aimed at C&I customers who use gas at a high load factor, implying that the gas is used for process applications rather than space heating.[16] In practice, however, there appear to be only four "regular service" customers remaining on this tariff, while the balance of the load relates to be Rate TS-F transportation service customers who are required to use Rate L for

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[12] See PECO Gas tariff page 18.

[13] There appear to be only three Rate OL customers with minimal volumes and revenues. See Attachment OCA-1-20(a), "JAB-4 OL" tab.

[14] As the details of Rate NGS service are confidential, more detailed information is addressed below.

[15] See RDK WP3.

[16] "Load factor" is industry jargon for the ratio of average demand to peak demand. If a customer uses the same amount of gas on every day of the year, its average demand and peak demand are the same, and the load factor is 1.0 (or 100.0%). Customers who use gas primarily for space heating have relatively low load factors, since the demand on extremely cold days tends to be 4 to 5 times the customer's use on the average day of the year, implying load factors of 0.20 to 0.25 (20 to 25 percent).

their Standby Sales Service volumes.[17] Of the four regular service customers in the FPFTY, one of those customers appears to represent a significant majority of the volume.[18]

Rate MV-F, Motor Vehicle Service - Firm: This tariff provides service to customers who use gas "exclusively as fuel for motor vehicles."[19] The Company forecasts that there will be 15 of these customers in the test year, with relatively high average annual volume of some 29,000 thousand cubic feet ("mcf").[20] Because these loads are not temperature sensitive, the class load factor is high and the unit cost to serve is relatively low. MV-F customers can take utility gas supply or Gas Choice service.

Rate MV-I, Motor Vehicle Service – Interruptible: Service is provided to customers whose sole use of gas is for motor vehicles and who maintain alternative fuel capability. The Company forecasts that there are only two of these customers in the test year, with relatively low volumes. The service is priced at "flex" rates, which are reportedly based on the cost of unleaded gasoline and diesel, but are capped at the tail block volumetric cost for Rate GC inclusive of purchased gas costs.[21] Because prices are bundled, MV-I customers take utility gas supply.

Rate IS, Interruptible Service: This tariff provides interruptible gas sales service to customers with alternative fuel capability whose summer month gas consumption is at least 3,000 mcf (or who also take service under another tariff). The Company forecasts that two customers will take this service, with average annual use of some 20,000 mcf. Tariff

[17] This issue is addressed in more detail below.

[18] Attachment OSBA-I-5(a).

[19] PECO Gas tariff page 59.

[20] It is unclear why PECO Gas treats MV-F customers as a low-volume customer class (see, e.g., PECO Gas tariff page 6), since the average customer volume exceeds that for Rate TS-F. It is similarly unclear why MV-I customers are not treated as low-volume customers, as their average annual usage is below that of the average Rate GC customer.

[21] Attachment OCA-I-22(a). However, the reported January 2020 price is $7.0362 per mcf for both gasoline and diesel, which works out to 82 cents per gallon for gasoline and 93 cents per gallon for diesel. The US DOE/EIA reported the January 2020 wholesale price for diesel at $1.858 per gallon, and the wholesale price for unleaded gasoline at $1.743 per gallon. (See RDK WP2 "Misc".) It is also not clear that the Company's FPFTY rate is consistent with the Rate GC constraint. See OSBA-II-20(b).

charges for distribution service include a posted customer charge and a flex rate volumetric charge, but all distribution revenues are credited to the PGC and PECO shareholders on a 75/25 basis.[22] For base rate cost and revenue allocation purposes, this class provides zero base rate revenues under current policy.

Rate TCS, (Interruptible) Temperature Controlled Service: This tariff provides interruptible service to customers with dual-fuel equipment with rated input of at least 2.1 million BTU per hour and estimated fuel usage of 5,000 mcf during the winter months of December through March.[23] The Company forecasts that 31 customers will take service under this tariff in the FPFTY. Like MV-I and IS, the tariff rate is a flex rate based on the market price of alternative fuels, and customers take utility sales service.[24]

Rate TS-F, Transportation Service – Firm: This tariff offers firm service to non-Choice transportation customers. These customers may also take standby gas supply service, for which they pay Rate GC or Rate L delivery rates. Those volumes and revenues are reportedly included in those rate classes. In addition, some customers who would otherwise take Rate TS-F service take negotiated rate service under Rate NGS, if they can "document a viable, currently available competitive alternative" to regular rate service. These volumes and revenues are included with TS-F. This class also includes customers in a wide range of sizes. Roughly 20 percent of the customers have annual usage below 2,000 mcf, while the largest customers have loads in excess of 100,000 mcf.

[22] Per Attachment OCA-I-22(a), the Rate IS flex rate is the same for all competing fuels, which include No. 2 heating oil, No. 4 heating oil, No. 6 heating oil and reprocessed oil. Like MV-I service, the competitive price appears to be far below actual market prices for those fuels. Unlike Rate MV-I, there does not appear to be a Rate GC cap on Rate IS pricing. Also, the net distribution revenues reported in the Company's proof of revenues for this class fall well short of those reported in Attachment OCA-I-22(a).

[23] According to the Company's response to OSBA-II-21(f), it does not appear that the Company enforces the minimum winter volume levels after initial eligibility is determined.

[24] Per Attachment OCA-I-22(a), the Rate TCS flex rate is the same for all competing fuels, which include No. 2 heating oil, No. 4 heating oil, No. 6 heating oil and reprocessed oil. Like MV-I and IS service, the competitive price appears to be far below actual market prices. Also like Rate MV-I, the competitive price is capped at the Rate GC tail block volumetric rate plus purchased gas costs, although it is not clear that the Company's FPFTY revenues are consistent with that constraint. See OSBA-II-21(b).

Rate TS-I, Transportation Service – Interruptible: This tariff provides basic interruptible transportation service to a customer who arranges for its own gas supply and is willing to accept being interrupted. A showing of alternative fuel capability does not appear to be required. The Company does not consider the peak demands for these customers in its gas supply planning, nor (presumably) does it consider the peak demands of this class in distribution system planning. Rate TS-I customers may obtain standby gas supply service from the Company and are required to pay regular rate tariff delivery charges (Rate L or Rate CG) to deliver those standby supplies. However, standby gas supplies (even delivered at the firm tariff rates) is considered to be interruptible.[25]

Q. Do you agree with the Company's definition of rate classes for cost allocation purposes?

A. No. The Company's tariffs for the TS-F and TS-I classes have substantially different tariff charges for customers above and below annual volumes of 18 million cubic feet ("mmcf"). For example, the Company's volumetric charge for Rate TS-F customers below 18 mmcf per year is more than double the volumetric charge for TS-F customers over 18 mmcf per year. Moreover, these customer classes represent a substantial percentage (28 percent) of the Company's annual throughput, and a not-insignificant amount of base rate revenues (7 percent). In contrast, the Company's GCOSS includes separate class categories for motor vehicle firm, motor vehicle interruptible, interruptible sales and temperature control service classes, which together represent 0.7 percent of throughput and 0.3 percent of base rate revenues. As filed, the Company has no cost allocation basis for the rate differentials in the TS-F and TS-I rate classes.[26]

Q. How do you address this issue?

A. I developed a working model of the Company's electronic cost allocation study, beginning with a replication of the Company's results.[27] I intended to modify my model to segregate costs for both TS-F and TS-I classes between smaller and larger customers in each class.

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[25] OSBA-II-16(d).

[26] OSBA-II-15.

[27] See RDK WP1.

However, the Company declined to provide the details necessary for me to do so.[28] I therefore attempted to address the rate design issues within the TS-F and TS-I classes by reviewing the information available regarding load patterns. Nevertheless, I recommend that the Commission require the Company to separately allocate costs to the smaller and larger TS-F and TS-I customer groups in the future.

Q. Turning to the issues of cost allocation methodology, what are the most important cost allocation issues for an NGDC like PECO Gas?

A. A GCOSS allocates rate base and associated capital costs, distribution expense, customer accounts/service expense, expense, administrative/general ("A&G") expense and taxes.[29] Often, costs are allocated on a derivative basis, based on costs already allocated. For example, depreciation, income taxes and return are often allocated in the same manner as or in proportion to rate base. General plant and A&G costs are typically allocated based on some combination of overall plant allocations or O&M expense or labor allocations. Thus, the overall results of a GCOSS are substantially driven by the allocation of a few large asset accounts. These "big ticket" issues for cost allocation are generally:

- Classification of mains costs, potentially into peak demand, throughput and/or customer components.[30] For PECO Gas, mains represent 50 percent of the Company's gross plant.
- Definition and derivation of the peak-demand allocation factor, including the treatment of interruptible load in the allocator.

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[28] OSBA-II-15(a)-(c).

[29] Distribution, customer accounts/service and A&G expenses are collectively called operating and maintenance ("O&M") expense.

[30] Cost allocation analysts use the jargon "functionalization," "classification," and "allocation." Functionalization involves assigning costs to the specific functions performed by a utility, such as gas supply, transmission, storage, distribution and customer service. Classification involves assigning costs into cost causation categories, such as throughput (also called commodity, volume, energy and average demand), peak demand, excess demand, and number of customers. Allocation is the assignment of classified costs to the various rate classes, using an allocation factor that is representative of the classification factor. For example, costs classified to peak demand may be allocated using each class' share of the NGDC's design day peak demand requirements.

- Allocation of meters and services costs. PECO Gas' meters and services cost are 42 percent of gross plant.

Q. Please describe the basic issues involved in gas utility mains cost causation.

A. Gas distribution mains are installed to meet two basic objectives: (a) to connect the customer with the interstate pipeline system (or other gas supply sources) and (b) to be able to transport sufficient gas to meet the demand of customers downstream under extreme peak conditions.

However, having stated that, it is not easy to develop an analytical model capable of reflecting these cost causation factors. Ideally, the cost of any particular segment of main would only be allocated to those specific customers who are served downstream from that segment. In practice, undertaking such an analysis can be detailed, costly and time consuming. Nevertheless, with the significant improvements in computer modeling of gas distribution systems, one would expect that this approach could be implemented in 2020. Alas, to my knowledge, no Pennsylvania natural gas utility has recently attempted such an approach.[31] And without significant efforts on the part of the utility, it is impossible for outsiders to conduct this type of analysis.

Q. What are the more traditional approaches to mains cost classification?

A. In place of the detailed modeling approaches various analytical models are used. These methods generally focus on the following questions:

- What causation factors best correlate with mains costs?
- Are mains costs causally related to the number of customers? And, if so, how should the "customer component" of mains costs be derived?
- How should mains costs that are not causally related to number of customers be allocated among the various rate classes?

[31] Actually, UGI Gas did prepare such an analysis in 1995. However, in more recent base rates proceedings, UGI Gas abandoned that approach.

Regarding the first question, the traditional cost allocation parameters include throughput, peak demand, excess peak over average demand, and number of customers. As a matter of terminology, a throughput allocation factor is equivalent to an "energy" allocator, a "commodity" allocator, a "volumetric" allocator, and an "average demand" allocator.[32]

Regarding the second question, the common-sense argument (to which I generally subscribe) is that more footage of mains must be installed to interconnect many small customers than to connect one larger customer with the same aggregate load. This is particularly appealing for small to medium business customers who are often more geographically concentrated in commercial areas, thereby requiring less mains footage. This conceptual argument is supported by aggregate industry statistical analysis.[33] Consequently, mains footage is causally related to the number of customers, and therefore mains costs are partially customer-related.

Commission precedent indicates that the Commission has rejected the use of a customer component for gas distribution utilities in Pennsylvania, in the most recent cases of which I am aware (although they date to 2006/2007).[34] However, more recent Commission precedent for electric distribution utilities, where the conceptual arguments regarding cost causation are similar, supports the recognition of a customer component for joint-use distribution plant allocation.[35]

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[32] Average demand is generally measured as annual throughput divided by 365 days. As such, it is arithmetically equivalent to annual throughput when used as an allocation factor. The ratio of average demand to peak day demand is generally referred to as load factor. High load factor customers typically use gas for manufacturing process applications; low load factor customers often rely on gas primarily for heating purposes.

[33] See, for example, a report prepared by Black & Veatch for Gaz Métropolitain, at http://publicsde.regie-energie.qc.ca/projets/235/DocPrj/R-3867-2013-B-0005-Demande-Piece-2013_11_15.pdf, pages 12-16.

[34] I review this precedent in more detail below.

[35] For example, PPL Electric used a minimum system methodology for many years for secondary system plant, and subsequently expanded the minimum system method to primary system plant in its 2010 and 2012 base rates cases. This methodology was fully litigated and explicitly approved by the Commission. *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-2010-2161694, at 46 (Order entered December 21, 2010), and *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-2012-2200597, at 113 (Order entered December 28, 2011.)

In this proceeding, the Company's GCOSS does not include a customer component for mains costs.

Q. Have you incorporated a customer component into your mains cost allocation in this proceeding?

A. While I believe that the economies associated with attaching fewer larger customers provide conceptual support for including a customer component in mains allocation, I have not done so in this proceeding for reasons of Commission precedent for gas distribution utilities.

Q. If there is no customer component of mains costs, what methods are in general use for allocating those costs?

A. The traditional allocation methods include three general approaches: a peak demand method; a peak-and-average ("P&A") method; and an average-and-excess ("A&E") method.

Because mains must be sized to meet the design day peak demand of all downstream customers, I conclude that the peak demand method is most consistent with cost causation.

Other analysts, however, favor the P&A method, in which allocation factors represent a weighted average (most often 50/50) of a throughput allocator and a peak demand allocator. Relative to the peak demand method, this approach assigns more cost to customers who use gas on a more level basis throughout the year (high load factor customers) and less cost to customers whose gas use is primarily for heating purposes. I respectfully disagree with the use of this allocation method, since mains costs are not causally related to average use. A main that serves a high load factor industrial customer with a design day load of 10 mcf per day and a set of low load factor residential and small commercial customers with a combined designed day demand of 10 mcf per day must be sized to meet maximum demand of 20 mcf per day. Each class is equally responsible for the cost of that main. A peak demand allocator would reflect that reality. By contrast, the P&A allocator would assign a majority of the costs to the higher load factor industrial customer.

The A&E allocation factor is a weighted average of average demand (i.e., throughput) and "excess" demand. Excess demand is measured as the difference between peak demand and average demand. Because this allocation factor consists of an average demand component and a "peak minus average" demand component, it is typically more similar in magnitude to a peak demand allocator than to a P&A allocator. However, this observation depends on the weighting factor used to derive the A&E factor. Under specific conditions, namely when the weighting factor is based on the system load factor and there is no diversity of demand across classes, the P&A allocator is arithmetically identical to the A&E factor.

In this proceeding, the Company uses the A&E allocation method (denoted average and extra), and it generally relies on a system load factor weighting of the average and the excess components. As such, the A&E allocator used by the Company produces results that are nearly identical to those that would result from a peak demand allocator.

Q. Please review Commission precedent with respect to mains cost allocation methods.

A. In a case involving PPL Gas at Docket No. R-00061398, the Commission approved an allocation of all mains costs using a variant on the A&E allocation method advanced by the utility expert witness. In that proceeding, the approved weighting was 40 percent to average demand and 60 percent to excess demand. This weighting was not based on system load factor.[36] Also, in a case involving the Philadelphia Gas Works ("PGW") at Docket No. R-00061931, PGW proposed to classify some mains costs as customer-related and the balance as demand-related, and proposed to allocate demand-related costs using a peak demand allocator. However, the Commission concluded that no mains costs should be classified as customer-related, and that mains costs should be allocated using a variant of the A&E allocation method advanced by the expert from what was then the Commission's Office of Trial Staff. In the PGW proceeding, the approved weighting was 50 percent to average demand and 50 percent to excess demand. This weighting was also not based on system load factor.[37] Moreover, the Commission explicitly indicated that the allocation

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[36] PA PUC et al. v. PPL Gas Utilities Corporation, Docket No. R-00061398 (Order entered February 8, 2007), pages 112 – 114.

[37] See PA PUC v. Philadelphia Gas Works, Docket No. R-00061931, Recommended Decision, July 24, 2007, page 63, and PA PUC v. Philadelphia Gas Works, Docket No. R-00061931 (Order Entered September 28, 2007), page 80.

should reflect "both annual and peak" demand. Going further back, the Commission explicitly approved the use of the P&A method in a proceeding involving National Fuel Gas Distribution at Docket No. R-00942991.

Q. What mains cost allocation method have you relied upon in this proceeding?

A. Consistent with Commission precedent, I accepted the Company's use of an A&E allocation factor. However, while I disagree that mains costs are causally related to average demands, I modified the Company's A&E allocation factor to implicitly include an average demand component. In particular, I modified the A&E allocator to be consistent with the Commission-approved practice at the Philadelphia Gas Works ("PGW"), wherein the average and excess components are each weighted at 50 percent.

Q. Please explain how the Company quantitatively develops the A&E allocation factor.

A. The A&E factor consists of three components: class average day demands, class excess day demands, and the weighting factor.

Average day demands are simply the total test year forecast volume divided by 365 days. The average demand allocator is arithmetically equivalent to an annual volume commodity allocator.

The excess demand allocator is based on peak demand *minus* average demand. Thus, the Company must develop a peak demand measure for each class. And it must do so for firm service and interruptible service customer classes. For firm service customers, the Company uses design day demands, which reflect the Company's estimate of the load level under design weather conditions. For interruptible service customers, the Company simply uses the average day demands as the peak, meaning that the excess demand factor in the A&E is zero. I discuss this issue at some length below.

The weighting factor determines how much the A&E allocator relies on average demand and how much relies on excess demand. Weighting the A&E with system CP load factor is the traditional approach. The Company uses an approach that includes all rate classes in the average day demand and only the firm peak design day demands, producing a 25.23 percent load factor for weighting.[38]

Q. Regarding the issue of developing peak day demands, how does the Company develop its design day demands for use in the A&E allocation factor?

A. Design day demands for the five firm service rate classes are shown in Exhibit JD-6, page 5, which reports that these values were sourced from "April 30, 2020 1307 (f) filing." The April 30, 2020 PGC filing does include the design day values used in the cost allocation study for Residential, Commercial, and Firm Transportation at FORM-IRP-GAS-1B page 2. The Company then backs its estimate of MV-F design day demand out of the Commercial value, based on an assumed 100 percent load factor.[39] The design day demand for Rate L is then set based on the standby demand for firm transportation service, also from the Section 16, page 7 of the PGC filing. Note that the Company appears to include *only* standby peak demand in Rate L in the GCOSS.

However, when pressed for more information about these design day demands, the Company (a) denies that any class-specific design day values are developed in the PGC filing,[40] and (b) acknowledges that there are four "pure Rate L customers" in Rate L, even though the Company does not appear to assign any design day demand to those customers.[41]

Given these apparent contradictions, my analysis of the design day demands is preliminary, pending clarification from the Company regarding the inconsistencies.

With that caveat, I have four concerns:

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[38] By way of contrast, a 24.48 percent load factor would produce an A&E allocator exactly identical to a peak demand allocator. The PECO A&E allocator is therefore tilted only slightly to average demand but is almost entirely peak-related.

[39] See attachment to OCA-I-2(a).

[40] OSBA-II-2(a).

[41] OSBA-II-13.

First, in the Section 1307(f) proceeding, the Company develops a design day demand value for the combined load of the firm service classes that are not daily metered. Because the Company bases its design day demand estimates from daily throughput, it derives the demand for those customers by taking total system sendout and backing out daily demands from those customers with daily meters. I'll call that the "Small Firm" group. How the Company segregates that the aggregate Small Firm design day demand value among the firm service classes is not known with certainty, since the Company effectively declined to respond to the OSBA interrogatory on that subject (OSBA-II-2(a)).. However, the Company's workpapers indicate that the design day load factor for the GR customers and the GC customers (including MV-F) is virtually identical. I therefore conclude that the Company has not made any independent evaluation of the load patterns of the various rate classes, but simply split the Small Firm design day demands between residential and all other based on volumes. Thus, the key allocation factor for mains costs apparently fails to recognize the difference in load patterns between residential and non-residential customers.

My remaining three concerns involve Rate L and Rate TS-F. The Company's GCOSS shows annual throughput for Rate L of 16.6 mcf, and design day demand of 1,416 mcf/day, with an implied load factor of 3.2 percent. Such a load factor would be nonsensical for any regular rate class, and it is particularly nonsensical for a "high load factor" rate class. Not surprisingly, this combination of load and peak demand for Rate L results in costs being assigned to the Rate L class that are far in excess of the class revenues.

Best I can determine, this problem results from the following factors.

- The Company does not appear to assign any design day demands to Rate L related to the four "pure" Rate L customers.[42]

- The Company requires that regular rate service, including Rate L, be used in conjunction with Rate TS-F when a transportation customer desires backup gas supply service. It is not unusual for a gas utility to provide backup gas sales

[42] The Company's PGC pre-filing indicates, "The daily standby sales service requirement is 1,416 MCF and is based on the sum of the standby sales quantities for Rate TS-F customers."

service, but in my experience, it is unusual for a utility to require the customer to pay a transportation rate for backup utility supplies from a different rate class. In effect, PECO tells its TS-F customers that if they want to buy back-up gas supply from the Company in the event their suppliers fail to meet their requirements, they must deliver that gas at a different rate than if their own gas supplier had provided the gas.[43] Thus, best I can tell, the Company has included the design day demands associated with TS-F customers standby loads in with regular Rate L customer loads.[44] However, because the demands for the standby load come with relatively little volume, the Company shows an unusually low load factor for the "high load factor" class.[45] A much superior cost allocation approach would be to include the volumes, peak demands, and associated base rate distribution revenues for the standby supplies in with the rest of the TS-F loads.

- The Company indicates that the 68,000 mcf/day design day demand for Rate TS-F is from the PGC filing. The PGC filing does show 68,000 mcf/day for all TS-F customers, but it offers no explanation as to how that value was derived. Moreover, the Company does not appear to have adjusted that value downward in order to take out demands related to customers served by directly assigned meters, as it does for the TS-F volumes.[46]

Q. What adjustments have you made to correct for these errors and inconsistencies?

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[43] As discussed further below, this rate design approach appears to be both unduly discriminatory and needlessly complicated. Transporting gas for TS-F and TS-I customers should reflect the Company's cost of transporting the gas regardless of whether the gas is supplied by an NGS or the Company.

[44] See OSBA-I-5, OSBA-II-13, OSBA-II-16.

[45] The Company also indicates that the revenues associated with the standby loads are included in Rate L revenues, not Rate TS-F. By way of contrast, however, the Company provides standby service to Rate TS-I customers, and it similarly requires that service to be delivered under regular firm service tariffs GC and L. In that case, however, the revenues appear to be reflected in the TS-I class. See the Company's proof of revenues in Exhibit JAB-4, pages 9-11.

[46] The Company's response to PAIEUG-III-2 does not indicate that the Company made an adjustment to design day demands, although it does make an adjustment to the average day demands. This may be why the class load factor for the non-directly-assigned TS-F customers is a relatively low 37 percent.

A. I developed design day demand load factors using a statistical analysis of monthly class loads and heating degree days, and applied design day conditions to the statistical analysis. I made these calculations both for a three-year historical period and the future test year. The details of this analysis are provided in RDK WP1. Average design day class load factors for the firm service classes are shown in Table IEc-2 below, which includes the Company's load factors, an average of my historical and test year statistical results, and the values used in my GCOSS (which reflect a scaling of the smaller customers to the Company's design day).

Table IEc-2
Firm Service Design Day Load Factors

	PECO GCOSS	RDK Analysis	RDK GCOSS
GR	20.9%	21.5%	20.1%
GC	20.9%	24.1%	22.5%
L	3.2%	43.1%	40.2%
MV-F	100.0%	104.0%	100.0%
TS-F	36.8%	51.6%	51.6%

Sources: RDK WP2

As shown, the load factor for the GC class is modestly higher than that for the GR class based on my analysis of actual weather sensitivity. Also, the Rate L and Rate TS-F load factors are more credible based both on volume history and the Company's load forecast. I therefore adjusted the Company's design day peak demands to reflect these patterns. I generally relied on an average of the history and the forecast load factors, normalized to be consistent with the Company's design day forecast for the non-daily-metered firm customers.

Q. Let's turn to the issue of the Company's treatment of interruptible service for mains cost allocation. Please start with a discussion of the conceptual issues of allocating costs to interruptible service customers.

A. As its name implies, interruptible service customers take service from a natural gas utility that is subject to being interrupted, typically during periods of extreme weather and correspondingly high system demand. In exchange, the customer is offered a rate below that for firm service.

A gas utility may offer an interruptible service option for two reasons. First, being able to interrupt a utility gas sales customer (who buys gas from the utility) during extreme periods will allow the utility to reduce its need for design day capacity. This cost savings typically involves reducing the need for storage deliverability capacity and/or peak shaving capacity such as LNG. Thus, allocating gas supply costs to these customers generally reflects a reduced charge for those services.

Second, the utility may offer interruptible gas transportation service, which would allow the utility to avoid making reliability and expansion investments in its distribution system by being able to interrupt the customers when the distribution system is stressed. Cost allocation for these customers thus tends to reflect a reduction in costs that are related to peak system demand relative to firm service customers.

Unfortunately, these two rationales for offering interruptible service are often muddled in utility cost allocation and rate design, particularly where legacy rates are in place associated with the historical practice of bundled gas supply and distribution service. For example, the interruptibility of utility gas supplies (often for economic reasons) may not provide any distribution benefits. For costing purposes, such a customer should be assigned a reduced gas supply costs, but no reduction to base distribution rate costs.

As a general rule, for utility costing purposes, the system benefits of interruptible sales service should reflect the savings in gas supply costs. In Pennsylvania, interruptible sales service options should be addressed in annual Section 1307(f) purchased gas cost ("PGC") proceedings. Distribution system benefits related to customer interruptibility are addressed in base rate proceedings.

Q. Please discuss the Company's treatment of interruptible service customers in developing its mains cost allocation method.

A. In this case, the Company proposes to treat customers in four rate classes as providing distribution benefits associated with their interruptibility, namely the MV-I, IS, TCS, and TS-I rate classes.

Of these, it does not appear that MV-I, IS or TCS customers offer any material distribution service benefits. For Rate MV-I, there has been no interruption for at least five years.[47] For Rate TCS, the Company has interrupted the class only once in the past five years, which the Company reports was for distribution reasons.[48] For Rate IS, the nature of the service appears to be related to the interruptibility of gas supply.[49] In contrast, the TS-I class was interrupted at least three times in the 2017 to 2019 period.[50] Since TS-I is transportation service, the class was necessarily interrupted for distribution reasons.

For costing purposes, there does not appear to be any justification for reducing the assignment of demand-related costs to these customers. The Company does not develop design day demands for these customers, because it bases its design day demand allocator on its gas supply analysis from the annual Section 1307(f) proceeding. As I indicated, however, the benefits of distribution interruptibility are not the same as those for gas supply interruptibility. For my cost allocation simulation, therefore, I estimated design day demands for customers in those classes and treated those customers as firm service customers for distribution cost allocation purposes.

For Rate TS-I, there is some evidence that the class is credibly interruptible for distribution system reasons. Some analysts argue that because a class is interruptible, the Company does not build capacity to meet those customers, and thus zero capacity costs should be assigned to the class. Instead, the Company proposes to use a methodology that substantially reduces but does not eliminate the allocation of capacity-related costs to this

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[47] OSBA-II-20(a).

[48] OSBA-II-21(a). The Company did not elaborate on the nature of the distribution constraint.

[49] Attachment OSBA-II-10(a), page 32-33.

[50] Attachment OCA-I-15(a).

class.[51] It does so by setting the "excess" portion of the allocation factor to this class to zero. While there is not much in the way of theoretical justification for this approach, it is not uncommon or even necessarily unreasonable. However, since the Company's A&E allocation factor is weighted at 25.3 percent average and 74.7 percent excess, the Company's allocation factor assigns relatively little mains cost to the interruptible classes. With the 50/50 A&E weighting in my GCOSS, the allocation of mains costs to interruptible customers is increased, but it remains well below that for firm service customers.

Q. Please explain how you modified the Company's design day demands and excess allocation factors to reflect your analysis of the interruptible classes.

A. My GCOSS includes design day demands for the MV-I, IS and TCS classes. Because the MV-I class has a 100 percent load factor, this change has no impact on the excess demand allocator and thus very little impact on the GCOSS. However, this change does serve to increase costs assigned to the IS and TCS classes.

Q. Please explain how the Company allocates meters and services costs.

Regarding the allocation of meters and services costs, the Company uses a modified direct assignment approach, which is generally consistent with sound utility cost allocation practice.

The Company's meters cost allocation is shown in SDR-COS-7. While there is no detailed description for this exhibit, it generally appears that the Company has compiled the number of meters by size for each rate class and applied the unit cost for each sized meter (inclusive of installation cost), to total the costs for each rate class. I do not believe the supporting calculations have been provided for this exhibit, and there are some anomalies in the results.[52] The resulting meters cost allocator is then applied to both meters plant and meters installation plant in the GCOSS. Pending clarification of the anomalies, I conclude that

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[51] Note also that the mains responsibility for some TS-I customers is addressed through direct assignment rather than allocation.

[52] From the IS column, the meter cost for a size "28" meter is $2,824, and from the MVI column the meter cost for a size "20" meter is $1,572. However, if those values are arithmetically inconsistent with the average meter cost for Rate L.

this is a reasonable approach for meters cost allocation. I add that the meters cost allocator reinforces how heterogeneous the Rate GC class is, as it shows that the class is served by 38 different meter sizes. Over 75 percent of the Rate GC meters are the same size as the most common Residential meters (sizes 15 to 20 and 33), although they are tilted more to the larger sizes than the Residential class.

Regarding services costs, the Company's allocation method is shown in Attachment OCA-I-2(a). As shown, the Company compiles its average service installation cost in three rate categories, namely Residential, Small C&I and Large C&I, for each of the past five years. It then categorizes each GCOSS rate class into one of the three groups and multiplies the unit service cost by the number of customers. As a practical matter, 99.6 percent of the Company's services costs are allocated to either the Residential class or Rate GC.

This approach is imperfect. First, the Company does not track whether the service installations over the past five years served multiple customers. Thus, it is unclear whether the service line costs are representative of the service lines for the entire population. Second, by multiplying the unit cost by number of customers, the Company fails to recognize that multiple customers are often served by a single service line. In particular, the Company indicates that a relatively high percentage of Rate GC customers are served by a service line that serves multiple customers. Thus, the Company's method would serve to overstate costs assigned to Rate GC.

However, the Company considers all Rate GC and the Rate MV-F customers to be in the Small C&I category, when in fact the MV-F customers and small but non-zero minority of the Rate GC customers are of similar size to the Large C&I customer group. This assumption therefore serves to understate costs assigned to Rate GC and Rate MV-F.

While the Company's method is imperfect, I conclude that the biases relating to allocating costs to Rate GC are in opposite directions. Moreover, it is not uncommon for services cost allocation in Pennsylvania to rely on even less information than that compiled by PECO Gas for this evaluation. I therefore made no changes to services cost allocation in my GCOSS.

Q. Do you have other recommendations regarding the GCOSS methodology?

A. I made the following technical changes to the Company's GCOSS model, which generally do not have a material impact on overall allocated costs:

- Residential current-rates revenue is set to equal the proof of revenues in Exhibit JAB-4;
- Throughput volumes for MV-F and MV-I are set equal to the proof of revenues in Exhibit JAB-4;
- Costs in Account 909 are allocated in proportion to the Company's CUSTADVT allocator, which appears to have been the Company's intent, but it inadvertently assigned all costs to the GC class;[53]
- I adjusted the Company's DISTPLTXAR allocation factor because it double-counts certain plant items.

Q. How do the results of your modified GCOSS compare to the Company's results?

A. Table IEc-3 below shows class rates of return at present rates for (a) the Company's GCOS, (b) my replicated version of the GCOS with Rates IS and XD-I split, (c) the effects of the modest changes I propose, and (d) the implications of treating Rate IS customers as firm for cost allocation purposes.

[53] OSBA-II-7(b).

Table IEc-3 Comparative GCOSS Results: Class Rates of Return at Current Rates		
	PECO Gas GCOSS	**RDK Alternative**
GR	4.7%	4.7%
GC	8.1%	9.0%
L	-2.1%	18.9%
MV-F	12.6%	4.6%
MV-I	32.2%	24.3%
IS	-5.6%	-5.1%
TCS	44.4%	13.4%
TS-F	6.5%	6.7%
TS-I	8.8%	3.2%
Total	**5.7%**	**5.7%**
Sources: RDK WP1, RDK WP2		

The following are my observations regarding the results of my GCOSS:

- The significant increase in Rate L class rate of return in my GCOSS primarily reflects the changes in design day demand for that class, to be consistent with actual load patterns.

- The reduction in class rate of return for the TS-I class is primarily due to the change in the weighting of the A&E allocation factor, which increases the cost responsibility related to average demand and reduces the importance of excess demand (which is zero for TS-I).

- Although Rate MV-F is firm, the change to the A&E allocator also causes a significant reduction in class rate of return, since MV-F has a 100 percent load factor and therefore zero excess demand.

- Including a design day demand factor and changing the A&E allocator also reduces the MV-I and TCS class rates of return, but both classes continue to exhibit class rates of return well in excess of system average.

- My changes have only modest impacts on allocated costs for the major firm service classes, namely GR, GC and TS-F. While each of the major changes I propose has material impacts on these classes, the effects tend to offset.

4. Revenue Allocation

Q. What is revenue allocation?

A. Revenue allocation is the assignment of the dollar net increase or decrease to each of the Company's rate classes in a base rates proceeding. In contrast, *rate design* determines how the allocated revenue is recovered from individual ratepayers within each class. From a cost recovery standpoint, revenue allocation addresses *inter-class* cross-subsidization issues, while rate design addresses *intra-class* cross-subsidization issues.

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

A. In general, allocated cost is the primary criterion used by regulators in the revenue allocation process. Most utilities and regulators adopt a policy in a base rates proceeding of attempting to move revenues more into line with allocated costs by varying the magnitude of the rate increases for the individual classes. However, regulators also subject the rate increases to other non-cost criteria of ratemaking. Of the traditional rate design criteria, the most common non-cost considerations in the revenue allocation process are:

- the *gradualism* principle (or avoidance of "rate shock"), in which large rate increases for individual customers or classes of customers are avoided; and
- the *value of service* principle, which is often used to mitigate rate increases for customers or customer classes with relatively elastic demand.[54]

Using these criteria, the utility will develop a proposal for assigning the increase in the revenue requirement among the classes that reflects both cost and non-cost considerations. With this proposal, the GCOSS can be simulated at both present and proposed rates to

[54] See, for example, Principles of Public Utility Rates, Second Edition, Bonbright, Danielsen, Kamerschen, 1988, pages 383 to 387. Note that the criteria in this text apply to the overall development of a utility rate structure. The criteria that I discuss in this testimony are those that apply to the revenue allocation portion of the process, which is only one aspect of the overall development of utility rates.

evaluate the magnitude of "progress" that has been made toward the policy of achieving cost-based rates.

Q. What does the Company propose for revenue allocation in this case?

A. The Company's proposed revenue allocation is shown in Table IEc-4 below (copied from Table IEc-1):

Table IEc-4
PECO Gas Proposed Revenue Allocation

	Increase $000	Increase %	ROR Current	ROR Proposed
GR	41,720	17.9%	4.7%	6.5%
GC	17,310	17.0%	8.1%	10.2%
L	35	46.0%	-2.1%	-0.9%
MV-F	97	20.5%	12.6%	16.1%
MV-I	1	10.6%	32.2%	35.3%
IS	0	--	-5.6%	-5.6%
TCS	56	8.1%	44.4%	47.4%
TS-F	5,370	32.1%	6.5%	9.7%
TS-I	2,378	25.0%	8.8%	12.0%
Total	**$66,787**	**18.5%**	**5.7%**	**7.7%**

Sources: RDK WP1, Exhibit JAB-1

Q. Is the Company's revenue allocation consistent with the results from its GCOSS?

A. No. Table IEc-4 above shows the Company's proposed rate increase by class, and the class revenue to cost ratio at present and proposed rates using the Company's GCOSS methodology.[55] As shown, under the Company's methodology, the GC, MV-F, MV-I, TCS and TS-I classes all exhibit class rates of return at present rates that are not only above system average but are above the Company's actual proposed rate of return. Nevertheless, the Company proposes to assign material rate increases to all those rate classes. Thus, even

[55] The revenue-cost ratio is, of course, the ratio of class revenue to class allocated cost, where class allocated cost includes the allowed return on capital and associated income taxes. The revenue-cost ratio is a metric that is far superior to the oft-misused indexed rate of return metric for revenue allocation purposes, because the indexed rate of return metric can imply progress toward cost-based rates when none exists.

if the Commission approves the Company's GCOSS as filed, the revenue allocation proposal should be revisited.

At this writing, it is my understanding that the Company's revenue allocation was based on an error in the originally filed GCOSS (that was corrected in response to OSBA-I-2), and that it is reconsidering its revenue allocation proposal. I would observe that the revenue allocation that is presented in the Company's (uncorrected) Exhibit JAB-1 shows nonsensical results. For example, the Rate GC class rate of return at present rates is reported at 8.11 percent, but after applying a 17.0 percent increase, the class rate of return falls to 7.85 percent. This is not arithmetically possible.

Q. Have you developed an alternative revenue allocation proposal?

A. I have. In so doing, however, I have separated a traditional revenue allocation proposal from a variety of other changes that I propose to rate recovery and overall tariff design.

The traditional revenue allocation proposal accepts the Company's positions with respect to (a) recovery of costs from negotiated rate customers, (b) the redirection of Rate IS margin revenues to the PGC and PECO Gas shareholders, and (c) revenue increases from MV-I and TCS classes.

I then address each of the other issues and make recommendations as to how the net revenue effect of those changes should be applied, if the Commission accepts my recommendation.

Q. Please explain your traditional revenue allocation proposal.

A. My revenue allocation proposal relies primarily on the results of my GCOSS, as tempered by principles of rate gradualism. Specifically, I used the following process:

- Calculate the dollar value of rate increase or rate reduction needed to align class revenues with class allocated costs in my GCOSS.

- Adjust the values calculated in the first step to eliminate any rate reductions. I make this adjustment to reflect principles of rate gradualism (recognizing that it is not consistent with the aim of moving the Rate GC revenues into line with allocated costs in this proceeding). The largest dollar value impact of this step is to increase revenues assigned to the Rate GC class by $10.6 million. However, adjustments are also made to the Rate L, MV-I and TCS classes which would otherwise see rate decreases.

- Adjust the cost-based increases downward to avoid applying a rate increase to any class that would exceed 1.5 times the system average, namely the MV-F and TS-I classes. This adjustment is also made in the spirit of rate gradualism. Given the large magnitude of the overall rate increase, I judged a 1.5-times factor to be reasonable. For the TS-I class, I limited the increase to 1.5 times system average as applied only to the non-negotiated rate customers.

- Adjust the cost-based rate increases for the MV-I, IS, and TCS classes to be consistent with the Company's proposal. As I indicated earlier, I do not understand how the Company determined that it will get a rate increase for the MV-I and TCS classes, but I implicitly accept the Company's FPFTY revenue from these customers.

- I then summed the adjustments from the preceding three steps, which produced a net reduction of $7.0 million. I used that $7.0 million to reduce the rate increases to the Residential (Rate GR) and TS-F rate classes. I only credit these classes because (a) they were not already capped based on the 1.5 times system average factor (MV-F, TS-I), and (b) they are not set based on market-based rates (MV-I, IS, TCS).

Following the reallocation, I confirmed that no class exhibited a rate increase in excess of 1.5 times the system average. The results are shown in Table IEc-5 below and detailed in RDK WP2.

Table IEc-5
RDK Proposed Revenue Allocation

	Increase $000	Increase %	ROR Current	ROR Proposed
GR	62,937	27.0%	4.7%	7.4%
GC	0	0.0%	9.0%	9.0%
L	0	0.0%	18.9%	18.8%
MV-F	132	27.7%	4.6%	7.2%
MV-I	1	10.6%	24.3%	26.8%
IS	0	--	-5.1%	-5.1%
TCS	56	8.1%	13.4%	14.7%
TS-F	1570	9.4%	6.7%	7.6%
TS-I	2,094	22.0%*	3.2%	4.8%
Total	**$66,787**	**18.5%**	**5.7%**	**7.7%**

* The increase for this class is 27.7 percent (1.5 times system average) for customers not subject to negotiated rates.

Sources: RDK WP2

Q. Please comment on the Company's revenue from negotiated rate customers.

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Q. If the Commission determines that the Company's negotiated rate discounts are not sufficiently justified, how should the additional revenues from these customers be reflected in your revenue allocation proposal?

A. For the TS-F class, any additional revenues from negotiated rate customers should be used to reduce the rate increase required from the other TS-F customers. For the TS-I class, the additional revenues should first be used to reduce the rate increase required from regular rate TS-I customers. However, if the revenue increase is more than sufficient to cover TS-

I revenues into line with allocated cost, the additional revenues should be credited to the Rate GR Residential class.

Q. Please address the treatment of Rate IS for revenue allocation purposes.

A. As I indicated earlier, Rate IS is essentially an interruptible gas sales service, consisting of two relatively large customers in the FPFTY. Service is interruptible, and rates are reset monthly reportedly at the cost of alternative fuel. For this service, none of the implied distribution margin is credited to base rates. Rather, the margin is split 75 percent to the PGC and 25 percent to the shareholders. In effect, these customers provide zero contribution to base rates. I have two recommendations regarding this service:

First, I recommend that margins from this service be used to offset base rates costs, for the following reasons:

- This tariff is an anachronism, dating from the time before retail competition for gas supply. The relevant Commission decision in this respect dates back to January 1980.[61] The Commission approved the pricing in 1979 in part based on its "being in accordance with the national energy policy," in the midst of the Iran hostage crisis during the Carter administration.
- Using base rate margins as a credit to PGC rates improperly subsidizes utility gas supply service at the expense of all base rate customers. This mechanism is therefore both anti-competitive and unfair to transportation service customers.
- There is no obvious reason why the Company should be allowed an extra profit on this service through the sharing mechanism, relative to any of its other tariff offers. Since prices are set by the price of alternative fuels, the extra profit earned by the Company is not particularly related to any of its efforts to retain these customers, but primarily by the relative price of alternative fuels. Moreover, as

[61] OSBA-II-10(a).

there are only two customers taking service under this tariff, the incentive does not appear to have been particularly successful in attracting new customers.[62]

- While it is true that the base rate margins the Company will earn under the tariff as currently structured are uncertain, they are no more uncertain than those for Rate TCS or Rate MV-I. As the Company is able and willing to estimate margins for those services in this base rate proceeding, it could also do so for Rate IS.

Based on the information currently available to me, the approximate margin from this service is $2.64 per mcf, which implies distribution margin of about $111,000, inclusive of customer charge revenue. In the event the Commission adopts this recommendation, the increased base rate revenues from Rate IS should be used to offset my proposed increases to the Residential and TS-F classes.

Second, the Company should consider eliminating the Rate IS tariff as a base rate option, for the following reasons:

- This service is primarily an interruptible gas supply service. PECO Gas should be free to offer interruptible gas supply service within its gas supply function, to be adjudicated in annual Section 1307(f) proceedings. Moreover, the market price uncertainty for these sales can continue to be accounted for in the reconciliation of the PGC.

- There is little obvious benefit to the interruptibility of this service to firm base rate customers in terms of avoided distribution costs.

- The pricing mechanism does not appear to reflect the cost of the alternative fuels upon which it is based. The January 2020 Rate IS price was $5.0035 per mcf, which works out to 66 cents per gallon for No. 2 heating oil and 72 cents per gallon for No. 6 fuel oil, both being well below contemporaneous fuel oil prices.

[62] UGI Gas put forward proposals with conceptual similarities for sharing its interruptible service margins in base rates cases at Docket Nos. R-2015-2518438 and R-2018-3006814. The proposals were withdrawn as part of settlement agreements.

Q. Please address the treatment of Rates MV-I and TCS for revenue allocation

Like Rate IS, the MV-I and TCS tariff options offer interruptible service at bundled sales/delivery rates, reportedly based on competitive fuel. In effect, these tariffs are set with the aim of maximizing the distribution revenue that can be earned from customers who competitive fuel alternatives. I expect that when these tariffs were established, the resulting implied distribution rates were generally set below regular base rates charges. With the expansion of local gas supplies from hydraulic fracturing, gas prices are lower and these tariffs now result in implied distribution charges that are higher than regular base rate charges. While the tariff indicates that the rates are capped at regular Rate GC rates, the Company's proof of revenue for the FPFTY appears to indicate otherwise.

Moreover, the interruptible nature of these supplies provides little or no benefit to the gas distribution system. Rate MV-I customers have not been interrupted for at least five years, and TCS customers were interrupted once over the past five years.

In my view, it is time to retire these tariffs, for a number of reasons:

- Regarding Rate MV-I, there are only two small customers taking service on this tariff. Moreover, natural gas vehicles do not appear to be a winning technology, and special rate treatment serves little purpose.
- The Company's proposed FPFTY rates for both services exceed the cost of Rate GC firm service.
- These tariffs are anti-competitive, in that they are designed to provide a lower-cost delivery service to customers taking utility gas service than the delivery options that are available to customers who use competitive natural gas suppliers. If the Company is going to offer discounted interruptible transportation service to smaller customers, it should offer that service to both sales and shopping customers.

I also observe that the Philadelphia Gas Works ("PGW") had a number of similar tariff mechanisms, and I believe they have generally been abandoned. As I mentioned earlier, PECO Gas can also offer interruptible gas supply service if it so chooses, but that is a matter for PGC proceedings.

5. Rate Design for Non-Residential Customers

Q. What issues do you address regarding rate design for non-residential customers?

A. I address the following:

- The Company's inequitable treatment of Rate GC customers in its DSIC cost recovery mechanism;
- Rate GC tariff design, notably the proposed increase in the customer charge and the steep decline in the volumetric block rates, resulting in much lower rates for large customers;
- Recovery of distribution system costs from TS-F and TS-I standby customers;
- Rate differentials in the TS-F and TS-I tariffs above and below 18 mmcf per year.

Q. Please discuss your concern regarding the Company's DSIC mechanism.

A. In reviewing the Company's proof of revenue exhibit in this proceeding, I observed that the DSIC percentage rate for the Rate GC class appeared to exceed both the 5 percent statutory limit for the DSIC and the corresponding DSIC rate for the Rate GR residential class. I requested an explanation from the Company in OSBA-I-4 and followed up with OSBA-II-22.

The DSIC mechanism was designed to allow utilities to recover certain distribution system replacement costs from customers without the need for a base rate proceeding, subject to an upper limit on the percentage charge and other consumer protections. It was enabled by the Pennsylvania legislature in Act 11 of 2011 and implemented by the Commission, notably in Docket No. M-2012-2293611.[63] In my experience, a DSIC percentage is calculated by determining the costs associated with DSIC-eligible spending and dividing

[63] https://www.puc.pa.gov/filing-resources/issues-laws-regulations/system-improvement-charges-act-11-of-2012/

that amount by total base distribution revenues. That percentage is then applied to each rate class.

PECO Gas does not follow that procedure.

As shown in Attachment OSBA-I-4(c), the Company develops its overall DSIC percentage rate by taking eligible expenses and dividing by total base distribution revenue (apparently excluding Rate TS customer charge revenue), capped at 5 percent. To recover that charge, the Company then allocates the DSIC costs among the rate classes based on *volumetric* charge revenue. My summary of the Company's method is shown in Table IEc-6 below.

Table IEc-6
PECO Gas DSIC Allocation Method ($000)

	Customer Charge Revenue	Volumetric Charge Revenue	Allocated DSIC Cost	DSIC Percent of Base Rates
Residential	69,709	152,484	10,044	4.5%
GC	15,229	79,864	5,261	5.5%
L	12	59	4	5.5%
MV-F/MV-I	7	443	29	6.5%
IS	5	30	2	5.6%
TCS	47	603	40	6.1%
TS-F/TS-I*	0	24,608	1621	6.6%
Total	**85,009**	**258,090**	**17,000**	**5.0%**

* It is unclear why the Company does not include any customer charge revenue for Rates TS-F and TS-I in determining the DSIC percentage. In practice, however, this allocation appears to result in a DSIC rate for the TS-F class of under 5 percent of base rate revenues. See RDK WP1 "RevPrf."

Source: Attachment OSBA-I-4(c), RDK WP2

The Company does not dispute that its method results in disparate DSIC percentage among the rate classes. The Company cannot cite to any Commission decision authorizing this approach. And the Company does not know of any other Pennsylvania utility which applies this cost allocation method for the DSIC.[64]

[64] OSBA-II-22(b), (d) and (e).

In my (non-legal) view, this approach does not appear to be consistent with the legislation or Commission DSIC implementation rules, which rely on percentages based on total base distribution rates. Moreover, it is not justified on a cost causation basis, because eligible DSIC costs include those recovered in both customer charges and volumetric distribution charges.[65]

To remedy this inequity going forward, I recommend that PECO Gas modify its allocation procedures to distribute DSIC-eligible costs among the rate classes based on total base rate revenues, in the same manner that the overall DSIC percentage is determined.

As shown in Table IEc-6, it also appears that PECO Gas has been applying DSIC percentages to certain rate classes above the statutory limit of 5 percent, which in my (non-legal) view appears to be inconsistent with the intent of Act 11. However, I defer to OSBA counsel as to whether those charges were unlawful and whether the excess charges should be refunded to ratepayers. I am advised that OSBA will present its legal opinion in its briefs in this matter.

Q. Please describe the Company's proposal for the Rate GC tariff.

A. Rate GC currently consists of a customer charge, a two-step declining block commodity charge, supplemented by the DSIC and TCJA charges that apply to all customers, and the MFC and GPC charges for recovery of additional base rates costs. As explained earlier, the TCJA and DSIC get zeroed out with new base rates (although the DSIC will go back into effect when investment minima are reached, generally near the end of the future test year).

Table IEc-7 below shows the current and proposed changes in tariff charges, as well as the bill implications for the average customer.

[65] For example, meters and services are eligible DSIC property, and these costs are typically recovered in customer charges. OSBA-II-22(c).

Table IEc-7 PECO Gas Rate Design Proposal: Rate GC			
	Current Rate	**Proposed Rate**	**Percent**
Customer Charge ($/mo.)	$28.55	$40.00	40.1%
First 200 mcf ($/mcf)	$3.7319	$4.5625	22.3%
Over 200 mcf ($/mcf)	$2.5924	$3.1694	22.3%
DSIC (%)*	5.6%	0.0%	-100%
TCJA (%)	1.31%	0.0%	-100%
Average Excl PGC/MFC/GPC	**$4.490**	**$5.255**	**17.0%**

* As discussed above, the Company has set a DSIC rate above the statutory cap for Rate GC.
Sources: RDK WP1, "RevPrf" tab.

In short, the Company proposes a disproportionate increase in the customer charge, with no relative change in the current declining block commodity charges.

Q. Is the proposed increase to the customer charge reasonable?

A. No. Setting the customer charge for utility general service rate classes is difficult due to the heterogeneous nature of the customers in the class. Customers come in a wide range of sizes and load patterns. For example, in the Company's GC class, approximately 8 percent or some 3700 customers have annual consumption that is below that for the average residential customers. Thus, the smaller customers in the class have less expensive meters and services than the average customer in the class. If the customer charge is set at the average customer-related cost for all customers in the class, smaller customers will necessarily be subsidizing larger customers.

Thus, to avoid cross-subsidization, I recommend that the customer charge for Rate GC be set no higher than the full customer-related cost for the residential class, which is approximately $28 per customer per month. Thus, the current customer charge of $28.55 should remain in effect. This approach is also justified by my proposal to assign a zero increase to the Rate GC class.

In the alternative, PECO Gas could take the approach used by other Pennsylvania NGDCs, namely that of differentiating the customer charge within the class between smaller and larger customers. As I noted earlier, Rate GC is an extremely diverse class, with an enormous range in customer sizes from smallest to largest. If a differentiated customer charge approach were adopted, the $28.55 would apply to smaller customers in the class, while a higher charge would apply to customers with annual volumes above some reasonable level. At this writing, I have not developed any specific proposal in this respect, but I am advised by counsel that OSBA is willing to work with the Company to develop such a proposal as part of any potential settlement negotiations in this case.

Q. Has the Company offered any cost support for its proposal to retain the declining block volumetric charge?

A. Declining block volumetric charges result in lower average unit rates for larger customers within the class. This tariff design has traditionally been used by utilities for three alternative purposes. First, it is often argued that because the customer charge does not fully recover customer costs, it is appropriate to include that recovery in the first block volumetric charge. Second, it is argued that because larger customers tend to have higher load factors, the volumetric unit distribution cost is lower for larger high load factor customers than for smaller low load factor customers, because distribution costs are substantially allocated based on peak demand. Third, the declining block tariff was designed such that the tail block reflected system marginal costs (particularly in the electric industry), recognizing that the incremental cost of service was often than the average cost.

The Company offers no evidence in support for any of these propositions. First, as I discussed above, the current customer charge fully recovers the customer-related costs for smaller customers, and thus there is no need to provide a rate discount to larger customers.

Second, the Company has not prepared any analysis that larger customers in the Rate GC class have a higher load factor than smaller customers. Based on the information provided by the Company, I prepared an analysis comparing the estimated design day load factor for each Rate GC customer with the average customer size. If larger customers actually had lower load factors, there would be clear statistical evidence of a positive correlation between load factor and customer size. That analysis shows that there is a positive but weak correlation between customer size and load factor, but it falls well short of that necessary to justify the Company's wide rate differential.[66]

Finally, the Company offers no evidence that the incremental cost of service is lower than the average cost. In fact, in a period when the Company is replacing low-cost depreciated assets with high cost plant, the incremental (or decremental) cost related to load is likely to be much higher than the average embedded cost. Moreover, even if incremental cost is below average cost, it is inequitable to assign those economies of scale disproportionately to large customers. Each unit of load contributes equally.

Q. What do you propose?

A. I propose that the Company reduce the volumetric charge differential by applying a larger percentage rate increase to the tail block charge. My overall proposal for an alternative Rate GC tariff design is presented in RDK WP 2 ("AltGC" tab) and summarized in Table IEc-8 below. Note that the values in Table IEc-8 are based on my proposed revenue allocation; a GC rate design based on the Company's proposal is also shown in RDK WP2.

Table IEc-8
RDK Rate GC Rate Design Proposal

	Current Rate	Proposed Rate	Percent
Customer Charge ($/mo.)	$28.55	$28.55	0.0%
First 200 mcf ($/mcf)	$3.7319	$3.9911	6.9%
Over 200 mcf ($/mcf)	$2.5924	$3.0072	16.0%
DSIC (%)*	5.6%	0.0%	-100%
TCJA (%)	1.31%	0.0%	-100%
Average Excl PGC/MFC/GPC	**$4.490**	**$5.255**	**17.0%**
Sources: RDK WP2, "AltGC" tab.			

Q. Please discuss the interaction of the TS-F and TS-I tariffs with Rate GC and Rate L.

A. The Company offers traditional transportation service on both a firm and interruptible basis in rates TS-F and TS-I respectively.[67] However, the Company offers a voluntary backstop

[66] See RDK WP3.

[67] Traditional transportation service is distinguished from the Company's retail "Gas Choice" service, which applies

"Standby Sales Service" to those transportation customers who find that to be a more economically attractive option than having their competitive suppliers meet the balancing requirements of the TS tariffs. However, for those standby volumes, the Company requires the TS customers to take delivery at Rate GC or Rate L base distribution rates, rather than the base TS transportation rates that would apply if the customer supplied its own gas.

For cost and revenue allocation purposes, it appears that the standby volumes and demands related to Rate TS-F are recorded in the Rate L and Rate GC classes, whereas the standby volumes related to Rate TS-I appear to be recorded in the TS-I category proof of revenues.

At this writing, I find little logic in this approach. First, the method implies that the Company charges a different distribution rate for delivering gas to a TS customer depending on whether the gas is supplied by the Company or the customer. As the delivery service is the same, this approach would appear to a textbook example of undue rate discrimination. Second, because there are few remaining regular Rate L customers, the Company's approach results in a nonsensical load factor for Rate L in the GCOSS at approximately 3 percent. This effectively renders the GCOSS useless for setting Rate L tariff charges.

Q. What then do you recommend regarding the delivery charges for standby service?

A. Gas supplies delivered to Rate TS-F and TS-I customers should be transported at the regular TS distribution rates, whether those supplies are provided by PECO Gas or by competitive natural gas suppliers. Moreover, the volumes and revenues associated with standby service for Rates TS-F and TS-I customers should be reflected in the GCOSS and the Company's proof of revenues in those classes, rather than serving to distort the revenues and costs for regular Rate GC and Rate L customers. Unfortunately, at this writing, I do not have the information necessary to make those changes.

Q. Please address the tariff charge differentials within Rate TS-F for customers above and below 18 mmcf per year.

to lower volume customers and includes more services from the Company.

A. The Company's proposed regular rate tariff for Rate TS-F includes a customer charge and a volumetric charge, both differentiated between customers below 18 mmcf per year and above 18 mmcf per year. The proposed charges are shown in Table IEc-9 below:

Table IEc-9 PECO Gas Rate TS-F Rate Design Proposal			
	Under 18 mmcf	**Over 18 mmcf**	**Differential**
Customer Charge ($/mo.)	$208	$249	-16.5%
Volumetric Charge ($/mcf)	$2.4847	$1.1859	109.5%
Sources: RDK WP1, "RevPrf" tab.			

As I indicated earlier, the Company declined to provide the information necessary for me to evaluate the cost of service differences between these two groups of TS-F customers. The Company similarly has not made any effort to evaluate whether the differentials are reasonable and has simply maintained the current rates differentials in its rate design proposal.[68]

I respectfully disagree. As I discussed earlier for Rate GC, there are two reasons why higher volumetric rates may reasonably apply to smaller customers. First, the customer charge could be under-recovering cost, and thus a higher volumetric rate should apply to smaller customer loads. For Rate TS-F, any such affect would be minimal. At most, the customer charge for the smaller customers is about $85 per month short of the average cost for the class, which would justify only a few pennies in the rate differential.[69] Moreover, smaller customers in Rate TS-F presumably have lower meters and services costs than the larger customers, and thus a lower customer charge is cost-justified.

Second the tariff charge for the larger customers could reflect higher load factors for those customers, since the demand-related costs for higher load factor customers are lower on a per-mcf basis. To evaluate whether this is the case, I conducted two different evaluations.

[68] OSBA-II-15(a).

[69] The fully loaded customer cost for all customers in Rate TS-F is $293, and the cost for the smaller customers is likely less. At $85 per month, $85 * 12 / 18,000 mcf comes to less than 6 cents per mcf in the differential.

First, using the monthly load data provided in OSBA-II-2(a), I estimated design day demands and associated load factors for both sub-groups of TS-F customers. This analysis did indicate that the load factors for larger customers were higher than for the smaller customers. However, the ratio of load factors was 1.43:1, which does not justify the 2.1:1 ratio between volumetric charges in the current and proposed tariff structure. Second, I reviewed the load factors based on customer contract demand (Transportation Contract Quantity "TCQ") for each TS-F customer, provided in response to OSBA-II-5. Overall, that analysis showed some statistically weak correlation between size of customer and load factor. This analysis similarly showed a higher load factor for customers above 18 mmcf, but again at a ratio (1.53) that falls well short of the Company's proposed 2.1:1 ratio.

I therefore conclude that the TS-F volumetric charge differential is excessive and should be reduced in this proceeding. Based on my revenue allocation proposal (a $2.6 million increase for Rate TS-F), I developed alternative rate design proposals for Rate TS-F in RDK WP2. I developed two alternatives, depending on whether or not the Commission determines that the discounted negotiated rates are reasonable. My proposal is summarized in Table IEc-10 below. As shown, the rates are lower if the Company's proposed negotiated rate discounts are rejected, since those customers absorb much of the proposed rate increase for the class. The tariff charges in Table IEc-10 are based on my revenue allocation proposal.[70]

[70] It is difficult to develop specific tariff rate charges at this stage of a base rates proceeding, given the significant uncertainty for the TS-F and TS-I classes regarding revenue allocation and the treatment of negotiated service customer revenues. I am advised by counsel that OSBA is willing to work with the Company to develop specific tariff charges as part of settlement negotiations, once the class revenue requirements are established.

Table IEc-10 RDK Alternative Rate TS-F Rate Design Proposals			
	Under 18 mmcf	**Over 18 mmcf**	**Differential**
No Change to Negotiated Rates			
Customer Charge ($/mo.)	$208	$249	-16.5%
Volumetric Charge ($/mcf)	$1.7384	$1.0717	62.2%
Negotiated Rates at Regular Tariff			
Customer Charge ($/mo.)	$208	$249	-16.5%
Volumetric Charge ($/mcf)	$1.6515	$0.9496	73.9%
Sources: RDK WP2, "Alt TS" and "Alt TS2" tabs.			

Q. Please address the tariff charge differentials within Rate TS-I for customers above and below 18 mmcf per year.

A. The Company's proposal for Rate TS-I is similar to that for Rate TS-F, in that it has bifurcated customer and volumetric charges for customers above and below 18 mmcf per year, and it has not made any effort to evaluate the reasonableness of the differential.

Unlike Rate TS-F, however, there is no load factor justification for a volumetric rate differential. Under the Company's cost allocation philosophy, demand-related costs are assigned to this class almost entirely on the basis of average annual volumes. Thus, there is no difference in allocated costs between small and large customers. I therefore developed alternative proposals for Rate TS-I designed to make progress toward reducing the unsupported rate differentials. These proposals are detailed in RDK WP2, and summarized in Table IEc-11 below. As was the case for TS-F, the regular firm service tariffs are considerably lower if the Commission rejects the Company's position on negotiated rates, because the increase from negotiated rate customers offsets the requirements from the regular rate customers. Note that for this calculation, I limited the overall increase for the TS-I class to that needed to move rates fully into line with allocated cost.

Table IEc-11 Alternative Rate TS-I Rate Design Proposals			
	Under 18 mmcf	**Over 18 mmcf**	**Differential**
PECO Proposal			
Customer Charge ($/mo.)	$251	$299	-16.1%
Volumetric Charge ($/mcf)	$1.9938	$1.0647	87.3%
RDK: No Change to Negotiated Rates			
Customer Charge ($/mo.)	$251	$299	-16.1%
Volumetric Charge ($/mcf)	$1.7385	$1.1215	49.9%
RDK: Negotiated Rates at Regular Tariff			
Customer Charge ($/mo.)	$251	$299	-16.1%
Volumetric Charge ($/mcf)	$1.3660	$0.9529	43.3%
Sources: RDK WP2, "Alt TS" and "Alt TS2" tabs.			

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.

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

OSBA-I-2*

OSBA-I-4

OSBA-I-6*

OSBA-II-2

OSBA-II-5

OSBA-II-7

OSBA-II-10

OSBA-II-13

OSBA-II-15

OSBA-II-16

OSBA-II-20

OSBA-II-21

OSBA-II-22

OCA-I-2

OCA-I-5*

OCA-I-6*

OCA-I-7*

OCA-I-15

OCA-I-20

OCA-I-22

OCA-X-2*

OCA-X-3*

PAIEUG-III-2

* Includes CONFIDENTIAL response or attachments

** All Referenced Interrogatory Responses can be accessed via PECO's Web Server Shared File

EXHIBIT IEc-3

ELECTRONIC WORKPAPERS OF ROBERT D. KNECHT

RDK WP1 – PECO 2021 GCOSS Replication

RDK WP2 – PECO 2021 GCOSS RDK Direct

RDK WP3 – Rate GC Monthly Loads

RDK WP4 – TSF TSI Review

Due to the voluminous nature of Workpapers RDK WP1 – RDK WP4 they are being circulated to parties via separate email simultaneous to service of Direct Testimony.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2020-3018929**
PECO Energy Company (Gas 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: December 22, 2020

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2020-3018929**
	:	
PECO Energy Company – Gas Division	:	

CERTIFICATE OF SERVICE

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

The Honorable Christopher P. Pell
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/s/ Steven C. Gray

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

DATE: December 22, 2020

COMMONWEALTH OF PENNSYLVANIA

January 19, 2021

The Honorable Christopher P. Pell
Administrative Law Judge
Pennsylvania Public Utility Commission
801 Market Street, Suite 4063
Philadelphia, PA 19107

Re: Pennsylvania Public Utility Commission v. PECO Energy Company – Gas Division / Docket No. R-2020-3018929

Dear Judge Pell:

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

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

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

Sincerely,

/s/ Steven C. Gray

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

Enclosures

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

OSBA Statement No. 1-R

R-2020-3018929
2/17/21 JK

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2020-3018929**
PECO Energy Company (Gas Division)	:	

Rebuttal Testimony of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Context
Cost Allocation
Revenue Allocation
Rate Design

Date Served: January 19, 2021

Date Submitted for the Record: ____________________

REBUTTAL TESTIMONY OF ROBERT D. KNECHT

1. <u>Introduction and Overview</u>

Q. Please state your name and briefly describe your qualifications.

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

Q. What is the purpose of this testimony?

A. This testimony responds to the direct testimony of the following intervenor witnesses in this proceeding:

- Context: Mr. Kevin W. O'Donnell, representing the Pennsylvania Office of Consumer Advocate ("OCA"); and Mr. Christopher Keller, representing the Commission's Bureau of Investigation and Enforcement ("I&E");

- Cost Allocation: Mr. Glenn A. Watkins representing OCA; and Ms. Billie LaConte representing the Philadelphia Area Industrial Energy Users Group ("PAIEUG");

- Revenue Allocation: Mr. Watkins, Ms. LaConte, and Mr. Ethan H Cline representing I&E;

- Rate Design: Mr. Watkins' rate design proposal regarding Rate IS;

- Allocation of Universal Service Costs: Mr. Roger D. Colton representing OCA and Mr. Mitchell Miller representing the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA").

These issues are addressed sequentially by subject matter in Sections 2 through 6. Exhibit IEc-R1 lists my electronic workpapers supporting this testimony that are being distributed to the parties.[1] I also have a correction to my direct testimony below and in Exhibit IEc-R2.

[1] RDK WP-R1 is a copy of my recommended cost allocation study from my direct testimony originally filed as

Q. What is the correction to your direct testimony?

A. My description on page 33 of my direct testimony regarding the information in Table IEc-3 inadvertently used language from a different proceeding. A redline corrected version of that testimony is provided in Exhibit IEc-R2 (which applies to both the public and confidential versions of my direct testimony). This correction has no impact on the conclusions and recommendations. I apologize for any confusion related to this error.

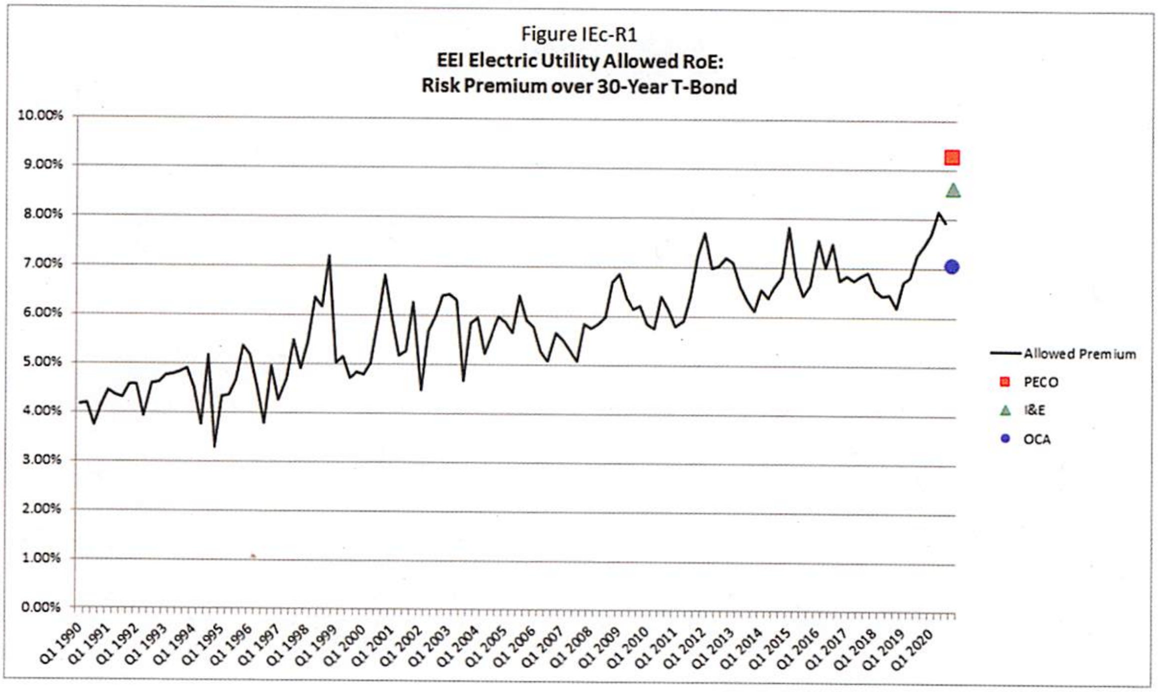
2. <u>Context</u>

Q. In your direct testimony, you presented a figure showing the historical trend in risk premiums related to electric utility return on equity ("RoE") awards. Please explain how the proposals of the various parties stack up against that pattern.

A. I have updated Figure IEc-1 to (a) include data from the Edison Electric Institute ("EEI") for the first three quarters of 2020, (b) calculate the risk premium award relative to a 30-year Treasury Bond rather than a 10-year instrument, to be more consistent with the views of the OCA and PECO Gas experts,[2] and (c) depict the parties' recommended risk premiums relative to the current 30-year Treasury yield. The results are shown in Figure IEc-R1 below, and the underlying data are provided in my electronic workpaper RDK WP-R2.

RDK WP2, supplemented by calculations used in this rebuttal testimony. RDK WP-R2 provides backup detail for exhibits in both my direct testimony and this testimony regarding trends in allowed equity risk premia for electric utilities.

[2] Use of the 30-year Treasury bond yield as the risk-free rate has only a modest impact on the overall pattern of the chart, namely that of a steady trend rise in the allowed risk premium over the past 30 years. I note Mr. Keller relies on the 10-year Treasury yield in his capital asset pricing model analysis.



As shown, both the Company and Mr. Keller advocate for a risk premium materially in excess of recent regulatory awards (as reported by the utility industry itself), and far in excess of the implied risk premium awards 30 years ago. Mr. O'Donnell's recommendation is generally in line with average risk premium awards of the past seven or eight years, but it too would do little to roll back the enormous increase in risk-adjusted returns granted by regulators over the longer-term.

3. <u>Cost Allocation</u>

Q. Please discuss the positions of the various witnesses regarding cost allocation.

A. All of the cost allocation/rate design intervenor witnesses recognize that the Company's initially filed gas class cost of service study ("GCOSS") contained errors related (a) to the derivation of the rate increase needed to achieve cost-based rates, and (b) to the class rates of return at the Company's proposed rates. The former error was corrected in the Company's response to OSBA-I-2; the latter error (in Exhibit JAB-1) has not yet been corrected. It should be recognized that these errors were related to summary calculations that come out of the GCOSS; they did not affect the basic "nuts-and-bolts" of the overall allocation model, nor did they affect the Company's calculation of class rate of return at present rates.

Ms. LaConte concludes that the Company's GCOSS "*. . . generally comports with accepted practices,*" but then asserts that "*. . . a portion of distribution mains should be classified as a customer-related cost,*" a position with which the PECO GCOSS does not comply. Ms. LaConte appears to rely on the Company's GCOSS (at present rates) for revenue allocation recommendations despite the methodological disagreement.

Mr. Cline indicates that his testimony addresses the issue of cost allocation (at page 2), but his analysis appears to be limited to the development of the cost basis for the residential class customer charge and revenue allocation. He appears to rely on the Company's GCOSS at present rates for both of those analyses.

Mr. Watkins develops an independent GCOSS, which reflects three technical changes to the Company's method and one major philosophical change. The technical changes have only minor impacts on allocated cost. Mr. Watkins' major change is to replace the Company's average-and-excess ("A&E") method for allocating mains plant with a peak-and-average ("P&A") method.

Thus, my cost allocation rebuttal testimony addresses Mr. Watkins' cost allocation study, primarily with respect to the allocation of mains plant.

Also, none of the cost allocation witnesses address the serious concern that I address in my direct testimony regarding the Company's peak demand allocator values. As such, I conclude that these experts rely on cost allocation analyses that are not particularly useful for revenue allocation or rate design in this proceeding.

Q. At pages 6 to 7, Mr. Watkins outlines the methods commonly used to allocation natural gas distribution mains. Do you generally agree with his review?

A. Yes. I would add a few observations. First, these methods produce huge differences in allocated costs. Second, none of those methods has a credible theoretical basis for allocating network costs. Third, I observe that these methods, and the supporting/opposing arguments, are essentially unchanged from those in use when I first became involved with utility cost allocation some thirty years ago, and I believe for many years before that.

Q. Please summarize your disagreement with Mr. Watkins regarding mains cost allocation.

A. My disagreement with Mr. Watkins is more theoretical than practical. Mr. Watkins argues that the P&A allocator with a 50/50 weighting of class average demand and class excess demand reasonably represents cost causation for gas distribution mains. In my view, cost causation for any particular main segment is causally related to the peak demand from customers downstream of that segment. Average demand is irrelevant, since the main must have sufficient diameter under sufficient pressure to meet the peak requirements of downstream customers. Cost causation for the overall system must reflect the topology of the distribution system, notably the nature and length of all the individual main segments needed to serve the customer base. I believe that this overall system is likely to exhibit geographical economies of scale, meaning that the cost to serve larger customers per unit of demand is lower than the cost to serve smaller customers. This view is based on the fact that residential customers tend to be smaller and more geographically diverse, and thus require more footage of mains per unit of demand. Commercial customers, by contrast, tend to be larger and are more geographically concentrated in business areas. As such, including a customer component in cost allocation could serve to reflect the economies of scale. However, I acknowledge that statistical support either for or against this conclusion is sparse. Moreover, the traditional methods for deriving a customer component to mains costs are not derived from this view of cost causation, and thus are unlikely to reflect these geographical economies of scale.

I therefore conclude that the only way to resolve the long-standing debate between the competing factions is to replace the generic methods described by Mr. Watkins with a system modelling approach that assigns the cost for each main to the downstream customers served by the main.

As a practical matter, I am unable to undertake such analysis in this proceeding, and I therefore rely on Commission precedent until such time as the parties weary of the endless debate about which terrible cost allocation method is the worst. As I will explain, the A&E method approved by the Commission in a PGW case in 2007 (which I use in my direct testimony) produces quantitative results that are similar to those from Mr. Watkins' P&A approach.[3]

Q. Do you agree with Mr. Watkins' thesis that a load-factor-weighted A&E allocator in the gas distribution industry will generally produce an allocation factor that is very similar or identical to a pure peak demand allocation factor?

A. Yes. I note, however, that the Commission's approval of the A&E allocation factor in the PGW and UGI PNG matters cited in my direct testimony did not use a load-factor weighting scheme, and thus produced an allocation factor that lies between an average demand and a peak demand allocator. Therefore, the Commission's use of a 50/50 weighted A&E factor in the PGW matter was consistent with its finding in that proceeding that the mains allocator should reflect both average demand and peak demand.

In this matter, my use of the Commission's 50/50 A&E factor produces an allocator that is approximately equivalent to an allocator that is 33% based on average demand and 67% based on peak demand. Thus, while Mr. Watkins may disagree with the Commission's use of an A&E allocation method, the Commission's method produces results that differ from his own only in the arbitrary weighting of average and peak components.

Q. Mr. Watkins argues that average demand is a cost causation factor because a gas distribution system would not be extended solely to meet peak demand. Do you agree?

A. No. Relying on a peak demand allocation factor does not mean that any customer will use the system only on peak any more than having a fixed price for an automobile implies that a customer would use the car only once per year. No one would buy a car if it was going to be used once per year. However, car dealers charge just as much for a car that will be used 100 days per year as for a car that will be used 360 days per year. I doubt that I would get much sympathy from the car dealer if I demanded that there be a lower charge for me if I bicycle to work, and a higher charge for other customers who commute exclusively by

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[3] Mr. Watkins acknowledges that this is the most recent Commission precedent for mains cost allocation, at page 13 footnote 9.

car. Just because no customer would use the car only once per year does not justify charging a higher price to more frequent drivers.

Q. Mr. Watkins argues that the economies of scale in mains costs justify the use of average demand in the allocation factor. Do you agree?

A. The economies of scale to which Mr. Watkins refers are those associated with an individual pipe segment, as distinguished from the geographical economies I cited to earlier. For any individual mains segment, I agree there are significant economies of scale in mains construction, related to both economies in cross-section and operating pressure. I do not agree that these economies imply that the costs for that mains segment are causally related to average demand. Curiously, advocates representing high load factor customers often use exactly this same argument to justify including a customer component in the allocation of mains costs. Neither position holds water.

Both arguments implicitly claim that some customer classes are proportionately more responsible for the economies of scale associated with any single main segment than the other classes. High load factor customer advocates generally argue there is a fixed cost of mains cost that should be assigned to all customers based on customer count. This approach assigns more economies of scale benefits to larger customers. Low load factor customer advocates like Mr. Watkins implicitly argue that the fixed costs that are not proportional to demand should be allocated based on average volumes, thereby disproportionately assigning the economies of scale benefits to low load factor customers. In reality, each main segment must be sized to meet the peak demand of all customers downstream from that segment. Every unit of peak demand on that main segment contributes equally to cost causation. As a matter of both common sense and equity, every unit of downstream peak demand should therefore share equally in the benefits associated with economies of scale for each particular piece of pipe.[4]

[4] Economic theory is less than helpful in this regard. The basic principle is that cross-subsidies are avoided as long as the rates for any customer or group of customers lies between the cost to serve only that customer (standalone cost) and the incremental cost. As a practical matter, any of the commonly used cost allocation methods could produce results within that range, due to the significant economies of scale.

Q. What, then, do you conclude regarding Mr. Watkins' use of the 50/50 P&A allocation method?

A. I disagree with the use of the 50/50 P&A method because (a) it is not consistent with cost causation, and (b) it is not consistent with Commission precedent. If the Commission is going to depart from precedent, it should require gas utilities to develop cost allocation methods that realistically reflect their customers' individual peak requirements and the physical configuration of their gas distribution systems. As I indicated earlier, the generic allocation methods and the parties' respective arguments have not changed for decades; continuing to argue over them serves little purpose. A fresh approach is needed.

Q. Please respond to Mr. Watkins' other cost allocation changes.

A. Regarding Mr. Watkins other changes:

1. Correct the DISTPLTXAR allocator: I agree, and I made this change in my alternative GCOSS in my direct testimony.

2. Include revenues from the Rate IS interruptible sales class that exceed the regular PGC charge in the GCOSS: This change does not affect the allocation of costs. Moreover, under current rates, this class does not provide any base rate revenues, because they are shared 75/25 between the PGC and shareholders. Thus, I chose not to include revenues from this class as "present rates" revenues. Nevertheless, I agree with Mr. Watkins that Rate IS should be modified or eliminated, and I address that issue in my rate design analysis.

3. Include incremental "forfeited discount" revenues in proposed rate revenues: I agree that these revenues should be included, and I do so in my GCOSS analysis.

Q. At the end of the day, how different are the cost allocation results among the three parties (PECO, Mr. Watkins and yourself)?

A. Table IEc-R1 below shows the class rates of return at present rates from the three alternative GCOSSs:

Table IEc-R1 Comparative GCOSS Results: Class Rates of Return at Current Rates			
	PECO Gas GCOSS	RDK Alternative	OCA Alternative
GR	4.7%	4.7%	4.9%
GC	8.1%	9.0%	8.8%
L	-2.1%	18.9%	0.2%
MV-F	12.6%	4.6%	3.5%
MV-I	32.2%	24.3%	25.0%
IS	-5.6%	-5.1%	3.2%
TCS	44.4%	13.4%	25.2%
TS-F	6.5%	6.7%	4.6%
TS-I	8.8%	3.2%	3.1%
Total	**5.7%**	**5.7%**	**5.7%**
Sources: RDK WP1, RDK WP2, OCA Statement No. 4, Table 6.			

Regarding the major rate classes (GR, GC, TS-F, TS-I):

- All three GCOSS analyses indicate that the GR Residential class is currently providing revenues well below allocated costs, implying that the class should be assigned a rate increase above system average;

- All GCOSS analyses indicate that the GC general service class shows a class rate of return that not only exceeds system average at present rates (5.7%) but exceeds the Company's full proposed rate of return (7.7%). To achieve cost-based rates under any GCOSS, a rate decrease would be required.

- Firm transportation service (Rate TS-F) exhibits an above-average class rate of return at present rates in both the Company's analysis and my analysis, but a below average rate of return in Mr. Watkins analysis. This difference results from the increased reliance on average demand in my analysis and the even greater reliance on average demand in Mr. Watkins analysis. In my analysis, this effect is partially offset by my changes to peak demand allocators.

- Interruptible transportation service (Rate TS-I) exhibits a high rate of return in the Company's analysis, and below-average rates of return in my analysis and Mr. Watkins' analysis, as a result of higher reliance on average demand in the mains allocation factor.

- Overall, therefore, there is relatively little disagreement regarding the cost allocation implications for Rates GR and GC, which together represent 92 percent of current base rate revenue. The material differences among the experts generally involve whether the TS-F and TS-I classes should be assigned rate increases above or below the system average.

For the smaller classes:

- The high-class rate of return for Rate L in my analysis is due to my modifications to the demand allocation factor for that class. Because neither PECO Gas nor Mr. Watkins makes those corrections, I conclude that their GCOSSs produce unreasonably low rates of return for Rate L.

- The class rate of return for the high-load-factor MV-F class are much lower in Mr. Watkins' and my GCOSSs, reflecting our higher reliance on average demand for mains cost allocation.

- Because tariff charges for Rates MV-I, TCS and IS are set based on market conditions, the differences in cost allocation results are not particularly relevant, at least in the current rate paradigm for those classes. The cost allocation differences across the three GCOSSs arise due to (a) increased reliance on average demand in both my analysis and Mr. Watkins', and (b) my determination that the interruptibility of these classes provides little benefit to other customers.

4. <u>Revenue Allocation</u>

Q. Please provide a comparison of the revenue allocation proposals in this proceeding.

A. Table IEc-R2 shows the proposed allocation of the rate increase in thousands of dollars; Table IEc-R3 shows the implications of that revenue allocation for average class percentage base rate increases. For consistency in comparison, I present each party's proposal based on the increase net of the Company's proposed credits for the GPC and MFC.[5] To my knowledge, no party has contested those values. Supporting details for these values are shown in RDK WP-R1.

Table IEc-R2
Comparison of Revenue Allocation Proposals ($000)

	PECO Gas	Knecht/OSBA	Watkins/OCA	Cline/I&E	LaConte/ PAIEUG
GR	41,720	62,937	59,947	65,169	53,750
GC	17,310	0	(436)	-2,254	9,119
L	35	0	29	35	35
MV-F	97	132	128	-21	-7
MV-I	1	1	0	0	0
IS	0	0	10	0	13
TCS	56	56	0	-30	0
TS-F	5,370	1,570	4,399	2,549	3,021
TS-I	2,378	2,094	2,711	1,338	903
Total	**$66,787**	**$66,787**	**$66,787**	**$66,786**	**$66,834**

Sources: RDK WP-R1

Table IEc-R3
Comparison of Revenue Allocation Proposals (% of Base Rates)

	PECO Gas	Knecht/OSBA	Watkins/OCA	Cline/I&E	LaConte/ PAIEUG
GR	17.9%	27.0%	25.7%	27.9%	23.0%
GC	17.0%	0.0%	-0.4%	-2.2%	9.1%
L	46.0%	0.0%	38.0%	46.4%	46.4%
MV-F	20.5%	27.7%	27.0%	-4.4%	-1.5%
MV-I	10.6%	10.6%	0.0%	0.0%	0.0%
IS	--	--	--	--	--
TCS	8.1%	8.1%	0.0%	-4.3%	0.0%
TS-F	32.1%	9.4%	26.3%	15.2%	18.1%
TS-I	25.0%	22.0%	28.5%	14.1%	9.5%
Total	**18.5%**	**18.5%**	**18.5%**	**18.5%**	**18.5%**

Sources: RDK WP-R1

[5] See footnote 1 at page 4 of my direct testimony for an explanation of the impact of the GPC and MFC credits for the Company's overall rate increase.

The parties' revenue allocation proposals generally are directionally consistent with their respective preferences for the cost allocation methodology (except for the PECO Gas proposal which I now understand will be modified in the Company's rebuttal testimony). My concerns regarding the parties' proposals are:

- Mr. Watkins proposes large rate increases for the TS-F and TS-I rate classes, at roughly 1.5 times the system average increase. While this approach is consistent with Mr. Watkins' cost allocation analysis, his proposal does not adjust for the fact that some TS-F and TS-I customers are on negotiated rates. As Mr. Watkins does not object to the negotiated rates for this proceeding (an issue I address below), his proposal would result in a particularly large increase for the non-negotiated rate TS-I customers. I estimate Mr. Watkins' proposed TS-I increase would be nearly 36 percent for those customers, roughly twice system average.

- Mr. Cline's proposal is the most aggressive for moving the GR and GC class rates into line with allocated costs. However, Mr. Cline's proposal does not appear to be consistent with his views on cost allocation for the TS-F and TS-I classes, particularly the latter. He assigns large rate increases to both of those classes, even though the class rate of return in the Company's GCOSS (upon which Mr. Cline relies) for Rate TS-I is higher than that for the Rate GC class.

- The OCA, I&E and PAIEUG witnesses all propose rate increases for Rate L that are in excess of twice the system average, consistent with the Company's proposal. As I explained in my direct testimony, these proposals appear to result from significant errors in the treatment of the Rate L class in the GCOSS. As such, I do not believe that any of these proposed increases for that class are reasonable.

- Ms. LaConte's revenue allocation is based on the Company's GCOSS methodology but is constrained by a judgmental limit on the maximum rate increase for any class of 1.25 times the system average. In my view, Ms. LaConte is unreasonably timid in assigning rate increases, particularly in light of the relatively long duration since the Company's last rate case. As the Company has not filed a base rates case since 2010, Rate GC customers have unfairly borne rates well in excess of allocated cost since then, and presumably for an even longer period. Given the lack of frequency in PECO Gas rate proceedings, it is important to make significant progress in this one. I conclude that Ms. LaConte's proposal fails to achieve that objective.

- Mr. Cline, Ms. LaConte and Mr. Watkins all propose a different level of rate increases for the market-based rate classes MV-I and TCI than those proposed by the Company.[6] As I indicated in my direct testimony, because the rates for these classes are set based on market conditions, it is not clear why the Company reports any increase at all for these classes. However, assuming the Company has indeed set the proposed rates for these classes based on forecast market conditions, any variation from the Company's proposal would need to reflect an assessment of prices for alternative fuels. For that reason, I accepted the Company's proposal. None of the other intervenor witnesses has presented market analysis, and therefore I do not believe that any of the proposed changes are justified. I recognize, of course, that the overall revenue impact for these classes is minimal.

Q. Please summarize the issues regarding revenues from negotiated rate customers.

A. PECO Gas has two types of rates that are not set based on allocated costs and other traditional ratemaking principles.

The first category comprises the market formula rates, in which a bundled gas supply and distribution rate is set monthly based on alternative fuel prices, and the base rate contribution is derived as the difference between the bundled market rate and the PGC cost. This category includes Rate IS, Rate TCS, and Rate MV-I. Whether these rate categories should continue is a rate design matter discussed below. In general, it would appear that

[6] The Rate IS revenues are similarly market-based, but as Mr. Watkins explains, base rate increases could effectively be achieved by ending the policy of crediting 75 percent of net revenues to the PGC and 25 percent to shareholders.

the Company's base rate revenues would decline relative to its forecast if these rates were closed, since the alternative firm rates are generally lower than the net market-based rates.

The second category involves negotiated rates for customers who have credible competitive alternatives, either in the form of alternative fuel, bypass to interstate pipeline, or alternative business opportunities. There are six customers in this group who take service under Rate NGS, but PECO Gas assigns the volumes, costs and revenues for these customers in Rates GC, TS-F and TS-I. Regarding these costs, I&E witness Mr. Cline, OCA witness Mr. Watkins and I appear to generally agree that the Company has not adequately demonstrated that the negotiated rate discounts are reasonable.

Q. What are the intervenors' alternative proposals regarding the market-based rates and negotiated rate discounts?

A. Despite identifying flaws and consistencies in the Company's justification for negotiated rates, Mr. Cline recommends *"... that the Company provide an update to the competitive analysis for any customer that has not had their alternative fuel source verified for a period of 5 years or more at the point at which PECO files a base rate case."* As I understand it, Mr. Cline's recommendation relates to both categories of market-based rates. Mr. Watkins provides detail regarding the failures of the Company to justify the rate discounts for three of the negotiated rate customers, and recommends that the Company re-evaluate the negotiated rate customers ability to use alternative fuel, and to provide the analysis to the Commission with or before the next base rates proceeding. In effect, both witnesses accept the Company's claim for current and proposed revenues for these customers in this proceeding.

Q. Do you agree with the proposals offered by Messrs. Cline and Watkins regarding the negotiated rate discounts?

A. No. The Company's ability to offer discounted rates to customers in special circumstances must necessarily come with a strong requirement that the Company justify that those rate discounts as both necessary and of reasonable magnitude. My direct testimony explains why the Company has failed to meet that requirement for most of its negotiated rate customers. Both Mr. Cline and Mr. Watkins agree that the Company has failed to reasonably demonstrate that the discounted rates are reasonable for at least some of these customers. The shortfall in revenues related to those customers *in this proceeding* should therefore be borne by shareholders *in this proceeding* and not ratepayers. It would be inequitable for the Commission to grant PECO a one-time "get out of jail free card" for its obligations to justify the negotiated rates and thereby pass the costs for those discounts on to other ratepayers.

Moreover, as I noted earlier, Mr. Watkins recommendation that current negotiated rates be approved for this proceeding implies that his revenue allocation proposal for the TS-I class would result in large increases for the non-negotiated rate customers within the class. In effect, Mr.Watkins' proposal for negotiated rate customers makes his revenue allocation proposal less reasonable.

Q. Mr. Cline includes a recommendation that negotiated rate customers be treated as a separate rate class for cost allocation in future base rates proceedings. Do you agree?

A. Yes. If the Commission determines that the Company has credibly demonstrated that the negotiated rate discounts are reasonable, these customers should constitute a separate class for cost allocation. Where rate discounts are justified, they benefit all rate classes. Tracking the discounted revenues and the cost shortfall separately makes it possible to identify the specific magnitude of the shortfall, as well as to reasonably recover that shortfall from the other classes. Including these customers with regular rate customers in particular rate classes (primarily TS-F and TS-I) makes it difficult to determine whether the regular rate customers within the class are reasonably contributing to costs, and it tends to require customers within these specific classes to be responsible for the entirety of the shortfall from the rate discounts.

Q. What are the positions of the parties with respect to a scaleback of the revenue allocation, in the event the Commission awards a rate increase (or decrease) below that proposed by the Company?

A. I&E witness Mr. Cline proposes that his revenue allocation be retained, and that any scaleback be applied only to his proposed increases for Rates GR, TS-F and TS-I. Ms. LaConte appears to support a proportional scaleback of her proposed revenue allocation, presumably for those classes for which she proposes an increase. Mr. Watkins also supports a proportional scaleback. I did not address the issue in my direct testimony.

Q. Please describe the implications of the "proportional scaleback" mechanism for adjusting allocated revenues for a reduced revenue requirement.

A. Because Pennsylvania base rates proceeding simultaneously evaluate a utility's revenue requirement, cost allocation and rate design, it is normal practice for the parties to develop revenue allocation proposals based on the utility's overall proposed increase. As that proposed increase is often reduced by the Commission, the Commission must then (a) approve a revenue allocation proposal at the full increase, and (b) approve a method to apply that reduction in revenue requirement to the various rate classes.

The most common approach for doing so in Pennsylvania cases is the "proportional scaleback," in which increases to each rate class are reduced in proportion to the overall reduction in the increase. Thus, for example, if the utility proposed increase is $100 million and the approved increase is $40 million, the revenue increase allocated to each class is adjusted by a factor of 0.4. That is, if the approved revenue allocation for the Residential class was $60 million of the $100 million, the scaled back increase would be 0.4 * $60 million = $24 million.

This approach has a couple of practical advantages. First, it is easy to understand and easy to calculate. Second, it maintains the same *relative* increases among rate classes. That is, if the percentage rate increase for the Commercial class is twice that of the Residential class at the full increase, it will also be twice the system average at the scaled back increase. Similarly, if the Residential class increase is 1.5 times the system average at the full increase, it would remain at 1.5 times the system average at the scaled back increase.

The disadvantages of the proportional scaleback are two-fold. First, the proportional scaleback only works if all the rate increases are positive. If the full requirements revenue allocation includes a rate reduction, the proportional scaleback produces a nonsensical result. In my example, if a class is assigned a $10 million reduction in the full requirements revenue allocation, the arithmetic would imply that class would get only a $4 million reduction with the scaleback. It is obviously unreasonable to *increase* the rates for a class because the overall revenue requirement is reduced. In addition, if the overall increase is rejected in favor of an overall decrease, the arithmetic would produce the nonsensical result implying that the classes originally assigned the largest increases would get the largest rate decreases. In effect, the result would be that the classes providing the largest cross-subsidies at the full revenue requirement would provide even larger cross-subsidies at the revised revenue requirement.

Mr. Cline correctly recognizes this problem in this case, in that he proposes to assign a rate reduction to the GC class at the full revenue requirement, but he excludes that class from the impact of a scaleback. The obvious downside to Mr. Cline's approach is that the GC class gets no benefit from any reduction in the overall revenue requirement, which is inequitable.

The second disadvantage of the proportional scaleback is that it serves to reduce the progress toward cost-based rates that is built into the full requirements revenue allocation. This is not a major concern when the scaleback is relatively small, such as reducing the magnitude of the increase by 20 percent (say, from $100 million to $80 million). However, when the amount being scaled back is relatively large, much of the economic efficiency and equity gained in the full requirements revenue allocation proposal is lost. Consider the example in Table IEc-4 below. (The values in this table are loosely based on the PECO Gas revenues, costs and revenue allocation in my direct testimony.)

Table IEc-R4
Impact of Proportional Scaleback: Illustrative Example

	Total	Residential	Commercial	Industrial
Filed Case				
Cost of Service	$430	$305	$ 90	$ 35
Current Revenues	$360	$230	$100	$ 30
Normalized R/C Ratio	***100%***	***90%***	***133%***	***102%***
Approved Increase	$ 70	$ 65	$ 0	$ 5
Implied Revenues	$430	$295	$100	$ 35
Proposed R/C Ratio	***100%***	***97%***	***111%***	***100%***
Scaleback Effect				
Scaleback of Costs (90%)	$387	$275	$81	$32
Scaleback of Increase	$ 27	$ 25	$ 0	$ 2
Resulting Revenues	$387	$255	$100	$ 32
Resulting R/C Ratio	***100%***	***93%***	***123%***	***101%***
Sources: RDK WP-R1				

In this example, at current rates, the residential class materially under-recovers costs, the commercial class over-recovers costs, and the industrial class slightly over-recovers cost, with costs measured at the current rate revenues.

The Commission then approves the following revenue allocation at the full proposed $70 million revenue requirement: The rate increase for the industrial class is set to bring costs into line with allocated cost. The commercial increase is set to zero, and the residential class is assigned the balance. This proposal results in a very substantial reduction in cross-subsidies. The residential class moves from recovering 90 percent of costs to 97 percent of costs, the commercial class moves from 133 percent to 111 percent, and the industrial class is set at cost-based rates.

However, suppose the Commission takes 10 percent off the cost claim or $43 million (simplified as an across-the-board increase in the example). This substantially reduces the required rate increase from $70 million to $27 million. If a proportional scaleback is adopted, none of that reduction is assigned to the commercial class, because its approved increase is zero. The vast majority of the reduction goes to the residential class, because it was assigned the largest share of the increase. Unfortunately, the end result of the scaleback is that there is much less progress toward cost-based rates than there was in the Commission-approved revenue allocation. Rather than going from 90 percent to 97 percent, the residential class revenue/cost ratio increases only to 93 percent. Similarly, the commercial class continues to pay revenues that are 23 percent in excess of costs, rather than only 11 percent. And the industrial class continues to over-recover costs.

Q. Is a significant reduction in the claimed revenue requirement a concern in this proceeding?

A. I believe it is. As I understand, the OCA witnesses have proposed that the allowed rate increase actually be a $24.9 million rate decrease.[7] As such, a material reduction in the Company's claimed revenue requirement is a credible scenario.

Q. How should a material reduction in the proposed rate increase be assigned among the various rate classes in this case?

A. In this case, there is (somewhat unusual) agreement among the parties that the Rate GC class is substantially over-recovering allocated costs and should be assigned a minimal increase at the full revenue requirement. Much of the progress toward cost-based rates for that class would be lost, however, with a proportional scaleback and a material reduction in the rate increase. I therefore propose a hybrid approach to a scaleback, in which the rate reduction is scaled back partly based on the proportional scaleback method and half based on current rate revenues. Table IEc-5 below shows how the arithmetic for this scaleback would work. I use the OCA proposed revenue allocation as an example, to show how a negative proposed increase would be addressed. Supporting formulae for this method are provided in RDK WP-R1.

[7] OCA Statement No. 2 page 6.

Table IEc-R5 RDK Proposed Scaleback Method: Example Based on I&E Revenue Allocation ($000)						
	OCA Revenue Allocation	Class Share of Increase (Excl. Negatives)	Class Share of Current Base Rates	Average Scaleback Factor	Reduced Revenue Requirement	Scaled Back Revenue Allocation
GR	59,947	89.2%	64.59%	76.88%	(32,125)	27,821
GC	(436)	0.00%	27.82%	13.91%	(5,812)	(6,248)
L	29	0.04%	0.02%	0.03%	(13)	15
MV-F	128	0.19%	0.13%	0.16%	(67)	61
MV-I	0	0.00%	0.00%	0.00%	0	0
IS	10	0.01%	0.00%	0.01%	(3)	7
TCS	0	0.00%	0.19%	0.10%	(40)	(40)
TS-F	4,399	6.54%	4.62%	5.58%	(2,333)	2,065
TS-I	2,711	4.03%	2.63%	3.33%	(2,065)	1,319
Total	**66,786**	**100.0%**	**100.0%**	**100.0%**	**(41,786)**	**25,000**
Calculations: RDK WP-R1						

As shown, this approach allows the GC class to partially share in the overall reduction of the revenue requirement, much of which would be lost in a traditional proportional scaleback. It may, of course, be argued that assigning the Rate GC class a rate decrease is inequitable when all other classes are assigned rate increases. However, I note (a) Mr. Cline actually proposes a rate decrease for rate GC even at the full revenue requirement, (b) not allowing the Rate GC class to benefit at all from a significant reduction in the revenue requirement would be inequitable, and (c) there is significant agreement among the parties that the Rate GC class revenues should be reduced materially relative to all other rate classes to reflect allocated costs. Thus, in the context of this proceeding, I do not believe this scaleback proposal is inequitable or unreasonable.

5. <u>Rate Design</u>

Q. What rate design issues do you address in this rebuttal testimony?

A. I observe that Mr. Watkins agrees with my recommendation that the Rate IS class be abandoned as being an anachronism that is no longer consistent with gas industry regulatory policy. He similarly voices the opinion that the margin sharing mechanism for this class is no longer reasonable or equitable.

I also observe that some of Mr. Watkins' arguments supporting his Rate IS recommendation would also support eliminating the MV-I and TCS rate classes, as I suggest in my direct testimony. In particular, Mr. Watkins correctly argues that the nature of gas competition has changed significantly since these tariffs were established, and that most customers who are interested in interruptible service do so through Rate TS-I rather than through the various bundled interruptible sales service rates that PECO continues to offer.

6. <u>Universal Service Cost Allocation and Recovery</u>

Q. What positions have parties taken with respect to the allocation and recovery of universal service costs?

A. The Company proposes to retain the current method, in which most universal costs are recovered in base distribution rates from Rate GR residential customers, and the balance is recovered in the reconcilable charge in the Universal Service Cost Recovery Mechanism ("USFC") that applies only to Rate GR. The parties objecting to that proposal are (a) OCA witness Mr. Colton and (b) CAUSE-PA witness Mr. Miller, both of whom recommend that universal service costs be assigned to all rate classes. Mr. Colton offers a general cost allocation methodology for implementing this recommendation, while Mr. Miller does not. Neither witness offers a specific revenue allocation or rate design proposal for the recovery of these costs from the non-residential classes, or for the credit to the residential class. Similarly, neither witness offers a rate impact analysis for the proposed change.

Q. Did the Commission invite the evaluation of this issue in base rate proceedings?

A. Yes. The Commission recently undertook a review of both the nature and the financing of low-income assistance programs, and it issued a final Policy Statement.[8] While there are detailed aspects to the Policy Statement, the key changes are (a) universal service benefits to low-income customers, and thus of course the associated costs, will increase

[8] "Final Policy Statement and Order," Pennsylvania Public Utility Commission, Docket No. M-2019-3012599, Order Entered November 5, 2019 ("Policy Statement").

substantially, and (b) the Commission would consider changing the current cost recovery policy.

Regarding the latter, the Commission ordered that "[u]tilities should be prepared to address recovery of CAP costs (and other universal service costs) from any ratepayer classes in their individual rate case filing *[sic]*."[9]

The Commission's primary motivation for considering a change in the cost recovery method was not based on any identifiable change in regulatory philosophy or cost causation principles.[10] The primary rationale for considering a change to the policy appears to be that the low-income assistance programs have become unaffordable to those residential customers who are ineligible or who otherwise do not participate in the programs.[11] The Commission expressed a concern that, under current policy, the higher universal service cost burden would result in unaffordable universal service charges for low-income customers not covered by the customer assistance programs ("CAPs").

Q. Has the issue been raised in other utility base rates proceedings?

A. I have participated in two such cases. In the recent UGI Gas base rates case at Docket No. R-2019-3015162, both OCA and CAUSE-PA raised the issue in their direct testimony, opposing the utility proposal to retain the status quo. That case was resolved by settlement and approved by the Commission, with no changes being made to the current policy of recovering all costs from the Residential class. In the ongoing Columbia Gas base rates case at Docket No. R-2020-3018835, both OCA and CAUSE-PA again raised the issue in direct testimony, again opposing the utility proposal to retain the status quo. In that proceeding, Administrative Law Judge ("ALJ") Katrina L. Dunderdale recommended

[9] *Id.*, page 104.

[10] The Commission does conclude that it has the legal right to make such a change, and that opposing parties did not demonstrate that such a change would have a negative impact on businesses. *Id.*, at 95-96.

[11] *Id.*, at 93.

against changing the existing policy without clearer guidance from the Commission, and the issue is now before the Commission for resolution.[12]

Q. What are the key conceptual differences in cost recovery policies for universal services?

A. I observe two general philosophies: the insurance model, and the public policy tax model.

The philosophy of recovering all costs from the residential class is based on the argument that only residential customers are eligible for the benefits. A universal service program is a form of insurance, in which residential gas customers are paying premiums to the utility, so that they will be eligible for cash benefits in the event they have an unfortunate turn in their economic circumstances. In this model, it can be argued that it is not unfair that only gas customers should get the benefits from the program, because it is only gas customers who pay for the program. It can also be argued that these programs are an integral part of utility service, and there is less need to separately report the charge on the utility bill.

The alternative model is the government policy tax model. This model, as described in some detail by both Mr. Colton and Mr. Miller, is based on the argument that there are societal benefits associated with assisting low-income residents. Under this paradigm, all customers should pay because all customers obtain the social benefits.[13] In effect, this form of a low-income programs looks like many other such government programs which provide both individual and societal benefits, and the costs of which are borne by the taxpayers. The government, of course, has a great deal more flexibility as to how and from whom it can recover those costs than does a regulated utility.

Q. Of the two models for recovery of utility low-income assistance programs, which do you advocate?

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[12] "Recommended Decision," Before Katrina L. Dunderdale Administrative Law Judge, Docket No. R-2020-3018835, page 399.

[13] I respectfully disagree with Mr. Colton that these benefits are a "public good," at least as that term is used by economists. See Reply Comments of the Office of Small Business Advocate, Docket No. M-2017-2587711, May 23, 2019, pages 6-8. Nevertheless, I do not disagree that there are societal benefits associated with government assistance to low-income residents, although there may also be societal costs depending on the nature of the programs.

A. My recommendation is that the Commission retain the insurance model, for reasons of cost causation and equity. In this model, customers pay for the benefits for which they are eligible. Residential customers benefit from the insurance, and residential customers pay for that insurance. Non-residential customers are not eligible for that insurance, and they therefore should not pay for the insurance.

While I acknowledge that there are ancillary benefits with policies that assist low income residents, I observe that using broad societal benefits for allocating utility costs may lead to more confusion and complexity in regulatory matters. If all societal benefits get factored into utility rate cost causation, there will be no end of claimants seeking special treatment. For example, the OSBA could argue that small businesses provide benefits to the economy in the form of job creation, economic dynamism, services for low-income communities, *et cetera, et cetera,* and are therefore deserving of subsidies from the other rate classes.

In addition, for cost recovery policy, the taxation model cannot easily be implemented across non-residential customers in a way that reflects the social benefits of the universal service programs. In the insurance model, residential customers of PECO gas pay for the insurance and they benefit from the program if the need arises. Other parties are unaffected. In the tax model, however, the social benefits from the PECO Gas' program inure to all residents, businesses and other organizations in PECO's service territory, regardless of whether they use gas.

As to the societal benefits of aid to low-income customers, it is not at all clear that utility programs represent a particularly effective means of assistance for low-income residents, except as it relates to providing an insurance policy to the specific residential customers who benefit from that insurance. In my view, achieving the broad societal benefits from low-income assistance is better accomplished through programs that (a) provide benefits to all low-income customers regardless of their heating fuel, (b) provide benefits to all low-income customers, regardless of whether they enroll in a utility program, (c) are carefully integrated into all other legislated benefits for low-income customers, and (d) are financed in a more progressive manner through taxation policy.

Q. Mr. Colton cites to legislative requirements that universal service charges be "non-bypassable" as a reason to assign the costs to all rate classes. Is that correct?

A. No. Non-bypassable refers to the issue of whether a customer can avoid paying for a particular charge by switching from utility gas supply to competitive natural gas supply. The current recovery mechanism is already non-bypassable, because universal service costs are recovered in base distribution rates and the USFC, both of which apply equally to sales and shopping customers. The bypass issue is unrelated to interclass allocation or public benefits. The non-bypassable nature of universal service costs is a recognition that the utility would not see any reduction in its universal service obligations as a result of a customer choosing to shop, and thus there is no reason to include universal service costs in the price-to-compare.

Thus, for the purposes of interclass cost allocation, the "non-bypassable" argument is a red herring. It would be both ridiculous (and presumably fraudulent) for a Rate GR residential customer to attempt to bypass universal service responsibility by becoming a Rate GC non-residential customer.

Q. How does Mr. Colton propose that the universal service costs be allocated and recovered from all rate classes?

A. Mr. Colton recommends that the costs be allocated on a "competitively neutral" basis, based on "the percentage of revenue provided by each customer class at base rates. In so doing:

- Mr. Colton does not specify the test year magnitude of universal service costs, or even define what specific cost items would be included in his proposed allocation;

- Mr. Colton does not provide any allocation calculations, or assessment of the impact of the proposed change on allocated costs;

- Mr. Colton also does not offer any recommendations regarding whether the "flex" rate classes with market-based rates or the negotiated rate customers should be assigned surcharges related to universal service costs;

- Mr. Colton does not offer any proposal for rate recovery of the allocated costs.

Q. Did OCA witness Mr. Watkins include OCA witness Mr. Colton's proposed allocation of universal service costs in his GCOSS, or the impact of such a change in his revenue allocation proposal?

A. No. Moreover, unlike other utilities, PECO recovers a significant majority of its universal service costs through regular base rates rather than through the reconcilable universal service charge. As such, Mr. Colton's proposal should be evaluated within the context of overall cost and revenue allocation.

Q. Have you developed an estimate of the impact of Mr. Colton's proposal across rate classes?

A. I developed an estimate of the impact on allocated cost as detailed below and provided in RDK WP-R1. I recognize that some of my estimates are imprecise due to a lack of information, but I believe the analysis reasonably represents the impact of Mr. Colton's proposal on overall cost and revenue allocation. My calculations are based on my initial revenue allocation proposal, to be able to show the impact of changing universal service cost allocation on revenue allocation.

I begin by estimating test year universal service costs. In its tariff, the Company currently includes only rate discounts in its reconcilable Universal Service Fund Charge.[14] In its proof of revenue analysis, the Company shows some $11.5 million in CAP discounts under proposed rates. However, because I propose higher rate revenues for the GR class than does PECO, I expect the higher rates would increase the CAP rate discounts. I therefore estimate the cost of the discounts at $12.2 million.

In addition, the Company's cost allocation detail indicates that there are some $1.5 million in LIURP costs included in Account 908, and $0.9 million in "CAP Rates" costs in Account

[14] PECO Gas Tariff page 36 indicates,"'Reconcilable Customer Assistance Program (CAP) Costs' – The difference between discounts provided to CAP customers (CAP revenue shortfalls) recovered through base rates and total CAP discounts, net of a 27% offset factor."

903.[15] I therefore added these amounts to the revenue shortfall, producing a CAP cost estimate of $14.55 million.

I then allocated that $14.55 million across all of the rate classes as proposed by Mr. Colton, using my calculation for base rate revenues. In so doing, I excluded the $14.55 million related to universal service from the GR class allocator, as I believe that was likely Mr. Colton's intent. I also included all flex rate revenues from the MV-I, TCS and IS classes, as well as all the negotiated rate revenues from the GC, TS-F and TS-I classes. That also appears to be Mr. Colton's intent, although it is unclear whether the Company can actually increase those rates without exceeding market-based rates.

The cost allocation results are shown in Table IEc-R6 below.

Table IEc-R6 **Estimated Cost Allocation Impact of OCA Universal Service Cost Proposal**		
	$000	**Cents/Mcf**
GR	10,046	23.9
GC	3,436	15.3
L	3	15.6
MV-F	21	4.7
MV-I	0	28.3
IS	--	--
TCS	26	14.3
TS-F	625	5.5
TS-I	396	2.7
Total	**14,552**	**16.0**
Sources: RDK WP-R1		

By way of comparison, if the GR class continued to be responsible for universal service costs, the cost per mcf for that class would be 34.7 cents per mcf. The net cost reduction for the GR class from Mr. Colton's proposal is therefore 10.7 cents per mcf, or about 76 cents per average monthly residential bill.

[15] See attachment to OCA-I-2.

Q. Is this proposal "competitively neutral?"

A. No. As shown in Table IEc-R6, large businesses would face a cost increase of 3 to 6 cents per mcf, while small businesses face cost increases over 15 cents per mcf. I doubt that the small retailer who competes with WalMart will agree with Mr. Colton that his proposal is competitively neutral.

However, if by "competitively neutral" Mr. Colton means that customers cannot avoid the universal service charge by switching from utility gas supply to competitive natural gas supply, both his proposal and the status quo are competitively neutral.

Q. Does this proposal reasonably assign universal service costs based on the public benefits alleged by Mr. Colton?

A. I do not believe so. The public benefits cited by Mr. Colton relate primarily to labor cost savings, in the form of reduced employee absenteeism and turnover. The benefits are therefore proportionate to employment, and there is presumably a reasonably high correlation between a firm's gas consumption and its overall employment level. It is difficult to believe that a large Rate TS-F or TS-I customer with many employees is deserving of a unit cost that is only 20 to 40 percent of that applied to smaller businesses, as Mr. Colton proposes. It is similarly difficult to believe that it is reasonable for a large gas consumer that attaches directly to an interstate pipeline, that gets all the same employee public benefits as PECO's customers, would be permitted under Mr. Colton's proposal to bypass the universal charge entirely.

Moreover, even within the PECO customer base, the largest beneficiaries are presumably the largest employers. PECO Gas, however, has no way to assign cost recovery on that basis. In fact, the largest PECO Gas customers who may also be large employers may be served through negotiated rates or have the potential to bypass PECO Gas entirely, making it impossible for PECO Gas to impose any charge on those customers to recover the social benefits.[16]

[16] This is a key feature of the PGW method for universal service costs, namely that the largest customers in the Rate IT class are exempt from the universal service charge.

Q. If the Commission were to adopt Mr. Colton's proposal and associated cost allocation methodology, what is the impact of that alternative cost allocation on your revenue allocation proposal?

A. To answer that question, I applied the identical revenue allocation methodology used in my direct testimony to the revised cost allocation proposed by Mr. Colton. Specifically, I started with my estimate of the cost-based increase needed to move rates into line with allocated cost from my GCOSS, and I adjusted those values for the cost changes shown in Table IEc-R6 above. I then adjusted those increases to (a) eliminate rate reductions, (b) limit the maximum increase to 1.5 times system average, and (c) retain the Company's proposed increases for the market-based MV-I, IS and TCS classes. The net adjustment credit was then reallocated back to the other classes in proportion to their assigned increase. The end result is shown in Table IEc-R7 below:

Table IEc-R7
Impact of OCA Universal Service Cost Allocation on RDK Revenue Allocation ($000)

	Direct Testimony	Alternative
GR	62,937	62,251
GC	0	0
L	0	0
MV-F	131	131
MV-I	1	1
IS	--	--
TCS	56	56
TS-F	1,570	2,256
TS-I	2,094	2,094
Total	**66,788**	**66,788**

Sources: RDK WP-R1

As shown, the OCA cost allocation change would have only a small impact on my revenue allocation proposal. Even with the increase in costs allocated to Rate GC and Rate L, those classes would still need rate decreases to come into line with allocated cost, and thus the allocated increase remains at zero. Rate TS-I and MV-F continue to be constrained by the 1.5 times system average increase rule, while the MV-I, IS and TCS rates remain market-based. The only impact then would be to shift about $0.7 million from Rate GR to Rate TS-F. The resulting impact on the GR class would be *de minimis*, resulting in a 26.7 percent increase rather than a 27.0 percent increase, reducing the average bill by 1.6 cents per mcf, or 12 cents per month. In contrast, the increase to the TS-F class would have a larger yet manageable impact, pushing the average increase up from 9.4 percent to 13.5 percent.

I therefore conclude that the OCA proposal would have only minimal impact on the affordability of PECO's rates in this proceeding. Nevertheless, I believe my revenue allocation proposal under this scenario remains based on sound regulatory principles, and I believe it should be adopted if the Commission approves Mr. Colton's proposed change in cost allocation methodology.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT IEc-R1

ELECTRONIC REBUTTAL WORKPAPERS

OF ROBERT D. KNECHT

RDK WP-R1 - PECO 2021 GCOSS RDK Rebuttal.xlsx
RDK WP-R2 Equity Risk Premia.xlsx

Workpapers RDK WP-R1 and RDK WP-R2 are being circulated to parties with the testimony via e-mail attachment

EXHIBIT IEc-R2

CORRECTIONS TO PAGE 33 FROM DIRECT TESTIMONY

Q. Do you have other recommendations regarding the GCOSS methodology?

A. I made the following technical changes to the Company's GCOSS model, which generally do not have a material impact on overall allocated costs:

- Residential current-rates revenue is set to equal the proof of revenues in Exhibit JAB-4;
- Throughput volumes for MV-F and MV-I are set equal to the proof of revenues in Exhibit JAB-4;
- Costs in Account 909 are allocated in proportion to the Company's CUSTADVT allocator, which appears to have been the Company's intent, but it inadvertently assigned all costs to the GC class;[53]
- I adjusted the Company's DISTPLTXAR allocation factor because it double-counts certain plant items.

Q. How do the results of your modified GCOSS compare to the Company's results?

A. Table IEc-3 below shows class rates of return at present rates for ~~(a)~~ the Company's GCOSS and, ~~(b)~~ my alternative ~~replicated~~ version ~~of the GCOS with Rates IS and XD-I split, (c) the effects of the modest changes I propose, and (d) the implications of treating Rate IS customers as firm for cost allocation purposes~~.

[53] OSBA-II-7(b).

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2020-3018929**
PECO Energy Company (Gas Division)	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Rebuttal Testimony labelled OSBA Statement No. 1-R and associated Exhibits IEc-R1 through IEc-R2 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: January 19, 2021

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2020-3018929**
	:	
PECO Energy Company – Gas Division	:	

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: January 19, 2021