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August 20, 2020

<u>Via Electronic Filing</u>
Rosemary Chiavetta, Secretary
PA Public Utility Commission
PO Box 3265
Harrisburg, PA 17105-3265

Re: Petition of PECO Energy Company for Approval of its Default Service Program for the Period from June 1, 2020 Through May 31, 2025 – Docket No. P-2020-3019290

Dear Secretary Chiavetta:

Consistent with Section 5.412a of the Commission's regulations, 52 Pa. Code § 5.412a, which requires the electronic submission of pre-served testimony, enclosed for electronic filing please find the following testimony and exhibits on behalf of the Electric Supplier Coalition ("ESC"). These documents were admitted into the record during the evidentiary hearing on July 30, 2020.

Testimony	**Name**	**Exhibits**
Direct – ESC St. No. 1	Travis Kavulla	TK-1 through TK-19
Surrebuttal – ESC St. No. 1-S	Travis Kavulla	

All parties and the presiding officer have been served previously with this Testimony. If you have any questions, please contact me.

Sincerely,

Karen O. Moury
KOM/lww
Enclosure

cc: Hon. Eranda Vero (w/o enc)
Certificate of Service (w/o enc)

CERTIFICATE OF SERVICE

I hereby certify that this day I served a copy of the ESC's Letter Filing Pre-Served Testimony upon the persons listed below in the manner indicated in accordance with the requirements of 52 Pa. Code Section 1.54.

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Dated: August 20, 2020

Karen O. Moury

Karen O. Moury

ESC Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of PECO Energy Company for Approval of Its Default Service Program for the Period From June 1, 2021 Through May 31, 2025	:	Docket No. P-2020-3019290

DIRECT TESTIMONY OF

TRAVIS KAVULLA

ON BEHALF OF THE ELECTRIC SUPPLIER COALITION

TOPICS:

General Observations About Competitive Retail Market
Default Service Provider Role
Time-of-Use Rates
Ten-Year Contracts for Solar Alternative Energy Credits
Recovery of Network Integration Transmission Costs
Existing and Proposed Retail Market Enhancement Programs

JUNE 16, 2020

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I. INTRODUCTION

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

A. My name is Travis Kavulla and I am Vice President, Regulatory Affairs for NRG Energy, Inc. ("NRG"). My business address is 804 Carnegie Center, Princeton, NJ 08540.

Q. HOW LONG HAVE YOU BEEN IN THIS POSITION?

A. I have been in this position since September 2019.

Q. WHAT ARE YOUR KEY RESPONSIBILITIES IN THIS POSITION?

A. In my current role, I lead a team of lawyers, economists and engineers to ensure that energy markets continue to deliver value for electricity consumers.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. My professional experience as well as my educational background are fully described in Exhibit TK-1. However, I wish to highlight some of this prior experience and background as it pertains to this proceeding. Most recently, I led the R Street Institute's energy program, and wrote and commented extensively on public utility regulation, including on matters of intra- and intercompany cost allocation. Prior to my time at R Street, I served eight years as a Commissioner at the Montana Public Service Commission ("MT PSC"), during which time I served as the Chairman of the MT PSC from 2011-2012 and as Vice Chairman from 2015-2019. While serving on the MT PSC, I was also the President of the National Association of Regulatory Utility Commissioners ("NARUC") and a member of the advisory council of the Electric Power Research Institute. In addition, I have served on the governing body of one of North America's largest real-time electricity markets, the Western Energy Imbalance Market. I received my Bachelor's degree in History from Harvard University and a Master's degree, also in

History, from the University of Cambridge, where I was a Gates Scholar. More details are set forth in Exhibit TK-1, which is attached.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION?

A. No.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE OTHER REGULATORY COMMISSIONS, COURTS OR LEGISLATIVE BODIES?

A. I have provided testimony before both the U.S. Senate Energy and Natural Resource Committee and the U.S. House Energy and Commerce Committee, as well as a number of state legislative committees. I have testified on behalf of NARUC and the MT PSC at technical conferences of the Federal Energy Regulatory Commission. I have filed comments before various state regulatory commissions, including those of California, Minnesota, New Jersey, and Rhode Island.

Q. ON WHOSE BEHALF IS THIS DIRECT TESTIMONY OFFERED?

A. This Direct Testimony is offered on behalf of NRG, Direct Energy Services LLC, Interstate Gas Supply, Inc. d/b/a IGS Energy, Vistra Energy Corp., Shipley Choice LLC, ENGIE Resources LLC and WGL Energy Services, Inc. (collectively, the "Electric Supplier Coalition" or "Coalition" or "ESC"). The members of the Coalition either directly or through affiliates or subsidiaries hold licenses issued by the Pennsylvania Public Utility Commission ("PUC" or "Commission") as electric generation suppliers ("EGSs") to supply generation services to retail consumers in the service territory of PECO Energy Company ("PECO").

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to offer the perspectives of the Electric Supplier Coalition on various aspects of the Petition of PECO Energy Company for Approval of its Default Service Program from June 1, 2021 through March 31, 2025 ("PECO DSP V Petition"). Specifically, my Direct Testimony addresses the following issues:

- General Observations About Competitive Retail Market Today
- PECO Transitioning Out of Default Service
- Time-of-Use Rates
- Ten-Year Contracts for Solar Alternative Energy Credits
- Recovery of Network Integration Transmission Costs
- PECO's Existing and Proposed Retail Market Enhancement Programs

Q. DO YOU HAVE SPECIFIC RECOMMENDATIONS IN EACH OF THESE AREAS?

A. Yes. My recommendations can be summarized as follows:

- The Commission should recognize the need to make structural changes to the competitive retail market so that competitive retail offerings will flourish, drive significant investment, or result in innovative product offerings;

- The Commission should transition PECO out of the default service provider role and make default service a true backstop provided by electric generation suppliers;

- In tandem with allowing PECO to offer a time-of-use rate, the Commission should approve it as the standard default rate, establish a framework under which electric generation suppliers may offer supplier consolidated billing, and should make other modifications that are either legally required or in the public interest;

- The Commission should deny PECO's proposal to enter into 10-year solar alternative energy credit contracts, or limit such contracts to the proposed default service plan program period;

- The Commission should reject PECO's proposed handling of network integration transmission services costs that is harmful to shopping customers and instead create a level playing field for all customers by incorporating transmission costs into PECO's nonbypassable charge;

- In examining the components of PECO's default service rate, PECO has failed to allocate identifiable costs related to its default service to its default service rate, which consequently is artificially low and which must be rectified by allocating a portion of overhead costs to that rate; and

- The Commission should modify certain aspects of the existing standard offer program and the proposed low-income customer shopping program so that they result in more meaningful retail market enhancements.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. Below is a table of the exhibits I am sponsoring. All are attached to my Direct Testimony.

TABLE OF EXHIBITS

Exhibit TK-1	Kavulla Resume
Exhibit TK-2	Lacey Article – Public Utilities Fortnightly
Exhibit TK-3	Lacey Article – The Electricity Journal
Exhibit TK-4	PECO Response to ESC-I-8
Exhibit TK-5	PECO Response to ESC-I-6
Exhibit TK-6	PECO Response to ESC-IV-9
Exhibit TK-7	PECO Response to ES-I-45
Exhibit TK-8	PECO Response to ESC-I-3
Exhibit TK-9	PECO Response to ESC-IV-14
Exhibit TK-10	Reliant Sample Bill
Exhibit TK-11	PECO Response to ESC-III-1
Exhibit TK-12	PECO Response to ESC-I-2
Exhibit TK-13	PECO Response to ESC-IV-13
Exhibit TK-14	PECO Response to ESC-I-21
Exhibit TK-15	PECO Response to ESC-IV-3
Exhibit TK-16	PECO Response to ESC-IV-12
Exhibit TK-17	PECO Response to ESC-I-14
Exhibit TK-18	PECO Response to ESC-I-1
Exhibit TK-19	PECO Response to ESC-II-8 and 8(a)

Q. IN REACHING YOUR CONCLUSIONS AND DEVELOPING YOUR RECOMMENDATIONS, PLEASE IDENTIFY WHAT YOU HAVE REVIEWED.

A. I have reviewed PECO's Petition, as well as the Direct Testimony of John J. McCawley, P.E.,[1] Joseph A. Bisti,[2] Carol Reilly,[3] and Scott G. Fisher,[4] and the accompanying

[1] PECO Energy Company Statement No. 1.

[2] PECO Energy Company Statement No. 2.

[3] PECO Energy Company Statement No. 3.

[4] PECO Energy Company Statement No. 4.

exhibits. I have also reviewed PECO's responses to discovery propounded by the Coalition and some responses provided at the request of other parties in this proceeding. In addition, I have familiarized myself with the provisions in Pennsylvania's Electricity Generation Customer Choice and Competition Act ("Competition Act")[5] that pertain to default service, along with the Commission's default service regulations[6] and policy statement governing default service.[7] Further, I have reviewed NARUC's "Electric Utility Cost Allocation Manual" ("NARUC CAM")[8] and NARUC's Guidelines for Cost Allocation and Affiliate Transactions ("NARUC Guidelines").[9] Additionally, I have examined a report released earlier this year by the Wind Solar Alliance, which was authored by Rob Gramlich and Frank Lacey.[10] Finally, I have studied an article authored by Frank Lacey entitled "Default Service Pricing Has Been Wrong All Along – Allows Utilities to Maintain Dominance in Markets," which was published in Public Utilities Fortnightly in January 2019,[11] and another article authored by Mr. Lacey called "Default service pricing – The flaw and the fix: Current pricing practices allow utilities to maintain

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5 66 Pa. C.S. §§ 2801-2815.

6 52 Pa. Code §§ 54.181-54.190.

7 52 Pa. Code §§ 69.1801-69.1817.

8 https://pubs.naruc.org/pub.cfm?id=53A20BE2-2354-D714-5109-3999CB7043CE

9 http://pubs.naruc.org/pub/539BF2CD-2354-D714-51C4-0D70A5A95C65

10 Rob Gramlich & Frank Lacey, "Who's the Buyer: Retail Electric Market Structure Reforms in Support of Resource Adequacy and Clean Energy Deployment," *Grid Strategies* (prepared for Wind Solar Alliance) (March 2020). ("Wind Solar Alliance Report"). https://windsolaralliance.org/wp-content/uploads/2020/03/WSA-Retail-Structure-Contracting-FINAL.pdf (accessed June 8, 2020).

11 Frank Lacey, Default Service Pricing Has Been Wrong All Along – Allows Utilities to Maintain Dominance in Markets, Public Utilities Fortnightly, January 2019, Pages 40-44. A copy is attached to my Direct Testimony as Exhibit TK-2.

market dominance in deregulated markets," which was published in the Electricity Journal in April 2019.[12]

II. GENERAL OBSERVATIONS ABOUT COMPETITIVE RETAIL MARKET TODAY

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS ON THE COMPETITIVE RETAIL MARKET THAT EXISTS IN PENNSYLVANIA TODAY, AND SPECIFICALLY IN PECO'S SERVICE TERRITORY?

A. I do. Pennsylvania historically has been a leader in opening its market to competition, for the benefit of consumers. When I led the nation's association of state utility regulators as president of NARUC, Pennsylvania's reputation in that regard was widely known. But, today, the unfortunate reality is that competition in Pennsylvania's electric market is stagnating.

Q. WHAT DO YOU POINT TO IN SUPPORT OF THAT OBSERVATION?

A. According to PECO's responses to Coalition discovery requests, shopping by residential customers has stagnated, with less than one-third of the residential customers in PECO's service territory shopping – a dynamic that has not changed the past several years. Indeed, the number of active and pending EGS customers in PECO's service area peaked in March 2017 at 507,005 and has recently declined with the number in February 2020 reaching a new low of 425,215 since November 2012 when the number of shopping customers was 419,176.[13] Without structural changes to improve the market, it is not realistic to expect that competitive retail offerings will flourish, drive significant generation investment, or result in innovative product offerings. In essence, Pennsylvania

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12 Frank Lacey, Default service pricing – The flaw and the fix: Current pricing practices allow utilities to maintain market dominance in deregulated markets, The Electricity Journal, Volume 32, Issue 3, 2019, Pages 4-10. A copy is attached to my Direct Testimony as Exhibit TK-3.

13 Exhibit TK-4 (PECO Response to ESC-I-8).

has a choice—either to let PECO and other utilities continue to monopolize the market, or to leverage the competitive market to its original, intended purposes.

Q. DOESN'T PECO DESCRIBE ITS "BASIC DEFAULT SERVICE MODEL" AS SUPPORTING THE "COMPETITIVE RETAIL ELECTRICITY MARKET"?

A. Yes, through the Direct Testimony of Mr. Fisher, PECO describes its "basic default service model" as supporting the "competitive retail electricity market."[14] However, the rationale offered by Mr. Fisher for this statement is that 102 EGSs currently serve PECO customers. When taken in a vacuum, 102 EGSs may seem like a robust group of market participants. However, this data point needs to be viewed from the lens of the number of PECO residential customers that are shopping for electric supply. Under the most recent data available for the month ending April 28, 2020, PECO had 1,511,836 residential customers on its distribution system and only 423,314 were either actively being served by EGSs or were to be switched to EGSs in the next 3 days.[15] What this means is that PECO is providing generation service to 72 percent of the customers on its distribution system, while 102 EGSs are supplying generation to the remaining 28 percent of the customers. The average market share for each EGS serving customers on PECO's distribution system is roughly 0.27% of the overall residential electric market. These statistics clearly demonstrate the dominant market share that PECO continues to enjoy in the provision of generation service to customers on its distribution system.

Q. WHAT ARE THE REASONS FOR THE STAGNANT MARKET?

A. The reasons are the structural flaws in the design of the retail market, which after an initial burst of enthusiasm and investment, have left it only a shadow of what it could be.

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[14] PECO Statement No. 4 at 4.

[15] Exhibit TK-5 (PECO Response to ESC-I-6).

The Wind Solar Alliance Report released earlier this year explores these flaws at some length. They boil down to the presence of a domineering default service provider ("DSP") and a persistently unlevel playing field between the DSP and EGSs. That unlevel playing field is evinced in the inability of EGSs to have a direct relationship with their customers, through monthly consolidated bills. That unlevel playing field also arises in the persistent cross-subsidization that causes distribution customers, including those who have chosen a product other than PECO default service, to nevertheless pay for costs related to PECO's default service. Indeed, the very presence of a DSP that is also the local transmission-and-distribution monopoly—a provider-of-first resort arrangement that has come to be accepted as inevitable, even though it was not inevitable in the design the authors of Pennsylvania's competition statute conceived[16]—biases customers toward the entity that physically meters them and bills them.

Q. WHAT ARE THE NEGATIVE CONSEQUENCES OF THIS?

A. The Wind Solar Alliance Report focuses on one negative consequence, namely the lack of long-term contracts that are signed to supply customers in Pennsylvania and other states that have a similar, domineering DSP. Simply put, EGSs are reluctant to make longer term investments in the market if its main competition—the DSP—both dominates the market by a default arrangement that consistently directs customers back to it *and* enjoys a regulatory model of assured cost recovery. For an EGS that must work to earn its customer and stake its own capital at risk, the model is not a feasible one to drive meaningful investments over the long term. In the presence of a dominant utility DSP, the EGS market is destined primarily to consist of shorter-run arrangements that undercut

[16] 66 Pa.C.S. § 2807(e).

the DSP. Likewise, without the ability to bill its customers directly, EGSs are put at a disadvantage in establishing meaningful, long-term relationships with their customers—further undermining the case for long-term investments, and also damaging the prospects of offering innovative products that cannot be conveyed in the small space that EGSs are afforded on PECO's bill.

Ironically, these negative developments then invite further tinkering with the default service to solve what the market does not seem to be offering. In this proceeding, PECO has proposed a long-term solar purchase—something a well-designed competitive retail market can amply provide. As the Wind Solar Alliance scorecard for Pennsylvania suggests, there is much room for improvement.[17] In my testimony, I propose several improvements in line with those detailed in that report.

Q. BUT ISN'T INVESTMENT IN GENERATION OCCURRING IN PENNSYLVANIA AND THROUGHOUT PJM?

A. Yes. But those investments are mostly a function of wholesale market design, including PJM's regional capacity market, where market administrators forecast forward demand and hold a competitive auction to procure it. Ideally, much of the heavy lifting currently left to the PJM capacity auction would instead be done by a diverse group of buyers seeking to cover their retail positions. In the highly competitive Texas market, for example, only 10-20% of total energy volumes transacted in the wholesale ERCOT market were unhedged by a bilateral contract.[18] This demonstrates that in a truly competitive retail market, a significant incentive faces EGSs to cover the positions they are contractually obligated to serve, or that they expect to serve in the future given

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17 Wind Solar Alliance Report, p. 19.

18 Potomac Economics, acting as ERCOT Independent Market Monitor, *Review of Summer 2019*, p. 23. https://interchange.puc.texas.gov/Documents/49852_6_1036679.PDF

expectations of their market share. This obligation drives investment in generating resources and, in particular, creates a virtuous cycle for renewable development, as many of those hedges take the form of renewable power purchase agreements.

Q. WHAT SPECIFIC IMPROVEMENTS HAVE YOU IDENTIFIED?

A. I propose a number of specific improvements including: (i) taking steps to transition PECO out of the default service role; (ii) adopting PECO's proposed time of use rate in tandem with implementing the ability of suppliers to issue consolidated bills to customers and requiring PECO to make several modifications to this product; (iii) rejecting PECO's proposal to solicit new ten-year contracts for solar alternative energy credits; (iv) rejecting PECO's proposal for the recovery of network integration transmission service costs; (v) making changes to PECO's proposed rate design for default service so that it contains all of the cost components incurred to provide default service; (vi) rather than simply continuing the existing Standard Offer Program ("SOP"), seizing an opportunity to implement improvements that might encourage greater participation by suppliers and consumers; and (vii) avoiding structuring PECO's proposed plan for shopping by low-income customers in a way that is unduly restrictive and contains elements that would create new challenges for suppliers in their interactions with consumers.

III. TRANSITION PECO OUT OF DEFAULT SERVICE

Q. WHAT DO YOU BELIEVE NEEDS TO OCCUR IN ORDER FOR PENNSYLVANIA TO REALIZE THE INTENDED BENEFITS OF THE COMPETITION ACT?

A. Pennsylvania law requires a DSP to supply non-shopping customers, or customers whose EGS has defaulted or otherwise not performed.[19] However, the law's requirement that

[19] 66 Pa.C.S. § 2807(e)(3.1).

PECO fill this role at the conclusion of the company's restructuring plan, when its retail generation rate caps expired in 2010.[20] The Commission for a decade has had the statutory ability to designate an "alternative supplier" of default service in the PECO territory.[21] A reformed DSP could be truly a provider of last resort, as the law intended, and not the first resort and dominant supplier in the market. To that end, it is critical that the Commission resume its discussions from 2012 and lay the groundwork to transition Pennsylvania's retail electricity market so that all customers are shopping for electricity and "default service" becomes a true backstop service provided by EGSs.[22]

In 2012, former Commissioner Cawley aptly explained that the "fundamental problem with the current default supply structure is that the majority of consumers will not make a proactive decision to choose an energy supplier when they are provided a default supplier if they do not choose one."[23] He pointed out that this "is especially so when customers are accustomed to receiving complete service from their electric utility."[24] Using an example in the service territory of Duquesne Light Company where multiple supplier offers were available that would be more than 20% lower than the utility's prices, Commissioner Cawley noted the lack of shopping and concluded that

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[20] 66 Pa.C.S. § 2807(e)(1); *Petition of PECO Energy for Approval of Its Default Service Program and Rate Mitigation Plan*, Docket No. P-2008-2062739 (Order entered June 2, 2009).

[21] 66 Pa.C.S. § 2803, definition of "default service provider."

[22] *Investigation of Pennsylvania's Retail Electricity Market*, Docket No. I-2011-2237952 (Secretarial Letter dated March 2, 2012). http://www.puc.state.pa.us/electric/pdf/RetailMI/RMI-SecLtr_Staff_Doc_EnBanc_Hearing030212.pdf

[23] *Investigation of Pennsylvania's Retail Electricity Market*, Docket No. I-2011-2237952 (Concurring and Dissenting Statement dated September 27, 2012) at 1. http://www.puc.pa.gov/pcdocs/1192963.pdf

[24] *Id.*

"mass market customers, including residential and small commercial customers, often will not make affirmative choices for their supplier unless they are required to."[25]

In making these observations, Commissioner Cawley was voicing what has in the years since become widely accepted: that government regulation establishes a "choice architecture"[26] that drives consumers to make—or, as here, not make—choices, even in a market that may seem unconstrained and fully competitive. Or as the Nobel laureate in economics Daniel Kahneman puts it about the positive choices that a consumer might make, but does not: "The default option is naturally perceived as the normal choice. Deviating from the normal choice is an act of commission, which requires more effortful deliberation, takes on more responsibility, and is more likely to evoke regret than doing nothing."[27]

Q. WHAT ARE SOME KEY BENEFITS OF REMOVING THE UTILITY FROM THE ROLE AS DEFAULT SERVICE PROVIDER?

A. The reasons offered in the above section where I make observations about the stagnation of the retail competitive market are also relevant here. If the Commission does not take action, it should expect the competitive retail market to further stagnate, to the ultimate disadvantage of consumers amidst the re-emergence of a monopoly that either lacks a strong incentive for innovation or efficiency, or which may face perverse incentives, necessitating constant scrutinizing by the Commission. In addition, there are several other benefits to not having a dominant DSP serving the vast majority of the market, especially a company that is an EDC.

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25 *Id.* at 2.

26 Richard Thaler, Cass Sunstein, and John Balz, "Choice Architecture," Ch. 25, *The Behavioral Foundations of Public Policy*, ed. Eldar Shafir (2013).

27 Daniel Kahneman, *Thinking, Fast and Slow* (2011), p. 413.

First, having the EDC exit the default service role will enable the EDC to focus on its core competencies and obligations for safe, reliable and adequate distribution service. Second, the selection process of an "alternative supplier" for DSP could have competitive characteristics that would allow the Commission to avoid the worst parts of regulating the EDC-as-DSP. Specifically, I would expect the Commission to ask aspirants to provide DSP service to participate in a competitive-offer process similar to what companies now do in vying to be wholesale suppliers to PECO's DSP. Instead of bidding for tranches that are then passed-through at cost, together with other costs that require the kind of litigation present in this proceeding, the companies bidding to be the DSP would present rival plans that the Commission and an independent evaluator would select from using a transparent methodology. In either case, the terms of the engagement could largely be fixed in advance, with the Commission approving "reasonable costs" that are collared by a competitive process.[28] This stands favorably in contrast to the status quo, where the Commission must make *ad hoc* decisions on conceptual topics within DSP design, such as the solar procurements that PECO proposes (Section V) or the allocation of the EDC's overhead costs (Section VII) and NITS charges (Section VI) that I raise, and watch as the cost consequences of those decisions accrue to consumers under an automatic adjustment provision.[29] Third, the DSP could be institutionally responsible for administrating the "choice architecture" that leads customers to more actively choose, while currently

[28] This is to say the Commission would define "reasonable costs" through the solicitation process, limiting the DSP's ability to collect higher costs after the fact, and providing an incentive to obtain further efficiencies that could be reflected in the next DSP phase. 66 Pa.C.S. § 2807(e)(3.9).

[29] *Id.*

PECO's programs have not resulted in a substantial increase in shopping, as evidenced by the slowing traffic now seen in the SOP described below (Section VIII).

Q. WHAT CAN THE COMMISSION DO ABOUT THESE PROBLEMS WITHIN PECO'S DEFAULT SERVICE PROCEEDING?

A. The Coalition recognizes that the Commission would likely prefer to address changes to the default service structure model on a statewide basis. However, the fact remains that each EDC files its own default service plan, which does not lend to such an approach. The evidence in the record in this proceeding shows a need for Commission action. Nonetheless, understanding that it is not realistic to expect PECO to submit a compliance filing in this proceeding that begins the process of moving it out of the DSP role, the Coalition suggests instead that the Commission direct PECO to hold a series of workshops with stakeholders commencing within 120 days following entry of a final order and to submit a report to the Commission within 120 days thereafter summarizing the alternative default service models identified by the stakeholders. Alternatively, the Commission could convene its own Office of Competitive Market Oversight-led collaborative following a similar timeline and approach. The point is that the default service model needs to change in order to allow the competitive market to function effectively. That will not happen unless the Commission embraces these concepts and displays a leadership role returning Pennsylvania to its status as a national leader in competitive energy markets. In addition to kickstarting this important change, there are a number of issues that have to be addressed regardless of which entity serves as DSP—as well as some that have to be resolved in this proceeding because PECO serves as DSP. I now turn to those topics.

IV. TIME-OF-USE ("TOU") RATES

Q. WHAT DOES PECO PROPOSE WITH RESPECT TO TOU RATES?

A. Through Direct Testimony, Mr. Bisti describes the key features of PECO's proposed TOU Rates, which would "differentiate prices across three periods (peak, off-peak and super off-peak) that remain constant year-round based on price multipliers designed to motivate shifting of usage from the higher-cost peak period to lower-cost peak periods."[30] He further explains that the TOU pricing periods are identical for the Residential and Small Commercial Classes. As he notes, the "proposed TOU rate design is structured to establish a rate premium above PECO's standard, fixed-price default service rate for usage during the peak period and rate discounts from this baseline price for usage during two off-peak periods."[31]

Q. WHAT IS YOUR VIEW OF THE OPPORTUNITY FOR AND BARRIERS TO MORE CUSTOMERS IN THE PECO SERVICE TERRITORY RECEIVING SERVICE UNDER TOU RATES?

A. It is an important and overdue development. PECO began its smart-meter rollout in 2012, and between the beginning of that year to the end of 2019 PECO's rate base associated with meters grew nearly $125 million, from $195 million to $320 million, at an approximately 8% annual average rate of growth.[32] The roll-out has resulted in smart-meter technology being nearly ubiquitous for PECO's residential and small-commercial customers who will be eligible for the proposed TOU rate, with 99.5% and 98.0% of

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30 PECO Statement No. 2 at 14.

31 PECO Statement No. 2 at 15.

32 Put another way, PECO's meter rate base has grown 64% over eight years. Figure calculated by subtracting the difference between the end of year plant balance for 2019 and beginning of year plant balance for 2012 in FERC Account 370-Meters. Exhibit TK-6 (Response to ESC-IV-9).

those classes respectively being served with a smart meter.[33] One of the often-promised benefits of smart meters is their ability to create an enhanced retail experience, including time-varying rates that better reflect the cost of energy at wholesale and the opportunity for demand to participate in response to a more dynamic price signal. As then-Commissioner Robert Powelson opined in his characteristically forward style when the Commission first implemented Act 129 providing for smart-meter technology, "To be frank, it is pointless to have smart meters if you are still going to have 'dumb' rates."[34] And yet, even as PECO customers have paid handsomely for this investment, a decade later they have little to show for it—at least as regards "smart" rates. According to PECO, they still won't, at least not through the DSP, even if the present filing is approved. That is because PECO proposes its TOU rate as only an opt-in, rather than a default product, and consequently "PECO expects enrollment in its proposed TOU rates to be small relative to the overall default service customer base."[35]

It does not have to be this way. Obviously, Pennsylvania telecommunications customers who once received a uniform service under a regulated rate structure today experience something very different. Depending on their provider, they are today able to track their data, enjoy free access to certain data as part of their subscription, and enjoy a variety of different rate and plan offerings that suit their needs. That is the ideal of the retail electric market—but we are far from accomplishing it. Indeed, today's electric market is structured in such a way that whatever competitive offering a customer might

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33 Exhibit TK-7 (PECO Response to ES-I-45).

34 *In re Smart Meter Procurement and Installation*, Docket No. M-2009-2092655 (Statement of Commissioner Powelson dated June 18, 2009).

35 Exhibit TK-6.

subscribe to, he or she would still receive the bill from Ma Bell. Indeed, in the Pennsylvania competitive retail market, even programs that have the purpose of introducing customers to this competition are branded as "PECO" programs.[36] At the same time the Commission considers an innovative product like TOU, it must think in tandem about the competitive structure of the market that should serve a marketplace whose customers want and need differentiated products.

Q. YOU SAY 'IT DOESN'T HAVE TO BE THIS WAY.' DO YOU HAVE A REAL-WORLD EXAMPLE IN THE ELECTRIC POWER SECTOR TO PROVIDE IN THIS REGARD?

A. Yes. In Texas, NRG's largest market, electric customers enjoy a wide variety of product offerings. Importantly, 1.25 million out of 7.45 million customers have voluntarily elected a price-responsive demand product—nearly a 17% adoption rate.[37] By contrast, the nationwide average for adoption of time-of-use rates by residential customers is a mere 1.7%.[38] This diversity of offerings, especially of TOU and like products, would not be possible if it were not for Texas allowing EGSs to directly bill their customers.

PECO has indicated that it will use its customers' bills by "depicting the time-of-use blocks and associated charges," which will inform customers how their usage fell into the on-peak, off-peak, and super-off-peak periods.[39] While it has not provided an

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36 See, e.g., Exhibit TK-8 (PECO Response to ESC-I-3). This discovery response contains the script that PECO uses to introduce customers to the Standard Offer Program, which is fully funded by EGSs, but yet is repeatedly referred to as the "PECO Smart Energy Choice Program."

37 Wind Solar Alliance Report, p. 4.

38 Ryan Hledik et. al., *The National Landscape of Residential TOU Rates: A preliminary summary*, Brattle Group (Nov. 2017), http://files.brattle.com/files/12658_the_national_landscape_of_residential_tou_rates_a_preliminary_summary.pdf.

39 Exhibit TK-9 (PECO Response to ESC-IV-14).

example of what this will look like.[40] PECO's approach in this regard is obvious. It would be absurd to serve a customer under a complex rate and not attempt to straightforwardly represent the charges associated with the time-variable elements of that rate.

As an example of a customer relationship around such a product looks like, I am sponsoring Exhibit TK-10, which is an example of a customer bill that retail provider Reliant, an NRG company, uses for its Reliant Free Weekends℠ 12 in the Texas ERCOT market. In Pennsylvania generally and in PECO's service territory specifically, EGSs do not have the ability to send such a bill to their customers. Instead, we are limited to 4 lines with 80 characters of text on PECO's bill.[41] We also do not have the luxury of sending customers a bill insert at all, much less at those customers' expense, as PECO proposes to do for its TOU product.[42] The barriers that prevent EGSs from billing customers directly should come down, in tandem with a Commission order allowing PECO as a DSP to offer any TOU product.

Q. WHAT WILL LIKELY HAPPEN IF THE COMMISSION DOES NOT ADOPT A RETAIL MARKET ENHANCEMENT ALLOWING SUPPLIER CONSOLIDATED BILLING AT THE SAME TIME THAT PECO TOU RATES ARE IMPLEMENTED?

A. Several harms will occur. First, the retail market will become more uncompetitive. It will result in a situation where only PECO is allowed to offer time-varying rates effectively. The Commission has noted both the challenges faced by EDCs in offering TOU rates and

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40 *Id.*

41 Exhibit TK-11 (PECO Response to ESC-III-1).

42 Id.

the importance of relying on retail EGSs to offer TOU products,[43] but this will not occur if EGSs lack the same billing model that would allow the PECO TOU product to be effective.

Second, the competition that will exist will tend toward a race to the bottom, further converging on time-limited offers for a low commodity cost, rather than on evolving the retail market and the EGS business model to a next-generation industry that leverages Pennsylvanians' investment in smart meters.

Third, it will cement incentives that are already misaligned with the presence of a dominant default supplier that enjoys pass-through recovery of its "reasonable" (often meaning, all) costs. When an EGS sells energy supply products, it is the EGS that takes the risk around the divergence between the rate charged to customers and the EGS' actual costs to supply those customers. In a similar vein, the EGS takes the risk around whether the TOU product will in an economically efficient manner shape a customer's demand.[44] PECO as a DSP takes no such risk. Indeed, PECO is proposing to socialize this risk not just to TOU customers—but to all its customers.[45] The answer to the question "who bears the risk?" is profoundly different when it comes to the utility in its DSP role versus an EGS's offering of TOU products. The Commission should want as many properly incentivized actors in the market offering TOU products so that they—and not customers—wear the risk of getting the retail price structure aligned to the actual value of

[43] *Investigation of Pennsylvania's Retail Electricity Market: Recommended Directives on Upcoming Default Service Plans*, Docket No. I-2011-2237952 (Tentative Order entered October 14, 2011) at 7.

[44] These trade-offs are evident, for example, when PECO describes why it is proposing a year-round TOU product rather than a seasonal one, as the Commission previously advised and which might have a stronger link to the wholesale market dynamics that TOU rates are intended to reflect. PECO Statement No. 2 at 17.

[45] PECO Statement No. 2 at 20-21.

energy supply at particular time periods balanced with the acceptability of these plans to customers.

These three harms are substantial, but they can be minimized or remedied if the Commission requires PECO to adopt supplier-consolidated billing ("SCB") at the same time or before PECO implements its time-variable rates. Of note, PECO already has SCB provisions in its Electric Generation Supplier Coordination Tariff.[46] Yet these provisions are ineffective because they have never been operationalized. No electronic data interchange process is in place and PECO would not at the moment be able to execute SCB were an EGS to request it. Additionally, various EGSs have asked the Commission to implement SCB and to enable EGSs to manage their bad debt on the same terms as apply to the EDC as the DSP.[47] Nevertheless, the tariff provisions represent a starting point for full SCB implementation and a Commission decision in this matter directing them to be resolved prior to TOU implementation is an appropriate resolution of the outstanding barriers to the EGS business model, especially as regards innovative products.

Q. SO DO YOU OPPOSE PECO'S PROPOSAL TO OFFER TOU RATES?

A. On the contrary, there is much to support in it. I have been advised by counsel that as a DSP, PECO has a legal obligation to offer such a rate to essentially all customers with smart meter technology.[48]

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[46] Supplement No. 27 to Tariff Electric Pa. P.U.C. No. 1 S, First Revised Page Nos. 97-101. https://www.peco.com/SiteCollectionDocuments/current_elec_supplier_tariff_eff_Sept082016.pdf

[47] *See, e.g., Notice of En Banc Hearing on Implementation of Supplier Consolidated Billing*, Docket No. M-2018-2645254 (Comments of the Electric Generation Supplier Coalition for Consolidated Billing dated May 4, 2018).

[48] 66 Pa. C.S. § 2807(f)(5); *DCIDA v. PUC*, 123 A.3d 1124 (Pa.Cmwlth. 2015), rehearing denied, 2015 Pa. Commw. LEXIS 472 (Oct. 30, 2015), appeal denied, 2016 Pa. LEXIS 1131 (Pa., June 1, 2016).

While PECO has offered its TOU rate as an opt-in for residential and commercial customers, it should be the default rate and instead allow customers to opt-out to real-time pricing or to an EGS product. The default rate should be a rate structure that better reflects underlying market-price dynamics. This is especially so because part of the rationale for the investment in ubiquitous smart-meter technology was a retail rate structure that took advantage of this investment, as Commissioner Powelson's opinion quoted above denotes. The current default standard rate does not take advantage of this substantial investment in smart meter technology. As Mr. Bisti observes, PECO's opt-in TOU pilot program delivered measurable load reductions, especially at peak, and saved the vast majority of enrolled customers money.[49]

Regardless of whether the DSP's TOU rate is opt-in or opt-out, however, the Commission should first ensure a level playing field for time-varying rate products offered by the DSP and EGSs in order to ensure that harms I have identified above are minimized. In addition, I have a handful of concerns about PECO's proposal itself.

Q. WHAT IS YOUR FIRST CONCERN WITH THE DETAILS OF PECO'S PROPOSAL?

A. It is the budget and timeline along which PECO proposes to offer its TOU rate. PECO proposes only $900,000 in expenses for customer communications around its TOU offering, and provides relatively few details around this program.[50] PECO suggests that the rate will be available in approximately a year from when the Commission approves the TOU rate in an order.[51] Based on my familiarity with TOU programs and my review

[49] PECO Statement No. 2 at 11-12.

[50] PECO Statement No. 2 at 23-24.

[51] *Id.* at 24.

of a recent report by Barbara Alexander of another public utility's implementation of more complex rate plans, it seems appropriate to expect a larger budget and a longer time horizon to implement a TOU rate that is intended to be widely adopted.[52] Of course, this is especially the case if the TOU rate is the default rate under DSP.

Q. WHAT IS YOUR NEXT CONCERN?

A. To the degree capital investments are proposed for the DSP program, they should be funded throughout the life of the DSP period. PECO estimates it will make $2.9 million in capital investments associated with the TOU rate's implementation.[53] Since these capital investments are intended to benefit DSP customers throughout the DSP period, it is appropriate that these be amortized over the period. The Generation Supply Adjustment ("GSA") portion of the PTC should begin reflecting those when the rate is first reset at the beginning of the DSP period in 2021 on amortization schedule equal to the 4-year DSP.

Q. DO YOU HAVE OTHER CONCERNS?

A. I do. PECO proposes two restrictions in their application that seem to run afoul of statutory requirements. The first concerns real-time price service.[54] Larger customers may take real-time price service under PECO's DSP.[55] However, Mr. Bisti does not propose to make this service available to residential and small commercial customers. PECO has

[52] Barbara Alexander, "An Evaluation of Arizona Public Service Company's Customer Education and Its Implementation," (May 19, 2020), prepared on behalf of the Staff of the Arizona Corporation Commission. Docket Nos. E-01345A-19-0236 and E-01345A-19-0003. Available online at https://docket.images.azcc.gov/E000006584.pdf (accessed June 8, 2020).

[53] PECO Ex. JAB-6.

[54] I use that term within its Pennsylvania statutory meaning of "a rate that directly reflects the different cost of energy during each hour," in which sense the PECO DSP's day-ahead hourly energy product qualifies. *See* 66 Pa. C.S. § 2806(m).

[55] PECO Statement No. 2 at 7.

confirmed that it has not included such a proposal in its DSP V filing.[56] Secondly, Mr. Bisti also proposes that "residential customers enrolled in PECO's [Customer Assistance Program] will not be eligible for the residential TOU Rate at this time."[57] This is not consistent with Pennsylvania law, in my understanding.

Q. HOW IS PECO'S OMISSION OF OFFERING REAL-TIME PRICING TO CERTAIN RETAIL CUSTOMERS INCONSISTENT WITH LAW?

A. The law states "the default service provider shall offer the time-of-use rates *and* real-time price plan to all customers that have been provided with smart meter technology."[58] With respect to customers' preferences, the law provides that "residential or commercial customers may elect to participate in time-of-use rates *or* real-time pricing."[59] It seems clear that when PECO acts in its role as a DSP, that it must offer at least one TOU rate structure and one real-time price plan. In other words, if PECO makes a filing for TOU rates without also providing for real-time pricing, as it has done in this proceeding, then the proposal appears to be inconsistent with state law. The real-time pricing that PECO is required to offer should also be incorporated into PECO's implementation campaign and associated expenditures should be estimated and priced into the GSA.

Q. DO YOU HAVE ANY VIEWS ON PECO'S SUGGESTED PROHIBITION ON CAP CUSTOMERS' ELIGIBLITY FOR TOU RATES?

A. The statute, and not PECO or the Commission, defines the set of customers to which default service providers like PECO must offer both TOU and real-time products. This

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[56] Exhibit TK-12 (PECO Response to ESC-I-2).

[57] PECO Statement No. 2 at 15.

[58] 66 Pa. C.S. § 2807(f)(5) (emphasis added).

[59] *Id.* (emphasis added).

includes all customers who have a smart meter, except in certain limited circumstances associated with how and when the smart meter was first installed.[60]

Q. HAVE YOU FOUND ANY OTHER OMMISSION IN PECO'S PROPOSAL?

A. Yes. The law requires a DSP with Commission-approved TOU rates and real-time price plans to "submit an annual report to the price programs and the efficacy of the programs in affecting energy demand and consumption and the effect on wholesale market prices."[61] It does not appear that PECO, as part of its proposal in this proceeding, proposed a process for making such reports to the Commission, or the form they will take, the information they will convey, or the likely expense of making such reports. However, in response to Coalition discovery, PECO suggests it will make a filing on its TOU plan annually.[62]. It should, and the costs of doing so should appropriately be allocated to the DSP.

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60 *Id.* In referring to § 2807(f)(2)(iii) as the group of customers to whom the requirement to offer a TOU rate and a real-time price applies, the Legislature in enacting § 2807(f)(5) contemplated that if a customer had a smart meter installed a smart meter at his or her own option pursuant to § 2807(f)(2)(i) prior to the smart meter roll-out, or as part of new construction pursuant to § 2807(f)(2)(ii), that the default service provider would not be under this obligation for that customers. Presumably, this was to relieve a DSP of offering a boutique rate that was not available to the majority of customers. Meanwhile, since it is my understanding that the Commission approved widescale smart meter deployments with depreciation schedules of 15 years or less, as contemplated in § 2807(f)(2)(iii), that a requirement therefore exists for the DSP to offer TOU and real-time price plans to all customers who receive service through such a meter. *In re Smart Meter Procurement and Installation*, Docket No. M-2009-2092655, Implementation Order entered Jun 18, 2009 at 14-15 and Ord. ¶ 6.

61 66 Pa. C.S. § 2807(f)(5).

62 Notably, PECO has not submitted reports on its real-time price plan, even though that offering appears to fall within the statutory obligation to file such reports, nor does it propose to include information on those products in the context of the reports it proposes to file on TOU. The Commission should require PECO to file reports consistent with the law. Exhibit TK-13 (PECO Response to ESC-IV-13).

Q. WHAT DO YOU RECOMMEND THE COMMISSION DO WITH RESPECT TO PECO'S TOU PROPOSAL?

The law suggests that the Commission must either "approve or modify" a DSP's proposal for TOU and real-time pricing.[63] I recommend the Commission adopt a retail market enhancement that permits EGSs the practical ability to market and bill TOU and like products to customers at the same time or before PECO itself is allowed to do so.[64] The approval of the PECO proposal should be contingent upon the implementation of this enhancement.

Additionally, the Commission should make a number of modifications to the PECO proposal:

1. It should approve the TOU rate as the standard default rate, allowing customers to shop if they would prefer a different rate, to promote the effective use of PECO's smart-meter investment and to make the default rate more reflective of underlying market conditions.
2. It should require PECO to submit a more robust customer education campaign on a realistic timeline.
3. It should require PECO to offer a real-time price plan to residential and small commercial customers, consistent with the law.
4. It should require PECO to offer these rates to all residential and small commercial customers who received a smart meter as part of the utility's rollout of those investments.

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63 *Id.*

64 As noted previously, this recommendation entails the implementation of SCB at the same time or before PECO's TOU product becomes available to customers.

5. It should require PECO to appropriately allocate TOU-related costs to DSP customers, including by making a full and appropriate cost allocation and by depreciating capital expenditures over the DSP plan period.
6. It should require PECO to include in its tariff the annual reports contemplated by law by DSPs' offering TOU rates and real-time price plans.

V. TEN-YEAR CONTRACTS FOR SOLAR ALTERNATIVE ENERGY CREDITS

Q. HOW DOES PECO PROPOSE TO COMPLY WITH PENNSYLVANIA'S ALTERNATIVE ENERGY PORTFOLIO STANDARDS ("AEPS") ACT?

A. PECO proposes a two-part approach to ensure that it complies with AEPS Act[65] requirements that PECO acquire and retire alternative energy credits ("AECs") in quantities equal to a percentage of their total retail sales of electricity to all of their retail electric end-use customers for each reporting period. For Tier I and Tier II AECs, PECO will require wholesale default service suppliers to transfer the amount based on the portion of default service load served by the wholesale default service supplier.[66] Separately, and by contrast, PECO proposes to contract directly for fixed-price, ten-year agreements to purchase up to 16,000 Tier I Solar AECs ("SAECs") annually through two solicitations (in 2021 and 2022). This would double the amount of SAECs that PECO directly procures under contract. PECO will employ a two-phase annual procurement process involving a competitive bid phase (the RFP) followed by a Standard Offer To Purchase ("SOTP") phase.[67] The SAECs to be procured through the long-term contracts are expected to satisfy approximately 25% of PECO's SAEC requirements during the

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65 73 P.S. §§ 1648.1-1648.8.

66 PECO Statement. No. 1 at 27-28.

67 PECO Ex. JJM-10 at 1.

DSP V plan period.[68] PECO will apply the remaining 16,000/year SAECs to be acquired pursuant to the process to future default service plan periods.

Q. DOES THE ELECTRIC SUPPLIER COALITION SUPPORT PECO'S SAEC PROCUREMENT PROPOSAL?

A. No. Entering into 10-year contracts, which extend six years beyond the proposed DSP program plan period, is not reasonable. The presence of these long-term contracts will impede the ability of the Commission to remove PECO as the default service provider and approve an alternative default service provider—a barrier that would be present for 10 years. Moreover, the use of long-term contracts by PECO places PECO's captive ratepayers at risk because they will be required to pay for the costs of contracts that may end up being uneconomic over their life. Finally, when default service providers are permitted to use the threatened lack of solar development as a reason for them to enter the market with a supply agreement to "correct" it, the willingness and ability of EGSs to undertake these projects (relying on private investment) is hampered.

Q. WHAT IS YOUR RECOMMENDATION?

A. PECO should require wholesale default service suppliers to deliver the full amount of PECO's AEPS requirements and not pursue the proposed 10-year SAEC contract. Alternatively, the 10-year SAEC proposal should be reduced to match the DSP four-year plan period.

Q. PLEASE EXPLAIN YOUR OBJECTIONS TO APPROVING PECO'S PROPOSED LONG-TERM CONTRACTS WITHIN THE CONTEXT OF THIS DSP PLAN PERIOD.

A. I do not object to long-term contracts generally. It is sometimes rational for a party to enter into one when it is risking its own capital and expects to have load to serve in an

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[68] PECO Statement. No. 1 at 28-29.

economically efficient way over that period of time. However, the program period for this default service plan is four years. While PECO has served as the default service provider since the expiration of generation rate caps, both the statute and the Commission's regulations contemplate the possibility of the default service provider role being shifted to an alternative default service provider such as an EGS.[69] It would be improper in this proceeding to take any action that either forecloses that possibility or creates future stranded costs that would unduly burden the potential for that important reform.

Furthermore, the Commission has previously directed EDCs not to enter into energy contracts that extend past the end date of the default service plan period and to limit the proportion of long term contracts that make up the default service energy plan portfolio.[70] Mr. McCawley cites to the Commission's regulations that he suggests shows that contracts can extend beyond the life of the DSP.[71] But this rule applies only to contracts for "electric power"; SAECS are not "electric power" and are instead part of the "electric generation supply" product.[72] Indeed, the fact that a similar rule does not exist for SAECs suggests they, in particular, should not be procured on a longer time horizon than the plan period.

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69 66 Pa.C.S. §§ 2803; 2807(e)(5); 52 Pa. Code § 54.183.

70 *Investigation of Pennsylvania's Retail Electricity Market: Recommended Directives on Upcoming Default Service Plans*, Docket No. I-2011-2237952 (Tentative Order entered October 14, 2011) at 4-5.

71 PECO Statement No. 1 at 21.

72 *Compare* 52 Pa. Code § 54.186(b)(1), defining the mix of instruments for a prudent procurement of "electric power" and 52 Pa. Code § 54.185(e)(1), associating the AEC requirement as part of "electric generation supply."

Q. ARE THERE OTHER REASONS WHY APPROVING PECO'S PROPOSED LONG TERM SOLAR CONTRACTS SHOULD BE REJECTED?

A. Yes. Entering into long term contracts, as PECO proposes here, places PECO's captive ratepayers at risk because they will be required to pay for the costs of contracts that may end up being uneconomic over their life. If PECO risked its own capital—as do EGSs—on a venture that could turn it a profit or loss, then the Commission should be supportive of long-term engagements. That, however, is not the case here, because PECO will be made whole via captive ratepayer dollars regardless of the outcome. As such, there is no financial incentive to execute a contract that is advantageous to PECO's consumers. Indeed, in the SOTP proposal PECO makes, it suggests it bid the *average successful offer price* from the RFP phase of the procurement to those who have SAECs available to sell it.[73] In other words, it is content to get the average of better prices—and not the best price. This is not consistent with how a normal, properly incentivized buyer would conduct solar procurements, in my view.

Q. SINCE PECO AS A DSP MUST ACQUIRE AECS, INCLUDING FOR THE SOLAR CARVE-OUT, WHAT DO YOU PROPOSE?

A. The simplest approach to this issue is to require the DSP's wholesalers incorporate their estimated cost of AEC/SAEC procurement into the bids they make as part of their tranched offers. This is what happens already with the vast majority of AEC procurements, and PECO gives no particular reason why, in effect, a portion of a subset of its AEC requirement—25% of its SAEC procurement requirement—should be procured in this way, unlike the manner in which it procures essentially everything else. This more standard approach would have the salutary effect of retaining a level playing

[73] PECO Statement No. 1 at 33.

field, because the wholesale suppliers face in effect the same business model as EGSs do, having to estimate the likely cost of AEPS compliance and factoring it into the offers they make to the PECO DSP and to their individual customers, respectively.

Q. ARE THERE REASONS TO WORRY THAT NOT ENOUGH SOLAR WILL BE AVAILABLE IN PENNSYLVANIA FOR THE MARKET TO MEET ITS MANDATED PROCUREMENT REQUIREMENT?

A. Mr. McCawley offers a report by the Commission about the state's AEPS compliance, which suggests an uptick in construction of in-state solar facilities will be needed for enough SAECs to be available to meet the legal requirement.[74] He also suggests that PECO's expanded procurement of solar "is consistent with the express policies of a variety of stakeholders in PECO's service territory, including the City of Philadelphia."[75] I find Mr. McCawley's reference to the City of Philadelphia interesting, because the city government's recent deal with ENGIE, a member of the Coalition I represent, is a positive example of what the EGS market can do on solar development when EGSs are given a chance. That deal includes an 80-MW solar facility in Adams County, which will according to a city news release will provide 22% of the city's electricity.[76] Unfortunately, when default supply utilities are allowed to use the threatened lack of solar development as a reason for them to enter the market with a supply agreement to "correct" it, it hampers the willingness and ability of EGSs to undertake these projects themselves. As I noted earlier, and as the authors of the Wind Solar Alliance report observe, EGSs that must stake their own capital at risk are going to be unwilling to make long-term investments if they forecast a persistently unlevel playing field where their

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[74] PECO Statement No. 1 at 29.

[75] *Id.*

[76] https://www.phila.gov/2020-02-06-city-and-engie-announce-power-purchase-agreement-staffing-plans/

competition is a rate-regulated utility with the ability to recover all its costs, even on bad deals. While PECO's previous solar PPAs were small, the ones it proposes here are double in size. It is time to establish confidence for investment by EGSs by adopting more significant reforms, which will do more over the long term to promote confidence and investment in renewables, including in-state solar needed to comply with the AEPS.

VI. RECOVERY OF NETWORK INTEGRATION TRANSMISSION COSTS

Q. WHAT ARE NETWORK INTEGRATION TRANSMISSION SERVICES ("NITS")?

A. Network Integrated Transmission Service ("NITS") charges reflect a load serving entity's share ("LSEs") of the approved transmission service rate for a given transmission owner's zone. LSEs include both EGSs and wholesale default service providers. Accordingly, *all* customer load (including shopping and non-shopping customers) on an EDC's system is allocated a share of transmission service costs. Transmission rate changes are not a function of market fundamentals, but of a FERC regulatory process largely driven by transmission owners like PECO and what they decide to spend in upkeep and reinvestment in their system.

Q. ARE NITS THE ONLY PJM CHARGES THAT HAVE THESE CHARACTERISTICS?

A. No. There are a number of wholesale cost obligations assessed by PJM that all LSEs are required to pay including: Generation Deactivation/Reliability Must Run charges; Regional Transmission Expansion Plan charges; and, Expansion Cost Recovery charges (collectively, "Other PJM Charges"). NITS and Other PJM Charges are generally referred to a Non-Market Based ("NMB") charges.

Q. WHY DO NMB CHARGES PRESENT SUCH DIFFICULTY IN COMPETITIVE MARKETS?

A. NMB Charges present difficulty because they are not a function of market fundamentals and, therefore, can be subject to very significant changes over what can be reasonably anticipated. When any of these NMB Charges experience significant price fluctuations, LSEs either must absorb them or pass them on to consumers.

Q. ARE YOU AWARE OF WHETHER THE COMMISSION IS FAMILIAR WITH THE PROBLEMS PRESENTED BY NMB CHARGES?

A. Yes. I am advised by counsel that Commission Staff was directed to perform an informal review of NMBs and that a Secretarial Letter was issued to EDCs on May 1, 2015 requesting the EDCs to respond to specific questions set forth in the letter. According to the May 1, 2015 Secretarial Letter, the intent of the investigation was "to determine if there is a need to address these non-market based wholesale market charges in a more uniform and comprehensive way that would facilitate and enhance the retail electric market during future proceedings."[77] Neither the information provided by the EDCs in response to the May 1, 2015 letter nor any other result of the Staff's informal investigation was shared publicly. PECO, in response to discovery in this proceeding, indicated that "after a reasonable search . . . it was unable to locate the written informal comments" shared with Commission Staff.[78] Then, in April 2017, Commission Staff announced its intent to reopen the NMB informal investigation and requested any interested stakeholder to submit informal comments by July 2017. Like the earlier investigation, none of the informal information received in July 2017 nor any other result

[77] The May 1, 2015 Secretarial Letter is included with the April 21, 2017 CHARGE Call Recap available on the Commission's website at http://www.puc.pa.gov/Electric/docs/OCMO/CHARGE_Recap042117.docx.

[78] Exhibit TK-14 (PECO Response to ESC-I-21).

of Staff's restarted investigation was publicly shared. No further information or action has occurred as a result of this Staff informal review.

Q. FOCUSING ON PECO, DOES PECO'S METHOD FOR RECOVERING COSTS FOR NITS AND OTHER PJM CHARGES SUFFER FROM THE INCONSISTENT APPROACH IDENTIFIED AS A CONCERN BY THE COMMISSION IN DIRECTING STAFF TO INVESTIGATION THE ISSUE?

A. Yes. PECO uses two very different methods of cost recovery depending on the specific NMB Charge. For NITS, PECO assumes the costs for *default service load only*. It passes through NITS price fluctuations to those default service customers through its Transmission Service Charge. Meanwhile, for the Other PJM Charges, PECO assumes the costs for *all* customers and recovers the costs from all customers (shopping and non-shopping) via the Non-Bypassable Transmission ("NBT") charge. PECO, within its own service territory, is applying two very different approaches. This matter can and should be addressed in this proceeding and the Commission should direct PECO to include recovery of NITS via the NBT charge so that the actual costs of all the NMB Charges are recovered from all customers.

Q. WHAT IS THE DIFFERENCE BETWEEN THE TWO COST RECOVERY METHODS UTILIZED BY PECO?

A. The difference between these two methods lies in how the LSEs have to factor in the costs of the NITS charges. EGSs bear the risk of estimating and pricing likely NITS charges. Meanwhile, PECO's wholesale default service suppliers and PECO itself pass that risk along to default service customers, who have their rates increased after the fact for any increase in NITS charges.

In contrast, for the Other PJM Charges, PECO socializes this risk of price fluctuation for all customers (shopping and non-shopping). In that situation, neither the wholesale default service suppliers nor the EGSs are required to factor in the costs of those charges.

Q. IS PECO'S APPROACH TO NITS REASONABLE?

A. No. PECO's approach creates an inherently unlevel playing field between it as the DSP and EGSs. In today's design, EGSs bear the risk of estimating costs—ironically, costs in part driven by PECO's managerial decisions on transmission investments and accounting decisions on how to estimate its future spending, which are not visible to EGSs—even while PECO is able to socialize any rate increases driven by its additional real and expected transmission costs to its DSP consumers after the transmission rate PECO has proposed to FERC has gone into effect. Moreover, if EGSs overestimate NITS costs or the risk that those costs will change during the term of its retail supply agreement, customers may end up paying more than if the NITS charges were passed through a nonbypassable charge like PECO's NBT charge after they are approved.

Q. ARE YOU RECOMMENDING THAT THE COMMISSION REQUIRE PECO TO ELIMINATE ITS CURRENT COST RECOVERY METHODOLOGY FOR NITS?

A. Yes. As I discussed above, PECO's current method is the worst possible approach to dealing with the unpredictable nature of the actual NITS costs to be assessed on all LSEs both because of the imparity with how PECO treats NITS for default supply customers and shopping customers and because having EGSs bear the cost of NITS may increase costs to customers.

Q. ARE YOU AWARE OF THE COMMISSION'S PREVIOUS DETERMINATIONS REGARDING THE COST RECOVERY OF NITS?

A. Yes. I have been advised by counsel that the Commission has rejected proposals requiring EDCs to be responsible for the costs of NITS for all LSEs citing a lack of evidence that the cost of NITS is volatile and unpredictable.[79]

Q. HAVE CIRCUMSTANCES CHANGED SINCE THE COMMISSION LAST REJECTED THESE PROPOSALS?

A. They have significantly changed. Most transmission owners in PJM now charge "formula" rates. This is a significant departure from traditional transmission ratemaking, and it promotes more frequent and sudden changes in NITS. That makes it harder for EGSs to estimate likely NITS costs over the term of the offers they make to the market.

Q. CAN YOU EXPLAIN MORE FULLY HOW THE COSTS THAT WILL BE ASSESSED TO ALL LSES FOR NITS ARE NOW DEVELOPED?

A. Yes. The annual revenue requirements for NITS are developed under either a "stated" or "formula" rate. Traditionally, utilities had to put on a rate case before FERC in order to justify their alleged cost of service in order to justify significant rate increases. These are "stated" rates—they are stated on the tariff sheet, and not subject to substantial change without rather involved regulatory proceedings. The length of those proceedings gives transmission customers like EGSs more time to plan and forecast likely rate changes.

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[79] *See, e.g., Petition of PECO Energy Company for Approval of its Default Service Program for the period from June 1, 2015 through May 31, 2017*, Docket No. P-2014-2409362 (Opinion and Order entered at December 4, 2014) at 53-54. The Commission has also approved FirstEnergy's approach which requires the wholesale supplier to include the costs of NITS as part of their bids to provide default service. *Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company for Approval of their Default Service Programs*, Docket Nos. P-2013-2391369, P-2019-2391372, P-2013-2391375, P-2013-2391378 (Opinion and Order entered July 24, 2014) at 31-32.

More recently, FERC has allowed transmission owners to change the rates they charge more frequently and more suddenly through “formula” rates. The inputs to the formula rates include the capital investments a transmission owner *expects to make* next year, the operating expenses it expects to have to pay for, as well as a return on the existing investments in its system. These rates are then trued up annually, such that if a transmission owner spent more or spent less than it initially projected, the rate can swing up and down in line with the under- or over-recovery.

Q. HAS PECO SOUGHT AND RECEIVED FERC APPROVAL TO MOVE FROM ‘STATED’ TO ‘FORMULA’ TRANSMISSION RATES RECENTLY?

A. Yes. On May 1, 2017, PECO filed a request with the FERC to begin implementation of a wholesale transmission formula rate.[80] On June 27, 2017, PECO received FERC approval to begin the implementation of a formula rate, starting December 1, 2017.[81] The formula rate structure allows PECO to receive current recovery of its costs. PECO files its transmission formula rate update as part of an annual process to reconcile the prior year’s rate to reflect any over- or under-recovery and to set the current year’s rate based on projected costs. PECO filed its 2020 Formula Rate Annual Update on May 29, 2020.[82]

Q. WHAT OTHER FACTORS CAN INFLUENCE THE ANNUAL PROJECTED REVENUE REQUIREMENT?

A. In the division problem that is at the heart of formula ratemaking, the dividend is the annual revenue requirement of the transmission owner’s projected cost of service—but

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80 PECO Energy Company PJM Interconnection, LLC, FERC Docket No. ER17-1519 dated May 1, 2017 available at: https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14578902

81 FERC Order Accepting and Suspending Filing, Subject to Refund, Establishing Hearing and Settlement Judge Procedures, FERC Docket No. ER17-1519 dated June 27, 2017 available at: https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14623778

82 PECO Energy Company Informational Filing of 2020 Formula Rate Annual Update, FERC Docket No. ER17-1519 dated May 29, 2020 available at: https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=15548295

the divisor is the PJM zone's total Network Service Peak Load (NSPL). Each LSE's NITS charge is based on their daily NSPL share of this annual revenue requirement. NSPLs are updated annually based on the prior year's peak load, which apart from any change in costs can nevertheless drive significant rate fluctuations as the divisor. When NSPL changes unexpectedly due to load increases—or as we have more recently seen, load decreases due to the COVID-19 pandemic[83]—that affects the ultimate quotient of this division problem, which is the rate charged to LSEs.

Q. DO YOU HAVE EXAMPLES OF ACTUAL IMPACTS TO LSES OF NITS RATES INCREASES?

A. Yes. Public Service Enterprise Group (PSEG) filed an annual formula rate update for rate year 2019.[84] PSEG's annual transmission revenue requirement effective January 1, 2019 was $1,194,757,707 (NITS Rate: $119,735.80/MW-Year). PSEG filed an updated annual revenue requirement on December 5, 2019. For the period beginning January 1, 2020, PSEG's new annual transmission revenue requirement was set at $1,526,297,808 (NITS Rate: $156,503.24/MW-Year), a 30.7% increase in the NITS Rate over the previous year.[85] Because of the effective date of the new NITS rates, LSEs had approximately a 25-day notice prior to the rate change. That is what I mean when I say

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83 PJM Details COVID-19 Impacts on Electricity Demand, Apr. 15, 2020. https://insidelines.pjm.com/pjm-details-covid-19-impacts-to-electricity-demand/ (accessed June 15, 2020).

84 Public Service Electric and Gas Company Informational Filing of 2019 Formula Rate Annual Update (Revision) FERC Docket No. ER09-1257 dated January 18, 2019 and available at: https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=15145006. The original filing for the 2019 Formula Rate Annual Update was dated October 15, 2018 and is available at: https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=15073350. PSEG filed several revisions to the original filing.

85 Public Service Electric and Gas Company Informational Filing of 2020 Formula Rate Annual Update (Second Revision) FERC Docket No. ER09-1257 dated January 17, 2020 and available at: https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=15073350. The original filing for the 2020 Formula Rate Annual Update was October 15, 2019 and is available at: https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=15073350. PSEG filed several revisions to the original filing.

that these rates change not just more frequently—on an annual basis—but also more suddenly, with a relatively short lead time. Below are similar increases for the FirstEnergy Companies: [86]

NITS Rates	Current NITS Rate	Current NITS Rate Effective Dates	Future NITS Rate	Future NITS Rate Effective Date
ATSI Zone	$55,074.34/MW/Year	Since January 1, 2019	$57,340.35/MW/Year	January 1, 2020
Allegheny Power Zone	$15,396.00/MW/Year	Since March 1, 2002	$15,396.00/MW/Year	March 1, 2002
MAIT Rates for ME & PN Zones	$28,796.22/MW/Year	Since January 1, 2019	$37,083.18/MW/Year	January 1, 2020

Q. WHY ARE THESE COSTS DIFFICULT TO ESTIMATE?

A. In order to track NITS costs, one must know or estimate a number of factors related to transmission projects. PJM provides a Transmission Cost Information Center (TCIC) that has data related to each transmission owner's rates, but TCIC must be verified against the actual sources of new project information (i.e. PJM Schedule 12 Appendix/Appendix A filings, PJM Transmission Expansion Advisory Committee updates and Subregional Transmission Expansion Plan updates). None of these rates are final until they are approved by FERC and are subject to adjustments during those proceedings. These annual updates may or may not be timed in a way that allows an EGS to accurately estimate what NITS costs will be during the relevant contract period with its customers, and as evidenced by the PSEG example, can vary significantly from year to year.

86 https://www.firstenergycorp.com/supplierservices/pa/me_pn/NITSRateInformation.html

Q. HAS THE ACTUAL COSTS OF NITS BEEN INCREASING OVER THE LAST SEVERAL YEARS?

A. Yes as displayed in the below table.[87]

NITS Rates ($/MW-Y)	Jan-20	Jan-19	Jan-18	% Increase Jan 2019 - Jan 2020	% Increase Jan 2018 - Jan 2019
MAIT	$37,083.18	$28,796.22	$26,069.39	28.8	10.5
PPL	$68,031	$58,865	$61,792	15.6	4.7
PSEG	$156,503.24	$119,735.80	$130,535.22	30.7	8.3

Q. DOES YOUR RECOMMENDATION CHANGE IF NITS RATES REMAIN STEADY OR DECREASE?

A. No. The core issue here is that NITS rates are unpredictable. While it poses a commercial difficulty for EGSs if NITS rates trend up and are unrecoverable, the fact that they are in the first instance unpredictable leads to a dynamic where EGSs will have to do something that PECO-as-DSP does not: forecast them. That likely will result in a risk premium added to EGS pricing, even if PECO rates end up being steady or going down. Moreover, when PECO rates go down, it means that EGS customers are likely paying more in transmission costs than the actual NITS rates, because of this process of estimation I have described. So it is the aspect of these NITS rates' unpredictable changes that are the issue, not just the direction of those changes.

Q. HOW DOES THE COALITION'S RECOMMENDATION SOLVE FOR THE UNPREDICTABILITY OF ACTUAL NITS COSTS?

A. NITS costs are driven by PECO's and other transmission owners' decisions on transmission spending. And with the change to formula ratemaking, they possess even

[87] Information from https://www.pjm.com/markets-and-operations/billing-settlements-and-credit.aspx under the heading "Network Integration Transmission Service Revenue Requirements & Rates."

more control over these charges than they once did. NITS as seen above has increased in its volatility, as well as in both the frequency and suddenness of the changes that occur. It is inappropriate to allow only PECO itself, for its default customers, to be immune from the risk of those price fluctuations—even while EGSs must absorb that risk in the prices they offer to retail customers. A better approach, one that establishes a level playing field and ensures that customers are paying only for the actual NITS costs, is to include the NITS costs associated with both default and shopping customers into PECO's existing NBT Charge, as Other PJM Charges already are.

Q. WHY SHOULD THE COMMISSION TAKE ACTION IN THIS PROCEEDING TO DIRECT PECO TO RECOVER THE COSTS OF NITS FROM ALL CUSTOMERS IN LIEU OF ITS CURRENT METHODOLOGY?

A. While the problem with cost recovery for NMB Charges has been difficult since the Commission first directed its Staff to informally investigate in 2014, the problem with NITS has become more difficult and continuing to do nothing about it makes no sense. There has been a persistently unlevel playing field between DSP and EGS, at least in the PECO service territory. The problem is getting worse, because PECO's decision to use formula rates has led to more frequent and sudden transmission rate changes. This places an even more significant burden on EGSs to estimate the price effect of PECO's managerial decision-making—even while PECO itself as a default supplier can collect the price changes from customers (and is of course paid them as a transmission owner) from its default customers after the fact. This situation is unreasonable and must be corrected.

VII. RECOVERY OF DEFAULT SERVICE COSTS

Q. WHAT IS THE COALITION'S POSITION ON THE RECOVERY OF DEFAULT SERVICE COSTS?

A. Although PECO bears substantial costs in providing default service, PECO has a regulated distribution business that absorbs many of those costs, effectively cross-subsidizing its default service offering. It is critical that the price to compare ("PTC") that is established through this default service proceeding actually reflect the costs that PECO is incurring to provide default service.

Q. WHY IS THIS AN APPROPRIATE PROCEEDING TO PURSUE THESE ISSUES?

A. PECO uses this proceeding to propose existing and likely future allocations associated with its DSP.[88] An important aspect of this proceeding is to design PECO's PTC to recover all of the costs associated with providing default service.[89] As such, the formula that is developed here will establish whether the design of the PTC properly recovers such costs.

Q. IS PECO RECOVERING ALL COSTS OF DEFAULT SERVICE THROUGH THE PTC?

A. No. As I will explain, PECO is today recovering no overhead costs that it incurs as a company to provide distribution service as an EDC and default service as a DSP through the PTC for default service. In addition, as I describe in my testimony related to PECO's TOU proposal (Section IV), PECO likely is underestimating the direct costs required to roll out TOU and is not appropriately amortizing its proposed capital expenditures over the life of the DSP plan period.

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88 *See* Exhibit JAB-6.

89 *See* 2807(e) of the Competition Act, 66 Pa.C.S. § 2807 (e)(3.9).

Q. WHAT ARE OVERHEAD COSTS?

A. Overhead costs are typically known as costs incurred by a business that cannot be directly assigned or attributed to a particular function of the business. They are sometimes called indirect, common or shared costs. Everyday examples of overhead costs include office rent, office furniture, information technology, human resources, computer equipment, office supplies, and administrative and general ("A&G") expenses. Typically, when such costs cannot be directly assigned or attributed to a particular function of the business, they are allocated among the business' various functions.

Q. IS PECO INCURRING OVERHEAD COSTS TO OFFER DEFAULT SERVICE?

A. Clearly it is. In this filing alone, PECO proposes to make upgrades to its IT system and customer call center in order to allow the company to answer questions about its proposed TOU product. Yet it includes only the estimated *incremental cost* of those system upgrades, rather than allocating embedded costs associated with these systems to its DSP.[90] This is the equivalent of a renter moving into an apartment building, but only being expected to pay to have the locks changed.

Even more strikingly, PECO is presenting the testimony of three of its employees in this proceeding. Yet none of the costs of their salaries, benefits, workspace, and work equipment are allocated to default service. In discovery, the Coalition asked for the "amount of time each [employee] will spend on an annual basis" during the DSP period on administering the DSP. PECO responded that "PECO does not track the time spent by any of its employees, including the witnesses in this proceeding, on issues related to

[90] Exhibit JAB-6.

default service."[91] As well, the Coalition asked how much time its customer service representatives would be expected to spend on the company's new TOU offering. PECO is proposing to use its "Company Care Center" to enroll customers in its new TOU offering.[92] But "PECO is not proposing to allocate any time associated with call center staffing to the cost of administering the DSP."[93] As with the capital costs of the IT system and customer call center, the PTC PECO has proposed is designed to take a free ride on the considerable overhead expenses associated with employees who do work related to PECO's role as a DSP, but whose costs are allocated entirely to distribution base rates.

These are only the most obvious examples. The reality is that PECO has other, substantial overhead costs, such as for its holding company's executives. And, similarly, none of their costs are allocated to default service, even though in my experience such executives spend a good deal of time talking about the evolving utility business model, of which default service is (unfortunately) a substantial part.

Q. DOES PECO CONCEDE THAT ITS PTC FOR DEFAULT SERVICE REFLECTS NO OVERHEAD COSTS?

A. Yes. PECO has indicated in response to ESC discovery that its current PTC includes no "indirect costs."[94] Rather, PECO proposes to continue recovering all indirect costs that it incurs to operate both its distribution and default service businesses through distribution rates.

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91 Exhibit TK-15 (PECO Response to ESC-IV-3).

92 PECO Statement No. 2 at 22.

93 Exhibit TK-16 (PECO Response to ESC-IV-12).

94 Exhibit TK-17 (PECO Response to ESC-I-14).

Q. HOW DO YOU RECOMMEND RECTIFYING THIS PROBLEM?

A. As I will describe in further detail below, I recommend rectifying this problem by the Commission requiring PECO to allocate a portion of its overhead costs to default service and recover them through the PTC.

A. <u>Direction Provided by Commission's Regulations Regarding Recovery of Costs through PTC</u>

Q. WHAT DIRECTION DO THE COMMISSION'S REGULATIONS PROVIDE ABOUT THE COSTS TO BE RECOVERED THROUGH THE PTC?

A. The Commission regulations require the PTC for default service to "be designed to recover *all* default service costs, including generation, transmission and other default service cost elements, incurred in serving the average member of a customer class."[95] The Commission's policy statement, which was adopted in tandem with these regulations, provides greater detail, identifying the specific cost elements that EDCs should recover through the PTC for default service.[96]

Q. WHAT SPECIFIC COST ELEMENTS DOES THE COMMISSION IDENTIFY IN ITS POLICY STATEMENT AS NEEDING TO BE RECOVERED THROUGH THE PTC?

A. The Commission's policy statement provides that:[97]

(a) The PTC should be designed to recover all generation, transmission and other related costs of default service. These cost elements include:

(1) Wholesale energy, capacity, ancillary, applicable RTO or ISO administrative and transmission costs.

(2) Congestion costs will ultimately be recovered from ratepayers. Congestion costs should be reflected in the fixed price bids submitted by wholesale energy suppliers.

(3) Supply management costs, including supply bidding, contracting, hedging, risk management costs, any scheduling and forecasting services provided exclusively for

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95 52 Pa. Code § 54.187(e).

96 52 Pa. Code § 69.1808(a) (emphasis added).

97 52 Pa. Code § 69.1808(a).

default service by the EDC, and applicable administrative and general expenses related to these activities.

(4) Administrative costs, including billing, collection, education, regulatory, litigation, tariff filings, working capital, information system and associated administrative and general expenses related to default service.

(5) Applicable taxes, excluding Sales Tax.

(6) Costs for alternative energy portfolio standard compliance.

B. <u>Cost Elements Included in PECO's PTC</u>

Q. WHICH COST ELEMENTS DOES PECO'S PTC INCLUDE?

A. PECO's PTC includes the cost elements that the policy statement identifies in (a)(1)-(3) and (5)-(6). PECO also includes certain costs associated with (a)(3)-(4). These elements include the direct costs that PECO incurs to pay for electricity in the wholesale market, the costs that PECO incurs to manage supply for the 1.5 million customers on default service, and the taxes and costs for alternative energy portfolio standard compliance.

Q. WHAT ABOUT THE ADMINISTRATIVE COSTS IDENTIFIED IN (A)(4) OF THE POLICY STATEMENT?

A. PECO's PTC includes some of the administrative costs identified in (a)(3) and (4) of the policy statement but also omits certain of these costs and understates the remaining costs. The administrative costs identified by the policy statement include "billing, collection, education, regulatory, litigation, tariff filings, working capital, information system and associated administrative and general expenses related to default service," as well as "administrative and general expenses" rated to the supply management activities described in (a)(3).[98]

[98] 52 Pa. Code § 69.1808(a)(4).

Q. WHICH ADMINISTRATIVE COSTS DOES PECO'S PTC OMIT?

A. Of the cost elements identified by the policy statement for recovery through the default service price, PECO's current PTC contains *no* administrative costs for billing, collection, education, regulatory, tariff filings or information system.[99] They also include A&G expense associated with either the supply management, customer relationship, or regulatory affairs aspects of administering the DSP.

Q. ARE YOU USING THE TERMS 'ADMINISTRATIVE COSTS' AND 'A&G' DISTINCTLY?

A. Yes. The policy statement defines a set of costs as "administrative costs" in (a)(4) that lists cost categories that relate to the customer service and regulatory affairs aspects of providing default service. A&G is separately identified in both (a)(3) and (a)(4). A&G costs traditionally include rent, utilities, insurance, and certain managerial salaries that need to be allocated to a business' component parts for accounting and, as here, ratemaking purposes.

Q. IS IT PLAUSIBLE THAT PECO SIMPLY DOES NOT BEAR CERTAIN COSTS IN RELATION TO PROVIDING DEFAULT SERVICE?

A. No. The Commission sensibly enumerated the cost categories that should be allocated to default service in its policy statement. If PECO does not actually incur any of those costs, it should explain in detail its theory of how it does not. To use but one example, by allocating zero costs for A&G expense associated with executive compensation, PECO is essentially asking the Commission to believe that its corporate executives do not spend a moment's time concerned about the company's role as a DSP, including highly visible

[99] Exhibit TK-18 (PECO Response to ESC-I-1).

issues like whether and how the company will enter into solar purchase agreements. That is not plausible.

Q. WHICH ADMINISTRATIVE AND A&G COSTS *DOES* PECO INCLUDE IN THE PTC?

A. PECO's PTC for March 1 to May 31 of this year included $46,492 for "litigation," $465,492 for "working capital," and $137,372 of A&G costs for an independent evaluator and external consultant. No other costs were allocated to the PTC.[100]

Q. WHAT IS THE RATE IMPACT OF THIS?

A. As a result of PECO excluding all overhead costs from the computation of its PTC, the total administrative costs to be reflected in the PTC that commences this DSP will amount to 0.005 cents/kWh for each procurement effective June 1, 2021 through August 31, 2021.[101] This tiny amount stands in stark contrast to the 0.19 cents per kWh included in the PTC to reflect working capital costs.[102]

C. <u>Why Omission of Overhead Costs is a Problem</u>

Q. WHY IS PECO'S FAILURE TO ALLOCATE ANY OVERHEAD COSTS TO DEFAULT SERVICE A PROBLEM?

A. Not only is PECO overlooking the express terms of the Commission's policy statement and regulations, but also by failing to allocate any overhead costs to the PTC for default service, PECO is allocating all of these costs to the regulated or monopoly distribution side of its business. This means that all overhead costs, such as human resources costs, incurred by PECO to run its two businesses—of providing distribution service and default service—are recovered by PECO wholly through distribution rates. As a result,

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[100] Exhibit TK-17.

[101] PECO Response to ESC-I-13.

[102] PECO Statement No. 2 at 4-5.

PECO is using its distribution revenues to subsidize the default service side of its business, which is in direct competition with the members of the Coalition.

Q. IS THIS HARMFUL TO THE COMPETITIVE RETAIL MARKET?

A. Yes. By using monopoly revenues to subsidize the side of its business that is directly competing with members of the Coalition, PECO is charging a price for default service that is artificially low. Naturally, EGSs have difficulty competing with an artificially low price for default service, which in turn means that they are unable to deliver the full array of the benefits of a truly competitive market to consumers – including access to a wide array of innovative products and services.

Q. ARE THERE OTHER INDICATIONS IN PENNSYLVANIA POLICY THAT SUGGEST WHAT ALLOCATION IS APPROPRIATE IN DEFAULT SERVICE RATEMAKING?

A. Yes. As I describe in our proposal to transition PECO out of its role as DSP, the Commission may designate an “alternative supplier” to perform in the role of default service provider in lieu of the electric distribution company (“EDC”).[103] A third party providing default service would not have regulated distribution revenues that it could rely upon to subsidize default service. It would necessarily have to recover a portion of its overhead costs from customers who are not purchasing generation from EGSs. The law providing that default service can be provided by an entity other than the EDCs underscores the separate and distinct nature of the two functions that PECO as a EDC/DSP combination company performs: 1) purchasing electricity for customers on its distribution system who do not purchase their supply from the competitive market, and 2) delivering electricity to all customers on its distribution system.

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[103] 66 Pa.C.S. § 2807(e)(3.1).

D. PECO's Proposal Runs Contrary to Industry Guidance

Q. DOES PECO'S PROPOSAL TO ALLOCATE ZERO OVERHEAD COSTS TO THE PTC FOR DEFAULT SERVICE RUN COUNTER TO INDUSTRY GUIDANCE?

A. Yes. PECO's proposal to allocate zero indirect costs to the PTC for default service is inconsistent with the NARUC Cost Allocation Manual ("NARUC CAM") and NARUC Guidelines.

Q. PLEASE EXPLAIN.

A. NARUC has published the NARUC CAM, which is an almost 200-page tome on cost allocation in utility ratemaking. The NARUC CAM states that "few analysts seriously question the standard that service should be provided at cost" and that this principle applies when setting rates "for individual services, classes of customers, and segments of the utility's business."[104] At that time, NARUC was envisioning an allocation of costs of monopoly services offered by a utility operating both monopoly and competitive markets. It is particularly compelling that NARUC recognized that costs should be allocated to each business segment, even if it is not operating as a separate business unit.

Q. PLEASE CONTINUE.

A. In addition, the NARUC Guidelines, which address cost allocation in the context of affiliate transactions, include a set of principles that are directly relevant to pricing default service. Specifically, according to the NARUC Guidelines, these cost allocation principles should be applied "whenever products or services are provided between a regulated utility and its non-regulated affiliate or division."[105] The NARUC Guidelines

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104 http://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD

105 http://pubs.naruc.org/pub/539BF2CD-2354-D714-51C4-0D70A5A95C65

also provide that "[t]he general method for charging indirect costs should be on a fully allocated basis."[106] This principle runs counter to the concept advanced by PECO where all overhead costs are simply allocated to the monopoly distribution service without any consideration given to whether that cost category would likewise be incurred to provide default service.

Q. DO YOU HAVE ANY OTHER INDUSTRY REFERENCES THAT SUPPORT YOUR VIEWS?

A. Yes. Earlier I referenced two articles authored by Frank Lacey, which have been published in Public Utilities Fortnightly and the Electricity Journal. In Mr. Lacey's Electricity Journal article, he refers to a practice engaged in by incumbent electric utilities serving as default service providers of allocating few to no indirect costs to default service rates. He explains that the resulting rate for utility-provided default service is a below-market price, which allows the utilities to maintain dominant market positions in the retail market.[107] To rectify this anti-competitive result, Mr. Lacey describes a "simple thought experiment to see if appropriate costs are being allocated to the default service business is to imagine what would happen if default service was severed from the utility's distribution business." In this proceeding, PECO is in effect suggesting to the Commission that it cost in the last full quarter less than $200,000 in administrative costs, other than working capital, to serve about 1 million customers default service, while incurring no administrative costs for billing, collection, education, regulatory, tariff filings or information system. As Mr. Lacey explains, "nearly every default service program would be bankrupt in a matter of days, if not hours, if it was removed from the

[106] *Id.*, Section B.4.

[107] Exhibit TK-2 at 4.

distribution business."[108] As Mr. Lacey concluded in the article published in Public Utilities Fortnightly, "[a]ppropriately allocating costs currently paid by distribution customers to default service is a critical next step in creating more competitively neutral energy markets in the United States." While he opined that this "one step will not create the perfect markets…it will remove a significant anti-competitive pricing advantage held by monopoly utilities."[109]

E. Summary of Recommendations

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO ADDRESS THE PROBLEM WITH DEFAULT SERVICE PRICING THAT YOU HAVE IDENTIFIED.

A. To address the problem with default service pricing that I have identified, I recommend that the Commission require PECO to modify its proposed rate design for default service to recover a reasonable or appropriate portion of its overhead costs through the PTC. Because PECO has said that it does not track its employees time, or track whether or not they work on DSP, it will be necessary to use an allocating methodology that takes each of the corporate cost centers that PECO has that relates to the Commission's policy statement and allocate some portion of them to the DSP PTC. This exercise would facilitate the recovery of all costs associated with default service through the default service rate, as required by the Commission's regulations. The Coalition envisions the following steps needing to occur:

1. PECO's modified rate design for the PTC for default service would need to include each and every administrative cost element specified in subsection 4 of

108 Exhibit TK-2 at 5.

109 Exhibit TK-3 at 44.

Section 1808 of the Commission's policy statement, and the A&G costs associated with subsection 3 of the same section. The policy statement identifies these administrative costs as including: "billing, collection, education, regulatory, litigation, tariff filings, working capital, information system and associated administrative and general expenses related to default service."[110]

2. PECO would need to use its 2018 cost of service study and scale it back to reflect the Commission-approved amount of the increase so as to quantify the total administrative costs in each of the above categories.
3. PECO would need to use reasonable or appropriate allocators to propose the allocation of a certain percent of each of these costs to the DSP. A variety of methodologies exist for this purpose, including some used by PECO and its parent and affiliates. The Coalition believes that PECO should initially propose the allocator(s) to be used in a compliance filing.
4. Upon the filing by PECO of a modified rate design, the Commission should afford all interested parties an opportunity to comment and/or present evidence showing the deficiencies of PECO's proposal.
5. As part of its ultimate approval of a new PTC that includes an appropriate allocation of the costs I have identified, the Commission should require PECO to record a regulatory liability associated with the incremental revenues it will collect through the PTC, in recognition that these should be refunded to distribution customers when PECO next files a base rate application in order to prevent double-recovery.

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[110] 52 Pa. Code § 69.1808(a)(4).

6. The Coalition believes that the Commission should require PECO to make such a filing in compliance with the Commission's order in this proceeding, and that the issue be addressed expeditiously to be implemented by June 2021. However, the change also could be implemented at some point during the program period since it will not otherwise disrupt the DSP.

VIII. <u>PECO'S EXISTING AND PROPOSED RETAIL MARKET ENHANCEMENT PROGRAMS</u>

A. <u>STANDARD OFFER PROGRAM</u>

Q. PLEASE BRIEFLY DESCRIBE PECO'S PROPOSAL WITH RESPECT TO THE STANDARD OFFER PROGRAM.

A. As explained in the Direct Testimony of Ms. Reilly, PECO proposes to continue the Standard Offer Program ("SOP") that was first implemented as part of PECO's second default service program.[111] She states that since June 1, 2017, the SOP has resulted in more than 26,000 residential customer and 500 small commercial customer referrals to EGSs that have voluntarily chosen to offer customers a twelve-month contract priced 7 percent below PECO's default service rate at the time of the offer.[112]

Q. DO YOU HAVE ANY COMMENTS ABOUT PECO'S SOP PROPOSAL?

A. Yes. Initially, I note that with the exception of modifications to PECO's call handling process and revisions to SOP training materials and scripts during the DSP IV proceeding, PECO has implemented the same SOP since 2013. No substantive modifications have been made since the DSP II proceeding. With the passage of time, it seems prudent to consider whether measures should be taken to "mature" the SOP. This

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[111] PECO Statement No. 3 at 16-17; *Petition of PECO Energy Company for Approval of its Default Service Program II*, Docket No. P-2012-2283641 (Order entered October 12, 2012) ("DSP II proceeding").

[112] PECO Statement No. 3 at 16.

is particularly important data point. According to PECO's data, the number of SOP referrals was the highest in 2015 and 2016, with total referrals of 74,056 and 70,763, respectively. The past three years of 2017 through 2019, the total program referrals have precipitously declined to 22,331, 10,088 and 8,750.[113]

Q. DOES THE COALITION HAVE SPECIFIC RECOMMENDATIONS FOR MODIFICATIONS?

A. Yes. The Coalition recommends that: (i) all new customers (who have not already made an affirmative choice of an EGS) be automatically enrolled in the SOP; (ii) PECO be required to allow SOP signups from its website; (iii) the script should be modified; and (iv) PECO should be required to revisit the situations in which the SOP is mentioned, particularly to default service customers who contact the call center, and to otherwise engage in periodic communications, such as quarterly when changes to the PTC occur, promoting SOP to all customers on default service.

Q. PLEASE EXPLAIN THE COALITION'S RECOMMENDATION FOR ALL NEW CUSTOMERS (OTHER THAN THOSE WHO HAVE ALREADY MADE AN AFFFIRMATIVE CHOICE OF AN EGS) TO BE AUTOMATICALLY ENROLLED IN THE SOP.

A. Currently, even though default service is intended to ensure that consumers continue to receive electricity even if they do not choose an EGS or in the event their EGS stops providing service, it has the connotation of being a provider of "first" resort service rather than a provider of "last" resort service. My earlier testimony discussed the predominant role that PECO has of providing default service to more than two-thirds of the residential customers on its system. Since the SOP has been designed to give customers a 7 percent discount off PECO's PTC for default service, while also introducing customers to

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[113] Exhibit TK-19 (PECO Response to ESC-II-8 and 8(a)).

participation in the retail market,[114] no reason exists to initially place a customer on PECO's default service. Rather, new customers (who have not already made an affirmative choice of an EGS) should automatically receive the benefit of this market enhancement program that was initially very successful in the referral of customers to EGSs participating in the SOP. Importantly, automatically placing these new customers on the SOP eliminates the notion of PECO's default service as the "first" service in which consumers enroll.

Q. PLEASE PROVIDE FURTHER DETAIL ABOUT THE ABILITY OF CUSTOMERS TO SIGN UP FOR SOP ON PECO'S WEBSITE?

A. Certainly. During a time when consumers are increasingly dependent on electronic enrollments or registrations for many products and services, they should be permitted to sign up for the SOP on PECO's website. Coalition member, Shipley, reports that 28% of its SOP enrollments through PPL Electric Utilities Corp. occur through the website. Since PECO customers can initiate service online, enrolling in the SOP could easily be incorporated in that process. An added benefit of website enrollments is that since no third party verification is required, the SOP fee should be waived or reduced.

Q. PLEASE DISCUSS THE RECOMMENDATION TO MODIFY THE SCRIPT THAT PECO IS USING FOR THE SOP.

A. PECO is proposing to continue using the current SOP script. Under this script, moving customers are advised, as follows:

> "Your new account number is [12345-67899]. In Pennsylvania, you can choose the supplier that provides your electricity without impacting the quality of service provided by PECO. PECO is sponsoring a program called the *PECO Smart Energy Choice Program* which may be able to offer you a potential savings

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[114] *Investigation of Pennsylvania's Retail Electricity Market: Intermediate Work Plan*, Docket No. I-2011-2237952 (Order entered 16, 2011), at pp. 9-21.

opportunity by enrolling with an electric generation supplier. Would you like to hear more?"

New customers are advised as follows:

"In Pennsylvania, you can choose the supplier that provides your electricity without impacting the quality of service provided by PECO. *PECO is sponsoring a program called the PECO Smart Energy Choice Program* which may be able to offer you a potential savings opportunity by enrolling with an electric generation supplier. Would you like to hear more?"

If the customer answers yes, then PECO continues:

PECO is responsible for delivering your electricity. The actual generation of the electricity you receive can be provided by PECO or a participating supplier of your choice. The *PECO Program* offers a fixed price of [SOP rate] cents/kWh for one year provided by an Electric Generation Supplier. The fixed Program price provides a 7% discount off of today's Price to Compare which is [PTC Rate] cents/kWh. PECO's Price to Compare changes quarterly in March, June, September and December. The *PECO Smart Energy Choice Program* price will not change during the 12 monthly bills, but the Price to Compare could be higher or lower than the *PECO Program* price during this period. Would you like to enroll in the *PECO Smart Energy Choice Program*?"[115]

Q. WHAT ARE THE COALITION'S OBSERVATIONS REGARDING THESE SCRIPTS?

A. Assuming the customer enrolls in the program, she will have heard no fewer than six times that it is the "PECO Smart Energy Choice Program," a "PECO Program," or that "PECO is sponsoring a program"—as indicated in the italicization above. Of course, the whole point of this program is to introduce customers to the competitive retail market in Pennsylvania—at a savings to them. It is inappropriate for PECO to slap its brand so aggressively on the program, which both frustrates one of its purposes and demonstrates the points I have earlier made about the deeply frustrating and conflicted role that PECO occupies as the DSP in this part of the state. Also, the underlined text references a "potential savings opportunity." That is not cogent. The word "opportunity" itself convenes possibility, not a sure thing. In any case, it is absolutely true that savings will be

[115] Exhibit TK-8 (emphasis added).

realized in the first PTC period, because the whole premise of the program is a 7% discount off of it. The useful clarification of the details that the PTC is subject to change then ensues if the customer expresses interest. Changing the language "which may be able to offer you a potential savings opportunity" to "which will offer you savings opportunity" would increase the attractiveness of the program to customers, causing them to want to hear more.

> Movers:
>
> "Your new account number is [12345-67899]. Also, PECO is implementing a Supplier Savings Program, which allows you to lower your electricity generation costs by 7%. Would you like to hear more?"
>
> Non-movers:
>
> "While I have you on the phone, PECO is implementing a Supplier Savings Program, which allows you to lower your electricity generation costs by 7%. Would you like to hear more?"
>
> If customer answers yes:
>
> Here's how it works. The program gives you a chance to lock in a fixed rate that is 7% lower than PECO's current price to compare. That means, instead of paying PECO's rate of [PTC Rate] cents/kWh today, you'll pay the Supplier's [SOP rate] cents/kWh. This fixed rate is provided by an approved electricity generation supplier, is good for 12 months, and can be cancelled any time without penalty. You can pick a supplier of your choice, or we will be happy to provide one for you. You'll still experience the same quality service from PECO. PECO's price to compare can change quarterly, so the price to compare could be higher or lower than this rate during the 12-month period. Can we go ahead and set you up with your discounted rate today?

Q. PLEASE FURTHER DISCUSS THE COALITION'S RECOMMENDATION TO EXPAND CONSUMER COMMUNICATIONS ABOUT THE SOP.

A. Given the significant drop in referrals over the past several years, the Coalition believes that it is necessary to revisit the situations in which consumers are told about the SOP. While the Coalition understands that the PECO would not discuss the SOP with customers who are calling in regarding outages or other emergencies, it may be possible to expand the list of scenarios in which PECO would inform default service customers about the availability of SOP. For instance, PECO does not have this discussion with non-moving customers who call in with billing disputes.[116] Those calls would seem to be ideal opportunities to discuss supplier savings through the SOP. In addition, PECO should be directed to engage in periodic communications, such as quarterly when changes to the PTC occur, promoting SOP to all customers on default service. Through these additional efforts, the Coalition expects that default service customers will become more aware of the availability of the SOP, have greater opportunities to realize the benefits of this program and gain a familiarity with interacting with EGSs in the competitive retail market.

B. SHOPPING BY CUSTOMER ASSISTANCE PROGRAM ("CAP") CUSTOMERS

Q. WHAT IS THE CURRENT STATUS OF SHOPPING BY CUSTOMER ASSISTANCE PROGRAM ("CAP") CUSTOMERS IN PECO'S SERVICE TERRITORY?

A. Currently, PECO CAP customers are not able to shop for electric generation supply.[117]

Q. DOES PECO PROPOSE TO CHANGE THAT AS PART OF THIS PROCEEDING?

A. Yes. In this proceeding, Ms. Carol Reilly testifying for PECO notes that in the Proposed Policy Statement Order, the Commission outlined uniform CAP shopping policies and requirements for EDCs.[118] Ms. Reilly further points to the Commission's Secretarial

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[116] PECO Response to OCA-I-2.

[117] PECO Statement No. 3 at 4.

[118] *Electric Distribution Company Default Service Plans – Customer Assistance Program Shopping*, Docket No.M-2018-3006578 (Proposed Policy Statement Order entered February 28, 2019) ("Proposed Policy Statement Order"); PECO Statement No. 3 at 4-5.

Letter dated January 23, 2020, acknowledging that its proposed CAP shopping policy statement was unlikely to be final in time for some upcoming DSP proceedings and therefore directing all EDC to use the prior guidance to develop CAP proposals as part of those filings.[119]

Q. DID PECO DEVELOP A CAP SHOPPING PLAN THAT IS CONSISTENT WITH THE COMMISSION'S PRIOR GUIDANCE?

A. Yes. Under PECO's proposed plan, EGSs would be required to charge CAP customers a rate for generation service that is at or below the PECO residential PTC at all times during the contract. Also, EGSs serving CAP customers may not enter into contracts that impose early cancellation and termination fees or other fees unrelated to generation service.[120]

Q. PLEASE DESCRIBE OTHER KEY FEATURES OF PECO'S CAP SHOPPING PROPOSAL.

A. EGSs wishing to serve CAP customers would be required to submit a notice of intent to participate and use PECO's "bill-ready EDC consolidated billing option for CAP customers. In addition, EGSs offering a rate do CAP customers would be required to post that rate on the Commission's PAPowerSwitch.com shopping website.[121] PECO also proposes to implement the program only after receipt of notices of intent to participate from at least five EGSs.[122]

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[119] PECO Statement No. 3 at 5.

[120] PECO Statement No. 3 at 5-6.

[121] PECO Statement No. 3 at 6-7.

[122] PECO Statement No. 3 at 14.

Q. WHAT ARE THE COALITION'S CONCERNS REGARDING PECO'S PROPOSAL?

A. The Coalition has identified three primary concerns with PECO's proposal. While the Coalition commends PECO for developing a proposal to permit shopping by CAP customers, it does not believe it is appropriate to: (i) require the EGS price to be at or below PECO's PTC the entire time; (ii) require EGSs to post their CAP shopping rate on the PAPowerSwitch.com shopping website; and (iii) commit to implementing the CAP shopping plan only upon confirmation that five EGSs intend to participate.

Q. PLEASE EXPLAIN YOUR CONCERNS WITH THE REQUIREMENT THAT THE EGS PRICE BE AT OR BELOW PECO'S PTC THE ENTIRE TIME.

A. The Coalition recognizes that this restriction is consistent with the Commission's proposed Policy Statement Order. However, as that is only a proposal at this time, PECO is not obligated to comply with all provisions of that order. Moreover, that approach wholly overlooks the fact that PECO's PTC is artificially low in that it does not reflect any overhead costs associated with providing default service.

Q. WHAT DOES THE COALITION RECOMMEND INSTEAD?

A. While it may be may be beneficial in some ways to require the initial offers to match the current PTC, it is not realistic to impose that requirement for the entire year. Particularly since PTCs are reconcilable and do not at any given time reflect the market, EGSs should be permitted on their own to adjust their prices during the program year to reflect the market conditions they are facing. Since customers may leave the EGS CAP Shopping program without penalty at any time, they will not be harmed.

Q. WHAT IS WRONG WITH PECO'S PROPOSAL TO REQUIRE EGSS TO POST THEIR CAP RATE ON PAPOWERSWITCH.COM?

A. Currently, the Commission does not require EGSs to post any rates, let alone all of its rates, on PAPowerSwitch.Com. If the Commission departs from this long-standing precedent to instead require EGSs to post their CAP rate on the shopping website, the result will be confusing to customers. Seeing a rate that has been developed only for a specific subgroup of PECO's customers would give others the impression that this rate is also available to them. Experience shows that confused customers often leads to the filing of more complaints with the Commission, which should be avoided in order to ensure satisfied consumers participating in the retail market. A better way of promoting transparency of the CAP rate would be to create a separate portal on PAPowerSwitch.com, which only customers on the CAP may access. In this way, the affected consumers could see the rate that is being offered but other consumers would only be able to access rates that may be available to them.

Q. WHAT IS THE COALITION'S OBJECTION TO PECO'S REQUIREMENT FOR FIVE EGS INDICATING AN INTENT TO SERVE CAP CUSTOMERS?

A. As a threshold matter, PECO has offered no reason for the number of five EGSs. It has also not explained why one, two, three or four EGSs could not serve as many CAP customers as five EGSs. The number of EGSs who are willing to participate should have no bearing on PECO's commitment to implement the program. Therefore, this condition should be eliminated.

Q. DOES THAT COMPLETE YOUR DIRECT TESTIMONY?

A. Yes; however, I reserve the right to supplement this testimony as may be appropriate.

Table of Exhibits

Exhibit TK-1	Kavulla Resume
Exhibit TK-2	Lacey Article – Public Utilities Fortnightly
Exhibit TK-3	Lacey Article – The Electricity Journal
Exhibit TK-4	PECO Response to ESC-I-8
Exhibit TK-5	PECO Response to ESC-I-6
Exhibit TK-6	PECO Response to ESC-IV-9
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Exhibit TK-8	PECO Response to ESC-I-3
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Exhibit TK-10	Reliant Sample Bill
Exhibit TK-11	PECO Response to ESC-III-1
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Exhibit TK-13	PECO Response to ESC-IV-13
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Exhibit TK-16	PECO Response to ESC-IV-12
Exhibit TK-17	PECO Response to ESC-I-14
Exhibit TK-18	PECO Response to ESC-I-1
Exhibit TK-19	PECO Response to ESC-II-8 and 8(a)

TRAVIS KAVULLA

travis.kavulla@nrg.com

VICE PRESIDENT, REGULATORY AFFAIRS **SEPT. 2019 – PRESENT**
NRG Energy, Inc. *Princeton, New Jersey*
Leader of the department responsible for the company's engagement with state and federal regulatory agencies, working to develop policy and ensure compliance with applicable laws and regulations.

DIRECTOR, ENERGY & ENVIRONMENTAL POLICY **JAN. 2019 – Sept. 2019**
R Street Institute *Washington, DC*
Led the energy program of a 501(c)(3) "think tank" dedicated to promoting free markets and effective government. Focused principally on the power sector, R Street's energy program supported three overarching policy goals: exposing power plants to competition, providing consumers a choice in energy provider, and efficiently networking markets together to ensure the robustness of competition. R Street led opposition to state and federal subsidies to specific generators or types of generation, and has promoted a transparent price on carbon emissions as a vehicle for environmental regulation. R Street also has promoted reforms that make it easier to construct energy infrastructure and license new technologies.

In furtherance of its policy goals, R Street publishes white papers and op- eds, files regulatory comments, and provides legislative testimony.

GOVERNING BODY MEMBER **JULY 2018 – AUG. 2019**
Western Energy Imbalance Market (EIM) *Folsom, CA*
One of five independent board members of the Western Interconnection's first regional, real-time electricity market, which is operated by CAISO. Nominated by market participants in 2018 and elected by the other governing body members to a term of three years. Left upon joining NRG. The governing body actively engaged with market participants and works to build upon the economic efficiency of the market. In 2018-19, significant reforms to EIM included revisions to local market power mitigation (increasing the default energy bid for hydroelectric resources) and a revision to how greenhouse gas emissions are accounted for in the marketplace. Market-design discussions for a day-ahead market also commenced, including considerations of energy price formation, transmission costs, and governance.

CHAIRMAN, NORTH AMERICAN NUMBERING COUNCIL **NOV. 2017 – Sept. 2019**
Appointed by FCC Chairman Ajit Pai to lead the stakeholder council responsible for providing the FCC comprehensive recommendations on several emerging topics associated with next-generation communications technologies. Topics on which the council engaged included measures to combat robo-calling through the creation of a call authentication trust anchor that certifies legitimate telephone calls, the creation of a nationwide number portability framework that allows 10-digit numbers to be ported freely throughout the United States and across different types of devices, and the modernization of toll-free number distribution through the establishment of an auction mechanism. While appointed as a utility commissioner, continued to serve in this role until Fall 2019 at the request of Chairman Pai. Online at http://nanc-chair.org

COMMISSIONER, CHAIRMAN (2011-13) & VICE-CHAIRMAN (2015-19) **JAN. 2011 – JAN. 2019**
Montana Public Service Commission *Helena, MT*
One of five commissioners of the State of Montana's utility commission, serving in leadership roles at the state, regional, and national level at various times. Responsible for regulating energy and water monopolies, as well as certain telecommunications companies and motor carriers in the

State of Montana. Nominated in contested Republican primary and elected to office in 2010, and re-elected without opposition in 2014 to a term expiring in 2018. Made decisions on hundreds of matters, with a focus on rate reviews of monopoly utilities, and the reform of ratemaking, interconnection, and reporting requirements for firms in markets transitioning to competition.

Testified before U.S. Congressional committees and in administrative proceedings and technical conferences of the Federal Energy Regulatory Commission (FERC) and the Environmental Protection Agency (EPA). Frequent speaker to organizations and conferences in the field of energy and telecommunications. Named by S&P Global Market Intelligence on its list of "The 10 most influential people in energy in 2016." Advised on the intersection of technological development and regulation as a member of the advisory council of the Electric Power Research Institute. Active participant in the Harvard Electricity Policy Group.

Other professional involvement includes leadership related to national and regional energy and telecommunications policy (detailed below).

AFFILIATED ROLES TO SERVICE ON THE MONTANA PUBLIC SERVICE COMMISSION

PRESIDENT, NAT'L ASSN. OF REGULATORY UTILITY COMMISSIONERS NOV. 2015 – NOV. 2016
MEMBER, EXECUTIVE COMMITTEE, NARUC NOV. 2014 – NOV. 2018
As NARUC President, supervised a newly hired executive director and established strategic direction of the organization, with 40 staff devoted to improving the practice of utility regulation. Afterwards, continued to serve as a board director and a member of NARUC's Executive Committee.

Focus as President at NARUC included several major initiatives involving energy and telecommunications, including:

- Engagement with FERC and others on the design and regulation of the wholesale electricity markets, including the interaction between Regional Transmission Organizations (RTOs) and states, and on the reform of Public Utility Regulatory Policies Act of 1978 (PURPA).
- Improved training for new utility commissioners, focused on basic issues of ratemaking.
- Supervised the advocacy before the FCC and federal courts on issues including the Universal Service Fund/Connect America Fund, municipal broadband pre-emption, inmate calling, and net neutrality.
- Writing and publication of a "Compensation and Pricing Manual for Distributed Energy Resources," such as a roof-top photovoltaic solar, in order to address controversies about cost-shifts in current net-metering policy.
- Analysis and critical response to the EPA's Clean Power Plan.

On operations, approved plans and supported new NARUC executive director to tighten criteria for staff performance review and eliminate excessive fringe benefits and pay raises. Led a retreat of executive committee to ensure that NARUC's international program and a NARUC-affiliated organization had wind-down or contingency plans in the eventuality that program revenue became unavailable. Online at http://www.naruc.org

CO-CHAIR, NORTHERN TIER TRANSMISSION GROUP JAN. 2013 – JULY 2018

Co-chair of the Steering Committee of NTTG, which undertakes regional transmission planning for a collection of utilities including PacifiCorp, Portland General Electric, Idaho Power, NorthWestern Energy, the Utah Associated Municipal Power Systems, and Deseret Generation & Transmission Cooperative. NTTG's Steering Committee approves regional transmission plans, provides policy guidance, and directs FERC filings on behalf of the group.

The Steering Committee's work in the past several years has included debating and approving the region's filings in response to FERC's Order 1000, requiring interstate transmission planning processes, as well as revisiting and improving the group's use of production cost modeling for the purposes of estimate the economic benefits of transmission expansion. Online at http://www.nttg.biz

CHAIRMAN, CMTE. ON REGIONAL ELECTRIC POWER COOPERATION OCT. 2016 – OCT. 2018

Co-chair, along with John Chatburn of the Idaho Governor's Energy Office, of CREPC, which twice per year brings together governor's offices, utility commissioners, and consumer advocates in order to improve relationships between states, utilities, and other stakeholders in the western United States and Canada.

MEMBER, EIM TRANSITIONAL COMMITTEE APR. 2015 – JULY 2016

CHAIRMAN, PUC ENERGY IMBALANCE MARKET WORKING GROUP JAN. 2012 – JULY 2015

Headed a successful effort by state regulators to evaluate the costs and benefits of forming a real-time energy market across the dozens of balancing authorities in the Western United States. The Public Utility Commissioners Energy Imbalance Market (PUC EIM) Working Group included a member from each of the Western Interconnection's utility commissions, and was a project of CREPC. Also served on the California Independent System Operator (CAISO) EIM Transitional Committee, which designed a regional governance model to oversee the largest real-time energy market in the Western United States.

DIRECTOR, WESTERN ELECTRICITY COORDINATING COUNCIL (WECC) FEB. 2013 – FEB. 2014

MEMBER, MEMBER ADVISORY COMMITTEE JAN. 2014 – NOV. 2015

Appointed to the WECC Board of Directors at a time when WECC, the regional reliability regulator for the Western Interconnection under the North American Electric Reliability Corp. (NERC), was undergoing a governance overhaul, bifurcating its reliability coordinator function from its standards, compliance auditing, and transmission planning functions. Acted as a strong advocate for bifurcation and the installation of an independent board of directors.

Served on the seven-member selection committee for WECC's CEO. Elected by WECC Members to the Nominating Committee, responsible for selecting independent board directors. Online at http://www.wecc.biz/

EARLIER WORK EXPERIENCE

FREELANCE JOURNALIST **JULY 2008 – DECEMBER 2010**

Contributed full-length pieces and reporting to a variety of sources, including *National Review*, the *Wall Street Journal*, the *Dallas Morning News*, Fox News, the *Times* of London, *Standpoint* magazine (UK), *The New Atlantis*, *Catholic World Report*, *The Claremont Review of Books* and other outlets. Based in England and Kenya in 2008 and 2009 and traveled widely in Africa, Europe, and South Asia. Special projects editor for National Review Online, supervising five journalists.

ASSOCIATE EDITOR **JAN. 2007 – OCT. 2007**

National Review and *National Review Online* *New York, NY*

Member of the editorial staff of biweekly magazine of politics and culture, leaving to become a Gates Scholar at Cambridge. Continues to contribute periodically.

EDUCATION

M.PHIL., HISTORY FALL 2007 – SUMMER 2008

University of Cambridge *Cambridge, England*

Gates Scholar, competitively awarded through the Gates Trust at Cambridge, funded by the Bill & Melinda Gates Foundation. Considerable field research conducted in pursuit of thesis, a critical history of government-led economic planning and the beginnings of development aid in the British colonial world of the 1950s.

B.A., HISTORY SEPT. 2002 – JAN. 2007

Harvard University *Cambridge, Mass.*

History, graduated *cum laude*. Columnist for campus daily, *The Crimson*, and editor of *The Salient*.

PROFESSIONAL AFFILIATIONS & HONORS

Chairman, North American Numbering Council, Nov. 2017 – Sept. 2019

President & Director, National Association of Regulatory Utility Commissioners; President (Nov. 2015 – Nov. 2016); Director (Jan. 2011 – Jan. 2019).

Co-Chairman, Northern Tier Transmission Group Steering Committee; Jan. 2013 – July 2018.

Member, Advisory Council, Electric Power Research Institute; Nov. 2014 – Aug. 2018.

Member, Federal Communications Commission's Federal-State Joint Board on Jurisdictional Separations; Dec. 2013 – Jan. 2019.

Chairman, Public Utility Commissioners Energy Imbalance Market Group, Dec. 2011 – 2015 (Chairman as of Dec. 2012).

Director, Board of Directors, Western Electricity Coordinating Council; Feb. 2013 – Feb. 2014

Director & Treasurer, Board of Directors, National Regulatory Research Institute; May 2012 – Nov. 2014.

Member, Advisory Council for Center for Public Utilities, New Mexico State University, Nov. 2011 – Jan. 2019.

Journalism Fellow; Phillips Foundation; July 2008 – July 2009 (currently known as the Robert Novak Fellow).

Gates Cambridge Scholar; Gates Trust, Bill & Melinda Gates Foundation, Cambridge, England.; 2007-08.

Exhibit TK-2

Default Service Pricing Has Been Wrong All Along

Allows Utilities to Maintain Dominance in Markets

By Frank Lacey, Electric Advisors Consulting

Default service prices have been wrong for two decades.

Most of the states that have implemented competition in electric and gas sales have employed a Provider of Last Resort, POLR, or default service to supply electricity to customers who do not select an alternative provider. Yet the utilities allocate few to no "costs to serve customers" to default service rates.

This practice has allowed the incumbent utilities to price default service below market rates. And it has allowed them to maintain unregulated monopoly-like power and dominant market positions in the energy markets in their respective service territories.

The failure to allocate costs appropriately to a utility business unit is in direct conflict with cost allocation guidance from the National Association of Regulatory Utility Commissioners, NARUC. Until the default service pricing distortion is corrected, utility default service providers will continue to hold an anti-competitive pricing advantage in the provision of retail electricity service.[1] Regulators should act to correct this major market flaw.

Default Service Rates Artificially Low

Several states have deregulated or restructured their energy markets to allow consumers to choose their own electric and or gas supplier. With few notable exceptions, the deregulation models adopted in these states called for the incumbent utility to become the POLR or default service provider.[2]

While initially envisioned to serve a small number of customers who needed a "last resort" provider, the market rules incorporated into most restructured markets placed all customers on last resort service at the inception of retail competition, making it more of a "default" service.

Because an appropriate amount of costs are not allocated to default service, customers are reluctant to leave their incumbent utility. They are receiving electricity that is subsidized by distribution rates.

The default service pricing subsidy provides the incumbent utilities with what are effectively unregulated monopolies. Default service customers are not being charged an amount that is reflective of the cost to serve them.

The lack of any meaningful cost allocations to default service allows (requires) the incumbent utilities in restructured states to understate the price of retail electricity. This practice effectively eliminates competitive suppliers from functioning in those markets.

This pricing error leads to numerous market flaws. Distribution rates are too high. Default service rates are too low. Customers are receiving incorrect and inappropriate price signals from their host utilities.

The failure to allocate costs appropriately to a utility business unit is in direct conflict with cost allocation guidance from NARUC.

Customers who have switched to competitive suppliers are subsidizing those who stay on default service. And competitive suppliers are at a distinct pricing disadvantage compared to default service providers, allowing the utility market power to proliferate in retail energy markets.

This pricing incongruity allows utilities to maintain a stronghold over customers in their service territory. It also has given rise to claims about overcharging by competitive suppliers.

Freestanding Default Service Business Couldn't Survive

It is easy to prove the anti-competitive pricing in default service. One only needs to contemplate how long a default service business could operate if it was removed from the distribution company but kept its current cost structure intact. The short answer is that it would survive for only a very short period of time – technically, not even a day.

Default service companies need to issue tens of thousands of invoices every day and then need to process revenues as they come in. But because no costs to serve customers are allocated to default service businesses, there would be no money to pay any employees to perform those functions, nor any other function involved in running a default service business.

The current default service businesses would be bankrupt in a matter of days, or even hours, if they were operated outside of the distribution utilities. Clearly, this is a fundamentally flawed

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FIG. 1 COMPARATIVE ELECTRIC CUSTOMER RATES

Electric customer rates of switching from utility to competitive retail provider.

		Percentage migration by customer count		
State	**Utility**	**Residential customers**	**Small and medium customers**	**Large customers**
DC	PEPCO	15.0	32.1	N/A
MD	BGE	23.9	41.0	96.5
	PEPCO	19.8	42.8	87.9
	POT ED	10.8	32.4	90.3
	Delmarva	13.8	35.8	96.9
NJ	ACE	12.8	32.2	87.1
	JCPL	16.6	38.1	83.7
	PSEG	9.7	24.7	81.0
	RECO	6.9	18.4	74.5
PA	Duquesne	29.9	39.9	63.1
	Met-Ed	30.2	45.1	86.3
	PECO	31.0	46.0	91.0
	Penn Elec	26.1	42.2	88.1
	Penn Power	24.2	46.3	100.0
	PPL	41.3	53.7	70.5
	West Penn	24.7	32.8	91.9
NY	Central Hud	13.1	23.1	78.0
	Con Ed	22.8	29.8	91.6
	Nat Grid	16.1	38.5	80.2
	NYSEG	18.6	35.2	66.0
	O & R	33.5	45.9	26.4
	Rochester	16.2	42.0	93.2
Maine	State-wide	14.1	42.6	84.2
Delaware	Delmarva	9.8	32.2	

system and one that conflicts with all traditional rate-making standards.

Cost allocation is a fundamental tenet of utility ratemaking. The principles of cost allocation are fully endorsed by NARUC and should be applied to default service as they are to all other utility rates.

Allocations are required to appropriately assign fixed costs to multiple products or services that drive the costs. The principles of cost allocation are the foundation for nearly every (if not every) utility rate, aside from default service rates.

The NARUC Cost Accounting Manual states:

"While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that *service should be provided at cost.* Non-cost concepts and principles often modify the cost of service standard, but it remains the primary criterion for the reasonableness of rates. The cost principle applies not only to the overall level of rates, but to *the rates set for individual services, classes of customers, and segments of the utility's business.*" Emphasis added.

NARUC has separately published cost allocation principles. The principles should be applied, according to NARUC "whenever products or services are provided between a regulated utility and its non-regulated affiliate or division." NARUC principles apply to default service, a business segment where many services are provided by the distribution company:

"The allocation methods should apply to the regulated entity's affiliates in order to *prevent subsidization* from and ensure equitable cost sharing among the regulated entity and its affiliates, and vice versa." Emphasis added.

NARUC states that the objective of its guidelines is to "lessen the possibility of subsidization in order to *protect monopoly ratepayers and to help establish and preserve competition* in the electric generation and the electric and gas supply markets." Emphasis added.

In fact, to ensure the competitiveness of markets, NARUC states that generally, "the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be *at the higher of* fully allocated costs or prevailing market prices." Emphasis added.

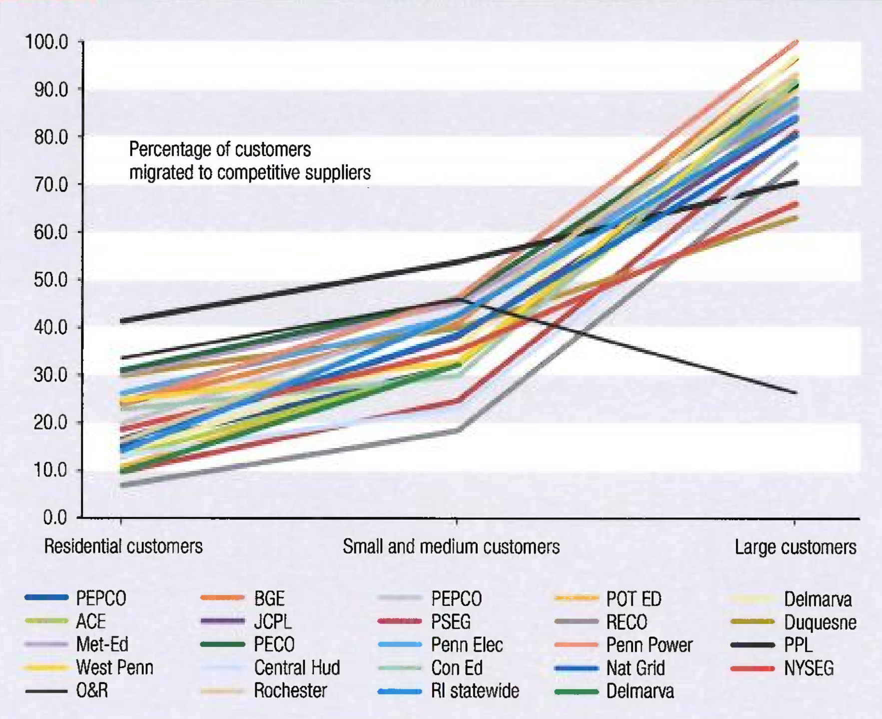
NARUC's objectives and guidelines have been ignored in pricing default service.

Market Distortions

The default service pricing anomaly has given rise to many market distortions and has resulted in competitive suppliers being cast in a negative light in many jurisdictions. It has caused competitive suppliers to spend millions of dollars in unnecessary marketing costs, regulatory costs and legal and compliance costs.

Most important, it has resulted in customer harm from being constrained to the utilities' "no service" products and from the

FIG. 2 CUSTOMER MIGRATION TRENDS ARE CONSISTENT ACROSS MARKETS



lack of product options that are available in more competitive markets.

Table One details the percentage of customers who have chosen a competitive electric supplier across many of the deregulated electricity markets. Despite two decades of competition and dozens of suppliers vying for customers in every market, the incumbent utility stronghold on the market, especially over residential customers, is painfully clear.

See Figure One.

At the low end, we see single digit migration rates for residential customers to competitive suppliers. The Pennsylvania market shows the most promising residential migration numbers – ranging from the mid-twenty percent range to just over forty percent in PPL's service territory.

States that have deployed municipal aggregations to facilitate customer migration are not included in this chart because aggregations are simply a regulatory fix that masks the pricing problem in the short-term. Municipal aggregations do not solve the pricing problems over time.

Figure Two shows the same data in graphical form. The utilities all show the same migration trends. Small customers do not migrate away from the utilities while the largest customers participate in the competitive markets at very high penetration levels.[3] See Figure Two.

Artificially Low Default Service Prices Harms Customers

Under an appropriate cost allocation approach, the customers will pay, on net, the same amount every year. Cost allocation does not cause an increase in costs to customers. It only moves costs to different buckets.

Because there is no total cost increase to customers with an appropriate cost allocation, the argument that the customers are better off under the current pricing model is flawed. In fact, because of the inaccurate pricing signal with the current model, customers are harmed in meaningful ways.

Most important, customers are not receiving the appropriate price signal for energy. This results in a potential to over-consume energy provided by default service providers, yielding what could be a higher overall monthly cost to the customer than would otherwise incur if the electricity was priced appropriately.

Customers who have switched to competitive suppliers are subsidizing those who stay on default service.

The distribution subsidy also creates a barrier to evaluating competitive offers. It is impossible for customers to assess fairly a competitive offer when the utility price is artificially low.[4] Because the basic competitive market product would be viewed as uneconomic by the consumers, competitive suppliers are less likely to invest fully in the market, depriving customers of other products and services that the suppliers might be inclined to offer in that market. Foregone products and services include many that might reduce a consumer's consumption overall, benefitting the customers and the environment.

Finally, the distribution subsidy results in a distribution rate that is too high. Customers who have moved away from the utility are forced to pay costs that benefit customers who remain on default service.

Recent Analyses Reveal Subsidies

Substantial analyses seeking to understand the magnitude of the distribution subsidy have been performed in two recent distribution rate cases. The results of those analyses have been presented to utility commissions in Pennsylvania and New

Jersey in the form of expert testimony in those respective cases. These analyses show that the subsidy is significant – a penny or more per kilowatt-hour – as high as fifteen percent of the default service rate.

In PECO's rate proceeding, Pennsylvania Public Utility Commission's docket R-2018-3000164, NRG Energy Company provided an analysis of PECO's distribution rates to determine if any distribution costs were being used to subsidize PECO's default service rates. The analysis showed that the subsidy of PECO's default service by PECO's distribution business amounts to 1.25 cents per kilowatt-hour for residential customers.

If that amount was properly allocated to PECO's default service rates, it would increase those rates by approximately fifteen percent. Of course, if the costs were properly allocated to default service, the corresponding cost components from the distribution rates would decrease by the same amount.

In PSEG's rate proceeding, New Jersey Board of Public Utilities docket ER18010029, I undertook on behalf of Direct Energy, a similar analysis. My analysis showed that the subsidy that PSEG distribution rates were providing to PSEG's default service amounts to 1.0 cents per kilowatt-hour to residential customers. Because PSEG's default service rates are higher than PECO's, an additional 1.0 cents per kWh represents a subsidy of about eight percent to residential default service rates.

In the PSEG rate case, not enough information was provided by the utility to determine the magnitude of costs (working capital, credit, bad debt, etc.) that should be directly assigned to default service. As a matter of conservatism in my analysis, I assumed that those should be only partially allocated.

If direct costs were assigned properly to default service and indirect costs were allocated appropriately, the actual costs to serve default service customers in New Jersey could be in the range of 1.5 cents per kilowatt-hour.

With default service rates ranging from the low single digits to the low teens in cents per kilowatt-hour in markets across the country, and the unallocated funds (or subsidies) ranging from 1.0 to 1.5 cents per kilowatt-hour, this subsidy can be valued anywhere between eight percent and fifty percent of a monthly default service charge. A subsidy of that magnitude, or that scale of utility "discount" severely distorts the market, unfairly advantages the utilities over competitive service providers and harms customers.

Conclusion

Appropriately allocating costs currently paid by distribution customers to default service is a critical next step in creating more competitively neutral energy markets in the United States. This one step will not create the perfect markets, but it will remove a significant anti-competitive pricing advantage held by monopoly utilities.

It will also remove a subsidy that competitive supply customers are forced to pay to benefit default service customers, and it will help create a market that competitive suppliers are more willing to invest in. At the same time, if implemented correctly, it keeps distribution utilities financially whole. It is a win-win-win solution benefitting all market participants.

Endnotes:

1. While this article is focused on electricity markets, the same pricing problems exist in gas markets. The costs to serve customers are not allocated to those customers' rates. Instead, they are charged to distribution customers.
2. Most of the deregulation models deployed in the U.S. are generally very similar. In contrast, Texas electricity customers and Georgia natural gas customers were placed with market participants at the inception of those markets and default service in those markets is truly a "last resort" service, not a "default" or "do nothing" service.
3. The one anomaly revealed in this chart is in the Orange & Rockland Utility in New York. It shows an uncharacteristic low level of customer migration at the large end of the customer spectrum. It is not clear whether this is a data error on the NY PSC website, or if there is a market anomaly in that market that results in the largest customers remaining with the utility.
4. Under no circumstance should any price, including the utilities' default service price, be considered a benchmark price. The default service price is for a specific product with a specific set of parameters associated with it. Additionally, as this article notes, it is heavily subsidized. It comes with a certain level of service and a limited ability for it to be modified in any way to meet customers' needs. Regardless, regulators in many states have mandated rules that require a comparison of all products to the utility default service price. These requirements include for example, a requirement that the default service price be placed on a customer's invoice, even if the customer is being served by another supplier, with a different product. Some have required that all sales interactions include a notice of the utilities' default service price.

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Default service pricing – The flaw and the fix
Current pricing practices allow utilities to maintain market dominance in deregulated markets

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ABSTRACT

Utility default service has been priced incorrectly for two decades. Incumbent utilities serving as default service providers for both electricity and gas allocate few to no "costs to serve" to default service rates. The indirect costs not allocated include billing, customer care, enrollments, metering, and other overhead and add up to billions of dollars annually. These costs are paid in distribution rates. The resulting rate for utility-provided default service is a below-market price, allowing the utilities to maintain dominant market positions in the retail markets for residential and small commercial customers. This pricing practice distorts the relevant retail electric and gas markets and harms customers and the markets. NARUC cost allocation guidelines advocate that the cost of utility resources used in the provision of default service should be allocated to that service. This paper presents a Default Service Equalization Adjustment Mechanism ("D-SEAM") that when deployed properly, will provide the default service utilities with a tool to allocate an appropriate amount of costs to default service rates and then adjust that allocation on a monthly basis to ensure the distribution utility is made whole financially as customers migrate off of default service. Without an appropriate allocation of cost to default service, incumbent utilities will maintain a dominant market position in the retail markets for residential and small commercial customers as a result of the significant subsidy provided by the distribution rates. Utilities should adopt, and/or the regulators should compel the adoption of a complete and appropriate allocation of costs to default service. It is only with this allocation that customers will be able to reasonably compare market offerings.

1. Introduction

1.1. Default service prices have been wrong for two decades

Several states have restructured their electricity and/or gas markets to allow for customer choice of energy suppliers. Most of these states have implemented a Provider of Last Resort ("POLR") provider or Default Service provider to provide electricity to customers who do not select an alternative provider. As long as default service remains the benchmark against which other offers are compared[1], it should be priced so that all of the costs incurred to provide default service are included. For it is only in that circumstance when competitive retail energy markets empower customers to meaningfully compare energy offers. Testimony presented in recent rate proceedings for PECO electric distribution utility in Pennsylvania and PSEG's electric and gas distribution utilities in New Jersey reveal the magnitude of the pricing subsidies that are present in those markets. The practice of not allocating costs appropriately to a utility business unit is in direct conflict with cost allocation guidance from the National Association of Regulatory Utility Commissioners ("NARUC"). Until the pricing distortion is corrected, utility default service providers will continue to hold an anti-competitive pricing advantage in the provision of what should be competitive retail electricity service. Regulators should act to correct this major market flaw.

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[1] For several reasons, including those discussed within this paper, utility-provided default service products and prices should not be a benchmark to compare any competitive service offerings. The default service price is for a very specific product with a very specific set of parameters associated with it. This rate is often reconcilable and reflects a price from a prior point in time in the market. Additionally, as this article notes, default service is heavily subsidized. It comes with a certain level of service and a very limited ability for it to be modified in any way to meet customers' needs. Regardless, regulators in many states have mandated rules that require a comparison of all products to the utility default service price. These requirements include for example, a requirement that the default service price be placed on a customer's invoice, even if the customer is being served by another supplier, with a different product. Some have required that all sales interactions include a notice of the utilities' default service price.

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The majority of states that have restructured retail energy markets report statistics on customer migration away from the incumbent utilities. This data shows clearly that the incumbent utilities in restructured states continue to hold strong market dominance in the residential and small commercial markets. For example, after nearly 20 years of competition, the majority of restructured states show migration rates of less than 20% of the residential electricity customers.[2]

The explanations proffered by the so-called "energy experts" all miss the simple truth – the incumbent utilities still hold vast market powers granted to them by their respective regulators. Most notably, the cost of providing default service is nearly fully- (and in some cases fully-) subsidized by the host utility's distribution customers. Yes, customers typically pay the full price for the electrons they receive. Customers, however, are not charged for billing, IT, overhead, or any other costs that should rightfully be allocated to default service. The simple thought experiment to see if appropriate costs are being allocated to the default service business is to imagine what would happen if default service was severed from the utility's distribution business. Under this imaginary scenario, nearly every default service program would be bankrupt in a matter of days, if not hours, if it was removed from the distribution business. This simple example should allow the reader to clearly see that utilities are not allocating adequate costs to default service.

2. Background

Several states within the United States have deregulated or restructured their retail energy markets to allow consumers to choose their own electric and/or gas supplier. While the utilities in these regions continue to maintain monopoly franchise rights over their "pipes and wires" businesses, their electric generation and gas supply businesses are now subject to competitive forces and customer choice of supplier. With few notable exceptions, the deregulation models adopted in these states called for the incumbent utility to become the POLR or default service provider. While initially envisioned to serve a small number of customers who were in need of a "last resort" provider, the market rules incorporated into most restructured markets placed all customers on "last resort" service at the inception of retail competition[3]. Because "last resort" became such an inappropriate phrase for what utility service has become, the name has morphed to "standard offer" or "default service" – the service for customers who fail to choose a competitive alternative. Unfortunately, embedded in this process are default service prices that are heavily subsidized by the host utilities' distribution companies. As a result, default service customers are misled about their retail market options and thus, frequently remain with their incumbent utility.

Some default service providers pass along some direct costs to their customers, such as the cost of credit to procure power in the open market. Some providers pass on no costs at all beyond the direct cost of the energy provided. No incumbent utility default service provider in the US passes along any indirect costs to its default service business. The indirect costs incurred to provide service to default service customers amount to billions of dollars annually and are being paid by distribution customers. This distorts significantly the retail energy markets, providing the incumbent default service provider with a pricing advantage that allows them to maintain market dominance in the residential and small commercial customer segments.

These subsidies are the primary reason that retailers focus on non-price issues and offer many value-added products and services. It is simply not practical to compete with standard offer service on price alone. In short, the default service rates offered to customers by incumbent utilities are artificially low, which leads to numerous market flaws: distribution rates are too high; default service rates are too low; customers are receiving incorrect and inappropriate price signals from their host utilities; consumers are not provided adequate information to make informed energy decisions; and customers who have switched to competitive suppliers are subsidizing those who stay on default service. This pricing incongruity allows the incumbent default service providers to maintain market dominance over customers in their service territories and it also has given rise to bogus claims of "overcharging" by competitive suppliers.

3. Data from recent analyses

Substantial analyses seeking to understand the magnitude of the distribution subsidy have been performed in recent distribution rate cases. The results of those analyses have been presented to Utility Commissions in Pennsylvania and New Jersey in the form of expert testimony in those cases. These analyses show that the subsidy is significant – a penny or more per kilowatt-hour – or more than 10% of the default service rate.

In PECO's rate proceeding (PA PUC Docket No. R-2018-3000164), NRG Energy Company presented an analysis of PECO's distribution rates that showed the subsidy of PECO's default service by PECO's distribution business amounts to 1.25 cents per kilowatt-hour for residential customers.[4]

In PSEG's rate proceeding (NJ BPU Docket No. ER18010029), Frank Lacey (the author of this article), an energy markets consultant and president of Electric Advisors Consulting, undertook on behalf of Direct Energy, a similar analysis that showed the PSEG distribution rates were providing default service subsidies of 1.0 cent per kilowatt-hour to residential customers and 0.67 cents per kWh to C&I customers.[5]

4. Proposed solution

The distribution companies should allocate the portion of costs incurred to operate the default service business to the that business and collect those costs from its customers on the energy portion of those customers' invoices. In order for the distribution company to fully collect its regulated revenue requirement, the distribution companies should also implement crediting, balancing and true-up mechanisms to ensure that it is never over- or under-collecting.

4.1. Cost allocation mechanism

Distribution resources that are used in the functioning of the default service business should be identified. The costs associated with these resources should be quantified as they would be in a rate proceeding. Once the bucket of costs is identified, an appropriate allocation

[2] This paper focuses on competitive electricity markets. The same dynamics discussed in this paper are also present in the competitive gas markets. The distribution companies significantly subsidize the commodity price by failing to allocate costs to serve default service customers. The solutions provided in this paper are applicable to gas distribution companies as well.

[3] A few deregulation models were implemented differently, and customers were immediately placed into the competitive market upon inception of the market. Notably, Texas electricity customers and Georgia natural gas customers were placed with market participants at the inception, or shortly after the inception of those markets.

[4] Direct Testimony of Chris Peterson on Behalf of NRG Energy Company, Pennsylvania Public Utility Commission v. PECO Energy Company, Docket No. R-2018-3000164, June 26, 2018.

[5] Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy and its affiliates before the New Jersey Board of Public Utilities, *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16, Electric and B.P.U.N.J. No. 16, Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief*, BPU Docket Nos. ER18010029 and GR18010030, OAL Docket No. PUC 01151-18, August 6, 2018.

6. NARUC principles require allocations to default service

The principles of cost allocation are fully endorsed by NARUC and should be applied to default service as they are to all other utility rates. The principles of cost allocation are the foundation for nearly every (if not every) utility rate, aside from default service rates. The principles of cost accounting are neither new nor novel to utility rate making personnel or regulators who approve rates. Yet despite the long history of cost allocation in the industry, the default service businesses have been allowed to operate since the inception of deregulation without an appropriate allocation of costs to serve default service customers.

The NARUC Cost Accounting Manual states:

"While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that service should be provided at cost. Non-cost concepts and principles often modify the cost of service standard, but it remains the primary criterion for the reasonableness of rates. The cost principle applies not only to the overall level of rates, but to the rates set for individual services, classes of customers, and *segments of the utility's business*. Cost studies are therefore used by regulators for the following purposes:

- To attribute costs to different categories of customers based on how those customers cause costs to be incurred.
- To determine how costs will be recovered from customers within each customer class.
- To calculate costs of individual types of service based on the costs each service requires the utility to expend.
- To determine the revenue requirement for the monopoly services offered by a utility operating in both monopoly and competitive markets.
- To separate costs between different regulatory jurisdictions."[8] (emphasis added).

These observations from NARUC are especially prescient given the date of the Cost Allocation Manual – January 1992. At that point in time NARUC was envisioning an allocation of costs of monopoly services offered by a utility operating in both monopoly and competitive markets. Even though it is likely the NARUC Manual did not envision default service as it is being offered today, the principles hold true from an accounting perspective and from a regulatory rate-making perspective and should be applied to default service.

Notably, NARUC's Manual expressly calls out costs allocated to "segments of the utility's business". In other words, it is appropriate to allocate costs to each business segment, even if it is not a separate business unit with profits and/or losses attached to it. Despite the foresight from NARUC, this guidance has been ignored by utilities in the provision of default service. This manual, dating back over 25 years is still available on the NARUC website.[9]

NARUC has separately published cost allocation principles. The principles should be applied, "whenever products or services are provided between a regulated utility and its non-regulated affiliate or division".[10] Under NARUC's first identified principle, direct costs "should be collected and classified on a direct basis for each asset, service or product provided."[11] The set of direct costs that should be charged to default service include, but is not limited to, the cost of credit, the cost of wholesale market departments, the costs of procurement, working capital, bad debt, the cost of communicating environmental attributes of default service supply (where required), and the cost of other regulatory requirements imposed on default service providers.

NARUC principles further apply to default service stating: "The allocation methods should apply to the regulated entity's affiliates in order to *prevent subsidization from, and ensure equitable cost sharing among the regulated entity and its affiliates*, and vice versa."[12] (Emphasis added.)

NARUC describes that the objective of its guidelines is to "lessen the possibility of subsidization in order to protect monopoly ratepayers and to *help establish and preserve competition in the electric generation and the electric and gas supply markets*."[13] (emphasis added) In fact, to ensure the competitiveness of markets, NARUC states that generally, "the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be at the *higher of fully allocated costs or prevailing market prices*."[14] (emphasis added) NARUC's cost allocation guidance and objectives have been ignored for two decades and the data shows that the incumbent utilities' monopoly-like stronghold over customers, especially residential and small commercial customers, remains.

7. Default service pricing harms markets

7.1. Default service providers maintain market dominance

The default service pricing anomaly results in a significant subsidy that provides the incumbent utilities default service businesses with anti-competitive pricing power. Default service customers are simply not being charged an amount that is reflective of the cost to serve those customers. The lack of any meaningful cost allocations to default service allows (requires) the incumbent utilities in restructured states to understate the price of retail electricity and eliminates competitive suppliers from functioning effectively in those markets.

In an ironic submission to the New York Public Service Commission, Commission staff offered the results of a Herfindahl–Hirschman Index ("HHI")[15] analysis, while trying to show market power among competitive suppliers. However, what the results actually showed is that each of the New York electricity markets was "highly concentrated" when the analysis included the incumbent utility (with HHI scores above 7000) but was unconcentrated without the incumbent utilities (with HHI scores as low as 420).[16] Rather than showing market power among competitive suppliers, this analysis clearly demonstrates the market dominance of the New York utilities. Commission staff testified further that the 23 largest competitive electric suppliers were serving less than 20% of the New York residential market.[17] That means that on average, the 23 largest competitive electric

[8] NARUC, Electric Utility Cost Accounting Manual, January 1992, found at *http://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD*

[9] See: https://pubs.naruc.org/pub.cfm?id=53A20BE2-2354-D714-5109-3999CB7043CE

[10] NARUC, http://pubs.naruc.org/pub/539BF2CD-2354-D714-51C4-0D70A5A95C65

[11] Ibid, Section B.1.

[12] Ibid, Section B.4.

[13] Ibid, Section D.

[14] Ibid, Section D.1.

[15] According to the US Department of Justice, the HHI is a commonly accepted measure of market concentration. The HHI is calculated by squaring the market share of each firm competing in the market and then summing the resulting numbers. The HHI considers the relative size distribution of the firms in a market. It approaches zero when a market is occupied by a large number of firms of relatively equal size and reaches its maximum of 10,000 points when a market is controlled by a single firm. Agencies generally consider markets in which the HHI is between 1,500 and 2,500 points to be moderately concentrated and consider markets in which the HHI is in excess of 2,500 points to be highly concentrated. *See* U.S. Department of Justice & FTC, *Horizontal Merger Guidelines* § 5.3 (2010).

[16] Prepared Direct Testimony of Joel Andruski, Associate Economist, Office of Market and Regulatory Economics, State of New York, Department of Public Service, In the Matter of ESCO Track I Proceeding, Cases 15-M-0127, 12-M-0476 and 98-M-1343, September 2017.

[17] Prepared Direct Testimony of the NY PSC Staff Panel: Bruce E. Alch, Chief, Retail Access and Business Advocacy, Office of Consumer Services; Craig Carroll, Utility Analyst 2, Office of Consumer Services; Peter Lavery, Utility Analyst, Office of Accounting, Audits and Finance; Kristine A. Prylo, Principal Utility Financial Analyst, Office of Accounting, Audits and Finance; David Shahbazian, Utility Auditor II, Office of Accounting, Audits and Finance, State of New York Department of Public Service, In the Matter of ESCO Track I

suppliers each hold less than a 1% market share, while one New York utility still holds an 87% share in the residential market in its service territory.

The New York Staff's HHI analysis effectively proves the utilities dominance in New York. The same result would be found in nearly every other deregulated market. The question then is: why do the utilities hold such a dominant position? It is clearly not the lack of interest from competitive suppliers. After all, the New York Staff cites to the "23 largest" suppliers, indicating that there are many more than 23 vying for customers' business. Do customers endear themselves to the utilities in every market? Not likely. Do the utilities offer one better product than the list of all products offered by competitive suppliers? Not likely. Or is the utilities pricing subsidy simply too great for competitive suppliers to overcome? Without performing any formal analysis on these first two questions, the answers seem obvious. The utility pricing advantage brought on by a lack of cost allocation is simply too great for the suppliers to overcome. All energy companies are purchasing power from the same wholesale markets. Utilities simply do not pass on the costs to service their customers. The pricing incongruity could not be more evident.

Because competitive suppliers must include all of their operating costs in their supply prices in addition to the wholesale cost of energy, competitive prices are frequently higher than those of the subsidized default service rates. Instead of regulators fixing the default service pricing, many have instead lobbed allegations of "overcharging" at the competitive suppliers.[18] Regulators and consumer advocates have launched investigations and suggested that residential markets be closed. As a result, competitive suppliers have spent millions of dollars defending their actions and fighting to maintain a presence in the markets.

7.2. Customer migration trends are consistent

The New York customer switching results discussed above are not unique. Table 2 below details the percentage of customers who have chosen a competitive electric supplier across many of the deregulated electricity markets. After two decades of competitive markets, we see a similar pattern of migration rates of customers to competitive suppliers across the restructured markets[19].

The results in Table 2 are not unexpected. In order to compete with default service, a competitive supplier has to either wait for a cycle in the wholesale markets that will allow for a more economic offering than default service, or the supplier has to offer a better, typically more expensive product. It is difficult to compete with the subsidized default service price.

Chart 1 below shows the same data in graphical form. The graph shows that the migration problem is not unique to any one utility jurisdiction. Small customers do not migrate away from the utilities while the largest customers participate in the competitive markets at very high penetration levels[20]. It is not clear whether the outlier in the Large Customer category reflects a data error on the NY PSC website, or if there is a market anomaly that results in the largest customers in that market remaining with the utility.

Table 2
Electric Customer Retail Choice Migration Rates[a].

		Percentage of Rate Class Switching By Customer Count		
State	Utility	Residential	Small and Medium	Large
DC[b,c]	PEPCO	15.0	32.1	N/A
MD[d]	BGE	23.9	41.0	96.5
	PEPCO	19.8	42.8	87.9
	POTED	10.8	32.4	90.3
	Delmarva	13.8	35.8	96.9
NJ[e]	ACE	12.8	32.2	87.1
	JCPL	16.6	38.1	83.7
	PSEG	9.7	24.7	81.0
	RECO	6.9	18.4	74.5
PA[f]	Duquesne	29.9	39.9	63.1
	Met-Ed	30.2	45.1	86.3
	PECO	31.0	46.0	91.0
	Penn Elec	26.1	42.2	88.1
	Penn Power	24.2	46.3	100.0
	PPL	41.3	53.7	70.5
	West Penn	24.7	32.8	91.9
NY[g]	Central Hud	13.1	23.1	78.0
	Con Ed	22.8	29.8	91.6
	Nat Grid	16.1	38.5	80.2
	NYSEG	18.6	35.2	66.0
	O & R	33.5	45.9	26.4
	Rochester	16.2	42.0	93.2
Maine[h]	State-wide	14.1	42.6	84.2
Delaware[i]	Delmarva	9.8	32.2	

[a]Data in this table gathered from each state's PUC or related website. Each state has differing definitions for C&I customer classes. Data from Ohio, Illinois and Massachusetts are not included in this table because each jurisdiction has engaged in robust community aggregation programs. Rhode Island data is not presented because Rhode Island does not report by rate class, the number of customers not participating in retail choice programs, so percentages by rate class cannot be calculated. Connecticut data is not shown here as its last reported data period is year-end 2014 and it also does not break down enrollment data by rate class.

[b]See: https://dcpsc.org/PSCDC/media/PDFFiles/Electric/electric_sumstats_no_cons.pdf. (Sept. 2018 data).

[c]See: https://dcpsc.org/PSCDC/media/PDFFiles/Electric/electric_sumstats_cons_dmnd.pdf. (Sept. 2018 data).

[d]See: https://www.psc.state.md.us/electricity/electric-choice-monthly-enrollment-reports/. (August 2018 data).

[e]See: https://www.state.nj.us/bpu/pdf/energy/edc07.pdf. (August 2018 data).

[f]See: https://www.papowerswitch.com/sites/default/files/PAPowerSwitch-Stats.pdf. (Sept 2018 data).

[g]See:http://www3.dps.ny.gov/W/PSCWeb.nsf/All/4759ECEE7586F24B85257687006F396E?OpenDocument (December 2017 data).

[h]See: https://www.maine.gov/mpuc/electricity/choosing_supplier/migration_statistics.shtml. (September 2018 data).

[i]See: https://depsc.delaware.gov/electric-regulation/#consumer. (April 2018 data).

7.3. Improper default service pricing harms Consumers

Customers are receiving an artificially low energy-price signal. This incorrect signal results in over-consumption of energy provided by default service providers. Because most residential customers are still on default service, the pricing anomaly results in system-wide over-consumption of electricity, increasing market prices for all consumers. On net, the artificially low price might actually yield what could be higher overall monthly costs to all customers because wholesale prices are impacted by increased consumption levels.

It is also impossible for customers to assess fairly a competitive offer

(footnote continued)

Proceeding, *Cases 15-M-0127, 12-M-0476 and 98-M-1343, September 2017.*

[18] In the aftermath of the Polar Vortex in 2014, a handful of suppliers charged higher prices than were typical in the market at the time. Regulators in some markets determined that certain suppliers acted in bad faith and penalized them. However, the recent analyses presented that allege systemic overcharging have incorrectly and inappropriately compared market-based electricity products to the subsidized default service rates on an apples-to-apples basis.

[19] States that have implemented municipal aggregations programs are not included in Table 2. Municipal aggregations might lead to more robust migration numbers, but they are only a short-term regulatory fix that temporarily masks the distribution subsidy. Municipal aggregations do not solve the pricing incongruity over time.

[20] The research on this paper and in support of the PSEG rate case showed that the subsidy for larger customers is smaller, on a per-kWh basis, than the subsidy for residential customers.

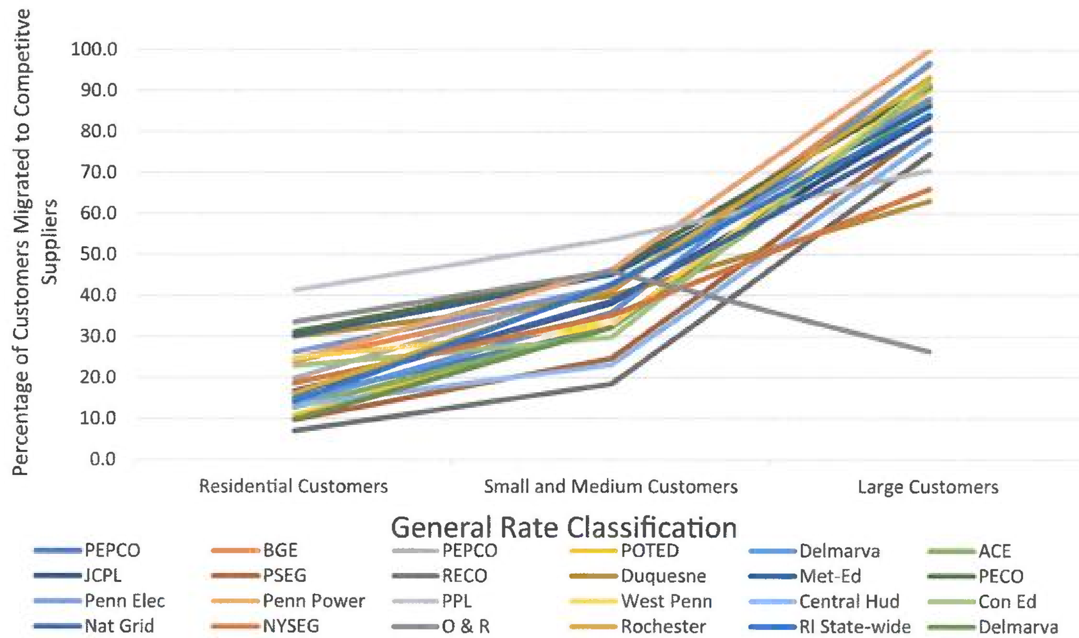

Chart 1. Customer Migration Trends are Consistent Across Markets.

when the utility price is artificially low[21] . Because the basic competitive commodity-only product would be viewed as uneconomic by the consumers, suppliers are less likely to invest fully in the market, depriving customers of other products and services including many that might reduce a consumer's overall consumption, which would benefit the customers and the environment. These products and services are available in the more competitive regions of the country but are not as readily available where the subsidized default service rates stifle competition.

Finally, the distribution subsidy results in a distribution rate that is too high. Customers who have moved away from the utility are forced to pay costs that benefit customers who remain on default service.

The lack of residential and small commercial customer energy savings options, products and services is the result of a failed regulatory paradigm. It is not a reflection of a failed market.

8. Arguments against Cost allocation are flawed

Stakeholders have generally proffered four arguments against allocating indirect retail costs to default service. The typical arguments are:

1) The costs are not avoidable and will be incurred by the distribution business whether or not they provide default service;
2) If costs are allocated to default service, the distribution utility will not be able to recover its full distribution revenue requirement as customers migrate to competitive suppliers;
3) Allocation of costs serves no purpose other than to increase rates on customers so that competitive suppliers can better compete with utility pricing; and
4) Utilities do not earn a profit on the provision of default service, so an allocation of costs is not needed.

All of these arguments are flawed.

[21] Under no circumstance should any price, including the utilities' default service price, be considered a benchmark price. See fn 1, supra.

8.1. Avoidable versus allocable costs

Simply stated, avoidable costs are direct costs. Fixed costs, which typically serve multiple purposes are considered indirect costs and should be allocated to the businesses which benefit from the resource. Direct or avoidable costs should be directly assigned (not "allocated") to the business unit incurring the costs. The existence of avoidable/ direct costs, however, does not mean that allocable/indirect costs don't exist. In order for businesses to properly price products and services, indirect costs must be appropriately allocated to the cost centers benefiting from the incurrence of the costs.

Our economy is replete with examples of businesses that allocate costs to more than one product, service or business unit. But we do not need to look past the rate cases prevalent in the utility industry to see cost allocations implemented. Under the theory of avoidable costs, one could argue that commercial customers shouldn't pay for distribution wires because if the commercial customers left the grid, the utility would still need to have the distribution wires in place to service residential customers. Of course, that argument is foolhardy. The cost of the distribution wires and services related to it are largely fixed costs that benefit all rate classes and are therefore allocated to all rate classes based on cost causation principles. It is inappropriate that utilities do not similarly assign direct costs and allocate an appropriate amount of indirect costs to default service.

8.2. Cost recovery

Utilities have argued against allocations to default service because if costs are allocated to that service and customers move to competitive supply, the utility will not be able to fully recover its allowed rates. This argument assumes a static accounting paradigm. If a utility simply lowered its distribution rate by one cent per kWh and increased default service rates by one cent per kWh, that argument would hold some validity. Further accounting and pricing tools can be developed that would ensure the utility is kept whole. The D-SEAM described above was presented in the PSEG rate case and fully resolves the cost recovery issue.

The cost recovery argument is a red herring. Utility tariffs are chock full of riders, true-ups, monthly adjustments and "make whole" mechanisms. It is clear that a true-up mechanism can be deployed that will ensure that default service customers are seeing a competitive energy price that will also ensure utilities are fully compensated for their revenue requirements.

8.3. Facilitate competition

Stakeholders have argued that any attempt to place cost on default service should be thwarted as the increased default service prices are simply a ploy to allow competitive service providers to compete more effectively on price. This argument is similarly flawed. The lack of allocation of costs is contrary to all rational business accounting practices, is contrary to NARUC guidance on cost allocation and allows utilities to maintain market power in the residential and small commercial customer segments. Incumbent utilities' default service market dominance has been maintained because the cost to serve default service customers is being subsidized inappropriately by distribution rates. No rational or prudent business would price products or services without a full and appropriate allocation of costs included.

Further, if the cost allocation is done correctly, every dollar allocated to default service is similarly deducted from distribution costs. In other words, it is a cost reallocation, not a cost increase. On net, default customers will pay no more for bundled energy (electrons and delivery) than they would pay prior to the reallocation of costs. The premise of competing against "higher rates" is simply a false premise.

8.4. Utility profitability

Some utilities have argued that there is no reason to allocate costs to the default service business because they do not earn a return on the provision of default service. Regardless of the validity of that statement, it is not a reason to justify an allocation approach. A properly run widget manufacturer should allocate costs to profitable and unprofitable lines of business. In the absence of such an allocation, the unprofitable line of business might be viewed as profitable, resulting in decisions that would cause further financial harm to the overall widget company (i.e., lowering the retail price on what are already unprofitable products). These irrational pricing decisions are the exact decisions that the default service utilities have been making (default service prices are too low and distribution rates are too high). If both services were truly competitive, the distribution would be run out of business by its lower-priced competitors and the underpriced default service "successes" would bankrupt the company. However, the utilities are protected from these irrational behaviors by virtue of the distribution monopoly.

The four primary arguments used to support the status quo are weak, at best. A cost allocation mechanism that keeps distribution companies whole as customers migrate on and off of default service could and should be implemented at all utilities that provide default service. The cost allocation implementation should include a comprehensive review of all utility costs inclusive of rate base assets, and all expenses, including executive salaries, legal departments, rate departments, customer service departments and all other employees and expenses. A measurable portion of those costs should be appropriately allocated to default service in accordance with NARUC guidelines and consistent with NARUC policies and objectives.

9. Conclusion

Default service pricing in the majority of the competitive retail energy markets is fundamentally flawed and allows the incumbent utilities to maintain a stronghold over their legacy customers in the residential and small commercial markets. Consistent with NARUC guidance, an appropriate amount of costs to serve default service customers should be allocated to default service rates. This is a critical next step in creating more competitively neutral retail energy markets in the US. This one step will not create the perfect market, but it will remove a significant pricing advantage held by incumbent utilities. It will also remove a subsidy that forces competitive supply customers to pay distribution rates that benefit default service customers, and it will help create a market in which competitive suppliers are more willing to invest. At the same time, if implemented correctly, it keeps distribution utilities financially whole. It is a win-win-win solution benefitting all market participants.

Frank Lacey President and Founding Principal Electric Advisors Consulting, LLC. Mr. Lacey is an experienced energy industry leader who has worked for advanced energy firms or consultancies for 25 years. He has been engaged in transforming the electricity industry throughout his career. His focus has been aligning business strategy with regulatory outcomes – interpreting rules and regulations and modifying strategies to align with those changes or seeking rule changes to align with strategies. Frank launched Electric Advisors Consulting, LLC in 2015. His mission is to help advanced energy companies develop strategies to integrate into existing markets or modify regulations so that the markets will accommodate advanced technologies and business plans.

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Response of PECO Energy Company
To Interrogatories of the
Electric Suppliers Coalition
ESC Set I
Response Date: 05/18/2020

ESC-I-8

Reference Fisher Direct Testimony, p. 20. You present a chart to show an increase in EGS participation in the PECO zone from December 2010 through December 2019.

A. Do you agree that since December 2016, the growth in EGSs serving residential customers has been relatively nonexistent?

B. Do you have data for the same time period as shown on this chart showing the number of residential customers have been served by EGSs? If so, please provide.

RESPONSE:

A. As of December 2016, 97 EGSs were serving residential customers in PECO's service area. The most recent data available is for the month ending April 28, 2020. As of the month ending April 28, 2020, 96 EGSs were serving residential customers in PECO's service area. The change during this time is therefore -1%. An assessment of whether this is considered "relatively non-existent" cannot be made without defining to what other growth rate and/or in what context this is being compared.

B. The following table provides historical numbers of residential customers being served by EGSs.

Month	Active or Pending EGS Customers*	Month	Active or Pending EGS Customers*	Month	Active or Pending EGS Customers*
12/10	44,935	2/14	466,572	4/17	505,868
1/11	119,840	3/14	465,065	5/17	502,658
2/11	165,191	4/14	463,299	6/17	500,005
3/11	205,478	5/14	462,103	7/17	497,012
4/11	225,816	6/14	460,065	8/17	492,235
5/11	245,682	7/14	457,318	9/17	489,102
6/11	260,226	8/14	459,395	10/17	487,900
7/11	273,806	9/14	462,028	11/17	487,134
8/11	287,795	10/14	464,194	12/17	485,582
9/11	297,711	11/14	466,870	1/18	482,936
10/11	308,501	12/14	468,431	2/18	479,839
11/11	317,725	1/15	469,591	3/18	478,667
12/11	326,365	2/15	470,003	4/18	476,751
1/12	335,716	3/15	470,072	5/18	472,604
2/12	344,736	4/15	471,120	6/18	469,527
3/12	354,135	5/15	471,431	7/18	466,089
4/12	360,289	6/15	472,541	8/18	461,060
5/12	368,926	7/15	474,066	9/18	457,724
6/12	374,910	8/15	475,717	10/18	454,479
7/12	384,536	9/15	478,120	11/18	451,972
8/12	391,435	10/15	478,330	12/18	448,933
9/12	394,609	11/15	480,188	1/19	446,723
10/12	411,449	12/15	481,757	2/19	444,275
11/12	419,176	1/16	484,694	3/19	442,078
12/12	428,043	2/16	486,066	4/19	440,213
1/13	436,695	3/16	488,337	5/19	438,373
2/13	440,335	4/16	489,949	6/19	436,517
3/13	444,149	5/16	491,355	7/19	434,872
4/13	448,178	6/16	493,968	8/19	432,375
5/13	448,549	7/16	496,358	9/19	431,138
6/13	445,985	8/16	498,248	10/19	430,914
7/13	442,810	9/16	498,685	11/19	429,389
8/13	440,620	10/16	500,010	12/19	427,888
9/13	441,753	11/16	502,672	1/20	426,149
10/13	444,041	12/16	504,344	2/20	425,215
11/13	449,989	1/17	505,538		
12/13	459,581	2/17	505,808		
1/14	463,982	3/17	507,005		

* Includes customers being served by EGSs and those who will be switched to EGSs within 3 days.

Responsible Witness: Scott G. Fisher and John J. McCawley

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ESC-I-6

Reference Fisher Direct Testimony, p. 4. You testify that the "basic default service model used by PECO has supported the competitive retail electricity market."

A. As support for this assertion, you state that "102 alternative electric generation suppliers…currently serve PECO customers." Please indicate whether these 102 suppliers include brokers and aggregators.

B. Please indicate the number of total residential customers on PECO's distribution system and the number of residential customers who are purchasing electricity from EGSs.

C. For residential customers, please indicate the total load (mW) of electricity and the total amount of that load that is being served by EGSs.

RESPONSE:

A. This number only includes entities that are licensed by the Pennsylvania Public Utility Commission to provide electric service in Pennsylvania as a "Supplier" as listed at http://www.puc.state.pa.us/consumer_info/electricity/suppliers_list.aspx, have completed the PECO EDI certification process, and are serving PECO customers.

B. The most recent data available is for the month ending April 28, 2020. As of this time, there were 1,511,836 residential customers on PECO's distribution system. Of those customers, 423,314 were either actively being served by EGSs or were to be switched to Retail Electric Suppliers in the next 3 days.

C. The most recent data available is for the month ending April 28, 2020. As of this time, residential customers with kW loads totaling 3,719,159.07 kW were on PECO's distribution system. Residential customers with kW loads totaling 1,103,951.19 kW were either actively being served by EGSs or were to be switched to Retail Electric Suppliers in the next 3 days. In this context, kW loads refer to Peak Load Contribution (PLC).

Responsible Witness: Scott G. Fisher and John J. McCawley

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ESC Set IV
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ESC-IV-9

Reference PECO's Statement 2 at 3. You state that you are proposing a TOU rate to residential and small commercial procurement classes to comply with a legal obligation "to offer TOU and real-time rates to all default service customers with smart meters."

A. What percentage of each of the residential and small commercial classes, by customer count, now have smart meters?

B. Provide a copy of the PECO's "smart meter technology procurement and installation plan" and the Commission's order approving the plan as the term is meant in 66 Pa.C.S. § 2807(f)(1).

C. When did PECO begin installing smart meters for its residential and small commercial classes?

D. Provide the average annual balance of plant recorded in Account 370 (Meters) for PECO's electric distribution company for each of the years since Act 129 became law.

E. How many residential and small commercial customers, as a percentage of total customers in those classes, does PECO forecast will take TOU service?

RESPONSE:

A. Please refer to PECO's response to ES-I-45.

B. Please refer to PECO's Smart Meter Technology Procurement and Installation Plan filed at Docket No. M-2009-2123944 available at the following link: http://www.puc.pa.gov//pcdocs/1050890.pdf.

C. Once the Company's advanced meter infrastructure was in place and successfully operating, PECO began universal deployment of smart meters to customers in March of 2012. Please refer to PECO's Smart Meter Universal Deployment Plan filed at Docket No. M-2009-2123944 available at the following link: http://www.puc.pa.gov/pcdocs/1209364.pdf.

D. The requested balances are as follows:

	FERC Account 370 (Meters)		
Year	**Beginning Balance ($)** *PECO FERC Form 1*	**Ending Balance ($)** *PECO FERC Form 1*	**Average Balance** *Calculated*
2008	$177,392,657	$180,285,197	$178,838,297
2009	$180,285,197	$180,761,794	$180,523,496
2010	$180,761,794	$183,821,557	$182,291,676
2011	$183,821,557	$194,746,419	$189,283,998
2012	$194,746,419	$221,190,083	$209,468,251
2013	$221,190,083	$328,806,113	$274,998,098
2014	$328,806,113	$265,903,096	$297,354,605
2015	$265,903,096	$288,246,273	$277,074,685
2016	$288,246,273	$297,110,100	$292,678,187
2017	$297,110,100	$304,938,954	$302,024,527
2018	$304,938,954	$308,064,927	$306,501,941
2019	$308,064,927	$319,728,402	$313,896,665

E. As discussed in PECO's response to ES-I-17, PECO expects enrollment in its proposed TOU rates to be small relative to the overall default service customer base. PECO has not quantitatively forecasted the number of customers expected to select these rates.

Responsible Witness: Joseph A. Bisti

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Response of PECO Energy Company
To Interrogatories of the
Environmental Stakeholders
ES Set I
Response Date: 06/01/2020

ES-I-45

Refer to Bisti Testimony, page 15. Please provide data on how many default service customers in each class have smart meters installed, in numbers, by percentage, and by zip code.

RESPONSE:

The table below contains the number and percentage of default service customers in each procurement class with smart meters installed:

GSA 1 (Residential)	**GSA 2 (Small Commercial)**	**GSA 3/4 (Large C&I)**
1,106,532	96,277	1,203
99.5%	98.0%	98.9%

Please refer to Attachment ES-I-45(a) for this data by zip code.

Responsible Witness: Joseph A. Bisti

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ESC-I-3

Reference Paragraph 54 of the Petition. Please provide PECO's current SOP customer scripts.

RESPONSE:

Below are PECO's current SOP customer scripts.

Movers:
"Your new account number is [12345-67899]. In Pennsylvania, you can choose the supplier that provides your electricity without impacting the quality of service provided by PECO. PECO is sponsoring a program called the PECO Smart Energy Choice Program which may be able to offer you a potential savings opportunity by enrolling with an electric generation supplier. Would you like to hear more?"

Non-Movers:
"In Pennsylvania, you can choose the supplier that provides your electricity without impacting the quality of service provided by PECO. PECO is sponsoring a program called the PECO Smart Energy Choice Program which may be able to offer you a potential savings opportunity by enrolling with an electric generation supplier. Would you like to hear more?"

If customer answers yes:
"PECO is responsible for delivering your electricity. The actual generation of the electricity you receive can be provided by PECO or a participating supplier of your choice. The PECO Program offers a fixed price of [SOP rate] cents/kWh for one year provided by an Electric Generation Supplier. The fixed Program price provides a 7% discount off of today's Price to Compare which is [PTC Rate] cents/kWh. PECO's Price to Compare changes quarterly in March, June,

September and December. The PECO Smart Energy Choice Program price will not change during the 12 monthly bills, but the Price to Compare could be higher or lower than the PECO Program price during this period. Would you like to enroll in the PECO Smart Energy Choice Program?"

Responsible Witness: Carol Reilly

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ESC Set IV
Response Date: 06/15/2020

ESC-IV-14

For customers that enroll in a TOU offering, how does PECO intend to depict the time-of- use blocks and associated charges on the supply portion of a customer's bill? Provide a pictorial example if available.

RESPONSE:

PECO will develop the bill print design depicting the time-of-use blocks and associated charges based on the final TOU rate design approved by the Commission in the final Order entered in this proceeding. A pictorial example is not available.

Responsible Witness: Joseph A. Bisti

CARD PAYMENT Exhibit TK-10

reliant
an NRG company

P.O. Box 3765, Houston, TX 77253
Reliant Energy Retail Services, LLC (PUCT Certificate #10007)

Reliant Account: Referral ID:		
Billing Date: 04/16/2020	Date Due: **05/04/2020**	Amount Due: **$ 100.58**

DO NOT PAY - Your card will be charged on 05/04/2020

Account Information

Invoice Number:

Customer Name:
Service Address:

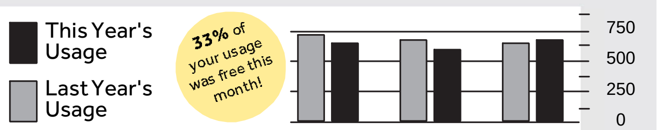
Questions or comments? We're available 24/7

toll-free 1.866.222.7100
TDD Device for Hearing Impaired: **1.888.467.3542**

Chat online at **reliant.com**

For outages or emergencies call Oncor Electric Delivery at 1-888-313-4747

Electricity Usage Summary



Billing Period	FEB	MAR	APR
Billing Days	30	31	30
Electricity Used (kWh)	674	622	704
Average High Temp	59°	67°	73°

***Temp Source:** National Weather Service **Region:** North Central Texas

Track your electricity usage and costs, review your history, see projected bill amounts and pay your bill online. Learn more at **reliant.com/myaccount.**

Your current contract will end in the coming months.

As a valued customer, you have the opportunity to sign up for a new term plan before your current one ends -- ensuring a seamless transition and peace of mind. See the last page of your bill for details.

Account Summary

Previous Amount Due		85.10
Payment 04/02/2020		-85.10
Balance Forward		**$0.00**
Reliant Free Weekends℠ 12 plan		
30 Day Billing Period From 03/16/2020 To 04/15/2020		
Weekday Energy Charge	475.37170 kWh @ $0.149175/kWh	70.91
Weekend Energy Charge	**228.62830 kWh @ $0.000000/kWh**	0.00
Oncor Electric Delivery Charges		28.60
Gross Receipts Tax Reimbursement		1.07
Current Charges		**$100.58**
AMOUNT DUE		**$100.58**

The average price you paid for electric service this month (per kWh) = $0.141

Your current plan is effective through your meter read on or after July 17, 2020.

Understanding your bill:
Go to **reliant.com/bill** for easy how-to information.

TX13

Thank you for being our customer.

20008/40015

For more information about residential electric service please visit www.powertochoose.com

reliant
an NRG company

P. O. Box 3765
Houston, TX 77253-3765

Reliant Account:

Date Due:	Amount Due:
05/04/2020	**$ 100.58**

*****DO NOT PAY - Your card will be charged on 05/04/2020*****

Account Information

Service Address

ESID	Customer Name	Service Address

Electric Usage Detail

Meter Number	Billing Days	Previous Meter Read	Current Meter Read	kWh Multiplier	kWh Usage	Electric Charges
	30	7,411 (03/16/2020)	8,115 (04/15/2020)	1	704	$70.91

ONCOR UPDATE - The last time Oncor changed its rates affecting the Delivery Charges line item on this account was 03/01/2020.

Notice to Customers -- The practice of adding charges for unrequested products or services is known as "cramming" and is prohibited by law. If you believe that any charge for a product or service appears on your bill has not been authorized by you, call Reliant at 1-866-222-7100 and request an investigation of this charge. If you are dissatisfied with our investigation, you may file a complaint with the Public Utility Commission of Texas (PUCT) at PO Box 13326, Austin, Texas, 78711-3326. PUCT phone number: Local (512) 936-7120, Toll-free in Texas (888) 782-8477. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136 or toll-free at 1-800-735-2988.

Miscellaneous Gross Receipts Tax Reimbursement: -- The Gross Receipts Tax (GRT) is a tax by the State of Texas on sellers of electricity. The GRT is imposed on sellers of electricity making sales to customers in incorporated cities or towns with a population greater than 1,000, and ranges from 0.581% to 1.997%. This tax reimbursement is applicable regardless of customer tax status.

*** C.A.R.E.** - Reliant is proud to offer the Community Assistance by Reliant (C.A.R.E.) Program that provides assistance to Reliant customers who are experiencing a hardship situation and need help paying their energy bills. This program is funded by customer contributions. Please write the amount of your donation in the space provided. This donation may be added to your total payment or a separate payment may be submitted.

reliant
an NRG company

Your plan expires soon—
Renew early for **greater peace of mind!**

Right now, you can extend the same great benefits on a new plan once your current plan ends. But you have to act fast.

Continue on a Reliant term plan and enjoy:

- A low energy charge (which is a component of your price)
- 24/7 customer service online or by phone
- Customized energy insights through weekly emails showing your home's detailed energy use

This offer ends May 11, 2020, so don't wait. Sign up on a new Reliant term plan today.

Two easy ways to sign up:

1. **Visit reliant.com/myrenewal** and enter promo code NEW
2. **Call 1.855.279.8089**

Don't wait—this is a limited-time offer.

Although there is no cancellation fee if you sign up for a Reliant plan before your current contract ends, choosing another retail electric provider before you receive your contract expiration notice could result in a cancellation fee. If you choose not to sign up on a new contract at this time, you'll receive your official contract expiration notice closer to the end of your current plan's term with the details of what will happen when it expires.

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Response of PECO Energy Company
To Interrogatories of the
Electric Supplier Coalition
ESC Set III
Response Date: 06/12/2020

ESC-III-1

Reference Bisti Direct Testimony, at p. 23. You indicate that PECO's communication plan regarding its TOU Rates will "include a one-time bill insert" to introduce the new TOU Rates and instruct customers on how to obtain more information.

A. If PECO received a request from an EGS to include information regarding the EGS's TOU Rates as part of a bill insert, would that request be honored? If not, why not?

B. Please provide bill inserts sent with monthly customer bills over the past 4 years, beginning June 1, 2016 through June 1, 2020.

RESPONSE:

A. PECO would not honor this request for the following reasons:

- **Lead time required may lead to outdated TOU content.** PECO rigorously schedules the development and production of its bill inserts for the entire calendar year no later than the last quarter of the prior year. Up to five inserts are sent with the bill each month in varying combinations, including gas/electric safety inserts, mandatory regulatory inserts, and others. The development and production schedule includes copy, draft, design, review, and printing for each of these. EGS TOU rate information that is not fixed for extended periods may therefore become outdated prior to reaching customers.

- **The costs of expanding insert capacity may outweigh its benefits.** The current weight limit for the bill (including inserts) is 2 ounces, and the equipment used by PECO's bill print vendor is programmed to stop inserting once that weight limit is reached. Consequently, some pre-planned inserts may not make it into the bill due to weight limits driven by postal costs. Assuming PECO's existing scheduled inserts continue as-is, expanding insert capacity to accommodate TOU content for all EGSs may require PECO to incur substantial costs associated with machinery purchases, upgrades, and maintenance deemed necessary by its bill print vendor.

- **EGSs serving customers may use available bill messaging space.** PECO provides the EGS up to four lines, each 80 characters in length, in the Message Center section of a utility-consolidated bill for messages directly related to the calculation or understanding of the EGS's portion of the bill. Please reference Page 92 of PECO's EGS Coordination Tariff at https://www.peco.com/SiteCollectionDocuments/CurrentEGSTariff.pdf. To the extent that the EGS's TOU rates are related to EGS billing of that customer, EGSs may use this space for related messages to their customers.

B. Bill inserts from March of 2019 through June of 2020 are currently available on PECO's website at https://www.peco.com/MyAccount/MyBillUsage/Pages/ViewBillInserts.aspx. Please refer to Attachments ESC-III-1(a)-(d) for the remaining bill inserts from June of 2016 through March of 2019.

Responsible Witness: Joseph A. Bisti

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ESC-I-2

Reference Paragraph 9 of the Petition. You state that PECO has an obligation under Act 129 "to offer TOU and real-time rates to all default service customers with smart meters." Please explain how PECO's proposal results in "real-time rates" being offered to all default service customers with smart meters. If it does not, please confirm that PECO has not offered a proposal that results in "real-time rates" being offered to all default service customers with smart meters. If this is not confirmed, please explain.

RESPONSE:

Act 129, 66 Pa.C.S. § 2806.1(m), defines "real-time price" as a rate that directly reflects the different cost of energy during each hour. PECO's DSP V proposal refers to such plans as "real-time rates." PECO's current hourly-priced default service rate offered to the Consolidated Large Commercial and Industrial ("C&I") Class conforms to this definition. PECO does not currently offer "real-time price plans" to default service customers with smart meters in the Residential or Small Commercial Classes and has not proposed to do so as part of DSP V.

Responsible Witness: Joseph A. Bisti

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ESC-IV-13

Please explain whether PECO in its DSP V is committing to "submit an annual report to the [TOU and real-time] price programs and the efficacy of the programs in affecting energy demand and consumption and the effect on wholesale market prices" (66 Pa.C.S. §2807(f)(5), and please provide any such report PECO submitted in the course of the current DSP in relation to its hourly priced default service.

RESPONSE:

PECO intends to submit an annual report as described above based on the final TOU rate design approved by the Commission in the final Order entered in this proceeding.

PECO has not submitted an annual report in the course of the DSP I, II, III, and IV as described above in relation to its hourly priced default service and does not plan to submit such a report in relation to its hourly priced default service for DSP V.

Responsible Witness: Joseph A. Bisti

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ESC-I-21

Reference McCawley Direct Testimony, p. 15 and the Commission's Secretarial Letter dated May 1, 2015 re: Informal Review of PJM Non-Market Based Charges as included with the April 21, 2017 CHARGE Call Recap, provide a copy of any written informal comments submitted by PECO to OCMO Staff as requested by the May 1, 2015 letter to include all information that may have been provided in 2015 or in July 2017 upon further request from OCMO Staff.

RESPONSE:

After a reasonable search of the Company's electronic records, PECO was unable to locate the written informal comments requested in this Interrogatory.

Responsible Witness: John J. McCawley

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ESC-IV-3

Reference PECO Statements No. 1-3. For each witness, please provide the following information:

A. The physical location at which he or she normally reports to work at PECO, notwithstanding the possibility that they may be partially or completely teleworking during the current pandemic, and the square footage of their office space.

B. The amount of time each will spend, on an annual basis, from June 1, 2021 through May 31, 2025, on default service issues, including but not limited to the proposed implementation of TOU rates, fixed-price ten-year agreements to purchase Solar Alternative Energy Credits, the recovery of network integration transmission costs, the Standard Offer Program, and a program to permit shopping by customer on customer assistance programs.

C. Whether each will utilize, from June 1, 2021 through May 31, 2025, PECO's information technology system, human resources, computer equipment, office furniture, and office supplies, in performing any functions related to default service. If each will not utilize these services, please explain.

RESPONSE:

A. Notwithstanding telework during the current pandemic, the three witnesses normally report to work at PECO's main office building at 2301 Market Street, Philadelphia, PA 19103. The square footage of their office space is as follows:

- John J. McCawley (PECO Statement 1) – 165 square feet
- Joseph A. Bisti (PECO Statement 2) – 170 square feet
- Carol Reilly (PECO Statement 3) – 165 square feet

B. PECO does not track the time spent by any of its employees, including the witnesses in this proceeding, on issues related to default service. PECO has not estimated the amount of time each identified employee will spend, on an annual basis, from June 1, 2021 through May 31, 2025, on issues related to default service, including but not limited to the proposed implementation of TOU rates, fixed-price ten-year agreements to purchase Solar Alternative Energy Credits, the recovery of network integration transmission costs, the Standard Offer Program, and a program to permit shopping by customer on customer assistance programs.

C. PECO confirms that each witness will utilize these services to perform their roles.

Responsible Witness: Joseph A. Bisti

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ESC-IV-12

Reference PECO Statement 2, Exh. JAB-6.

A. Is PECO proposing to recover the estimated $3.8 million associated with implementing TOU rates as those costs are actually incurred?

B. Please provide a budget associated with both the estimated expense and capital expenditures for the implementation of TOU.

C. Has PECO previously made capital expenditures in relation to its DSP? Please explain.

D. When PECO makes capital expenditures in relation to its DSP, does it collect those through the GSA as they are made or does it depreciate them? If the latter, please state what depreciation lifespan the capital expenditures forecast to be made in DSP V will have.

E. PECO states on Statement 2 at 22 that customers may enroll in TOU "through the Company's Care Center." What amount of time associated with personnel staffing that call center is PECO proposing to assign to the cost of administering the DSP, if any?

RESPONSE:

A. PECO is proposing to recover the TOU implementation costs over the DSP V period. This includes both O&M and capital expenditures, both of which PECO proposes to recover as operating expenses for ratemaking purposes consistent with the Commission's direction in PECO's DSP II proceeding. *See Petition of PECO Energy Co. for Approval of its Default Service Program II*, Docket No. P-2012-228364 (Opinion and Order entered Oct. 12, 2012), pp. 63-64.

B. See PECO's response to OSBA-I-3(a).

C. PECO made capital expenditures for information technology to support the implementation of its DSP I and DSP II plans.

D. PECO recovered these capital expenditures through the administrative cost component of the GSA for ratemaking purposes. PECO is proposing to do the same for capital expenditures associated with DSP V TOU implementation as described in PECO's response above to subpart (A).

E. PECO is not proposing to allocate any time associated with call center staffing to the cost of administering the DSP.

Responsible Witness: Joseph A. Bisti

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ESC-I-14

Reference Bisti Direct Testimony, p. 5. You indicate that PECO "allocates administrative costs to the procurement classes based on default service supply sales unless a direct assignment is required."

A. Please explain whether the administrative costs are indirect, direct or both.

B. Provide detail as to each administrative cost that is directly assigned to the procurement classes.

C. Provide detail as to each indirect administrative cost that is allocated to the procurement classes.

RESPONSE:

A. All of the administrative costs identified in PECO's response to ESC-I-1-C are direct costs.

B. Credits from AllConnect and Kandela, which are included in the subpart "i" administrative cost category in PECO's response to ESC-I-1-C, are directly assigned to the Residential and Small Commercial procurement classes.

C. None of the administrative costs identified in PECO's response to ESC-I-1-C are indirect costs.

Responsible Witness: Joseph A. Bisti

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ESC-I-1

Reference Paragraph 34 of Petition. You state that the "GSA also includes administrative cost and working capital factors." Please identify all administrative cost components that are included in the GSA.

A. Please specifically indicate whether the GSA includes the following administrative cost elements identified by the Commission's Policy Statement at 69 Pa. Code § 69.1808(a)(4): billing, collection, education, regulatory, litigation, tariff filings, information system and associated administrative and general expenses related to default service.

B. For any cost element identified in the Policy Statement that is not included in the GSA, please explain its omission.

C. Please provide a schedule similar to that produced in PECO's last base rate case at Docket No. R-2018-3000164 as Set III-1 (see attached), using PECO's current price to compare ("PTC"), which shows the amount of costs that would be recovered for each of the elements referenced in ESC-I-1-A.

RESPONSE:

A. The GSA associated with PECO's current PTC for the period of March 1, 2020 through May 31, 2020 includes administrative cost elements directly associated with its wholesale power supply contracts for default service. These include directly associated administrative and general costs, such as a default service independent evaluator to oversee the procurement process, as well as regulatory and litigation costs associated with PECO's default service plans and tariff filings. The GSA also includes a charge for working capital. Please refer to PECO's response to ESC-I-1-C below for more details.

B. The GSA associated with PECO's current PTC for the period of March 1, 2020 through May 31, 2020 does <u>not</u> include the following administrative cost elements:

a. <u>Billing and Collections</u>: All customers receiving default service are also PECO distribution customers and already receive a PECO bill. Uncollectible accounts expense for all electric service, including default service, is recovered in distribution base rates.

b. <u>Education:</u> The GSA may at times include education about retail market enhancements not paid for by EGSs. No such costs are included in the current GSA. In general, the GSA does not include costs associated with educating customers about the benefits of shopping for electricity, as PECO recovers these costs from all distribution customers.

c. <u>Information System ("IT"):</u> The GSA may at times include IT costs that relate specifically to the provision of default service. No such costs are included in the current GSA.

C. Administrative costs projected for current quarter (March 1, 2020 thru May 31, 2020), broken down by:

a. Billing: $0.
b. Collection: $0.
c. Education: $0.
d. Regulatory: $0.
e. Litigation: $46,492
f. Tariff Filings: $0.
g. Working Capital (See Note 1): $465,492
h. Information System: $0.
i. Administrative and General Expenses Related to Default Service (including costs for the independent evaluator and external consultant): $137,372

Note (1) Working capital is included the above response because the Commission includes it as an Administrative Cost in the Policy Statement at 52 Pa. Code § 69.1808(a)(4). As disclosed in PECO's Electric Service Tariff, the Generation Supply Adjustment (GSA) incorporates working capital as a stand-alone component and does not include working capital in the GSA's administrative cost factor.

Responsible Witness: Joseph A. Bisti

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ESC-II-8

Provide total number of customers that have been enrolled in the SOP to date. Also provide this information by month for each month that the program has been in place.

RESPONSE:

Refer to PECO Attachment ESC-II-8(a).

Responsible Witness: Carol Reilly

PECO Standard Offer Program Referrals													
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**July**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**	**Total SOP Referrals**
2013	N/A	N/A	N/A	N/A	N/A	N/A	N/A	NA	NA	2655	2039	1907	**6601**
2014	2052	1621	2284	2302	NA	NA	NA	8424	7290	6819	5229	6226	**42247**
2015	5248	4648	5305	5193	5809	7394	7861	8161	7106	6471	5366	5494	**74056**
2016	4753	5151	5334	5026	7639	8356	8112	8109	5367	4744	4219	3953	**70763**
2017	3904	3492	2694	1319	1577	1676	1743	1779	1296	1148	897	806	**22331**
2018	998	771	708	626	929	910	1014	940	848	856	748	740	**10088**
2019	775	768	809	780	832	769	874	717	553	773	557	543	**8750**
2020	694	560	621	628									**2503**
Total To-Date	**18424**	**17011**	**17755**	**15874**	**16786**	**19105**	**19604**	**28130**	**22460**	**23466**	**19055**	**19669**	**237339**

N/A = Not Applicable, SOP started August 2013

NA = Data Not Available

ESC Statement No. 1-S

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of PECO Energy Company for	:	
Approval of Its Default Service Program	:	
for the Period From June 1, 2021 Through	:	Docket No. P-2020-3019290
May 31, 2025	:	

SURREBUTTAL TESTIMONY OF

TRAVIS KAVULLA

ON BEHALF OF
THE ELECTRIC SUPPLIER COALITION

JULY 23, 2020

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I. INTRODUCTION

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

A. My name is Travis Kavulla and I am Vice President, Regulatory Affairs for NRG Energy, Inc. ("NRG"). My business address is 804 Carnegie Center, Princeton, NJ 08540.

Q. DID YOU PREVIOUSLY SUBMIT TESTIMONY IN THIS PROCEEDING?

A. Yes, I submitted Direct Testimony, ESC Statement No 1, on June 16, 2020.

Q. ON WHOSE BEHALF IS THIS SURREBUTTAL TESTIMONY OFFERED?

A. This Surrebuttal Testimony is offered on behalf of NRG, Direct Energy Services LLC, Interstate Gas Supply, Inc. d/b/a IGS Energy, Vistra Energy Corp., Shipley Choice LLC, ENGIE Resources LLC and WGL Energy Services, Inc. (collectively, the "Electric Supplier Coalition" or "Coalition" or "ESC"). The members of the Coalition either directly or through affiliates or subsidiaries hold licenses issued by the Pennsylvania Public Utility Commission ("PUC" or "Commission") as electric generation suppliers ("EGSs") to supply generation services to retail consumers in the service territory of PECO Energy Company ("PECO").

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my Surrebuttal Testimony is to respond to various portions of the Rebuttal Testimony submitted on July 9, 2020 by PECO, the Office of Consumer Advocate ("OCA"), the Office of Small Business Advocate ("OSBA"), the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-"PA") and the Tenant Union Representative Network and Action Alliance of Senior Citizens of Greater Philadelphia ("TURN *et al.*") relating to the Petition of PECO Energy Company for Approval of its Default Service Program from June 1, 2021 through March 31, 2025 ("PECO DSP V Petition"). The witnesses submitting Rebuttal Testimony to which I am responding include: John J. McCawley (PECO St. No. 1-R); Joseph A. Bisti, (PECO St. No. 2-R); Carol Reilly (PECO St. No. 3-R); Scott G. Fisher (PECO St. No. 4-R); Steven L. Estomin (OCA St. No. 1R); Barbara R. Alexander (OCA St. No. 2R); Brian Kalcic (OSBA St. No. 1-R); Harry Geller (CAUSE-PA St. 1-R); and Philip A. Bertocci (TURN St. No. 1-R).

Q. HAVE YOU CHANGED YOUR RECOMMENDATIONS BASED ON THEIR REBUTTAL TESTIMONY?

A. Generally, I have not changed my recommendations. However, I do note throughout this Surrebuttal Testimony when I agree with another witness' view or when the Coalition is willing to accept a modification or different result based on a suggestion made by another witness. To the extent that I am silent about a witness' Rebuttal Testimony, that should not be viewed as agreement.

II. <u>GENERAL OBSERVATIONS ABOUT COMPETITIVE RETAIL MARKET TODAY</u>

Q. WHAT GENERAL OBSERVATIONS DID YOU MAKE IN YOUR DIRECT TESTIMONY ABOUT THE COMPETITIVE RETAIL MARKET TODAY?

A. In referring to PECO's data, I observed that less than one-third of the residential customers are shopping – a dynamic that has not changed in the past several years. I observed that without structural changes to improve the market, it is not realistic to expect that competitive retail offerings will flourish, drive significant generation investment, or result in innovative product offerings. (ESC St. No. 1 at 6).

Q. DID YOU OFFER YOUR THOUGHTS ON THE REASONS FOR THE STAGNANT MARKET?

A. Yes. Relying on the Wind Solar Alliance Report released earlier this year,[1] I pointed to the presence of a domineering default service provider ("DSP") and a persistently unlevel playing field between the DSP and EGSs. Indeed, the very presence of a DSP that is also the local transmission-and-distribution monopoly—a provider-of-first resort arrangement that has come to be accepted as inevitable, even though it was not inevitable in the design the authors of Pennsylvania's competition statute conceived[2]—biases customers toward the entity that physically meters them and bills them. Therefore, I identified several improvements should be made. (ESC St. No. 1 at 8-9).

Q. WHAT SPECIFIC IMPROVEMENTS HAVE YOU IDENTIFIED?

A. I proposed a number of specific improvements including: (i) taking steps to transition PECO out of the default service role; (ii) adopting PECO's proposed time of use rate in tandem with implementing the ability of suppliers to issue consolidated bills to customers and requiring PECO to make several modifications to this product; (iii) rejecting PECO's proposal to solicit new ten-year contracts for solar alternative energy credits; (iv) rejecting PECO's proposal for the recovery of network integration transmission service costs; (v) making changes to PECO's proposed rate design for default service so that it contains all of the cost components incurred to provide default service; (vi) rather than simply continuing the existing Standard Offer Program ("SOP"), seizing an opportunity to implement improvements that might encourage greater participation by suppliers and

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1 Rob Gramlich & Frank Lacey, "Who's the Buyer: Retail Electric Market Structure Reforms in Support of Resource Adequacy and Clean Energy Deployment," *Grid Strategies* (prepared for Wind Solar Alliance) (March 2020). ("Wind Solar Alliance Report"). https://windsolaralliance.org/wp-content/uploads/2020/03/WSA-Retail-Structure-Contracting-FINAL.pdf (accessed June 8, 2020).

2 66 Pa.C.S. § 2807(e).

consumers; and (vii) avoiding structuring PECO's proposed plan for shopping by low-income customers in a way that is unduly restrictive and contains elements that would create new challenges for suppliers in their interactions with consumers. (ESC St. No. 1 at 9-10).

Q. DID OTHER WITNESSES, IN THEIR REBUTTAL TESTIMONY, COMMENT ON YOUR OBSERVATIONS ABOUT THE MARKET?

A. Yes. Mr. Geller's Rebuttal Testimony comments on these observations. According to Mr. Geller, the slow-down in residential shopping rates "is the result of excessive pricing in the competitive market, leading consumers to make an *affirmative choice* to return to or remain on default service." (CAUSE-PA St. 1-R at 4). He refers to amounts that consumers have paid on average above the price to compare over the last five years. He also estimates that in March and April of this year, residential shopping customers were charged $22,108,500 more than they would have been charged for default service. (CAUSE-PA St. 1-R at 4; CAUSE-PA Exhibit 1). Mr. Fisher also refers to instances in which competitive retail suppliers have been charging more than default service rates and cites Mr. Geller's statistics. (PECO St. 4-R at 36-37).

Q. HOW DO YOU RESPOND?

A. First, computations of the amount that consumers in the competitive market may be paying over the PTC fail to take into consideration a variety of value-added offerings that EGSs in the market provide to consumers, such as reward points, longer-term certainty (than quarterly) of prices and renewable energy products. Second, it is not surprising that the PTC for default service may be lower than prices offered in the retail competitive market, given PECO's failure to include any overhead costs in its PTC. Such omission naturally drives the PTC down to unrealistic levels, which is why the Coalition is seeking to rectify this problem in this proceeding.

Q. WHAT DOES MR. GELLER SAY ABOUT PRICE?

A. He testifies that the "primary purpose of establishing a competitive electric shopping market for residential customers is price." (CAUSE-PA St. 1-R at 4).

Q. DO YOU AGREE?

A. I certainly agree that price is an important purpose of having a competitive retail market. However, I also note a significant role of the competitive retail market is to provide consumers with access to a broad array of innovative products and services from a variety of different suppliers. Indeed, a well-functioning market entails suppliers competing with one another – not the default service provider – to bring the benefits of competition to consumers.

III. <u>TRANSITION PECO OUT OF DEFAULT SERVICE</u>

Q. WHAT DID YOU SUGGEST NEEDS TO OCCUR IN ORDER FOR PENNSYLVANIA TO REALIZE THE INTENDED BENEFITS OF THE COMPETITION ACT?

A. I testified that it is critical that the Commission resume its discussions from 2012 and lay the groundwork to transition Pennsylvania's retail electricity market so that all customers are shopping for electricity and "default service" becomes a true backstop service provided by EGSs. In order to move in that direction, I suggested that the Commission direct a process at the end of this proceeding to examine alternative default service models. (ESC Statement No. 1 at 14).

Q. HAVE ANY WITNESSES IN THEIR REBUTTAL TESTIMONY DISAGREED WITH THIS RECOMMENDATION?

A. Yes. Mr. Geller has testified that removal of PECO from the DSP role would "disrupt the critical safety net that default service was intended to provide – allowing all those who choose not to shop in the competitive market to continue to obtain stable, regulated electric service at the least cost over time." (CAUSE-PA St. 1-R at 5). In addition, Mr. Fisher described the Coalition's proposal would "abandon the underlying prudent mix of default service supply products that has been established and tested over multiple default service plans to provide price stability and other benefits for mass market customers." (PECO St. No. 4-R at 42). Mr. Estomin and Mr. Bertocci offered similar testimony opposing the Coalition's proposal. (OCA St No. 1R at 2-3; TURN St. No. 1-R at 1-3).

Q. HOW DO YOU RESPOND?

A. What the other parties are overlooking is that the Coalition is not proposing that default service be provided without any parameters or protocols. The Coalition submits that competition among suppliers to provide default service to non-shopping customers is the most effective way to ensure that the price most accurately reflects the market and the best price that is available. In my Direct Testimony, I proposed that the Commission establish a process so that it can indeed develop the rules that would be applicable to alternative default service models and providers. I note that a lengthy timeframe should not be needed now when the Commission has already devoted substantial resources to examining these issues and can readily pick up where it left off at that time.

IV. TIME-OF-USE (“TOU”) RATES

Q. WHAT WAS YOUR TESTIMONY CONCERNING PECO’S PROPOSED TIME-OF-USE (“TOU”) RATES?

I observed that PECO’s smart-meter roll-out was an important and overdue development and noted that one of the often-promised benefits of smart meters is their ability to create an enhanced retail experience, including time-varying rates that better reflect the cost of energy at wholesale and the opportunity for demand to participate in response to a more dynamic price signal. (ESC St. No. 1 at 15-16). For that reason, I opined that as the Commission considers an innovative product like TOU, it must think in tandem about the competitive structure of the market that should serve a marketplace whose customers want and need differentiated products. My specific suggestion was that as the Commission allows PECO as a DSP to offer any TOU product, it must remove the barriers that prevent EGSs from issuing supplier-consolidated bills to customers. (ESC St. No. 1 at 17-20). I also recommended that PECO should offer the TOU rate as the default rate and allow customers to opt-out to real-time pricing or to an EGS product. ESC St. No. 1 at 21). Further, regardless of whether the DSP’s TOU rate is opt-in or opt-out, I stressed that the Commission should first ensure a level playing field for time-varying rate products offered by the DSP and EGSs in order to ensure that harms I have identified above are minimized. (ESC St. No. 1 at 21).

Q. DID YOU ALSO EXPRESS CONCERNS ABOUT PECO’S PROPOSAL?

A. Yes. I expressed concerns about PECO’s proposed timeline, as being too short, and budget, as being too small, and about the relatively few details that PECO provided about the program. I also suggested that to the extent capital investments are proposed for the DSP program, they should be funded throughout the life of the DSP period. In addition, I noted that real-time price service should also be made available to residential and small commercial customers. Finally, I stated that PECO should make a filing with the Commission on its TOU plan annually. (ESC St. No. 1 at 21-24).

Q. WHAT SPECIFIC MODIFICATIONS DID YOU RECOMMEND?

A. Specific modifications I recommended included: : 1) adoption of supplier consolidated billing in conjunction with TOU implementation and approval of the TOU as the standard default rate; 2) requiring a more robust customer education campaign on a realistic timeframe; 3) requiring PECO to offer a real-time price plan to residential and small commercial customers; 4) requiring the appropriate allocation of TOU-related costs to DSP customers; and 5) requiring PECO to include in its tariff the annual reports contemplated by law. (ESC St. No. 1 at 25-26).

Q. YOU OBSERVED IN DIRECT TESTIMONY THAT THE CURRENT SPACE ON A PECO BILL THAT AN EGS MAY USE IS NOT SUFFICIENT TO REPRESENT MORE COMPLEX PRODUCTS, LIKE TOU RATE OFFERINGS. DOES PECO OR ANY INTERVENOR CHALLENGE THAT ASSERTION?

A. They do not. They oppose the implementation of supplier consolidated billing, while at the same time appearing to concede that EGSs would not have an equal opportunity to market these products to customers.

Q. WHAT DO INTERVENORS SUGGEST AN EGS MAY DO, IN LIEU OF BEING ABLE TO SEND A BILL TO CUSTOMERS?

A. The consumer advocates and PECO in this proceeding suggest that my arguments for a level playing field are misplaced, because EGSs may already use dual billing to bill consumers separately for generation charges—leaving a customer to pay both that bill, and also the bill that PECO would send her for distribution charges. (PECO St. 1-R at 16; OCA St. 1-R at 6; CAUSE-PA St. 1-R at 8). To say the least, this is a puzzling position for a consumer advocate to take. In my experience as a consumer, I seek to reduce the number of separate monthly bills I am obligated to pay. I doubt many consumers would be eager to pay two bills, rather than one, for the electricity service they receive. Regardless, these suggestions do not solve for the policy harm that I identified in my direct testimony—an uneven playing field in the absence of supplier-consolidated billing whose unevenness widens further when products like TOU are introduced.

Q. DO OTHER PARTIES HAVE OTHER ADVICE FOR HOW AN EGS MIGHT OFFER TOU SERVICE ON AN EVEN PLAYING FIELD WITHOUT THE OPPORTUNITY TO SEND A SINGLE, CONSOLIDATED BILL TO CONSUMERS TO GRAPHICALLY REPRESENT THAT SERVICE?

A. Mr. Estomin suggests that "EGSs also have available direct mail, email, telephone messaging, and text messaging options." (OCA St. No. 1 at 6.) Mr. Estomin suggests also that an EGS might develop an app for this purpose. *Id.* I welcome his suggestions, but make two observations. First, these suggestions still fall short of the ability to send the official and authoritative communication to one's customer that is the monthly bill for service, whether in paper or digital form. Second, to the degree Mr. Estomin suggests a range of other possibilities for EGSs to interact directly with their generation customers, it would seem to set up a market that will only cause an even greater variety of "customer confusion" that other consumer advocates, such as Mr. Bertocci, say that supplier-consolidated billing would risk. (TURN St. No. 1 at 8.) That is because customers would continue receiving an official communication about their EGS TOU charges from PECO—in what little space that the message would be scaled to—while receiving a different message in both style and substance from the EGS using one or more other mediums.

Q. MR. KALCIC, TESTIFYING FOR THE OFFICE OF SMALL BUSINESS ADVOCATE, SUGGESTS THAT EGSS HAVE HAD AN EIGHT-YEAR LEAD

TIME TO IMPLEMENT TOU AND STILL HAVE NOT, MAKING YOUR SCB ARGUMENT OPPORTUNISTIC. (OSBA ST. NO. 1-R AT 4). HOW DO YOU RESPOND?

This is a chicken-and-egg problem. The lack of SCB makes offering TOU in an effective manner difficult. This stands in contrast to the Texas competitive retail market, where as I earlier testified price-varying retail products are numerous and growing in scale. (ESC St. No. 1 at 17). The lack of EGS offerings like this in Pennsylvania is not for lack of interest in TOU. Indeed, NRG was the company that ran the TOU pricing pilot on behalf of PECO. In the future, I believe that TOU opportunities will be more significant, especially as a greater level of digitization permeates the devices interconnected on the customer side of the grid and supply shows a greater level of variability as renewables are added. On this point, I agree with the general trends that Karl R. Rabago has identified (Environmental Stakeholders St. No. 1 at 11-12). But the ability of EGSs to successfully offer a diverse array of products that are admittedly more complex—but also more valuable—depends on their ability to communicate those products' design and billing in a transparent and direct way with customers. That is why SCB is so important.

Q. DO PARTIES RAISE SUBSTANTIAL ARGUMENTS AGAINST THE ADOPTION OF SUPPLIER-CONSOLIDATED BILLING?

They do. PECO disagrees with the Coalition's proposal to implement SCB in conjunction with TOU rates, referring to recent Commission proceedings, in which the Commission has so far declined to move forward with implementation, citing concerns about legality, consumer protections and sufficient EGS interest. (PECO St. No. 2-R at 15). OCA highlighted consumer protection issues and likewise referred to recent Commission proceedings. (OCA St. No. 1R at 6-7). Similarly, the Rebuttal Testimony of CAUSE-PA and TURN raised many of the same issues as PECO and OCA, with both parties attaching their Comments and Reply Comments to the Rebuttal Testimony. (CAUSE-PA St. 1-R at 8-9; TURN St. 1-R at 8). OSBA also suggests that because SCB is currently under investigation by the Commission, it is outside the scope of PECO's proposed default service plan. (OSBA St. 1-R at 5).

Q. HOW DO YOU RESPOND?

A. NRG joined with four other EGSs to form a coalition to present supplier perspectives in the SCB proceeding. That coalition comprehensively addressed every point that the utilities and consumer advocates raised, by (i) fully explaining the Commission's legal authority to implement SCB; (ii) urging the Commission to implement SCB in a manner that ensures the continuation of all consumer protections; and (iii) firmly expressing, not only their commitment to use SCB when it is implemented, but conveying to the Commission the importance of this tool to the continued growth of Pennsylvania's competitive retail market. The comments and reply comments of the coalition advocating for the implementation of SCB are likewise incorporated herein and may be accessed on the Commission's website.[3]

Q. HOW DO YOU RESPOND TO THE CLAIMS THAT THE SCB DOCKET, AND NOT THIS ONE, IS AN APPROPRIATE PLACE TO RESOLVE ANY CONCERN?

A. The SCB proceeding at which these comments and reply comments were filed was launched over two years ago. Parties are not required to forego raising issues that are pending in a generic proceeding at the Commission, particularly when a utility-specific proposal is under review that necessitates a consideration of such issues. Since PECO has taken this opportunity to propose a TOU rate—one that EGSs could not implement

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[3] EGS SCB Coalition Comments: http://www.puc.state.pa.us/pcdocs/1565417.pdf; EGS SCB Coalition Reply Comments: http://www.puc.state.pa.us/pcdocs/1583056.pdf.

on an equivalent basis—it is important that SCB be addressed in tandem to remedy that inequity. It matters less where procedurally the particulars of policy choices within SCB are housed, than it does that the Commission here announce that before more complex TOU rates are offered by PECO that those EGSs who do business within the PECO service territory will have an equivalent opportunity to offer those more complex rates with SCB.

PECO already has stated that the TOU rate will be available in approximately a year following Commission approval. I believe it could take longer, either by necessity or, per my recommendation, by suspending TOU implementation until SCB is ready to go-live. As was made clear during the SCB proceeding, its successful implementation will entail a resolution of certain issues, such as the development of protocols for ensuring the continuation of existing consumer protections by clearly defining the rights and obligations of electric distribution companies and EGSs, the establishment of the necessary electronic data interchange transactions and the creation of a process that requires EGSs to show that they are technically and financially able to perform SCB.

Q. WHY IS MAKING TOU RATES 'OPT-OUT' AS OPPOSED TO 'OPT-IN' IMPORTANT?

A. It seems to me that most parties are simply going through the motions on the TOU issue in this proceeding, knowing that PECO is under a legal obligation to offer it—but not taking seriously TOU's prospects or even actively seeking to minimize them. PECO has suggested that there will be very little uptake of the service. (ESC St. No. 1 at 16; Exhibit TK-6 (Response to ESC-IV-9). Yet, the Pennsylvania legislature clearly had in mind customer-facing rate designs that took advantage of smart meters when it authorized significant amounts of spending on them. If one accepts that there is some level of inertia associated with the way things always have been, the right approach to fulfilling the Pennsylvania legislature's policy ambitions on smart meters is to apply the age-old advice of "try it, you might like it" to TOU. In addition, no party in this proceeding has seriously disputed that the TOU rates better reflect the economics of power supply than a single, undifferentiated, round-the-clock price; shouldn't the more market-reflective rate be the default?

Q. WHY DO PARTIES OBJECT TO AN 'OPT-OUT' TOU RATE AS THE DEFAULT RATE?

A. PECO, OCA, and OSBA all refer to the statute that suggests customers "may elect" TOU, which they argue impliedly means it cannot be an opt-out construct, but one that customers must opt into. (PECO St. No. 2-R at 14; OCA St. No. 2R at 4; OSBA St. No. 1-R at 3).

Q. DO YOU DISAGREE?

A. I do. Counsel will address the legal argument in briefs that the parties are raising. In summary, however, this statute does not pose a bar to my policy recommendation, and the parties' witnesses are relying on a misinterpretation of it. Moreover, if the statute were interpreted as PECO, OCA and OSBA advocate, it would pose a substantial barrier to reform of rate design for default service in the future. I doubt this can be what the legislature intended.

Q. WHAT KIND OF BARRIERS WOULD THE PECO/OCA/OSBA INTERPRETATION POSE?

A. A TOU rate is defined by law as any that "reflects the costs of serving customers during different time periods, including off-peak and on-peak periods."[4] That definition

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[4] 66 Pa. C.S. § 2806.1(m).

encompasses a wide universe of possible rate designs—ranging from “critical peak pricing” rates that incentivize lower usage during the highest-demand hours of the year to electric-vehicle charging rates that discount nighttime charging. The parties are essentially arguing that the legislature, without even directly referring to default service rate design, created a requirement that default rates for residential and commercial customers can only be fixed-rate, round-the-clock prices. This strikes me as a very indirect route to have codified that intention, were it the legislature’s intent to do so.

Q. ARE THERE OTHER IMPLICATIONS OF THE STATUTORY PROVISION TO WHICH PECO/OCA/OSBA CITE?

A. Yes. As I observe in my direct testimony, PECO is obligated to offer a real-time price plan so that certain customers may “elect” it. It has not done so here.

Q. DOES PECO RESPOND TO YOUR CONTENTION?

A. Yes. Mr. Bisti argues, “With the combination of PECO’s proposed TOU Rates and the hourly-priced default service rate for the Consolidated Large Commercial and Industrial Class, a TOU or real-time pricing program will be available to all of the Company’s default service customers with smart meters.” PECO St. No. 2-R at 14. Mr. Bisti is apparently suggesting that because C&I customers have real-time pricing plans and, assuming PECO’s proposal for TOU for residential and small commercial customers is approved in this proceeding, that all customers will have one or the other option—in compliance with his view of the law.

Q. WHAT IS WRONG WITH MR. BISTI’S CONTENTION?

A. 66 Pa. C.S. § 2807(f)(5) states, “*Residential or commercial customers* may elect to participate in time-of-use rates *or* real-time pricing.” (emphasis added). Those customers may not elect time-or-use rate or real-time pricing if one of those two things is not available to them. Consequently, it does not seem relevant if *some* customers have access to real-time pricing if the classes identified in the statute do not.

Q. ARE THERE IMPLICATIONS OF THIS STATUTORY PROVISION AS IT RELATES TO THE AVAILABILITY OF TOU RATES TO CAP CUSTOMERS?

A. Yes. As I explain in my direct testimony, the law itself defines the customers to whom these services must be offered—specifically, customers with smart meter technology. It does not provide for additional limitations, and by specifying the customers that are eligible, it forecloses the Commission's opportunity to put TOU (or for that matter real-time pricing) off-limits to certain customers on the basis of administrative decision making. I am somewhat sympathetic to those that argue that the CAP program is in some respects incompatible with the TOU rate design PECO has proposed, although in general I think certain parties are being too paternalistic about the ability and willingness of low-income consumers to save money through TOU. Regardless, the statute answers this question for me, for PECO, for other parties, and for the Commission.

Q. WHAT MIGHT THE COMMISSION DO TO AMELIORATE CONCERNS ON THIS POINT?

A. The Commission can approve with modifications the PECO proposal, so long as that decision otherwise coheres to the law. In my view, the Commission should require a longer lead time and a greater budget for customer education to ensure the harms that some advocates identify do not occur. The additional time could accommodate the implementation of SCB on a parallel track, the required implementation of a real-time pricing option, and could be used to ease concerns that parties have expressed about TOU—without falling back to the easy but wrong remedy of simply foreclosing a TOU program to an ever larger number of customers.

Q. FINALLY, YOU PROPOSE IN YOUR DIRECT TESTIMONY THAT TOU IMPLEMENTATION COSTS SHOULD BE SPREAD OVER THE DURATION OF THE DSP, AND THAT LONG-LIVED INVESTMENTS SHOULD PROPERLY BE CAPITALIZED. WHAT IS MR. BISTI'S RESPONSE?

A. He suggests that PECO will "recover TOU-related implementation costs," including capital expenditures, as an operating expense. (PECO St. No. 2-R at 22.) Meanwhile, he agrees with me that the recovery should be "over the DSP V term." *Id*. That is a satisfactory outcome.

V. TEN-YEAR CONTRACTS FOR SOLAR ALTERNATIVE ENERGY CREDITS

Q. WHAT DID YOU SAY ABOUT PECO'S PROPOSAL TO COMPLY WITH PENNSYLVANIA'S ALTERNATIVE ENERGY PORTFOLIO STANDARDS ("AEPS") ACT?

A. Through my Direct Testimony, the Coalition opposed PECO's proposal to enter into 10-year contracts. The presence of these long-term contracts will impede the ability of the Commission to remove PECO as the default service provider and approve an alternative default service provider—a barrier that would be present for 10 years. Moreover, the use of long-term contracts by PECO places PECO's captive ratepayers at risk because they will be required to pay for the costs of contracts that may end up being uneconomic over their life. Finally, when default service providers are permitted to use the threatened lack of solar development as a reason for them to enter the market with a supply agreement to "correct" it, the willingness and ability of EGSs to undertake these projects (relying on private investment) is hampered. (ESC St. No. 1 at 26-31).

Q. WHAT WAS YOUR RECOMMENDATION?

A. PECO should require wholesale default service suppliers to deliver the full amount of PECO's AEPS requirements and not pursue the proposed 10-year SAEC contract.

Alternatively, the 10-year SAEC proposal should be reduced to match the DSP four-year plan period. (ESC St. No. 1 at 27).

Q. SPECIFICALLY, WHAT DO YOU PROPOSE?

A. The simplest approach to this issue is to require the DSP's wholesalers incorporate their estimated cost of AEC/SAEC procurement into the bids they make as part of their tranched offers. This is what happens already with the vast majority of AEC procurements, and PECO gives no particular reason why, in effect, a portion of a subset of its AEC requirement—25% of its SAEC procurement requirement—should be procured in this way, unlike the manner in which it procures essentially everything else. This more standard approach would have the salutary effect of retaining a level playing field. (ESC St. No. 1 at 29-30).

Q. WHAT PARTIES OPPOSED YOUR SOLAR RECOMMENDATIONS AND WHY?

A. PECO opposed my recommendation on the basis that the amount of solar AECs PECO is seeking to procure is small, and that there no real impact to EGS investment of PECO's proposal. (PECO St. No. 1-R at 14-15). OCA also opposed my recommendation, claiming as well that PECO's proposal has no impact on EGS investment, that any existing contract could be transferred to a new Default Service Program and that the long-term solar AEC contracts operate as a hedge against large price increases and not necessarily a means to secure the lowest possible price at any time. (OCA St. No. 1R at 9-11).

Q. PLEASE EXPLAIN YOUR VIEW OF HOW PECO'S LONG-TERM CONTRACTING WITH SOLAR AFFECTS EGS WILLINGNESS TO DO THE SAME.

A. PECO has an ability through the law to obtain a full and current recovery of whatever it spends. EGSs do not. Consequently, it does not matter to PECO whether or not there is a particular customer (or a diminishing or growing set of customers) for the contracts for SAECs (or any other product) that the DSP enters into. There will always be a backstop due to the law's guarantee of rate recovery. EGSs do not have that ability. Instead, when they sign a contract for (or build themselves) a solar project or other agreement for a power supply resource, they expose their shareholders to significant risk that their bet will be wrong—unless they can cover that supply position with an offsetting position to resell those SAECs (or other product) to a customer. In the Pennsylvania retail market, there are large customers, like the City of Philadelphia, that have proven willing to enter into longer-term deals.

That market is not present for residential and small-commercial customers. Mass-market customers do not sign long-term contracts even in the highly competitive Texas retail environment, where products tend to be limited to 36 months at most.[5] To be sure, the Texas equivalent of EGS are indeed making longer-termed investments than that in the Texas market. Those, however, are predicated on the view that the other EGSs face the same exposure to risk of entering (or not entering) into such supply deals as the contracting EGS. In other words, there is no default retailer that automatically recovers the costs of improvident investments from a set of customers regardless of what happens.

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[5] Based on a search of the www.powertochoose.org website on July 19, 2020.

This level playing field results in an EGS willingness to enter into deals because a level playing field for longer-term investment in generation exists.

In short, OCA and PECO express a view that suggests that whatever PECO may do to invest in renewables will not have an impact on EGSs' ability to invest in renewables. (OCA St. No. 1R at 11; PECO St. No. 1-R at 15). That simply is not the case in a market where long-term retail contracts are not present—which in Pennsylvania's residential and small-commercial mass market they are not, including for the additional reason not present in Texas that retailers would not be able to pass through any price excursions for certain costs, such as transmission, to customers through such a contract.[6] The reality is that a dominant firm's investment in the market will naturally crowd out other participants. When this is paired with the special ability that dominant firm enjoys to get cost recovery regardless of the economic outcome of its bets, that ultimately can have a significant impact of a competitive marketplace to work. This is the message of the Wind Solar Alliance report I relied upon in my direct testimony; its message is a prescient one, and I hope the Commission will heed it.

Q. DO YOU HAVE OTHER RESPONSES TO PECO AND OCA'S CRITICISMS OF YOUR POSITION?

A. Yes. I do not agree with OCA that a long-term contract could simply be transferred or assigned to an alternative default service provider if PECO ceases to function in that role after DSP V. Rather, I would expect that parties would argue the existence of the contract as a reason not to transfer the default service role. In addition, saddling a new

[6] *Guidelines for Use of Fixed Price Labels for Products With a Pass-Through Clause*, Docket No. M-2013-2362961 (Order entered November 14, 2013) ("Fixed Means Fixed Order").

default service provider with the contract may impact the default service product the alternate default service provider could bring to the market.

Meanwhile, PECO's witness Mr. McCawley suggests that I have misunderstood the meaning of one of the Commission's jurisprudence associated with a prudent mix of short- and long-term resources by distinguishing AECs from commodities like energy. (PECO St. No. 1-R at 14, fn 14.) Mr. McCawley does not address the heart of my criticism, where I note that nothing in the Commission's regulations entails a supply mix for SAECs that includes long-term procurements, which makes this conversation different from a discussion of energy. (ESC St. No. 1 at 28, fn 72.) Indeed, there are valid policy reasons why it should not, as I describe above: While the marketplace for energy is relatively well established, the market for SAECs and other renewables remains in a fledgling state in Pennsylvania and if EGSs come to believe they will be crowded out by a DSP that has guaranteed cost recovery, they will be reluctant to invest risk capital.[7]

Finally, Mr. McCawley has suggested I incorrectly testified that the price offered by PECO to sellers of SAECs in a second-round procurement would be based on the average cost of solar in Pennsylvania, instead of the average of the winning bids of the first round. I believe I did, in fact, understand what PECO is proposing, and my criticism of it from my direct testimony still holds, unrebutted: "Indeed, in the SOTP proposal PECO makes, it suggests it bid the average successful offer price from the RFP phase of the procurement to those who have SAECs available to sell it. In other words, it is content to get the average of better prices—and not the best price. This is not consistent

[7] Here I note that Mr. McCawley, while proposing a relatively small procurement for PECO, is defending his position against environmental intervenors through Mr. Rabago who are arguing for an outcome that would swallow large parts of what could be a competitive market.

with how a normal, properly incentivized buyer would conduct solar procurements, in my view." ESC St. No. 1 at 29.

VI. RECOVERY OF NETWORK INTEGRATION TRANSMISSION COSTS

Q. WHAT RECOMMENDATION DID YOU OFFER REGARDING NETWORK INTEGRATION TRANSMISSION SERVICES ("NITS") CHARGES?

A. I recommended that the Commission direct PECO to include the recovery of NITS via its currently existing Non-Bypassable Transmission ("NBT") rather than continuing the status quo whereby PECO recovers the costs of NITS for default service customers only. (ESC St. No. 1 at 33).

Q. WHAT PARTIES OPPOSE YOUR RECOMMENDATION?

A. My recommendation is opposed by PECO (PECO St. No. 1-R at 26-19), PAIEUG (PAIEUG St. No. 1) and Calpine (Calpine St. No. 1).

A. Response to PECO

Q. AS A THRESHOLD MATTER, DOES PECO AGREE THERE IS AN ISSUE WITH ITS CURRENT COST RECOVERY MECHANISM FOR NITS?

A. No. Before addressing the merits of my proposal, Mr. McCawley first attempts to cite to prior Commission orders and the Commission Staff's stalled Informal Investigation as support for the status quo. (PECO St. No. 1-R at 16-17, and 19).

Q. DO YOU AGREE THAT EITHER OF THESE ARE A REASON TO NOT PURSUE THIS ISSUE HERE?

A. No. As I stated in my Direct Testimony, I was advised by counsel about the Commission's prior rejection of similar proposals but explained why circumstances have changed since then to merit a reevaluation of this issue. (ESC St. No. 1 35). Regarding the Informal Investigation, Mr. McCawley seems to be taking the view that the Informal Investigation is the better place to address this issue. (PECO St. No. 1-R at 19). While the Coalition would welcome a serious statewide review of this issue, as explained in my Direct Testimony, the Commission's Informal Investigation of this issue (which began in 2015) does not appear to be a current, on-going effort focused on reaching a timely resolution. (ESC St. No. 1 at 32-33). Moreover, the fact that PECO was unable to produce any of the information provided to the Commission Staff as part of that Informal Investigation tends to support the view that relying on the Informal Investigation to seriously address and resolve this issue is not reasonable.

Q. DOES PECO AGREE THAT NITS PRESENT A PROBLEM OR THAT CIRCUMSTANCES HAVE CHANGED TO WARRANT A REVIEW OF THE STATUS QUO?

A. No, while Mr. McCawley acknowledges the change to "formula rate" approach, he argues that I did "not demonstrate that annual rate changes are in fact a significant burden for EGSs" and claims that I support the "socialization" to all customers based on the unpredictability of the level of NITS rate changes. (PECO St. No. 1-R at 17).

Q. HAS MR. MCCAWLEY FAIRLY CHARACTERIZED YOUR TESTIMONY?

A. No. Notably, he fails to address several key points about why the status quo needs to be revised. First, as explained in my Direct Testimony, PECO's recovery of the actual costs of NITS for default service customers is a significant competitive advantage over EGSs' recovery of "anticipated or forecasted" costs of NITS from their shopping customers. Apart from advantaging the historical monopoly provider, this current market structure subjects <u>shopping customers only</u> to risk premiums which may or may not reflect actual costs. (ESC St. No. 1 at 39). Second, I explained in my Direct Testimony – with examples – the difficulty of attempting to accurately forecast the NITS rate and how the final FERC approved rate may not be revealed with much lead time for EGSs to factor it into their pricing. (ESC St. No. 1 at 37-38). Notably, this is not a problem for PECO because it simply collects the price changes from default service customers (and is paid them as a transmission owner). Perhaps the fact that PECO is so differently positioned than any other EGS in the market is the reason why Mr. McCawley fails to see the burden of the status quo on EGSs. The table below, taken from my Direct Testimony, shows how these changes can either be substantial—or not. As can be seen, one rate stayed the same year-on-year and another increased by almost 30 percent. In any case, these changes under formula rates are more sudden and more frequent, which together with the potential for volatility result in the issue I pose in my direct testimony. (ESC St. No. 1 at 38).

NITS Rates	Current NITS Rate	Current NITS Rate Effective Dates	Future NITS Rate	Future NITS Rate Effective Date
ATSI Zone	$55,074.34/MW/Year	Since January 1, 2019	$57,340.35/MW/Year	January 1, 2020
Allegheny Power Zone	$15,396.00/MW/Year	Since March 1, 2002	$15,396.00/MW/Year	March 1, 2002
MAIT Rates for ME & PN Zones	$28,796.22/MW/Year	Since January 1, 2019	$37,083.18/MW/Year	January 1, 2020

Q. SETTING ASIDE YOUR DISAGREEMENT WITH PECO ABOUT WHETHER OR NOT A PROBLEM EXISTS, DOES PECO IDENTIFY TRANSITION PROBLEMS WITH YOUR RECOMMENDED APPROACH?

A. Yes. Mr. McCawley claims that transitioning the recovery of NITS to the NBT could lead to what he calls the “double-charge” problem and the “unbundling” problem. Basically, he argues that shopping customers’ existing contracts already factor in a cost for NITS and shifting the cost recovery to all distribution customers will result in them paying for NITS twice. Relatedly (his “unbundling” issues), he claims EGSs have structured their contracts to factor in the cost of NITS and attempting to identify a cost for that component and then removing it “could require additional negotiation. (ESC St. No. 1 at 17-18).

Q. IS THE IMPACT OF A TRANSITION TO YOUR PROPOSED NITS RECOVERY ON EXISTING SHOPPING CUSTOMERS' CONTRACTS AN INSURMOUNTABLE BARRIER?

A. No, it is not. We would not be opposed to any reasonable transition mechanism that would address concerns related to existing contracts with shopping customers or to the mechanics of how to transition to my recommended cost recovery approach. Just as PECO did when it first created the NBT, the change in cost responsibility can be limited to only new charges associated with NITS occurring after the Commission's final order in this proceeding. By limiting the change in cost responsibility to new charges, there is no concern over "double recovery" for customers' existing EGS contracts. Alternatively, the change in cost responsibility could be deferred to a later date, such as June 2022, to provide a transition period during which many EGS contracts would expire and renew. The new renewal rates offered would reflect removal of the cost obligations from EGSs and address concerns over potential "double recovery." In sum, there are a variety of transition mechanisms that can be considered.

B. <u>Response to PAIEUG</u>

Q. WHAT CONCERNS DOES PAIEUG RAISE REGARDING YOUR PROPOSED CHANGE TO NITS COST RECOVERY?

A. Like Mr. McCawley, Mr. Pollock attempts to explain why the current cost recovery mechanism is not problematic for EGSs and how the shift could have the impact of recovering NITS charges twice. In addition, Mr. Pollock argues that the shift in cost recovery would "sever the link between cost recovery and cost causation." (PAIEUG St. No. 1 at 4).

Q. DO YOU AGREE WITH MR. POLLOCK'S ARGUMENTS ABOUT WHY THE CURRENT COST RECOVERY MECHANISM FOR NITS SHOULD NOT BE PROBLEMATIC FOR EGSS?

A. No. Mr. Pollock appears to be focused on the fact that the date NITS rates will become effective is known. (PAIEUG St. No. 1 at 6). However, knowing when something is going to change but not by how much is not particularly useful. Mr. Pollock also identifies the factors involved in determining the change and notes that this information is "typically found in an EDC's FERC Form 1." (PAIEUG St. No. 1 at 7). These filings, however, are made on a lagging basis—while formula rates are made on a forward basis. As I observe in my direct testimony, these rates are subject to particular volatility associated with forecasts of the roll-in to rates of large capital projects. FERC Form 1 does not contain this forward-looking information. Mr. Pollock is attempting to create the impression that EGSs have easy access to the future NITS rates, which is not the case. This is not the accurate as I detailed at length in my Direct Testimony. (ESC St. No. 1 at 36-38).

Mr. Pollock also refers to the Texas market with the broad statement that "this [NITS cost recovery structure] has not prevented competitive suppliers from active participation." (PAIEUG St. No. 1 at 8). Yet one important aspect of the Texas competitive retail market is that it allows retailers to enter into contracts with customers that include adjustment clauses for transmission expenses. The Pennsylvania market does not.[8] His argument therefore stands as a reason to adopt the proposal I have made.

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[8] *See* Fixed Means Fixed Order.

Q. DO YOU AGREE WITH MR. POLLOCK'S VIEW THAT SHIFTING THE COST RECOVERY MECHANISM FOR NITS WOULD "SEVER THE LINK BETWEEN COST RECOVERY AND COST CAUSATION?"

A. No. Mr. Pollock's argument focuses on how LSEs are billed NITS, i.e. on the basis of a customer's contribution in the zonal peak hour load and claims that PECO's available cost recovery charge mechanisms (the TSC and the NBT) does not align with how LSEs are billed by PJM. (PAIEUG St. No. 1 at 4-5). I am not aware of any legal requirement that the assessment of wholesale FERC approved charges billed by PJM to LSEs is required to directly match the recovery of the LSEs from their customers.

Q. DOES MR. POLLOCK'S REBUTTAL TESTIMONY HIGHLIGHT ANY OTHER POINTS YOU WOULD LIKE TO ADDRESS?

A. Yes, Mr. Pollock correctly recognizes that EGSs have to rely on risk premiums given the requirement for them to forecast future NITS rates and, according to him, the EGS is "wearing the risk." (PAIEUG St. No. 1). The issue here is a lack of a level playing field. PECO as a DSP does not have to "wear the risk"—even though, ironically, it is the same company that is responsible for driving the fluctuations of NITS in what it projects to spend in capital and operating costs for its transmission system. It is perverse that PECO would be able to socialize the risk of its own decision making as it relates to the pricing of default service, even while EGSs are expected to bear that risk.

C. <u>Response to Calpine</u>

Q. WHY DOES CALPINE OPPOSE YOUR PROPOSAL TO SHIFT THE CURRENT COST RECOVERY MECHANISM FOR NITS?

A. Ms. Merola characterizes our proposal as an effort "to shed and shift market risk" that would "simultaneously limit existing and potential customers' product and service choices." (Calpine St. No. 1 at 3-4).

Q. DO YOU AGREE WITH THIS ASSESSMENT?

A. In part. I agree that in an ideal world, all market risk would be reflected in all price offers to consumers, including the estimation of likely transmission prices over the term of the offered contract. And yet that is not the world in which we live, because PECO—notably, unlike the situation in FirstEnergy—socializes the risk to non-shopping customers for whatever transmission costs end up being, even while not establishing EGSs on a level playing field.

VII. RECOVERY OF DEFAULT SERVICE COSTS

Q. WHAT POSITION DID YOU SET FORTH IN YOUR DIRECT TESTIMONY CONCERNING THE RECOVERY OF DEFAULT SERVICE COSTS?

A. I expressed the view that it is critical that the price to compare ("PTC") that is established through this default service proceeding actually reflect the costs that PECO is incurring to provide default service. Yet, as I explained, PECO today is recovering no overhead costs that it incurs as a company to provide default service as a DSP through the PTC for default service. Additionally, PECO proposes to continue recovering all indirect costs that it incurs to operate both its distribution and default service businesses through distribution rates. (ESC St. No. 1 at 41-43).

Q. WHAT DID YOU RECOMMEND TO RECTIFY THIS PROBLEM?

A. I recommended rectifying this problem by the Commission requiring PECO to allocate a portion of its overhead costs to default service and recover them through the PTC. Absent such allocation, I explained that not only is PECO overlooking the express terms of the Commission's policy statement and regulations. I have demonstrated through my direct testimony that PECO employees are indeed spending time administering and implementing DSP, the cost of which are not allocated to DSP. But because PECO does not track the time and resources its employees spend on administering and implementing PECO, PECO has deprived itself and other parties the opportunity to make a direct assignment of costs. Instead, those costs will have to be allocated through a less direct methodology. ESC St. No. 1 at 44-48).

Q. HOW DID YOU RECOMMEND THAT THIS ALLOCATION OCCUR?

A. To address the problem with default service pricing that I have identified, I recommended that the Commission require PECO to modify its proposed allocation and rate design for default service to recover a reasonable or appropriate portion of its overhead costs through the PTC. I further testified that upon the filing by PECO of a modified allocation and rate design, the Commission should afford all interested parties an opportunity to comment and/or present evidence showing the deficiencies of PECO's proposal. (ESC St. No. 1 at 51-53).

Q. DOES PECO RESPOND TO THE EVIDENCE THAT ITS EMPLOYEES ARE SPENDING TIME AND RESOURCES ON DSP, WHICH ARE NOT BEING ALLOCATED TO THE PRICE OF THAT SERVICE?

A. To some degree. In its entirety, the question-and-response posed to Mr. Bisti on the issue of PECO employees' time spend working on DSP reads as follows: Q. Mr. Kavulla argues that PECO is improperly omitting certain A&G expenses from its PTC, *such as those associated with PECO employees and executives* that may spend time on issues related to default service. Do you agree? A. No. The Company's allocation of A&G expenses is appropriate and consistent with prior allocations that have been approved by the Commission. *When A&G expenses are incurred to fulfill the Company's default service obligations, such as costs for the independent evaluator and internal consultants, those costs are included in the PTC*." (PECO St. No. 2 at 9. Emphasis added).

In his answer, Mr. Bisti overlooks the relevant part of my contention, and indeed the way the question in PECO's own testimony is phrased. The issue is how PECO allocates to DSP the cost of its employees' time and resources spent working on DSP issues; Mr. Bisti simply talks past the issue, asserting that when third parties are hired for DSP, those costs are allocated to DSP. That is not the issue here. The issue is that PECO employees are spending time administering and implementing DSP, and yet the cost of that time is not allocated to DSP. That is inappropriate.

Q. BUT HOW DO WE KNOW THAT PECO EMPLOYEES ARE SPENDING THEIR TIME ON DSP?

A. To name but one highly obvious example, Mr. Bisti is literally spending his time and his company's resources preparing testimony in support of PECO's DSP plan. This, I think, is an incontrovertible fact. I identify a number of PECO employees on pages 42-43 of my direct testimony who are spending time administering and/or implementing DSP. Mr. Bisti does not rebut the evidence that they are spending time on DSP. Yet, nevertheless, he is not proposing to allocate the cost of that time to the price to compare of PECO's DSP.

Q. SO HOW DOES MR. BISTI ATTEMPT TO JUSTIFY HIS POSITION TO ALLOCATE NO COSTS ASSOCIATED WITH PECO EMPLOYEES TO DSP DESPITE THE FACT THAT PECO EMPLOYEES WORK ON DSP?

A. Mr. Bisti argues that "PECO's default service obligations are part of its duties as an EDC" and since "PECO has an obligation to provide default supply to all distribution customers who do not take generation service from an EGS," the time PECO employees spend on DSP "support the Company's distribution customers generally (shopping and non-shopping)" and are thus properly allocated to all distribution customers. PECO St. No. 2 at 6. Yet, Mr. Bisti also offers in the same breath: "If a cost is incurred as a result of fulfilling the Company's default service obligations, PECO allocates the cost to default service." *Id.*

Q. WHAT DO YOU MAKE OF MR. BISTI'S ARGUMENT?

A. It is internally contradictory. He appears to be suggesting that because DSP is part of the EDC business, it benefits all distribution customers—and thus costs associated with DSP should be allocated to distribution (both shopping and non-shopping) customers. And, yet, if that were the case, then it would not be appropriate to allocate the independent third party evaluator or other consultants working on DSP to the DSP price to compare; after all, the same logic that leads Mr. Bisti not to allocate PECO employees' time to DSP would apply to these costs as well.

In any case, Mr. Bisti's argument that EDC and DSP are not separate businesses is irrelevant. The Commission's policy statement includes categories of costs to allocate to DSP, as I observe in my direct testimony. The Commission's policy statement does not provide distinctions for whether it is a PECO employee or a third-party contractor doing work on DSP.

Q. HAS THE COMMISSION EVER EXPRESSED IN AN ORDER THE SAME RATIONALE THAT MR. BISTI ARGUES IN MAKING A FINDING ON ALLOCATION TO DEFAULT SERVICE?

A. No. The Commission has approved proposals in 2010 and 2015 that apparently contained no allocation of such costs to DSP, although the allocation was not challenged in these proceedings by any party. The Commission did not opine one way or another in their order. More recently, in PECO's 2018 case to establish EDC base rates, NRG raised objections to this allocation. In denying NRG's arguments, the Commission ruled, in an excerpt that Mr. Bisti quotes in support of his reasoning: "A theory that underlies NRG's proposal is that the categories of costs incorporated in alternative energy suppliers' charges to their customers should be the same as the categories of costs incorporated in PECO's PTC. However, rate design is governed by the principle of cost causation. The principle requires that the cost of supplying public utility services is allocated to those who cause the costs to be incurred."[9]

Notably, the Commission's expressed view is *different* than the rationale that Mr. Bisti offers. It does not foreclose adopting the position the ESC offers on this point, which is to allocate the cost of the time and resources PECO employees spend on DSP to the price to compare of DSP. Indeed, one cannot simultaneously adopt the view that third-party contractors' doing work on DSP and PECO employees' doing work on DSP should somehow be subject to different outcomes when the Commission's lens of "cost causation" is applied.

Q. YOU HAVE MENTIONED TIME *AND RESOURCES* THAT PECO EMPLOYEES SPEND ON DSP IN PROVIDING YOUR TESTIMONY HERE. WHAT DO YOU MEAN BY THE INCLUSION OF THE WORD 'RESOURCES'?

A. When PECO employees work on DSP issues, they are also inescapably relying on the systems that are in place to help them do that work, including office space, information technology, human resources, and management. These are costs that support PECO's business in its entirety—when employees spend time directly on DSP, there must be an accounting of the corporate infrastructure that supports those employees. If PECO did account for employees' time directly, that might be the basis for an allocation, but it does not. It simply asserts that an allocator of zero is appropriate. It is not, as the facts of this

[9] *See Pa. P.U.C. vs. PECO Energy Co.*, Docket No. R-2018-3000164 (Order entered Dec. 20, 2018) (the "*2018 Distribution Rate Order*"), quoted at PECO St. No. 2 at 5.

proceeding demonstrate that PECO employees do work directly on DSP (but simply do not account for their time when they do).

Q. DO ANY OTHER PARTIES RAISE ISSUES WITH YOUR PROPOSAL ON THE ALLOCATION OF COSTS TO DSP?

A. Yes. OCA echoes PECO, at abbreviated length. Mr. Estomin particularly emphasizes his view that my testimony relies on my view that DSP should be treated as a standalone service for the purpose of allocating costs to it. OCA St. No. 1 at 11-13. That is indeed my view of what constitutes a best practice of inter- and intracompany cost allocation. However, it is *not necessary* to agree with me on that perspective in order to make the kind of allocation I am proposing above—where the facts demonstrate PECO employees have worked, are working, and will continue to work on DSP's administration and implementation. As I note above, the application of principles of cost allocation, which both Mr. Bisti and Mr. Estomin cite to, will likewise trigger an allocation of these costs to DSP. As such, there should be an allocation of the time and resources they are spending on DSP.

Q. MR. BISTI SUGGESTS THAT YOU ARE 'UNABLE OR UNWILLING' TO PROPOSE AN ALLOCATION METHODOLOGY FOR THE COSTS YOU HAVE IDENTIFIED. HOW DO YOU RESPOND?

A. Mr. Bisti's proposition is unfair. PECO has adopted so simple and absolute a methodology that it is starkly wrong, and is now trying to shift its burden in the presence of facts that make PECO's methodology unapprovable. PECO should not get to float a paper airplane across the room and expect intervenors to come back with a jet. The Commission should use its power to approve, deny, or modify PECO's proposal in this proceeding, and require on compliance a proposal from PECO that complies with a ruling that finds PECO's initial proposal unreasonable for the reasons I have offered above.

The Coalition would welcome the opportunity to assist PECO in developing an allocation methodology so that indirect costs are fairly and correctly allocated to default service.

VIII. PECO'S EXISTING AND PROPOSED RETAIL MARKET ENHANCEMENT PROGRAMS

A. STANDARD OFFER PROGRAM

Q. DID YOU OFFER TESTIMONY ABOUT PECO'S PRPOOSAL TO CONTINUE THE STANDARD OFFER PROGRAM ("SOP") THAT WAS FIRST IMPLEMENTED AS PART OF PECO'S SECOND DEFAULT SERVICE PROGRAM?

A. Yes. Given the sharp decline in program referrals the past three years, I testified that measures should be considered to mature the SOP. (ESC St. No. 1 at 53-54).

Q. WHAT WERE YOUR SPECIFIC RECOMMENDATIONS FOR MODIFICATIONS?

A. The Coalition recommended that: (i) all new customers (who have not already made an affirmative choice of an EGS) be automatically enrolled in the SOP; (ii) PECO be required to allow SOP signups from its website; (iii) the script be modified; and (iv) PECO be required to revisit the situations in which the SOP is mentioned, particularly to default service customers who contact the call center, and to otherwise engage in periodic communications, such as quarterly when changes to the PTC occur, promoting SOP to all customers on default service. (ESC St. No. 1 at 54-58).

Q. WHICH WITNESSES ADDRESSED YOUR TESTIMONY IN THEIR REBUTTAL TESTIMONY?

A. The witnesses who addressed my Direct Testimony on the SOP are Carol Reilly (PECO St. No. 3-R), Harry Geller (CAUSE-PA St. 1-R), Barbara Alexander (OCA St. No. 2R), and Brian Kalcic (OSBA St. No. 1-R).

Q. DOES THE REBUTTAL TESTIMONY OF THESE WITNESSES CHANGE ANY OF THE VIEWS YOU EXPRESSED IN YOUR DIRECT TESTIMONY ABOUT PECO'S SOP PROPOSAL?

A. No.

Q. AS TO YOUR PROPOSAL FOR THE AUTOMATIC ENROLLMENT OF NEW CUSTOMERS ON SOP WHO HAVE NOT ALREADY MADE AN AFFIRMATIVE CHOICE, HOW DO WITNESSES FOR OTHER PARTIES RESPOND?

A. Ms. Reilly disagrees with this proposal due to the voluntary nature of the SOP. (PECO St. No. 3-R at 15). Ms. Alexander opposes this recommendation, contending that customers must give affirmative consent to enroll with an EGS. She claims that the ESC proposal would "eviscerate the concept of 'choice' and 'shopping' and enroll customers with an EGS without their consent," which she calls "slamming." (OCA St. No. 2R at 3-4). Similarly, Mr. Geller claims that automatically enrolling new customers in SOP would be tantamount to slamming. He also objects to the need for customer to remain active in order to ensure savings throughout the SOP. (CAUSE-PA St. 1-R at 11-12). Mr. Kalcic likewise disagrees with automatically enrolling new customers in SOP who have not affirmatively elected to take service from an EGS. Mr. Kalcic's concern is that SOP customers must monitor changes in PECO's PTC and, if necessary, switch back to default service in order to receive the lowest rate available. He states that no customer should be enrolled in PECO's SOP unless the customer elects to participate. (OSBA St. No. 1-R at 6-7).

Q. HOW DO YOU RESPOND TO THESE WITNESSES?

A. As I explained in my Direct Testimony, default service is intended to ensure that consumers continue to receive electricity even if they do not choose an EGS or in the event their EGS stops providing service. Despite this provider of "last" resort purpose for default service, it continues to have the connotation of being the provider of "first" resort service for customers who do nothing. Continuing to foster this connotation is inconsistent with promoting the development of a competitive retail market. (ESC St. No. 1 at 54-55). Also, it makes no sense why new customers, who have not already made an affirmative choice of an EGS, would not automatically receive the benefit of a 7 percent discount off PECO's PTC.

Q. WHAT ABOUT THE CLAIMS THAT AUTOMATIC ENROLLMENT IN THE SOP IS THE EQUIVALENT OF SLAMMING?

A. As to the witnesses who describe automatic enrollment in the SOP as "slamming," they appear to have overlooked the reality that when PECO enrolls a customer in default service who fails to choose an EGS, the concept is the same. The customer is not choosing PECO, but rather is simply opting to do nothing. Also, the idea that a customer may have to pay attention to the market, PTCs and SOP prices should not prevent the Commission from taking the important step of reducing reliance on default service. To the contrary, the best way for customers to become familiar with the competitive market is to actively engage and participate in it. In that way, they will find the products and services being offered by EGSs that best suit their individual needs.

Q. HOW DO WITNESSES FOR OTHER PARTIES RESPOND TO YOUR PROPOSAL FOR AN ONLINE ENROLLMENT PROCESS FOR SOP?

A. Ms. Reilly does not believe this proposal should be adopted. She indicates that PECO initially allowed customers to enroll in the SOP via telephone or the Company's website beginning in 2013, but in 2015, the Company implemented system changes to allow SOP suppliers the option to select the rate class of customer accounts they wish to enroll. However, PECO did not enable web-enrollment functionality to separate SOP enrollments by rate class because of the cost and the relatively low level of SOP enrollment through PECO's website from 2013 through March 2015, which was approximately 3% of total SOP enrollments. (PECO St. No. 3-R at 15-16). Ms. Alexander does not object to my suggestion for PECO's website to include an option to participate in the SOP, but noted that her agreement "depends on ensuring that all the required disclosures are presented prior to the customer's agreement to enroll with an EGS. (OCA St. No. 2R at 7).

Q. HOW DO YOU RESPOND?

A. As to Ms. Alexander's agreement with my suggestion being contingent upon required disclosures being presented during the online enrollment process, I note that it is not possible to do that because all EGSs have different disclosure statements. Rather, the Coalition suggests that the information that is made available during an online enrollment simply mirror the script that is used when the process occurs through a customer service representative. Regarding PECO's resistance to my recommendation, I do not see any persuasive reason offered by Reilly's testimony for not allowing online SOP enrollments. As PECO permits new customers to enroll for new service online, it makes sense that since SOP enrollment is one of the options available to the customer, it should likewise be available in that forum. While PECO's online SOP enrollments may have been relatively low during the early years of the program, customers are much more inclined today than even five years ago to conduct their business through online transactions. Also, customers may have more familiarity with the program now and be prompted to select it even without a call center representative making a pitch for it. Although Ms. Reilly makes a reference to "cost," she does not quantify the cost, and it is difficult to imagine that the cost of adding a box for a new customer to choose SOP would be so significant as to justify depriving customers of a tool that would allow them to electronically enroll for the SOP and save money.

Q. HOW DO THE PARTIES RESPOND TO YOUR PROPOSAL FOR SOP SCRIPT CHANGES?

A. My proposals on the script were twofold: 1) eliminate the PECO branding of the SOP; and 2) remove the term “potential” from savings since the customer would save 7% off the PTC in the first month of the contract. Ms. Reilly has no objection to the discontinuance of its brand name for the SOP. She testifies that PECO will select a new name for the SOP based on market research and customer feedback that does not utilize the PECO corporate name. (PECO St. No. 3-R at 15). However, Ms. Reilly objects to my suggestion to revise the phrase “potential savings opportunity” to eliminate the term “potential” because this language is intended to convey that the SOP discount does not guarantee savings over the life of the contract. (PECO St. No. 3-R at 13). Similarly, Ms. Alexander objects to changes to the scripts that would emphasize savings since the discount off the PTC is only guaranteed for one month. (OCA St. No. 2R at 4). For the same reasons, Mr. Geller, likewise opposes the ESC’s proposal to highlight the guaranteed savings in the first month of SOP. (CAUSE-PA St. 1-R at 13).

Q. PLEASE RESPOND.

A. The fact remains that in at least the first month of the SOP, the customer will save 7% off the PTC. That is not a potential for savings; that is real savings. I continue to believe that potential should be eliminated from the script, especially when the word “opportunity” continues to be used to describe the possibility of savings. I am, however, pleased to see that the SOP will no longer be branded as a PECO program.

Q. WHAT ARE THE VIEWS OF WITNESSES FOR OTHER PARTIES ON YOUR PROPOSAL TO EXPAND THE SCOPE OF CUSTOMER CALLS IN WHICH THE SOP MAY BE PRESENTED?

A. Ms. Reilly states that the ESC "provides no compelling justification" for this proposal. She further explains that PECO currently offers the SOP during all calls from new/moving customers, except for calls related to outages, emergencies, terminations and billing disputes, during which she indicates that such a presentation would be inappropriate. (PECO St. No. 3-R at 15-16). Ms. Alexander disagrees that billing dispute calls are a proper forum for promoting shopping with tan EGS, describing the calls as being typically complicated. (OCA St. No. 2R at 6). Mr. Geller objects to offering SOP in additional situations, such as when a customer calls in with a billing dispute. He suggests that these customers are often in a high-stress situation and PECO's call center staff must remain focused on resolving that dispute. (CAUSE-PA St. 1-R at 13).

Q. HOW DO YOU RESPOND?

A. In my Direct Testimony, I pointed to the sharp decline in SOP referrals the past couple of years. That is a compelling enough reason to look at the existing SOP and identify areas where it could be improved so that more customers are aware of it. As to the claims of the other witnesses that billing disputes are "typically complicated" or occur in "high-stress situations," I submit that neither of these statements is documented in any way. While I am not advocating for discussing SOP when a customer is facing termination, I do not believe it would be problematic for PECO's call center representatives to offer this program once a customer's billing dispute has been resolved. Many such calls may be quite simple or even in the nature of inquiries, and these opportunities should be used to make customers familiar with the SOP.

Q. WHAT ARE THE RESPONSES TO YOUR PROPOSAL FOR ADDITIONAL PERIODIC COMMUNICATIONS BY PECO WITH DEFAULT SERVICE CUSTOMERS ABOUT SOP?

A. Ms. Reilly states that when the Commission established the SOP, it provided specific direction to offer it during customer contacts to EDC call centers. She testifies that it was not intended to include other communications to default service customers. She also suggests that quarterly communications to default service customers would increase administrative costs. (PECO St. No. 3-R at 16-17). Ms. Alexander believes that promoting SOP during quarterly communications about PTC changes, which occur through the bill, is not "appropriate." She also notes that "PECO's website prominently informs customers about their right to shop for generation supply and includes references to the PAPowerSwitch.com." (OCA St. No. 2R at 6).

Q. HOW DO YOU RESPOND?

A. The whole point of my Direct Testimony on this issue is that in recent years, referrals to the SOP have sharply declined. What the Commission first thought about conveying the availability of this program to customers is no longer relevant or sufficient. PECO certainly has plenty of opportunities during which it communicates with customers. Ms. Alexander does not explain her concern with having the availability of SOP communicated along with PTC changes through the bill and I continue to believe that coordinating a message about SOP with PTC changes would be an effective way to let consumers know about the program. However, that is not the only means, and I offered it only as an example. Ms. Alexander points to the information that PECO has on its website about shopping and I note that in the link she provided, nothing appeared about SOP. PECO should include information about the SOP on its website where it tells customers about shopping.

B. SHOPPING BY CUSTOMER ASSISTANCE PROGRAM ("CAP") CUSTOMERS

Q. WHAT IS THE CURRENT STATUS OF SHOPPING BY CUSTOMER ASSISTANCE PROGRAM ("CAP") CUSTOMERS IN PECO'S SERVICE TERRITORY?

A. Currently, PECO CAP customers are not able to shop for electric generation supply. However, as part of this proceeding, PECO submitted a proposed plan, under which EGSs would be required to charge CAP customers a rate for generation service that is at or below the PECO residential PTC at all times during the contract. Also, EGSs serving CAP customers may not enter into contracts that impose early cancellation and termination fees or other fees unrelated to generation service. PECO also proposes to implement the program only after receipt of notices of intent to participate from at least five EGSs. In addition, EGSs offering a rate do CAP customers would be required to post that rate on the Commission's shopping website, PAPowerSwitch.com. (PECO St. No. 3 at 4-7).

Q. DID YOU DESCRIBE THE COALITION'S CONCERNS REGARDING PECO'S PROPOSAL?

A. Yes. I identified three primary concerns of the Coalition with PECO's proposal, noting that it is not appropriate to: (i) require the EGS price to be at or below PECO's PTC the entire time; (ii) require EGSs to post their CAP shopping rate on the PAPowerSwitch.com shopping website; and (iii) commit to implementing the CAP shopping plan only upon confirmation that five EGSs intend to participate. (ESC St. No. 1 at 60).

Q. WHICH WITNESSES RESPONDED TO YOUR DIRECT TESTIMONY ON CAP SHOPPING?

A. Ms. Reilly (PECO), Ms. Alexander (OCA), Mr. Geller (CAUSE-PA) and Mr. Bertocci (TURN) submitted Rebuttal Testimony in response to my Direct Testimony on CAP shopping. (PECO St. No. 3-R at 4-5; OCA St No. 2R at 7-8; CAUSE-PA St. 1-R at 13-18; TURN St. No. 1-R at 4-7).

Q. WHAT DO THESE WITNESSES HAVE TO SAY ABOUT YOUR OBSERVATION REGARDING THE NEED FOR THE SUPPLIER'S PRICE TO BE AT OR BELOW THE PRICE TO COMPARE THE ENTIRE TIME?

A. As noted above, I expressed concerns about EGSs being required to offer CAP customers a price at or below the PTC for the entire term of the contract, particularly when – as the Coalition has shown – PECO's PTC is artificially low. (ESC St. No. 1 at 60). Also, we have no insight into PECO's future quarterly PTC adjustments. Ms. Reilly points out that the proposed restriction on EGS pricing for CAP customers is consistent with the Commission's guidance in the Proposed Policy Statement Order. Further, she notes that EGS participation is voluntary and EGSs can offer term lengths and other provisions that they believe are necessary to address price risk. Therefore, she believes that offering CAP customers a rate below the PTC for the entire contract term strikes a reasonable balance among a variety of competing concerns. (PECO St. No. 3-R at 4). Ms. Alexander suggests that the Coalition's proposal lacks specificity because I did not propose how often or by what amount the EGSs could charge more than the PTC. She also emphasizes the importance of ensuring that CAP customers receive affordable bills. (OCA St. No. 2R at 7). Mr. Geller expresses similar concern. (CAUSE PA St. 1R at 15). Mr. Bertocci does as well, and also notes that CAP customers may not be able to cancel their contracts before they incur charges in excess of the PTC and will also face challenges identifying when EGSs charges exceed the PTC even after they have been incurred. TURN St. No. 1-R at 5-6).

Q. HOW DO YOU RESPOND?

A. While the Coalition continues to believe that the PTC, until such time as it is modified to include all costs that PECO incurs to provide default service, should not be used to limit EGS prices for the entire contract term, we are willing to accept PECO's original proposal for the EGS price to be at or below the PTC for the duration of the contract, given that CAP customers are at least finally being given the opportunity to shop for generation service. The Coalition, as well as its individual members, reserve the right to litigate in future or separate proceedings that the PTC should not be used to restrict EGS prices to CAP customers beyond perhaps an initial term after enrollment.

Q. WHAT ARE THE VIEWS OF THE WITNESSES FOR THE OTHER PARTIES ON YOUR CONCERNS ABOUT EGSS BEING REQUIRED TO POST THE CAP RATE ON PAPOWERSWITCH.COM?

A. To address my concern about non-CAP customers being confused if they see CAP rates on PaPowerSwitch.com, I suggested that a portal be created on the website for publishing CAP rates. Ms. Reilly does not agree that a separate portal is necessary and instead suggests that utilizing an additional filter for CAP rates "would minimize customer confusion and promote transparency." (PECO St. No. 3-R at 5). In response to my concern, Ms. Alexander likewise disagrees with creation of a separate portal but suggests that the website could allow a CAP customer to check a box and be directed to a separate where CAP offers would be available. (OCA St. No. 2-R at 7-8). Mr. Geller simply objects to the Coalition's proposal as unnecessary and costly. (CAUSE-PA St. 1R at 15).

Q. PLEASE RESPOND.

A. While the Coalition suggested that a portal be created for CAP customers, so as to avoid the confusion of non-CAP customers seeing the published rates and not having access to them, we understand that the costs of a separate portal may make this solution unattractive. A portal is not the only way to avoid customer confusion, and the Coalition believes that a CAP filter as described by Ms. Reilly would be helpful. However, the solution proposed by Ms. Alexander of having a CAP customer check a box and be directed to a separate page appears to be more in line with the idea of a portal and would make it more likely that CAP customers would take note of the special information, while other customers would not be confused by having this rate in the mix of offers that are available. Therefore, the Coalition believes the proposal advanced by Ms. Alexander (or something very similar to it) should be implemented.

Q. AS TO YOUR CONCERNS ABOUT PECO'S FIVE SUPPLIER THRESHOLD BEFORE IT IMPLEMENTS CAP SHOPPING, HOW DID THE WITNESSES FOR THE OTHER PARTIES RESPOND?

A. As I noted, PECO offered no explanation or basis for its requirement for five EGSs to notify PECO of their intent to participate in CAP shopping before implementation. Since the number of EGSs who are willing to participate should have no bearing on PECO's commitment to implement the program, I recommended eliminating this condition. (ESC St. No. 1 at 61). In her Rebuttal, Ms. Reilly notes PECO's continued believe that the receipt of five notices from EGSs is a reasonable threshold before incurring the necessary program and information technology expenses. (PECO St. No. 3-R at 4-5). Ms. Alexander and Mr. Geller believe that PECO's proposal is reasonable in order to prevent the expenditure of ratepayer funds for a program that does not solicit sufficient EGS interest. (OCA St. No. 2-R at 8; CAUSE-PA St. 1R at 16).

Q. WHAT IS YOUR RESPONSE?

A. The Coalition's original question – of why five suppliers is the threshold – still has not been answered. It seems that PECO just viewed five as being a good number of commitments to move forward and other parties think that is reasonable. The Coalition continues to believe that the commitments of five suppliers should not be an absolute make or break point for the implementation of CAP. If three or four EGSs provide notice of an intent to participate, PECO should not be relieved of the obligation to implement CAP shopping. At a minimum, PECO should be required to communicate with those EGSs to determine their interest and level of commitment. If PECO continues to have concerns about whether there is sufficient interest among EGSs in the program, it should notify the Commission of a delay and repeat the process after one year. Otherwise, with a four-year DSP, CAP shopping in PECO's service territory would not occur until after 2025.

Q. DOES THAT COMPLETE YOUR SURREBUTTAL TESTIMONY?

A. Yes.