ECKERT SEAMANS ATTORNEYS AT LAW

Eckert Seamans Cherin & Mellott, LLC
213 Market Street
8th Floor
Harrisburg, PA 17101

TEL: 717 237 6000
FAX: 717 237 6019

Karen O. Moury
717.237.6036
kmoury@eckertseamans.co,

May 9, 2022

Via Electronic Filing
Rosemary Chiavetta, Secretary
PA Public Utility Commission
400 North Street
Harrisburg, PA 17120

Re: Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company for Approval of their Default Service Programs for the Period From June 1, 2023 through May 31, 2027; Docket Nos. P-2021-3030012, P-2021-3030013; P-2021-3030014; P-2021-3030021

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 Retail Energy Supply Association ("RESA") and NRG Energy, Inc. ("NRG") in the above matter. This testimony was duly admitted to the record at the hearing held in the above proceeding on April 13, 2022 before Administrative Law Judge Jeffrey A. Watson.

Testimony	Witness	Exhibits
RESA/NRG St. No. 1	Direct Testimony of Travis Kavulla	RESA/NRG Exhibits TK-1 through TK-26
RESA/NRG St. No. 1-R	Rebuttal Testimony of Travis Kavulla	No Exhibits
RESA/NRG St. No. 1-SR	Surrebuttal Testimony of Travis Kavulla	No Exhibits

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

Sincerely,

/s/ *Karen O. Moury*
Karen O. Moury

KOM/lww

Enclosure

cc: Hon. Jeffrey A. Watson (letter only) (via email only)
Cert. of Service w/enc. (letter only) (via email only)

CERTIFICATE OF SERVICE

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

Via Email Only

Kenneth M. Kulak, Esquire
Catherine G. Vasudevan, Esquire
Brooke E. McGlinn, Esquire
Morgan, Lewis & Bockius LLP
1701 Market Street
Philadelphia, PA 19103-2921
Ken.kulak@morganlewis.com
Catherine.vasudevan@morganlewis.com
Brooke.mcglinn@morganlewis.com

Tori L. Giesler, Esquire
Darshana Singh, Esquire
FirstEnergy Service Company
2800 Pottsville Pike
PO Box 16001
Reading, PA 19612-6001
tgiesler@firstenergycorp.com
singhd@firstenergycorp.com

Patrick M. Cicero, Esquire
Darryl A. Lawrence, Esquire
Christy M. Appleby, Esquire
Harrison W. Breitman, Esquire
Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923
OCAFEDSP2021@paoca.org

Erin K. Fure, Esquire
Office of Small Business Advocate
555 Walnut Street
1st Floor, Forum Place
Harrisburg, PA 17101
efure@pa.gov

Allison C. Kaster, Esquire
Bureau of Investigation & Enforcement
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120
akaster@pa.gov

Susan E. Bruce, Esquire
Charis Mincavage, Esquire
McNees Wallace & Nurick LLC
100 Pine Street
PO Box 1166
Harrisburg, PA 17108
sbruce@mcneeslaw.com
cmincavage@mcneeslaw.com

Elizabeth R. Marx, Esquire
Lauren N. Berman, Esquire
Ria M. Pereira, Esquire
John W. Sweet, Esquire
Pennsylvania Utility Law Project
118 Locust Street
Harrisburg, PA 17101
pulp@pautilitylawproject.org

Todd S. Stewart, Esquire
Hawke McKeon & Sniscak, LLP
100 North Tenth Street
Harrisburg, PA 17101
tsstewart@hmslegal.com

Colleen P. Kartychak, Esquire
John White, Esquire
Exelon Corporation
1310 Point Street
Baltimore, MD 21231
Colleen.kartychak@exeloncorp.com
John.White@exeloncorp.com

Thomas J. Sniscak, Esquire
Whitney E. Snyder, Esquire
Phillip D. Demanchick, Jr., Esquire
Hawke McKeon & Sniscak, LLP
100 North Tenth Street
Harrisburg, PA 17101
tjsniscak@hmslegal.com
wesnyder@hmslegal.com
pddemanchick@hmslegal.com

John F. Lushis, Jr., Esquire
David Berger, Esquire
Norris McLaughlin, P.A.
515 W. Hamilton Street, Suite 502
Allentown, PA 18101
jlushis@norris-law.com
dberger@norris-law.com

Brian R. Greene, Esquire
GreeneHurlocker, PLC
4908 Monument Avenue, Suite 200
Richmond, VA 23230
BGreene@GreeneHurlocker.com

Michael A. Gruin, Esquire
Stevens & Lee
17 N. Second Street, 16th Floor
Harrisburg, PA 17101
michael.gruin@stevenslee.com

A. Michael Gianantonio, Esquire
Robert Peirce and Associates
707 Grant St. 125 Gulf Tower
Pittsburgh, PA 15219
MGianantonio@peircelaw.com

James Laskey, Esquire
Norris McLaughlin, P.A.
400 Crossing Blvd., 8th Floor
Bridgewater, PA 08807
jlaskey@norris-law.com

May 9, 2022

/s/ Karen O. Moury
Karen O. Moury, Esq.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company for Approval of Their Default Service Programs for the Period From June 1, 2023 Through May 31, 2027	:	Docket Nos. P-2021-3030012 P-2021-3030013 P-2021-3030014 P-2021-3030021

DIRECT TESTIMONY OF

TRAVIS KAVULLA

ON BEHALF OF
RETAIL ENERGY SUPPLY ASSOCIATION
AND NRG ENERGY, INC.

TOPICS:
Competitive Retail Market
Default Service Provider Role
Time-of-Use Rates
Long-Term Solar Procurements
Recovery of Default Service Costs
Other Default Service Rate Issues
Customer Referral Program
Operational Issues

FEBRUARY 25, 2022

Table of Contents

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 1825 K. St. NW, Suite 1203, Washington, D.C. 20006.

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. Prior to joining NRG, 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. Before that, 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 RESA/NRG Exhibit TK-1, which is attached.

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

A. Yes. I submitted Direct and Surrebuttal Testimony in the proceeding initiated by the filing of the Petition of PECO Energy Company for Approval of Its Default Service Program for the Period from June 1, 2021 through May 31, 2025 at Docket No. P-2020-3019290. In that proceeding, I addressed several topics that are similar to the issues raised by the Joint Petition filed by Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company (collectively, the "Companies") for Approval of Their Default Service Programs ("DSP VI Petition"), along with their Direct Testimony.

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

A. Yes. 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, Maryland, Minnesota, New Jersey, New York, and Rhode Island.

Q. ON WHOSE BEHALF IS THIS DIRECT TESTIMONY OFFERED?

This Direct Testimony is offered on behalf of the Retail Energy Supply Association[1] ("RESA") and NRG. As electric generation suppliers ("EGSs") licensed by the

[1] The comments expressed in this filing represent the position of the Retail Energy Supply Association (RESA) as an organization but may not represent the views of any particular member of the Association.

Pennsylvania Public Utility Commission ("Commission"), RESA members and NRG subsidiaries supply generation services to retail consumers in the Companies' service territories. RESA is a trade association of energy companies including Pennsylvania licensed EGSs that supply electric generation service to retail customers in the Companies' distribution service territories and throughout the Commonwealth.

NRG is a leading integrated power company built on dynamic retail brands and diverse generation assets. NRG is the leading integrated energy and home services company powered by its customer-focused strategy, strong balance sheet, and comprehensive sustainability framework. A Fortune 500 company, NRG brings the power of energy to millions of North American customers. Our family of brands help people, organizations and businesses achieve their goals by leveraging decades of market expertise to deliver tailored solutions. Working in concert, its dynamic multi-brand retail strategy coupled with supply risk-management forms a uniquely positioned, integrated competitive energy provider. Its retail brands serve more than six million customers across North America, including a significant share in Pennsylvania, so significant, in fact, that NRG's northeast retail business is headquartered in Philadelphia. NRG's subsidiaries include several EGSs that are actively serving residential, commercial, industrial and institutional customers in the Companies' service territories and throughout Pennsylvania.[2]

Founded in 1990, RESA is a broad and diverse group of retail energy suppliers dedicated to promoting efficient, sustainable and customer-oriented competitive retail energy markets. RESA members operate throughout the United States delivering value-added electricity and natural gas at retail to residential, commercial and industrial energy customers. More information on RESA can be found at www.resausa.org.

[2] As EGSs in Pennsylvania, NRG subsidiaries hold licenses as follows: Direct Energy Business, LLC – Docket No. A-11025; Direct Energy Business Marketing, LLC – Docket No. A-2013-2368464; Direct Energy Services, LLC – Docket No. A-110164; Energy Plus Holdings LLC – Docket No. A-2009-2139745; Gateway Energy Services Corporation – Docket No. A-200902137275; Independence Energy

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to offer the perspectives of RESA and NRG on various aspects of the Companies' DSP VI Petition for the period of June 1, 2023 through May 31, 2027. Specifically, my Direct Testimony addresses the following issues:

- General Observations About Competitive Retail Market Today
- Importance of Revisiting Default Service Model
- Time-of-Use Rates
- Long-Term Solar Procurement
- Need to Ensure Default Service Rates Recover All Costs
- Other Default Service Rate Issues
- Customer Referral Program
- Operational Issues

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 open one or more proceedings following the entry of an Order on the Companies' DSP VI Petition to:

  (1) reexamine the current structure of default service and consider whether it should be modified so that it is truly a back-stop option that is supplied by EGSs; and

  (2) revisit the default service regulations and policy statement and determine whether revisions should be made to ensure that electric distribution companies ("EDCs") are recovering all default service costs through the default service rates.
- In tandem with allowing the Companies to offer a time-of-use ("TOU") rate, the Commission should approve the TOU rate as the standard default rate;
- The Commission should dispense with the misnomer of "Price to Compare" when referring to default service rates;

Group LLC d/b/a Cirro Energy – Docket No. A-2011-2262337; Reliant Energy Northeast LLC d/b/a NRG Home/NRG Business/NRG Retail Solutions – Docket No. A-2010-2192350; Green Mountain Energy Company – Docket No. A-2009-2139745; Stream Energy Pennsylvania, LLC – Docket No. A-2010-2181867; and XOOM Energy Pennsylvania, LLC – Docket No. A-2012-2283821.

- The Commission should not permit the Companies to transition from quarterly to semi-annual adjustments of their default service rates;
- The Commission should reject the Companies' 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 modify certain aspects of the existing Customer Referral Program to increase participation by consumers; and
- The Commission should require the Companies to address lingering operational issues affecting EGSs' ability to bill for supply services and get paid.

Q. ARE YOU SPONSORING ANY EXHIBITS?

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

RESA/NRG Exhibit TK-1	Kavulla Resume
RESA/NRG Exhibit TK-2	Lacey Article – Public Utilities Fortnightly
RESA/NRG Exhibit TK-3	Lacey Article – The Electricity Journal
RESA/NRG Exhibit TK-4	Statewide Shopping Statistics – January 2022
RESA/NRG Exhibit TK-5	Statewide Shopping Statistics – January 2017
RESA/NRG Exhibit TK-6	Companies' Response to RESA/NRG-II-1
RESA/NRG Exhibit TK-7	Companies' Response to OCA-I-21
RESA/NRG Exhibit TK-8	Companies' Response to OCA-I-34
RESA/NRG Exhibit TK-9	Companies' Response to OCA-I-31
RESA/NRG Exhibit TK-10	Companies' Response to OCA-I-27
RESA/NRG Exhibit TK-11	Companies' Response to OCA-I-32
RESA/NRG Exhibit TK-12	Reliant – Sample Bill
RESA/NRG Exhibit TK-13	Companies' Response to OCA-I-24
RESA/NRG Exhibit TK-14	Companies' Response to OSBA-I-10
RESA/NRG Exhibit TK-15	Companies' Response to RESA/NRG-I-3
RESA/NRG Exhibit TK-16	Companies' Response to Shipley-II-5 and Shipley-II-6
RESA/NRG Exhibit TK-17	Companies' Response to RESA/NRG-I-4
RESA/NRG Exhibit TK-18	Companies' Response to Shipley-I-8
RESA/NRG Exhibit TK-19	Companies' Response to RESA/NRG-I-6
RESA/NRG Exhibit TK-19	Companies' Response to RESA/NRG-I-6
RESA/NRG Exhibit TK-20	RESA PA - Energy Market Savings Report for December 2021
RESA/NRG Exhibit TK-21	Companies' Response to OCA-I-7, Att. D
RESA/NRG Exhibit TK-22	Companies' Responses to OCA-I-10, Att. C, and Shipley-I-3, Att. A
RESA/NRG Exhibit TK-23	Companies' Responses to Shipley-I-1, Att. A, and Shipley-I-4
RESA/NRG Exhibit TK-24	Companies' Responses to Shipley-I-5
RESA/NRG Exhibit TK-25	Screen Shots of Companies' Website
RESA/NRG Exhibit TK-26	Companies' Responses to RESA/NRG-II-6 and RESA/NRG-II-7

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

A. I have reviewed the Companies' DSP VI Petition and the Direct Testimony of Joanne M. Savage,[3] James H. Catanach,[4] and Patricia M. Larkin,[5] as well as their accompanying exhibits. I have also reviewed the Companies' responses to discovery propounded by RESA and NRG, along with some responses provided at the request of other parties in this proceeding. In addition, I have refamiliarized myself with the provisions in Pennsylvania's Electricity Generation Customer Choice and Competition Act ("Competition Act")[6] that pertain to default service, along with the Commission's default service regulations[7] and policy statement governing default service.[8] Further, I have reviewed NARUC's "Electric Utility Cost Allocation Manual" ("NARUC CAM")[9] and NARUC's Guidelines for Cost Allocation and Affiliate Transactions ("NARUC Guidelines").[10] Additionally, I have examined a report released in 2020 by the Wind Solar Alliance, which was authored by Rob Gramlich and Frank Lacey.[11] Finally, I have studied an article authored by Mr. Lacey entitled "Default Service Pricing Has Been

---

3 Companies' St. No. 1.

4 Companies' St. No. 2.

5 Companies' St. No. 3.

6 66 Pa. C.S. §§ 2801-2815.

7 52 Pa. Code §§ 54.181-54.190.

8 52 Pa. Code §§ 69.1801-69.1817.

9 https://pubs.naruc.org/pub.cfm?id=53A20BE2-2354-D714-5109-3999CB7043CE (last accessed February 25, 2022).

10 https://pubs.naruc.org/pub.cfm?id=539BF2CD-2354-D714-51C4-0D70A5A95C65 (last accessed February 25, 2022).

11 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 (last accessed January 31, 2022).

Wrong All Along – Allows Utilities to Maintain Dominance in Markets," which was published in Public Utilities Fortnightly in January 2019,[12] and another article authored by Mr. Lacey called "Default service pricing – The flaw and the fix: Current pricing practices allow utilities to maintain market dominance in deregulated markets," which was published in the Electricity Journal in April 2019.[13]

II. GENERAL OBSERVATIONS ABOUT COMPETITIVE RETAIL MARKET

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS ON THE COMPETITIVE RETAIL MARKET THAT EXISTS IN PENNSYLVANIA TODAY?

A. I do. Pennsylvania historically has been a leader in opening its market to competition, for the benefit of consumers. When I led the National Association of Regulatory Utility Commissioners ("NARUC") 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. A review of PaPowerSwitch, the Commission's shopping website, reveals that 26.7% of Pennsylvania's retail customers were purchasing electric generation supply from EGSs as of January 31, 2022, with only 24.7% of residential customers purchasing supply from EGSs.[14] Five years earlier, as of January 31, 2017, 36.9% of Pennsylvania's retail

12 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 RESA/NRG Exhibit TK-2.

13 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 RESA/NRG Exhibit TK-3.

14 https://www.papowerswitch.com/media/hk5lcnwp/paps_numbers123121.pdf (last accessed February 15, 2022). For ease of reference, the results are also attached as RESA/NRG Exhibit TK-4.

customers were purchasing electric generation supply from EGSs, while 35.3% of residential customers were purchasing supply from EGSs.[15]

Q. HAVE YOU ALSO REVIEWED INFORMATION ABOUT THE LEVEL OF SHOPPING IN THE COMPANIES' SERVICE TERRITORIES?

A. Yes. According to the Companies' responses to RESA/NRG discovery requests, shopping by residential customers has steadily and meaningfully declined over the past five years in each of the Companies' service territories. The chart below shows the percentages of residential customers who were purchasing electric supply from EGSs in January 2017, as compared to January 2022.[16]

Operating Company	January 2017	January 2022
Metropolitan Edison Company	34.96%	22.14%
Pennsylvania Electric Company	30.96%	19.47%
Penn Power Company	28.17%	18.79%
West Penn Power Company	28.14%	18.6%

While not as significant of declines, the commercial classes also have fewer customers purchasing supply from EGSs in 2022 than they had five years ago. Commercial customer shopping statistics have gone down from 46.9% in January 2017 to 40.77% in January 2022.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THESE STATISTICS?

A. This downward trend in customers participating in the competitive retail market is significant and warrants recognition by the Commission of a need to make structural

[15] These results are attached as RESA/NRG Exhibit TK-5.

[16] The Companies' entire response to RESA/NRG Set II-1, from which this chart was derived, is attached as RESA/NRG Exhibit TK-6.

changes to the market. 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 has a choice – either to let electric distribution companies ("EDCs") continue to monopolize the market, or to take steps to leverage the competitive market to its original, intended purposes. Action in this proceeding for the Companies is warranted based on the facts and circumstances of their service territories.

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. The Wind Solar Alliance Report released in March 2020 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. This dynamic arises in the persistent cross-subsidization that causes distribution customers, including those who have chosen a product other than the Companies' default service, to nevertheless pay for costs related to that 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[17]—biases customers toward the entity that physically meters them and bills them. As I will explain later, these general principles can be seen in the context of the Companies' provision of default service and resulting impacts on the competitive market.

[17] 66 Pa.C.S. § 2807(e).

Q. WHAT ARE THE NEGATIVE CONSEQUENCES?

A. The Wind Solar Alliance Report focuses on one negative consequence, the hesitancy of EGSs to enter into long-term supply contracts to serve their customers. This reality is present in Pennsylvania and other states that have a similar, domineering DSP. Simply put, EGSs are reluctant to make longer term investments in the market so long as the historical monopoly provider both dominates the market by a default arrangement that consistently directs supply customers back to it while it also continues to receive the benefit of a regulatory model of assured cost recovery from all distribution ratepayers. EGSs do not have a guaranteed customer recovery mechanism or a captive base of ratepayers through which to funnel the costs of providing supply service. Instead, EGSs must work to earn and keep every single customer and stake their own capital at risk. The current DSP model is not a feasible one to incent EGSs 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 the DSP while hampering the ability of EGSs to develop more innovative and a greater variety of competitive products and services for consumers

Ironically, these negative developments lead DSPs to offer proposals to further tinker with default service to solve what the market does not seem to be offering. For example, in this proceeding, the Companies have proposed a long-term solar purchase to benefit default service customers only, requiring ratepayers to bear the burden if the solar purchase ends up costing more than the market price. As the Wind Solar Alliance scorecard for Pennsylvania suggests, there is much room for improvement[18] and the

[18] Wind Solar Alliance Report, p. 19.

proposals offered by the Companies are not the solution; rather, the default service model itself needs to be addressed. 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. There are certain investments in generation made on the strength of longer-term retail contracts of large customers, some of whom may obtain naming rights or other social benefits from visibly associating themselves with new renewable generation projects. Other investments are undertaken through commandeering public policy mandates. And perhaps most of all, investments in generation continue to be 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, however, 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.[19] 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 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.

---

[19] Potomac Economics, acting as ERCOT Independent Market Monitor, *Review of Summer 2019*, p. 23. https://interchange.puc.texas.gov/Documents/49852_6_1036679.PDF (last accessed February 25, 2022).

Q. WHAT SPECIFIC IMPROVEMENTS HAVE YOU IDENTIFIED?

A. I propose a number of specific improvements including: (i) a Commission commitment to launch a separate proceeding that focuses on transitioning the DSP role from EDCs to EGSs; (ii) to the extent that the Commission determines to retain the existing structure with EDCs in this role, a commitment to examination of the default service rates to ensure that they recover all costs related to the provision of default service, including indirect costs incurred by an EDC on a company-wide basis; (iii) adoption of the Companies' proposed time of use rate as the singular default service option, avoiding the needless complication of having multiple "default" offerings, some more reflective of wholesale costs than others; (iv) rejection of the Companies' proposal to transition from quarterly to semi-annual adjustments of the default service rates; (v) discontinuance of the use of the misnomer "Price to Compare" when referring to default service rates; (vi) rejection of the Companies' proposal to solicit new ten-year contracts for solar energy; (vii) implementation of modifications to the existing Customer Referral Program ("CRP") to encourage greater participation by consumers; and (vii) resolution of operational issues affecting the ability of EGSs to bill for supply services and get timely paid for the same.

III. <u>REEXAMINATION OF DEFAULT SERVICE PROVIDER ROLE</u>

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

A. I believe that Pennsylvania needs to reexamine the structure that places EDCs in the default service role by launching a separate proceeding within 180 days of the issuance of a Final Order in this proceeding. Pennsylvania law requires a DSP to supply non-shopping customers, or customers whose EGS has defaulted or otherwise not performed.[20] However, the law's requirement that the EDCs fill this DSP role ended when their retail generation rate caps expired,[21] which occurred for the Companies during the 2009-2011 timeframe.[22] For over a decade, the Commission has had the statutory ability to designate an "alternative supplier" of default service in the EDC's service territories.[23] 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 purchasing supply from EGSs, either by selecting an EGS or by receiving "default service" from an EGS.[24]

In 2012, former Commissioner James 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."[25] He pointed out that this "is

[20] 66 Pa.C.S. § 2807(e)(3.1).

[21] 66 Pa.C.S. § 2807(e)(1).

[22] 66 Pa.C.S. § 2807(e)(1); *See Joint Petition of Metropolitan Edison Company and Pennsylvania Electric Company for Approval of Their Default Service Program, See, Joint Petition of Metropolitan Edison Company and Pennsylvania Electric Company for Approval of Their Default Service Program*, Docket Nos. P-2009-2093053, P-2009-2093054 (Order entered Nov. 6, 2009); *Petition of Pennsylvania Power Company for Approval of Default Service Program for the Period from January 1, 2011 through May 31, 2013*, Docket No. P-2010-2157862 (Order entered November 17, 2010); *Petition of the West Penn Power Co. d/b/a Allegheny Power for Approval of its Retail Elec. Default Serv. Program and Competitive Procurement Plan for Service at the Conclusion of the Restructuring Transition Period*, Docket No. P-00072342 (Order entered July 25, 2008).

[23] 66 Pa.C.S. § 2803, definition of "default service provider."

[24] *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 (last accessed February 25, 2022).

[25] *Investigation of Pennsylvania's Retail Electricity Market*, Docket No. I-2011-2237952 (Concurring and Dissenting Statement dated September 27, 2012) at 1. https://www.puc.pa.gov/pcdocs/1192963.pdf (last accessed February 25, 2022).

especially so when customers are accustomed to receiving complete service from their electric utility."[26] 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 "mass market customers, including residential and small commercial customers, often will not make affirmative choices for their supplier unless they are required to."[27]

While RESA and NRG are not advocating as part of this proceeding that the Companies' default service option be eliminated for any class of customers, Commissioner Cawley's observations underscore the importance of the Commission launching a proceeding to reexamine the existing default service model. Commissioner Cawley was voicing what has in the years since become widely accepted: that government regulation establishes a "choice architecture"[28] 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."[29]

---

[26] *Id.*

[27] *Id.* at 2.

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

[29] Daniel Kahneman, *Thinking, Fast and Slow* (2011), p. 413.

Q. WHAT ARE SOME KEY BENEFITS OF REEXAMINING THE CURRENT MODEL OF HAVING THE UTILITY AS THE 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 scrutiny by the Commission. In addition, there are several other benefits of not having a dominant DSP serving the vast majority of the market, especially an entity that is an EDC.

First, if other entities assume the DSP role, this model will enable the EDCs to focus on their 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 the Companies' default service. 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.[30] Third, the DSP could be institutionally responsible for administrating the "choice architecture" that leads customers to more actively choose, while currently the Companies' programs have not resulted in a substantial increase in shopping, as evidenced by the slowing traffic now seen in the CRP described below.

Q. WHY ARE YOU PROPOSING THAT THE COMMISSION ADDRESS THIS ISSUE AS PART OF A SEPARATE PROCEEDING?

A. RESA and NRG recognize that the Commission would likely prefer to address changes to the default service structure model on a statewide basis, and that approach benefits EGSs as well since these issues would be handled uniformly throughout the Commonwealth. The evidence in the record in this proceeding of the declining shopping statistics in the Companies' service territories shows a need for Commission action, such as through an Office of Competitive Market Oversight-led collaborative following a timeline established by the Commission. Other retail market enhancements, such as Purchase of Receivables Program and Standard Offer Programs, have had their genesis in default service proceedings.[31] Additionally, the FirstEnergy Companies' merger proceeding was the catalyst for the Commission's Retail Markets Investigation.[32]

---

30 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).

31 *See, e.g., Joint Petition of Metropolitan Edison Company and Pennsylvania Electric Company for Approval of Their Default Service Programs*, Docket Nos. P-2009-2093053 and P-2009-2093054) (Order entered November 6, 2009, at 42); *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-2011-2273650, P-2011-2273668, P-2011-2273669 and P-2011-2273670 (Order entered August 16, 2012, at 146-150).

32 *Joint Application of West Penn Power Company d/b/a Allegheny Power, Trans-Allegheny Interstate Line Company and FirstEnergy Corp. for a Certificate of Public Convenience under Section 1102(a)(3) of the Public Utility Code approving a change of control of West Penn Power Company and Trans-Allegheny Interstate Line Company*, Docket Nos. A-2010-2176520 and A-2010-2176731 (Order entered March 8,

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 the Companies serve as DSP. I now turn to those topics.

IV. TIME-OF-USE RATES

A. Companies' Proposal

Q. WHAT DO THE COMPANIES PROPOSE WITH RESPECT TO TOU RATES?

A. In the DSP VI Petition, the Companies note that they currently offer optional TOU pricing through their Rider K, Residential TOU Default Service Riders. Further, as part of the DSP V Settlement, the Companies explain that they agreed to make a specific proposal regarding their residential TOU rate offerings in the earlier of their first base rate case or DSP VI following full implementation of smart meter back-office functionality. Since this functionality and the smart meter plan are expected to be fully implemented as of December 31, 2022, the Companies are proposing to implement new TOU rates in this proceeding.[33]

Through Direct Testimony, Ms. Larkin describes the key features of the Companies' proposed TOU rate design, explaining that prices will be differentiated across three periods (on-peak, super off-peak and off-peak). Further, she notes that the

2011, at 46-47); *Investigation of Pennsylvania's Retail Electricity Market*, Docket No. I-2011-2237952 (Order entered April 29, 2011, at 2).

[33] DSP VI Petition, ¶ 50.

Companies' proposal is "designed to motivate customers to shift usage to lower-cost, off-peak hours."[34] She also explains that the TOU pricing periods are identical for the Residential and Small Commercial Classes. As she testifies, the "proposed TOU rate design is structured to establish a rate premium compared to the Companies' standard, on-time varying default service rate during the on-peak period and rate discounts from the applicable PTC Rider rate during two off-peak periods."[35]

Q. HAVE THE COMPANIES PROPOSED TO PLACE ANY RESTRICTIONS ON THE ELIGIBILITY OF CONSUMERS TO SELECT THE TOU RATE?

A. Yes. Residential customers enrolled in the Companies' Customer Assistance Programs will not be eligible for the TOU Rate. In addition, if a customer decides to leave the TOU Rider for any reason, the customer is not eligible to re-enroll in the TOU Rate for twelve months.[36]

B. Importance of TOU Rates

Q. DO YOU OPPOSE THE COMPANIES' PROPOSAL TO OFFER TOU RATES?

A. On the contrary, there is much to support in it. It is an important and overdue development. I have been advised by counsel that as DSPs, the Companies have a legal obligation to offer such a rate to essentially all customers with smart meter technology.[37]

The Companies commenced their smart-meter deployment in 2014[38] and by May 15, 2019 had achieved their goal of 98.5% saturation of smart meters, with approximately

---

34 Companies' St. No. 5 at 15.

35 Companies' St. No. 5 at 15.

36 Companies' St. No. 5 at 16.

37 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).

38 Companies' 2015 Smart Meter Technology Procurement and Installation Plan Annual Progress Report filed at Docket Nos. M-2013-2341990, *et al.* (last accessed February 17, 2022).

99% (2.063 million) of all smart meters having been deployed by June 30, 2019.[39] As of June 30, 2021, the Companies had invested over $920 million in smart meters.[40] By December 31, 2022, the smart meter plan is expected to be fully implemented.[41] The roll-out has resulted in smart-meter technology being nearly ubiquitous for the Companies' residential and small commercial customers who will be eligible for the proposed TOU Rate. 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."[42] And yet, even as the Companies' customers have paid handsomely for this investment, several years later they have little to show for it—at least as regards "smart" rates.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE PROPOSED TOU RATE?

A. The Companies are proposing to offer their TOU Rate as an opt-in for residential and commercial customers. This will not result in substantial enrollment in or visibility for the TOU Rate. As I explain below, the current iteration of TOU offered by the

---

39 Companies' 2019 Smart Meter Technology Procurement and Installation Plan Annual Progress Report filed at Docket Nos. M-2013-2341990, *et al.* (last accessed February 17, 2022).

40 Companies' 2021 Smart Meter Technology Procurement and Installation Plan Annual Progress Report filed at Docket Nos. M-2013-2341990, *et al.* (last accessed February 17, 2022).

41 Companies' St. No. 1 at 6.

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

Companies has enrolled *less than a hundred customers*. I recommend that the TOU Rate should be *the* default service rate available to non-shopping customers. Customers who do not wish to be on the TOU Rate would be free to opt-out to an EGS product.

The default rate should be a rate structure that better reflects underlying market-price dynamics and the foundational principles of cost allocation. For example, the Companies have appropriately proposed to allocate capacity-related costs to the peak period of TOU rates.[43] Those costs are driven by and incurred upon the basis of customers' usage at peak times, not off-peak times. It is therefore appropriate that a "default" product reflect to a more appropriate degree an allocation of these costs, which the TOU Rate does and which a round-the-clock default rate does not do. A default TOU Rate takes advantage of the expensive investment in ubiquitous smart-meter technology, consistent with the expectations of those regulators who authorized the capital spending on which the company earns a return, as Commissioner Powelson's opinion quoted above denotes. In my experience, a seminal problem of utility regulation is that utilities, once capital investments are approved in rate base, have very little incentive to operationalize them to their maximum efficiency. Specifically in this case, the current default service rate does not take advantage of this substantial investment in smart meter technology. I note that the Commission has already referred to TOU rates as a "form of default service."[44] The next natural step is to make the Companies proposed TOU Rate, with our proposed modifications, the default service rate.

[43] Companies St. No. 5 at 18.

[44] Companies' St. No. 5 at 20, footnote 14, citing *Pa. P.U.C. v. PPL Elec. Utils. Corp.*, Docket No R-2011-2264771 (Opinion entered August 30, 2012 at 22-23).

Q. IS THERE ANOTHER REASON FOR MOVING IN THIS DIRECTION?

A. Yes. On February 4, 2022, ChargEVC-PA filed a Petition to Initiate a Proceeding to Issue a Policy Statement on electric utility rate design for electric vehicle ("EV") charging in Pennsylvania.[45] As an advocate for advanced EV adoption, ChargEVC-PA highlights the importance of time-varying rates that provide a clear price signal to customers to avoid charging during peak times when system costs and demand are high. By approving the Companies' proposed TOU Rate as the default service rate, with the modifications proposed by RESA and NRG, the Commission would be promoting the adoption of EVs in Pennsylvania. Indeed, the proposal advanced here by RESA and NRG is consistent with the sentiments previously expressed by the Commission regarding the need for the availability of TOU rate offerings to facilitate EV adoption.[46] I also note that the Companies have explained that they incorporated a super-off peak pricing period in the proposed TOU rate design to provide cost savings to customers who elect the TOU Rate and charge their EVs during the overnight low-priced energy hours.[47]

Q. HOW DO YOU RECOMMEND STRUCTURING THE PROPOSED TOU RATE DESIGN?

A. I have reviewed the discovery, including confidential material, and I support the rate design proposed by the Companies for the TOU Rate. It coheres to cost allocation

---

45 The Petition is docketed at P-2022-3030743 and is available here. (last accessed on February 23, 2022).

46 *Investigation into Default Service and PJM Interconnection, LLC Settlement Reforms*, Docket No. M-2019-30071701 (Secretarial Letter issued January 23, 2020, at 6-7).

47 In response to the Commission's Secretarial Letter issued on January 23, 2020 at Docket No. M-2019-3007101 directing EDCs to explore time-varying rates in the context of EV expansion, the Companies incorporated a super-off peak pricing period in the proposed TOU rate design to provide cost savings to customers who elect the TOU Rate and charge their EVs during the overnight low-priced energy hours. RESA/NRG Exhibit TK-7 (Companies' Response to OCA-I-21).

principles in its allocation of capacity-related costs to the peak period. It is designed to shape peak energy pricing to well-documented price differentials that exist in the PJM marketplace in the relevant hours. And it is appropriate to establish a super-off-peak period, just as other jurisdictions have. It is indeed a more reasonable rate than a round-the-clock rate, and for that reason it should be *the* default rate. Moreover, I see nothing in the Companies' proposal that would make it infeasible for the Commission to adopt the proposed TOU Rate as *the* default rate.

The Companies are proposing to benchmark the TOU tiers off of the default auction results. It could be superior to place the TOU tiers as tranches out to be bid by those wholesalers participating in the DSP auction, and as part of that auction instruct bidders to price capacity-related costs into their bids for the on-peak tier of the TOU Rate. However, it is also an acceptable approach to accomplish the same effect through ratemaking that occurs after the auction, which is to say to conduct the DSP auctions as they have been proposed, establish the tiers based on the multipliers that the Companies have proposed, and then reconcile collected revenues to the costs of all elements of DSP.

Q. DOES THE COMMISSION HAVE THE AUTHORITY TO REPLACE THE CURRENT DEFAULT SERVICE PRODUCT STRUCTURE WITH A TOU RATE?

A. I am advised by counsel that it does. Nothing in the statute requires a specific "type" of default service rate, only that it be procured through competitive processes and that it be available to customers who do not elect a competitive market. I am aware that the statute provides that residential or commercial customers may elect to participate in TOU rates.[48] However, I do not believe that provision precludes the Commission from establishing

[48] 66 Pa.C.S. § 2807(f)(5).

TOU rates as the default service rate since as I explain above, customers can either elect to participate in the Companies' proposed time-varying rates or shop for their electric supply in the competitive market. While I understand that legal counsel will more fully explain this in briefing, my testimony focuses on all the policy reasons and benefits to customers that would result from adopting our recommendation.

C. Likely Success of Proposed TOU Rate

Q. HOW SUCCESSFUL ARE THE COMPANIES' CURRENT TOU RIDERS?

A. Approximately 1 residential customer for every 20,000 smart meters is enrolled in TOU. Or, in percentage terms, five-thousandths of one percent (0.005%) have enrolled. From June 2019 through December 2021, the number of residential customers enrolled in the current TOU Rider has ranged from 44 to 97 each month, with 95 residential customers enrolled as of December 2021.[49] This is an abysmal record that suggests that TOU will not be widely adopted unless major changes occur.

Q. DO THE COMPANIES ANTICIPATE GREATER ADOPTION OF THE PROPOSED TOU RATE?

A. The Companies have not estimated the number of residential customers who will enroll in the proposed TOU Rate.[50] In addition, I note that although the Companies plan to develop educational materials and intend to establish a web page dedicated to the TOU Rate, no customer outreach plans are available for review.[51] The Companies have also not yet designed the bill for the proposed TOU Rate.[52]

---

49 RESA/NRG Exhibit TK-8 (Companies' Response to OCA-I-34, including Attachment A).

50 RESA/NRG Exhibit TK-9 (Companies' Response to OCA-I-31).

51 RESA/NRG Exhibit TK-10 (Companies' Response to OCA-I-27).

52 RESA/NRG Exhibit TK-11 (Companies' Response to OCA-I-32).

Q. WHAT ARE YOUR OBSERVATIONS REGARDING THE LIKELY ADOPTION OF THE PROPOSED TOU RATE BY CUSTOMERS?

A. I see no reason to expect that the TOU Rate will be anything other than vastly undersubscribed. The Companies have no target for TOU enrollment, and they have not presented any enrollment plans that are likely to result in substantial enrollment. The Companies' recent history of enrollment is extremely underwhelming. It need not be this way. Other jurisdictions have wisely moved in the direction of actually making use of their smart-meter investments for retail rate applications, as was anticipated when these investments were approved in Pennsylvania.

Q. IN YOUR OPINION, WOULD IT BE JUST AND REASONABLE TO APPROVE A DEFAULT RATE IN THIS PROCEEDING THAT IS NOT TIME-OF-USE BASED?

A. After reviewing the Companies' work papers in support of their TOU Rate, my answer has to be "no." The TOU Rate appropriately allocates capacity-related costs to the peak period in a way that the Companies' default rate design does not. Approving a non-TOU rate as the default inevitably means a default rate that is substantially less cost-reflective, based on the Companies' own evidence. In light of that evidence, as well as what is now possible with smart meters, which allows the TOU Rate to become essentially ubiquitous, the experience of other jurisdictions that have adopted TOU as the default for residential customers, it would not be reasonable to approve a default rate that is not TOU.

Q. CAN YOU PROVIDE SOME EXAMPLES OF WHAT THOSE OTHER JURISDICTIONS HAVE DONE?

Yes. I will highlight several. Let me begin with **Michigan**, which decided to implement default TOU for residential customers after years of unimpressive results from opt-in programs. On June 30, 2015, the Michigan Public Service Commission ("MPSC") issued orders to make TOU rates available for smart-metered retail customers of DTE Electric

("DTE") and Consumers Energy Company by January 1, 2017, and to develop strategies for education, outreach, marketing and customer support necessary for successful implementation of TOU rates.[53] However, TOU rates remained purely opt-in, and participation among residential and small commercial customers was disappointingly low. At its May 15, 2020 meeting, the MPSC issued an order establishing TOU as the standard retail rate design for Consumers Energy Company.[54] The MPSC has given DTE until Summer 2023 to implement a TOU pricing structure to be applicable to its broader customer base.[55]

California was in a similar position to Pennsylvania in 2014; smart meters were installed throughout the state and policy support given for voluntary TOU rates, but very limited adoption was seen for residential customers.[56] The California Public Utilities Commission ("CPUC") had already recognized the value of mandatory TOU rates and had defaulted commercial and industrial customers to various types of TOU rates through action taken in 2008.[57] From the benefits seen from mandatory commercial and

---

[53] *In the matter, on the Commission's own motion to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11(3) et seq., with regard to DTE Electric Company*, MSPC Case No. U-17689, Order of June 20, 2015; *In the matter, on the Commission's own motion, to commence a proceeding to implement the provisions of Public Act 169 of 2014; MCL 460.11(3) et seq., with regard to Consumer Energy Company*, MPSC Case No. U-17688, Order of June 30, 2015 at 31-32. Available here. (last accessed February 24, 2022).

[54] *In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief*, MPSC Case No. U-20134, Order of May 19, 2020, Exhibit A at 3. Available here. (last accessed February 24, 2022).

[55] *In the matter of the application of DTE Electric Company for approval of its Advanced Customer Pricing Pilots*, MPSC Case No. U-20602, Order of February 6, 2021 at 6. Available here. (last accessed February 24, 2022).

[56] In 2014, Pacific Gas and Electric had 3.4% of residential customers on TOU rates, Southern California Edison 0.52%, and San Diego Gas and Electric 0.60%. See CPUC Decision 15-07-001, p. 90.

[57] CPUC Decision 08-07-045.

industrial TOU as well as the benefits seen in other jurisdictions, California mandated that utilities default all customers to TOU rates beginning in 2019.[58] The enactment was performed to reduce overall system costs and greenhouse gas emissions by reducing electric demand during the peak periods, when fossil energy was heavily relied upon. Analysis from pilot TOU programs in California found a roughly 3 to 6 percent decrease in summer peak period demand, with most customers seeing no change or slight decreases in their annual bills.[59] Protections were put in place to minimize the impact on price volatility and customer bills in the default TOU program.[60]

Finally, the Commission should refer to **Ontario**, a restructured jurisdiction like Pennsylvania, where TOU rates have been the default rates since 2005 for customers with installed smart meters, which are now ubiquitous. In adopting TOU rates as the default, the Ontario Energy Board reasoned that the TOU pricing was developed to provide stable and predictable electricity pricing, encourage conservation and ensure the price consumers pay for electricity better reflects the price paid to generators. There, customer awareness and responsiveness to TOU rates is substantial, as documented by research the Ontario regulator has commissioned.[61] Additionally, making TOU rates the default have accomplished the real and intended effects in terms of changing customer behavior,

---

58 CPUC Decision 15-07-001. *See Adoption of electricity prices consistent with Decision 15-07-001*, 2016 WL 3167338 (Cal.P.U.C.)

59 California Statewide Opt-in Time-of-Use Pricing Pilot Final Report, March 2018, available at: https://energynews.us/wp-content/uploads/2020/09/Statewide_Opt-in_TOU_Evaluation-Final_Report-2.pdf (last accessed February 24, 2022).

60 For example, the times used and price differential was gradually changed over time so customers could adapt to the new rate structures. In addition, residential customers had bill protection in the first year to assure their annual bills for a similar amount of electricity was no higher than under a flat rate structure.

61 Ipsos Public Affairs, Ontario Energy Board - Consumer Perceptions Research - Phase 1: Qualitative Exploration, 2014, page 12; available at: https://www.oeb.ca/oeb/_Documents/EB-2004-0205/Ipsos_Reid_Consumer_Perceptions_Research_Report.pdf (last accessed February 24, 2022).

reducing capacity costs. Since the roll-out of the smart meters, the Ontario Energy Board has directed distribution companies to conduct research to gather information to assess the impact of TOU pricing. According to the Navigant Consulting report on the impact of TOU rates, TOU rates have led to a reduction in residential summer on-peak consumption as well as to a reduction in the average demand during the summer on-peak period.[62]

When Ontario Energy Board most recently reviewed its default TOU program in 2020, a report by Guidehouse recommended that the basic default TOU framework be retained, or augmented with additional characteristics that are even more dynamic.[63] Like I am proposing in this proceeding, customers who for whatever reason do not wish to be enrolled in Ontario's default TOU rate can and do shop for alternative products in the competitive retail market. In Ontario, consumers may also select an inverted block rate[64] offered as an opt-out from the default TOU; however, Ontario consumers may not select a "default" product like the Companies here propose, which is to say a round-the-clock price that does not vary based on usage or on time. If they wish to enter into a contract for such a product, they must do so via a competitive retailer who bears the uncertainty and hedging risk of the customer's usage relative to the open market. In sum, Ontario in its ratemaking decisions has wisely recognized that the job of regulation is to better align

---

62 Navigant Consulting: Time of Use Rates in Ontario – Part 1: Impact Analysis; available at: https://www.oeb.ca/oeb/_Documents/EB-2004-0205/Navigant_report_TOU_Rates_in_Ontario_Part_1_201312.pdf (last accessed February 24, 2022).

63 Guidehouse, Regulated Price Plan Pilot Meta-Analysis, December 22, 2020; available at: https://www.oeb.ca/sites/default/files/report-RPP-Pilot-Meta-Analysis-20211110.pdf

64 Also called a tiered rate, the rate design coheres to marginal cost principles albeit on a longer-run time scale by requiring a consumer to pay a higher price per kilowatt-hour when the customer's monthly usage increases beyond an initial block, e.g., 600 kilowatt-hours. In Ontario, this inverted block rate option is seasonal for residential consumers.

retail and wholesale and marginal-cost pricing, and is leveraging its investment in smart meters to accomplish that.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE EXPERIENCES OF MICHIGAN, CALIFORNIA, AND ONTARIO?

A. Principally, I conclude that regulators in other North American jurisdictions are gradually realizing that TOU will only be successful if enrollment is the default in the market's "choice architecture," and that regulators are increasingly comfortable with having TOU products as the default for residential customers—just as Pennsylvania already is comfortable doing so with certain customer classes today. Michigan, California, and Ontario have chosen to make use of their advanced-metering infrastructure to actually advance reforms that align residential retail rates better toward actual cost of service. These lessons may actually be more applicable to Pennsylvania than even certain jurisdictions like Michigan, which have largely rate-based generation and transmission investments. That is because, in default service, capacity-related costs *can* effectively be avoided, while in a purely cost-of-service environment with a concentrated and captive customer base, a lower demand throughput merely would mean higher rates. Consequently, the logic that Michigan and California regulators employed for their decisions would hold in Pennsylvania—and in fact be amplified due to the restructured nature of its market. Put another way, it is particularly important where a utility is offering a "default" product in a restructured market for that product to be reflective of actual pricing trends. Likewise, to the degree that captive customers of utilities in California or Michigan might be alienated by their monopoly utilities' ratemaking practices, Pennsylvania's market structure offers a relief valve that those states do not because it permits shopping for products, including those that are not TOU. Ontario, meanwhile, offers an example of a jurisdiction that has long adopted TOU for residential customers, has had success with it, and has iteratively improved upon it. All told, Pennsylvania should follow these examples, and ensure that it is leveraging the powerful tool of smart meters, as was intended.

Q. ARE YOU PROPOSING THAT THE TOU RATE BE THE DEFAULT RATE TO THE EXCLUSION OF OTHER DSP-OFFERED RATES?

Yes. Having multiple DSP rate products is needlessly confusing and gives the offerings within DSP an appearance of "shopping" when, of course, the rate-regulated offerings therein are merely a simulation of the competitive retail market and not intended to be a replacement for it. Since the law requires the DSP to offer a TOU Rate (but not a fixed rate), and since the TOU Rate here coheres to the principles of ratemaking in a manner that is superior to a fixed rate, the TOU Rate should be the one and only default rate offered by the DSP to each customer class. (Indeed, commercial customers with a peak load contribution of 100 kW already have a time-varying rate as their sole option for default supply.)[65]

This does not mean that customers will not have access to fixed-rate products. There are many, many products in the competitive retail market that offer customers fixed prices with term contracts. And of course, "fixed means fixed" in that market, as the Commission has required.[66] Meanwhile, when the DSP offers an ostensibly "fixed" rate it is subject to surcharges and reconciliations if the costs end up higher than collected revenues in the period for which that supposedly "fixed" rate is charged. A genuinely

---

[65] Companies' St. 1 No. 5 at 2-3.

[66] *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 rate is more appropriately offered by an EGS because offering a fixed rate naturally involves a risk associated with unanticipated customer load and wholesale prices, which risk it is an EGS's job to manage, hedge, and in any case bear unto itself. Part of the Companies' education in the rollout of a TOU Rate should be to inform customers who do not wish to take service under a TOU Rate of their options to be obtain genuinely fixed rates on term contracts from the competitive markets.

If, however, the Commission determines that a fixed-rate product nevertheless should be available through the DSP, it should not make this the default rate and it should enroll customers in it only upon their express request. In other words, the Companies should ensure that the TOU Rate is in all meaningful respects *the* default rate.

D. <u>Effect of DSP TOU Rate on Competitive Offerings</u>

Q. ARE THERE SHORTCOMINGS IN THE CURRENT RETAIL MARKET STRUCTURE THAT HAMPER THE ABILITY OF AN EGS TO OFFER TOU?

A. Yes. In tandem with the EDCs offering TOU products, reliance on EGSs in the competitive market to offer TOU rates is important to improving customer adoption of TOU rates and ensuring that the benefits of investment in smart meter technology are realized. A significant barrier faced by EGSs in making TOU rate offerings, however, is the inability to effectively present TOU rates on customers' bills in a way that shows the customers how their shifts in usage affect their energy costs. The only option that EGSs in Pennsylvania have for issuing bills to their customers is to send a dual bill, so that the customers are receiving two electric bills – one from their EDC and one from their EGS. Only the EDCs have the option of issuing consolidated bills because supplier consolidated billing has not been approved or implemented by the Commission. Customers have repeatedly told EGSs that they want to receive a single bill containing both the distribution and generation supply charges. As a result, for mass market customers, EGSs rely on the EDCs to bill their supply charges, and EGSs are limited to 4 lines on EDC's bills.[67] Despite the value that EGSs can offer in terms of TOU pricing and leveraging the investment in smart meter technology, the limitations of the EDC consolidated bill significantly hamper EGSs' efforts. For customers to understand how their shifts in energy usage are affecting their costs, they need to see these price signals.

Q. 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.[68] By contrast, the nationwide average for adoption of time-of-use rates by residential customers is a mere 1.7%.[69] 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. As an example of a customer relationship around such a product looks like, I am providing an example of a customer bill that retail provider Reliant, an NRG company, uses for its Reliant Free Weekends[SM] 12 in the Texas ERCOT market.[70]

---

[67] *Investigation of Pennsylvania's Retail Electricity Market: Joint Electric Distribution Company – Electric Generation Supplier Bill*, Docket No. M-2014-2401345 (Order entered May 23, 2014, at 13).

[68] Wind Solar Alliance Report, p. 4.

[69] Ryan Hledik et. al., *The National Landscape of Residential TOU Rates: A preliminary summary*, Brattle Group (Nov. 2017), available here. (last accessed February 24, 2022).

[70] RESA/NRG Exhibit TK-12.

Q. ARE YOU RECOMMENDING IN THIS PROCEEDING THAT THE COMMISSION DIRECT THE COMPANIES TO IMPLEMENT SUPPLIER CONSOLIDATED BILLING?

A. No. While RESA and NRG continue to pursue avenues for addressing this fundamental flaw in the competitive market, the Commission has been reluctant to move forward with this critical retail market improvement to delivering transparency and accountability to consumers. Therefore, instead of advancing this initiative as part of this proceeding, RESA and NRG are recommending that the Commission require the Companies to permit EGSs to display their supply charges in a way that shows the customer the impact of TOU pricing. Since the Companies are already redesigning their bills to show the proposed TOU Rate,[71] they should be obligated to afford EGSs a similar opportunity.

I am aware that the Office of Consumer Advocate asked in discovery whether the Companies' billing system allows an EGS to bill a different TOU rate structure than the option proposed in this filing. The Companies responded that their "billing system does not limit the terms of EGS products and contracts, including time-varying generation rates, provided to customers that are not enrolled in the Companies' Customer Assistance Programs."[72] While RESA and NRG are following up with additional discovery, I am interpreting the Companies' response as meaning that EGSs can offer their choice of TOU prices, but not that the Companies are committing to display TOU pricing of EGSs or provide sufficient space on the bill for EGSs to show the customers the impact of changing their behavior. All of this underscores the importance of the Commission revisiting supplier consolidated billing in the near future so that EGSs may be on a level

---

[71] Companies' St. No. 5 at 22.

[72] RESA/NRG Exhibit TK-13 (Companies' Response to OCA-I-24).

playing field in terms of showing customers how their shifts in usage affected their total energy bill. I also do not understand what is meant by the last part of the sentence in the Companies' discovery response since EGSs are not precluded from offering products and services, including time-varying generation prices, to customers who are enrolled in the Companies' Customer Assistance Programs.

Q. WHAT WILL LIKELY HAPPEN IF THE COMMISSION DOES NOT PURSUE SUPPLIER CONSOLIDATED BILLING IN THE NEAR FUTURE?

Several harms will occur. First, if EGSs are not afforded the same opportunity to present TOU products on bills that the Companies are giving themselves, the retail market will become more uncompetitive. It will result in a situation where only the Companies are allowed to offer time-varying rates effectively. The Commission has noted both the challenges faced by EDCs in offering TOU rates and the importance of relying on retail EGSs to offer TOU products,[73] but this will not occur if EGSs lack the ability to display their TOU pricing on customers' bills in a way that would make their TOU products 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

[73] *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.

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.[74] The Companies as DSPs take no such risk. Indeed, the Companies are proposing to socialize this risk not just to TOU customers—but to all its customers.[75] 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 as possible in the market offering TOU products so that they—and not customers—bear the risk of getting the retail price structure aligned to the actual value of energy supply at particular time periods balanced with the acceptability of these plans to customers.

Q. WHAT DO YOU RECOMMEND THE COMMISSION DO WITH RESPECT TO THE COMPANIES' TOU PROPOSAL AND TO ENSURE ITS COMPETITIVE NEUTRALITY WITH WHAT AN EGS MAY DO?

A. I recommend that the Commission adopt a retail market enhancement that permits EGSs the practical ability to market and bill TOU and like products to customers. The approval of the Companies proposal should be contingent upon the implementation of this enhancement, within a specified number of days after the issuance of a Final Order in this proceeding. And I recommend that the TOU product be the exclusive default service product made available to customers who do not elect a competitive supplier.

---

[74] These trade-offs are evident, for example, when the Companies describe why they are 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. Companies' St. No. 5 at 15; RESA/NRG Exhibit TK-14 (Companies' Response to OSBA-I-10).

[75] Companies' St. No. 5 at 20.

E. Specific Concerns with Companies' TOU Rate Proposal

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

A. The Companies should not be permitted to preclude residential customers who are enrolled in a CAP from being on the Proposed TOU Rate. This is not consistent with Pennsylvania law, in my understanding. The statute, and not the Companies or the Commission, defines the set of customers to which DSPs like the Companies must offer TOU products. This includes all customers who have a smart meter, except in certain limited circumstances associated with how and when the smart meter was first installed.[76] The mandate in the law does not make any exceptions. A fundamental feature of the Competition Act is choice, and all customers should have the same choices regardless of their income levels. Therefore, I recommend that all residential customers be eligible for the proposed TOU Rate. Indeed, if our recommendation that the proposed TOU Rate should be the default service rate is adopted, then customers enrolled in CAP cannot be precluded from receiving the rate.

Q. DO YOU HAVE ANY OTHER CONCERNS?

A. Yes. It is the budget and timeline along which the Companies propose to offer their TOU Rate. The Companies estimate only $300,000 in expenses for training and information

---

[76] *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.

technology changes to their billing and customer information systems to support TOU enrollment, billing, meter data management, customer service scripting, and net metering excess generation tracking, and provides relatively few details around this program.[77] The Companies suggest that the rate will be available in less than a year from when the Commission approves the TOU Rate in an order.[78] Based on my familiarity with TOU programs and my review 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 possibly a longer time horizon to implement a TOU rate that is intended to be widely adopted.[79] Of course, this is especially the case if the proposed TOU Rate is the default rate under the DSP.

Q. HAVE YOU FOUND ANY OMISSION IN THE COMPANIES' PROPOSAL?

A. Yes. The law requires a DSP with Commission-approved TOU rates 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."[80] It does not appear that the Companies, as part of their proposal in this proceeding, propose 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. The Companies should be directed to file such annual reports and appropriately allocate the costs of doing so the default service rate.

---

77 Companies St. No. 5 at 22.

78 *Id.* at 24.

79 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 (last accessed February 16, 2022).

80 66 Pa. C.S. § 2807(f)(5).

V. LONG-TERM SOLAR PROCUREMENT

Q. DO THE COMPANIES PROPOSE LONG-TERM SOLAR PROCUREMENT?

A. Yes. The Companies propose to continue procuring solar energy and solar photovoltaic alternative energy credits ("SPAECs") through multi-year, fixed-price power purchase agreements ("PPAs") with total capacity of at least 7 MW and up to 20 MW.[81] In his Direct Testimony, Mr. Catanach explains the Companies' proposal for the PPAs to have terms of greater than four and no more than 10 years from utility-scale and grid connected solar projects located in Pennsylvania.[82] As noted by Mr. Catanach, the Companies propose to allocate the SPAECs to default service suppliers based on the percentage of residential load they served in a compliance year.[83]

Q. DO RESA AND NRG SUPPORT THE COMPANIES' PROPOSAL FOR LONG-TERM SOLAR PROCUREMENT?

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 approve an alternative DSP—a barrier that would be present for 10 years. Moreover, the use of long-term contracts places the Companies' 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 DSPs 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.

---

81 DSP VI Petition, ¶ 15.

82 Companies' St. No. 3 at 21.

83 Companies' St. No. 3 at 23.

Q. WHAT IS YOUR RECOMMENDATION?

A. The Companies should require wholesale default service suppliers to deliver the full amount of their AEPS requirements and not pursue the proposed long-term solar procurement. Alternatively, the Commission should direct the Companies to modify solar procurement to four years to match the proposed DSP VI program period. In addition, the Commission should reject the Companies' proposal to procure SPAECs only for their non-shopping load.

Q. PLEASE EXPLAIN YOUR OBJECTIONS TO THE COMPANIES' 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 economically efficient way over that period of time. However, the proposed program period for this default service plan is four years. While the Companies have served as the DSP since the expiration of generation rate caps, both the statute and the Commission's regulations contemplate the possibility of the DSP role being shifted to an alternative default service provider such as an EGS.[84] 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.[85] Of note, the

---

[84] 66 Pa.C.S. §§ 2803; 2807(e)(5); 52 Pa. Code § 54.183.

[85] *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.

Companies acknowledged in responding to discovery that they have not determined how the remaining years of the contracts will be handled if the Commission, in the interim, were to approve a different entity to provide default service in the Companies' service territories.[86]

Q. ARE THERE PROTECTIONS FOR THE CUSTOMER THAT COULD BE WRITTEN INTO THESE CONTRACTS TO ADDRESS THIS CONCERN?

A. While I recommend this proposal simply be rejected, if the Companies' proposal is adopted, then the Commission should modify it by requiring the Companies to include in any contract that extends beyond their current DSP period language that relieves customers of any obligations whatsoever in relation to that contract if the Companies are not renewed as the DSP in subsequent periods. This will protect customers from stranded costs in the event of a change in law or regulatory policy as it relates to which entity provides DSP service in the Companies' service territories.

Q. ARE THERE OTHER REASONS WHY THE COMPANIES' PROPOSAL FOR LONG-TERM SOLAR PROCUREMENT SHOULD BE REJECTED?

A. Yes. Entering into long term contracts, as the Companies propose here, places their 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 the Companies risked their 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 the Companies 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 the Companies' consumers.

---

[86] RESA/NRG Exhibit TK-15 (Companies' Response to RESA/NRG-1-3).

Q. SINCE THE COMPANIES AS DSPS MUST ACQUIRE ALTERNATIVE ENERGY CREDITS, INCLUDING FOR THE SOLAR CARVE-OUT, WHAT DO YOU PROPOSE?

A. The simplest approach is to require the DSP's wholesalers to incorporate their estimated cost of solar 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 the Companies give no particular reason why, in effect, a portion of a subset of its AEC requirement—25% of its SPAEC 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, 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 Companies as DSPs 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. Yes. Unfortunately, when default supply utilities are allowed to use the promotion of solar development as a reason for them to enter the market with a supply agreement to support it, it hampers the willingness and ability of EGSs to undertake these projects themselves. It also hampers the willingness of solar developers to enter into contracts with EGSs when they know they can contract with the utility on a long-term basis and interferes with the ability of EGSs in the market to procure SPAECs. 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 competition is a rate-regulated utility with the ability to recover all its costs, even on bad deals. 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. In the approach I propose, the DSP will obtain sufficient SAECs through their wholesalers, who like EGSs are competitive actors that must manage their risk and costs. That ensures a substantially more level playing field than what the Companies are recommending in this proceeding.

Q. PLEASE EXPLAIN YOUR OBJECTIONS TO THE COMPANIES' PROPOSAL TO PROCURE SPAECS FOR ONLY THEIR NON-SHOPPING LOAD.

A. As an initial matter, I note that this proposal represents a departure from the Companies' prior practices. In the Direct Testimony of Mr. Catanach submitted with DSP V, he explained that Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec") and Pennsylvania Power Company ("Penn Power") would procure SPAECs for 100% of their shopping and non-shopping load. He further described this practice as being consistent with the process followed under DSP IV.[87] The model used by West Penn Power Company ("West Penn") differed in that West Penn proposed to continue requiring each default service supplier to provide SPAECs associated with the load served by the default service supplier. West Penn proposed an exception to that general rule for SPAECs procured under existing long-term contracts previously approved by the Commission would be used to reduce the number of SPAECs the default service suppliers would otherwise be obligated to transfer to West Penn.[88] The Commission approved these proposals.[89]

---

[87] Companies' St. No. 2 in DSP V at 23.

[88] *Id.*

[89] *Petition of Metropolitan Edison Company for Approval of a Default Service Program, et al.*, Docket No. P-2017-2637855, *et al.* (Order entered September 4, 2018).

Despite proposing to depart from past practices approved by the Commission for Met-Ed, Penelec, Penn Power and West Penn, the Companies offer no rationale for doing so. Indeed, in response to discovery in this proceeding, the Companies note that they will procure 100% of SPAECs on behalf of EGSs in 2022 and 2023, while procuring none for EGSs in 2024. They also confirm that the costs of SPAECs are presently recovered from all customers through Met-Ed, Penelec and Penn Power riders on a non-bypassable basis because they are allocated to both default service suppliers and EGSs.[90]

Besides the Companies failing to offer any justification for this departure from prior practices, their proposed approach is not based on sound rationale because it places EGSs competing in the retail market on an unlevel playing field with default service suppliers. When default service suppliers are not required to procure their own SPAECs, but EGSs are, the resulting prices for default service cannot be meaningfully compared to the prices charged by EGSs.

VI. RECOVERY OF DEFAULT SERVICE COSTS

Q. WHAT IS RESA AND NRG'S POSITION ON THE RECOVERY OF DEFAULT SERVICE COSTS?

A. Although the Companies incur substantial costs in providing default service, they have regulated distribution businesses that absorb many of those costs, effectively cross-subsidizing their default service offerings. If EDCs remain in the DSP role, it is critical that the default service rate actually reflects the costs that an EDC is incurring to provide default service so that the competitive market functions properly and delivers the benefits of a robust market to consumers.

[90] RESA/NRG Exhibit TK-16 (Companies' Responses to Shipley-II-5 and Shipley-II-6).

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

A. An important aspect of this proceeding is to design the Companies' default service rates to recover all of the costs associated with providing default service.[91] As such, the formula that is developed here will establish whether the design of the Companies' default service rates properly recover such costs. However, given the time constraints of this proceeding, and our preference for default service pricing being handled on a uniform basis throughout the Commonwealth, RESA and NRG are urging the Commission to further pursue these issues through a statewide proceeding, based upon the evidence we are presenting here.

Q. ARE THE COMPANIES RECOVERING ALL COSTS OF DEFAULT SERVICE THROUGH THE DEFAULT SERVICE RATE?

A. No. As I will explain, the Companies today are recovering no overhead or indirect costs that each of them incurs on a Company-wide basis to provide distribution service as an EDC and default service as a DSP through the rate for default service. All of these costs are recovered through their monopoly distribution rates.

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.

---

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

Q. ARE THE COMPANIES INCURRING OVERHEAD COSTS TO OFFER DEFAULT SERVICE?

A. Clearly they are. In this filing alone, the Companies propose to make IT upgrades to their billing and customer information systems. Yet they include only the estimated *incremental cost* of those system upgrades, rather than allocating embedded costs associated with these systems to their default service rates. The only costs reflected in the default rates are those that are directly attributable to default service.[92] This is the equivalent of a renter moving into an apartment building, but only being expected to pay to have the locks changed. Additionally, no costs for employees who work on both distribution service and default service issues are included in the default service rates.[93] The default service rates proposed by the Companies are designed to take a free ride on the considerable overhead expenses associated with employees who do work related to the Companies' role as DSPs, but whose costs are allocated entirely to distribution base rates.

These are only the most obvious examples. The reality is that the Companies have 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.

---

[92] Companies' St. No. 1 at 22; RESA/NRG Exhibit TK-17 (Companies' Response to RESA/NRG-I-4).

[93] RESA/NRG Exhibit TK-18 (Companies' Response to Shipley-I-8).

Q. DO THE COMPANIES CONCEDE THAT THEIR RATES FOR DEFAULT SERVICE REFLECT NO OVERHEAD COSTS?

A. Yes. The Companies indicated in response to discovery that their default service rates include "no indirect costs of providing default service."[94] Rather, the Companies propose to continue recovering all indirect costs that it incurs to operate both its distribution and default service businesses through distribution rates.

Q. HOW DO YOU RECOMMEND RECTIFYING THIS PROBLEM?

A. As I describe in further detail below, if the Commission decides to keep EDCs in the DSP role, I recommend rectifying this problem by the Commission launching a statewide proceeding that focuses on the cost categories that are in each EDC's rate for default service. Upon receipt of that information, the Commission should permit stakeholders to file comments identifying cost categories that the EDCs may have omitted. The Commission should then issue guidance via a revised policy statement, followed by the promulgation of regulations, which require the EDCs in the earlier of their next base rate case or DSP proceeding to include specific cost categories in the default service rate, rather than in distribution rates, along with proposed allocations of these costs as between default service and distribution service and a rationale for the proposed allocation method.

[94] RESA/NRG Exhibit TK-19 (Companies' Response to RESA/NRG-I-6).

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

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

A. The Commission regulations require the rate 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 rate 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 the default service rate should be designed to recover all generation, transmission and other related costs of default service. These cost elements include:[97]

(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 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.

95 52 Pa. Code § 54.187(e).

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

97 52 Pa. Code § 69.1808(a).

(5) Applicable taxes, excluding Sales Tax.

(6) Costs for alternative energy portfolio standard compliance.

B. <u>Cost Elements Included in the Companies' Rates for Default Service</u>

Q. WHICH COST ELEMENTS DO THE COMPANIES' RATES FOR DEFAULT SERVICE INCLUDE?

A. The Companies' rates for default service include the cost elements that the policy statement identifies in (a)(1)-(3) and (5)-(6). They also include certain costs associated with (a)(3)-(4). These elements reflect the costs directly attributable to default service that the Companies incur to pay for electricity in the wholesale market, the costs that the Companies incur to manage supply for over 1.5 million customers on default service, and the taxes and costs for alternative energy portfolio standard compliance.

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

A. The Companies' rates for default service include some of the administrative costs identified in (a)(3) and (4) of the policy statement but also omit certain of these costs and understate 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]

Q. WHICH ADMINISTRATIVE COSTS DO THE COMPANIES' RATES FOR DEFAULT SERVICE OMIT?

A. Of the cost elements identified by the policy statement for recovery through the default service price, the Companies' current rates for default service contain *no* administrative

[98] 52 Pa. Code § 69.1808(a)(4).

costs for billing, collection, education, tariff filings or information system. They include A&G expenses only if they are directly attributable to default service, such as the costs to conduct procurements, a default service independent evaluator to oversee the procurement process and the regulatory filing and litigation costs associated with the Companies' default service programs.[99]

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 THE COMPANIES SIMPLY DO 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 the Companies do not actually incur any of those costs, they should explain in detail their theory of how they do not. To use but one example, by allocating zero costs for A&G expense associated with executive compensation, the Companies are essentially asking the Commission to believe that their corporate executives do not spend a moment's time concerned about the Companies'

[99] RESA/NRG Exhibit TK-18 (Companies' Response to Shipley-I-8).

roles as DSPs, including highly visible issues like whether and how the Companies will enter into solar purchase agreements. That is not plausible.

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

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

A. Not only are the Companies ignoring the express terms of the Commission's policy statement and regulations, but also by failing to allocate any overhead costs to the rates for default service, they are allocating all of these costs to the regulated or monopoly distribution sides of their businesses. This means that all overhead costs, such as human resources costs, incurred by the Companies to each run their two businesses—of providing distribution service and default service—are recovered by the Companies wholly through distribution rates. As a result, the Companies are using their distribution revenues to subsidize the default service sides of their businesses, which are in direct competition with RESA members and NRG subsidiaries.

Q. IS THIS HARMFUL TO THE COMPETITIVE RETAIL MARKET?

A. Yes. By using monopoly revenues to subsidize the side of their businesses that are directly competing with RESA members and NRG subsidiaries, the Companies are charging prices for default service that are artificially low. When the default service is underpriced, consumers are deprived of the full range 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 RATE SETTING?

A. Yes. As I describe in our proposal for the Commission to launch a proceeding that reexamines the proper entity to perform in the role as DSP, the Commission may designate an "alternative supplier" to perform in the role of default service provider in lieu of the EDC.[100] 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 the Companies perform as EDCs/DSPs: 1) purchasing electricity for customers on their distribution systems who do not purchase their supply from the competitive market, and 2) delivering electricity to all customers on their distribution systems.

D. Companies' Proposal Runs Contrary to Industry Guidance

Q. DO THE COMPANIES' PROPOSAL TO ALLOCATE ZERO OVERHEAD COSTS TO THE RATES FOR DEFAULT SERVICE RUN COUNTER TO INDUSTRY GUIDANCE?

A. Yes. The Companies' proposal to allocate zero indirect costs to the rates for default service is inconsistent with the NARUC Cost Allocation Manual ("NARUC CAM") and NARUC Guidelines. Founded in 1889, NARUC is a non-profit organization dedicated to representing the state public service commissions who regulate the utilities that provide essential services such as energy. NARUC's mission is to serve the public interest by

---

[100] 66 Pa.C.S. § 2807(e)(3.1).

improving the quality and effectiveness of public utility regulation. NARUC members have an obligation to ensure that utility services are provided at rates and conditions that are fair, reasonable and nondiscriminatory for all consumers.[101] I was honored to serve as a leader in NARUC during my time as a state commissioner, including as its president in 2015-2016.

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."[102] 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."[103] The NARUC Guidelines also provide that "[t]he general method for charging indirect costs should be on a fully

---

[101] NARUC History and Background (last accessed February 14, 2022).

[102] NARUC CAM (last accessed February 14, 2022).

[103] NARUC Guidelines (last accessed February 14, 2022).

allocated basis."[104] This principle runs counter to the concept advanced by the Companies 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 DSPs 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.[105] 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." 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 distribution business."[106] Further, I agree with Mr. Lacey's conclusion 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

---

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

[105] RESA/NRG Exhibit TK-2 at 4.

[106] RESA/NRG Exhibit TK-2 at 5.

"one step will not create the perfect markets…it will remove a significant anti-competitive pricing advantage held by monopoly utilities."[107]

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 if the Commission rejects the recommendation to reexamine the role of the EDC as the DSP, the Commission open a separate proceeding within 180 days of the entry of a Final Order on the Companies' DSP VI, which reviews the cost categories that each EDC is currently including in its default service rate. RESA and NRG note that the failure of an EDC to include indirect costs in the default service rate was likewise demonstrated in the 2018 rate case filed by PECO Energy Company. While ultimately the Commission did nothing to correct the flawed pricing, no factual dispute existed in that proceeding regarding the omission of overhead costs from the default service rate, suggesting that this is not a problem that is limited to the Companies.[108] Indeed, RESA and NRG have no reason to believe that all of the EDCs are allocating indirect costs in the same manner as the Companies.

If the Commission accepts the recommendation to reexamine the role of the EDC as the DSP, I recommend that the Commission launch this separate proceeding within 360 days of the entry of a Final Order on the Companies' DSP VI if no changes are made to the current DSP model. After giving stakeholders an opportunity to comment or

---

[107] RESA/NRG Exhibit TK-3 at 44.

[108] *Pa. P.U.C. v. PECO Energy Division*, Docket No. R-2018-3000164 (Order entered December 20, 2018).

holding an evidentiary hearing, the Commission should issue an Order determining which cost categories support the provision of default service and directing the EDCs in the earlier of their next base rate case or DSP proceeding to include proposals for the allocation of these costs to default service. In this manner, the Commission would be assured that the EDCs are recovering all costs associated with default service through the default service rate, as required by the Commission's regulations.

VII. OTHER DEFAULT SERVICE RATE ISSUES

Q. DO YOU HAVE A RECOMMENDATION ABOUT THE CONTINUED USE OF THE TERM "PRICE TO COMPARE"?

A. Yes. Unless or until the accurate pricing of default service is addressed, the Commission should dispense with the misnomer – "Price to Compare" or PTC. Referring to the rate charged by EDCs as the PTC is misleading since the default service rate cannot be meaningfully compared to supplier prices. Largely, this is due to the issue I discuss above about the failure of the Companies to include all of the costs in the default service rate that are necessarily incurred to provide default service. In addition, EGSs frequently offer "green" products, which typically are more costly. EGSs also provide other value-added benefits ranging from airline miles to charitable contributions to reward programs that make price comparisons meaningless.[109] It is my hope and expectation that more EGSs will offer TOU and other time-varying rate products if the Commission follows what I recommend in that section of my testimony. The sum of this retail activity is this: More than 25 years after passage of the Competition Act, the focus should no longer be on what EGSs offer in comparison to the EDC's default service rate, but rather should be

[109] RESA's Pennsylvania Energy Market Savings Report for December 2021 is attached as RESA/NRG Exhibit TK-20. It shows examples of notable offers made by EGSs, including one year of free Amazon Prime, a National Park Pass, and a $50 contribution to the Children's Hospital of Philadelphia.

on competition among EGSs, who are each vying among themselves to serve retail electric customers in Pennsylvania. Any comparison to the default service rate is meaningless. Therefore, the Commission should discontinue use of the nomenclature "Price to Compare" and seek to ensure that the competitive market is structured in a way that promotes competition among EGSs. The price charged by the EDC, acting as DSP, for electricity should simply be referred to as the "default service rate."

Q. PLEASE DESCRIBE THE COMPANIES' PROPOSAL TO SHIFT FROM QUARTERLY TO SEMI-ANNUAL ADJUSTMENTS IN THEIR DEFAULT SERVICE RATE.

A. Through the Direct Testimony of Ms. Larkin, the Companies explain their proposal to shift from quarterly to semi-annual adjustments in the default service rates. The rationale provided by the Companies is that fluctuations in default service prices would be smoothed out and clearer pricing signals would be sent to customers and competitive suppliers.[110]

Q. WHAT ARE THE VIEWS OF RESA AND NRG ON THIS PROPOSED CHANGE?

A. RESA and NRG are opposed to the Companies' proposal to shift from quarterly to semi-annual adjustments of the default service rate. Contrary to the Companies' suggestion that this proposal would send clearer pricing signals, less frequent adjustments of the default service rate would actually further remove it from reflecting the market over time. As the Commission has previously recognized, default service rates inherently pass along false or misleading price signals due to reconciliation and the mix of contracts and often are "not correlated to wholesale energy markets and may move in directions opposite of

[110] Companies' St. No. 5 at 7.

wholesale energy market trends."[111] Moreover, the default service rate should not be designed to reduce volatility. To the extent consumers desire price stability, those offers are available in the competitive market. I further note that in pitching the CRP to customers, the Companies emphasize the fact that the EGS price will remain the same throughout the year rather than being adjusted on quarterly basis.[112] As I discuss below, enrollments in the CRP have been steadily declining in recent years. Consumers would likely be even less willing to sign up for the CRP if the default service rate is adjusting only on a semi-annual basis. Therefore, the Commission should reject the Companies' proposal to shift from quarterly to semi-annual adjustments of the default service rate.

Q. IF THE COMMISSION ACCEPTS THIS CHANGE, DO YOU HAVE ANY RECOMMENDATIONS?

A. If the Commission accepts this change, it should not require EGSs serving customers enrolled in CAP to keep prices at or below the Companies' default service rates for the entire term of the program. Such a requirement would further discourage EGSs from serving these customers since the prices it would be charging would not reflect current market conditions and, in fact, could be far below the costs incurred to provide electric generation supply. RESA and NRG recognize that this restriction is consistent with the Commission's proposed Policy Statement.[113] However, as that is only a proposal at this time, the Companies are not obligated to comply with all provisions of the order. Moreover, that approach wholly overlooks the fact that Companies' default service rate is

---

[111] *Investigation of Pennsylvania's Retail Electricity Market: End State of Default Service*, Docket No. I-2011-2237952 (Order entered February 15, 2013, at p. 12).

[112] RESA/NRG Exhibit TK-21 (Companies' Response to OCA-I-7, Attachment D).

[113] *Electric Distrib. Co. Default Serv. Plans – Customer Assistance Program Shopping, Proposed Policy Statement and Order*, Docket No. M-2018-3006578 (Order entered February 28, 2019).

artificially low in that it does not reflect any overhead costs associated with providing default service.

VIII. CUSTOMER REFERRAL PROGRAM

Q. PLEASE BRIEFLY DESCRIBE THE COMPANIES' PROPOSAL WITH RESPECT TO THE CUSTOMER REFERRAL PROGRAM.

A. As explained in the Direct Testimony of Ms. Savage, the Companies propose to continue the existing Customer Referral Program ("CRP") throughout DSP VI. Ms. Savage notes that the Commission directed script improvements to ensure that customers are reasonably being presented the opportunity to enroll in the CRP. The only modification proposed by the Companies is to reflect their proposal to modify adjustments in the default service rate from a quarterly to a semi-annual basis.[114]

Q. HAVE YOU EXAMINED THE RECENT TRENDS IN PARTICIPATION IN THE COMPANIES' CRP?

A. Yes. Based on discovery responses provided by the Companies, I note that enrollment in the CRP has steadily declined over the past few years.[115] For example, West Penn had 812 residential referrals in June 2019, which declined to 497 in June 2020 and to 298 in June 2021. A review of the other operating companies shows similar trends. My observation is that enhancements should be made to the CRP to reverse these trends and encourage greater participation in the CRP by customers. This is an important program that is designed to offer customers a risk-free way to participate in the competitive market and could be an effective introduction that gives customers an opportunity to understand the benefits that EGSs offer.

[114] Companies' St. No. 1 at 11-12.

[115] RESA/NRG Exhibit TK-22 (Companies' Responses to OCA-1-10, Attachment C, and Shipley-I-3, including Attachment A).

Q. DO RESA AND NRG HAVE SPECIFIC RECOMMENDATIONS FOR MODIFICATIONS?

A. Yes. RESA and NRG recommend that: (i) all new customers (who have not already made an affirmative choice of an EGS) be automatically enrolled in the CRP; (ii) the Companies be required to allow CRP signups from its website; and (iii) the Companies should be required to revisit the situations in which the CRP is mentioned, particularly to default service customers who contact the call center, and to otherwise engage in periodic communications, such as when changes to the default service rates occur, promoting CRP to all customers on default service.

Q. PLEASE EXPLAIN YOUR RECOMMENDATION FOR ALL NEW CUSTOMERS (OTHER THAN THOSE WHO HAVE ALREADY MADE AN AFFIRMATIVE 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 the Companies have of providing default service to about 80% of the residential customers on their systems. Since the CRP has been designed to give customers a 7 percent discount off the Companies' rate for default service, while also introducing customers to participation in the retail market,[116] no reason exists to initially place a customer on 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 has been successful in promoting consumer participation in

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

the market. Importantly, automatically placing these new customers on the CRP also eliminates the notion of the Companies' default service as the "first" service in which consumers enroll.

Q. PLEASE PROVIDE FURTHER DETAIL ABOUT THE ABILITY OF CUSTOMERS TO SIGN UP FOR CRP ONLINE.

A. The Companies have indicated that customers may not enroll online for the CRP, but have noted that customers may electronically sign up for service from the Companies.[117] 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 online for the CRP. Since customers can initiate service online, enrolling in the CRP could easily be incorporated in that process. Indeed, I note that the Companies propose in this proceeding that customers be able to enroll online in the proposed TOU Rate.[118] An added benefit of website enrollments is that since no third-party verification is required, the CRP fee should be waived or reduced.

Q. PLEASE FURTHER DISCUSS YOUR RECOMMENDATION TO EXPAND CONSUMER COMMUNICATIONS ABOUT THE CRP.

A. Given the significant drop in referrals over the past few years, RESA and NRG believe that it is necessary to revisit the situations in which consumers are told about the CRP. In discovery, the Companies indicated that the calls that trigger the offer of the CRP to residential and small commercial customers include a billing inquiry, customer choice calls or during a move-in for new or existing customers for transfers or services.[119] In addition to providing this information during these calls, the Companies should be

---

[117] RESA/NRG Exhibit TK-23 (Companies' Responses to Shipley-I-1, Attachment A, and Shipley-I-4).

[118] Companies' St. No. 5 at 21.

[119] RESA/NRG Exhibit TK-24 (Companies' Responses to Shipley-I-5).

directed to engage in periodic communications, such as quarterly when changes to the default service rates occur, promoting SOP to all customers on default service.

I also believe that the Companies should make the CRP more prominent on their websites. In response to discovery, the Companies explained the steps that must be taken to access this information. From each of the Companies' home pages, a Customer Choice link is located on the bottom right hand side. When that link is clicked, it takes the user to a page explaining Pennsylvania's electric choice program and lists several topics on the left.[120] The CRP is not included among those topics. Rather, to access CRP information, it is necessary to click on Pennsylvania on the tool bar, which takes the user to another page with a CRP link.[121] Upon clicking on the CRP link, a customer may access information about the CRP. A minor modification should be implemented so that the CRP link appears on the Customer Choice page, along with other information about competition.[122]

Through these additional efforts, RESA and NRG expect that default service customers would 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.

---

120 Customer Choice link. (last accessed February 24, 2022).

121 Pennsylvania link. (last accessed February 24, 2022).

122 Screen shots of relevant portions of each page described here are included in RESA/NRG Exhibit TK-25.

IX. OPERATIONAL ISSUES

Q. DO RESA AND NRG HAVE ANY OPERATIONAL ISSUES TO RAISE REGARDING THE COMPANIES' INTERACTIONS WITH SUPPLIERS?

A. Yes. EGSs have been experiencing significant delays in receiving customer usage data from the Companies that is needed to prepare and send billing information to the Companies. Under the bill ready approach, EGSs send the supply charges to the Companies for inclusion on bills, which reflect both the EGS prices and the customer's usage. Due to the delays that are occurring, EGSs are unable to send the bill ready supply charges for inclusion on the bills and are not getting timely paid.

Q. DO THE COMPANIES HAVE SUPPLIER TARIFF PROVISIONS ADDRESSING THE TRANSMITTAL OF INFORMATION TO SUPPLIERS?

A. Yes. In the Companies' Supplier Tariffs, they commit to supplying data that is reasonably required by an EGS in a thorough in timely manner. The Supplier Tariffs also obligate the Companies to make available to an EGS daily files containing meter readings, total kWh usage and other information for each EGS's customers as it becomes available by billing route. Further, under the Supplier Tariffs, the Companies are required to provide the EGS with sufficient meter data on a timely basis.[123] Despite these provisions, EGSs are experiencing delays of more than 90 days in obtaining the customer usage data that is needed to providing charges to be included on customers' bills.

Q. WHAT DO YOU RECOMMEND?

A. RESA members are working informally through the Companies' supplier portal to resolve this issue, which has been a long, drawn-out process. In response to RESA/NRG

[123] For e.g., see Metropolitan Edison Company Electric Pa. P.U.C. No. S-1, Original Pages No. 16, 4.10 (Supply of Data), No. 30, 10.7 (Meter Data Provided by the Company to an EGS), and No. 30, 12.1 (Customer Billing by the Company).

formal discovery in this proceeding, the Companies confirm that they have experienced delays in transmitting customer usage data to EGSs since the first quarter of 2021. The Companies describe the issue as involving some smart meters going into an error state and failing to send meter reads. They further note that they are exploring solutions to address these delays and that they are working to expeditiously resolve the issues with the goal of substantially reducing delays in customer interval usage data transmission by mid-March.[124] In the event that those efforts are not successful, I recommend that the Commission direct the Companies to revise their Supplier Tariffs to provide a specific number of days within which they will provide usage data to suppliers. This timeframe should be no less than 15 days since it is readily available to the Companies and needed by EGS to be paid for the electric generation supply service they provide.

Q. DOES THAT COMPLETE YOUR DIRECT TESTIMONY?

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

[124] RESA/NRG Exhibit TK-26 (Companies' Responses to RESA/NRG-II-6 and RESA/NRG-II-7).

Verification

I, Travis Kavulla**,** state that I am Vice President, Regulatory Affairs for NRG Energy, Inc. and providing the foregoing Direct Testimony of the Retail Energy Supply Association and NRG Energy, Inc. I hereby state that the facts contained in the foregoing Direct Testimony are true and correct to the best of my knowledge, information and belief. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

February 25, 2022

/Travis Kavulla/

Travis Kavulla, Vice President
Regulatory Affairs, NRG Energy, Inc.

RESA/NRG EXHIBITS

RESA/NRG EXHIBIT TK-1

TRAVIS KAVULLA

travis.kavulla@nrg.com

VICE PRESIDENT, REGULATORY AFFAIRS **SEPT. 2019 – PRESENT**
NRG Energy, Inc. *Washington, D.C.*
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.

RESA/NRG EXHIBIT TK-2

RESA/NRG 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

Frank Lacey has worked in competitive energy markets since their inception as a consultant to utilities navigating restructuring and as a direct market participant once the markets opened. After more than twenty years in the industry, he launched Electric Advisors Consulting, in the fall of 2015. His focus is assisting clients with energy market issues – regulatory, strategic and business. His clients include energy market participants and end-use consumers. He can be reached at frank@eacpower.com.

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.

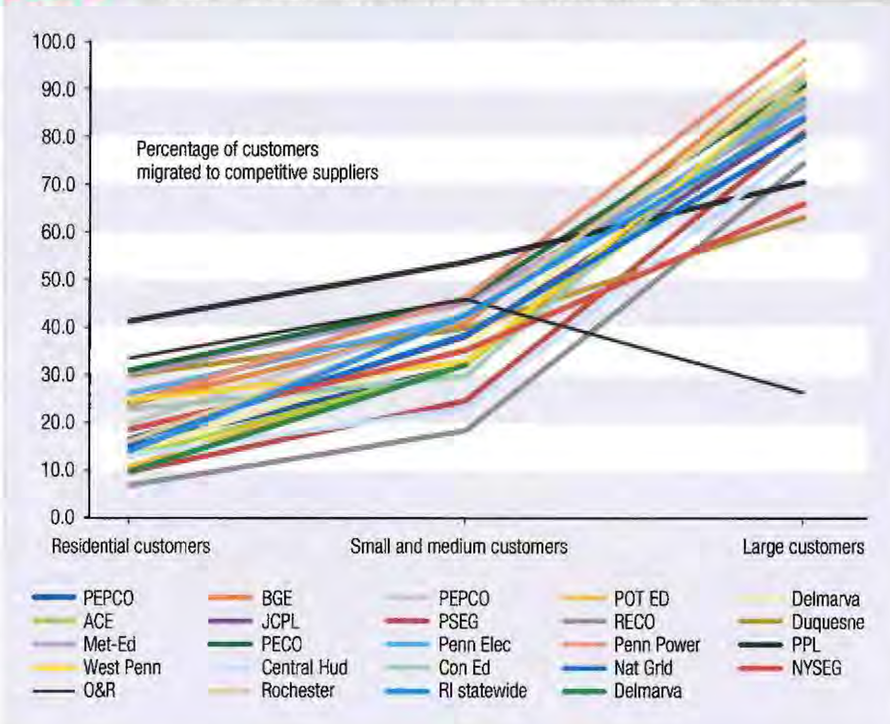
Most important, it has resulted in customer harm from being constrained to the utilities' "no service" products and from the lack of product options that are available in more competitive markets.

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.

FIG. 2 CUSTOMER MIGRATION TRENDS ARE CONSISTENT ACROSS MARKETS



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.

RESA/NRG EXHIBIT TK-3

The Electricity Journal 32 (2019) 4–10

Contents lists available at ScienceDirect

The Electricity Journal

journal homepage: www.elsevier.com/locate/tej

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

Frank Lacey

Electric Advisors Consulting, LLC, 3 Traylor Drive, 19382, West Chester, PA, United States

ARTICLE INFO

Keywords:
Default service
Cost allocation
Energy markets
Electric competition
Deregulation
Market power
Market concentration
D-SEAM
Electricity price
Cross-subsidies

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.

E-mail address: frank@eacpower.com.

[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.

https://doi.org/10.1016/j.tej.2019.02.002

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.

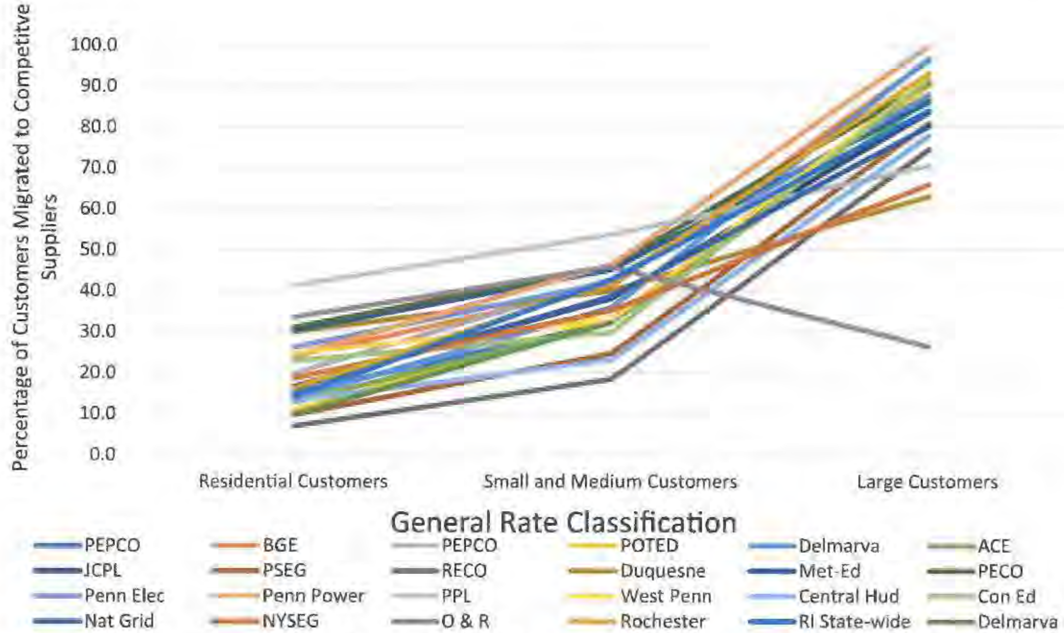


Chart 1. Customer Migration Trends are Consistent Across Markets.

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.

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

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

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.

RESA/NRG EXHIBIT TK-4

RESA/NRG Exhibit TK-4

PAPowerSwitch Monthly Update

Pennsylvania Public Utility Commission

CUSTOMERS WHO HAVE SWITCHED TO AN ELECTRIC GENERATION SUPPLIER

AS OF JANUARY 2022

Electric Utility	Date Updated	Total Switching Customers			Residential Switching Customers			Commercial Switching Customers			Industrial Switching Customers		
		#	%	% of Load	#	%	% of Load	#	%	% of Load	#	%	% of Load
Citizens Electric	1/1/22	60	.9	26.1	4	.1	.1	34	2.9	14.7	22	53.7	82.3
Duquesne	1/25/22	150,969	24.9	65.7	127,457	23.4	23.7	22,868	37.0	80.8	644	61.3	95.7
Met-Ed	1/26/22	144,267	24.7	55.1	114,636	22.3	21.9	28,143	41.5	62.7	1,488	89.1	94.0
PECO	1/25/22	434,846	26.0	53.0	365,170	24.0	25.0	63,143	39.0	51.0	6,533	83.0	92.0
Penelec	1/26/22	134,453	22.8	59.8	98,728	19.7	19.3	34,133	40.1	62.0	1,592	91.5	96.0
Penn Power	1/26/22	37,767	22.2	57.7	28,072	18.9	18.8	9,214	44.4	70.1	481	87.9	96.4
Pike County	9/26/17	2,082	44.0	47.0	1,660	44.0	48.0	419	44.0	49.0	3	43.0	41.0
PPL	1/31/22	521,070	35.5	64.1	431,068	33.7	36.9	87,837	47.3	82.0	2,165	67.4	96.4
UGI	1/2/22	1,189	1.8	18.1	404	0.7	0.9	711	8.2	33.4	74	42.1	65.2
Wellsboro Electric	1/31/22	59	0.9	24.0	0	0	0	49	3.9	24.1	10	83.3	73.9
West Penn Power	1/26/22	156,521	20.9	55.9	118,252	18.7	18.2	36,662	31.4	58.6	1,607	87.1	91.9
Statewide Total	1/31/22	1,583,283	26.7	56.0**	1,285,451	24.7	25.8	283,213	39.7	65.6	14,619	80.4	93.2

* Percentage based on the total number of customers of regulated electric utilities in Pennsylvania as of 1/31/22. (5,208,140 Residential + 713,682 Commercial + 18,192 Industrial = 5,940,014 Total Customers).

** Percentage represents megawatt hours currently delivered by alternative suppliers.

PAPUC

RESA/NRG EXHIBIT TK-5

PAPowerSwitch Monthly Update

Pennsylvania Public Utility Commission

www.PAPowerSwitch.com

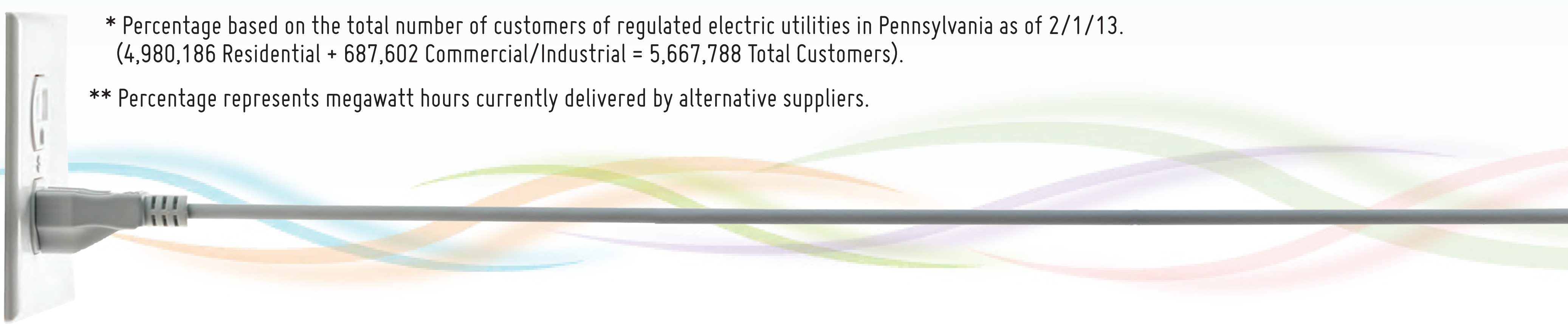
CUSTOMERS SWITCHING TO AN ELECTRIC GENERATION SUPPLIER

JANUARY 2017

Electric Utility	Date Updated	Total Switching Customers			Residential Switching Customers			Commercial Switching Customers			Industrial Switching Customers		
		#	%	% of Load	#	%	% of Load	#	%	% of Load	#	%	% of Load
Duquesne	1/21/17	191,056	32.2	68.6	164,916	31.1	32.8	25,431	42.0	81.9	709	63.4	95.5
Met-Ed	1/25/17	206,356	36.5	65.2	173,783	34.9	35.2	31,832	47.9	74.7	741	85.3	96.9
PECO	1/24/17	589,971	36.0	64.0	505,538	35.0	36.0	81,561	50.0	72.0	2,872	92.0	97.0
Penelec	1/25/17	193,030	32.9	65.7	155,149	30.9	32.0	37,144	43.9	70.5	737	86.6	93.0
Penn Power	1/25/17	50,277	30.5	61.9	40,407	28.7	28.7	9,698	46.9	73.0	172	92.3	92.3
Pike County	12/27/16	2,255	47.0	50.0	1,811	48.0	54.0	441	45.0	51.0	3	43.0	41.0
PPL	1/21/17	642,015	44.9	76.2	539,616	43.4	49.3	99,679	55.1	89.3	2,720	71.1	98.6
UGI	1/21/17	1,250	2.0	22.7	347	0.6	0.9	830	9.9	43.5	73	40.3	70.1
West Penn Power	1/25/17	214,792	29.0	62.9	174,393	28.1	28.2	39,821	33.8	68.4	578	90.6	95.5
Statewide Total	1/25/17	2,091,002	36.9	68.8**	1,755,960	35.3	36.9	326,437	48.3	78.7	8,605	85.2	96.7

* Percentage based on the total number of customers of regulated electric utilities in Pennsylvania as of 2/1/13. (4,980,186 Residential + 687,602 Commercial/Industrial = 5,667,788 Total Customers).

** Percentage represents megawatt hours currently delivered by alternative suppliers.



RESA/NRG EXHIBIT TK-6

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

RETAIL ENERGY SUPPLY ASSOCIATION AND NRG ENERGY, INC. Set II, No. 1

"Reference Direct Testimony of Joanne Savage, page 4. You explain that the purpose of default service is to provide electric generation service to customers who do not select an EGS or whose EGS stops serving them.

A. Please provide the number and percent of customers currently receiving electric generation supply from electric generation suppliers. In providing this information, please break it down by individual Company and by residential, commercial and industrial classes.

B. Please provide the number and percent of customers, by Company, that have purchased electric generation supply from electric generation suppliers, on a monthly basis from January 1, 2017 through December 31, 2021. In providing this information, please break it down by individual Company and by residential, commercial and industrial classes."

RESPONSE:

A. and B. See ME/PN/PP/WP Response to RESA-NRG Interrogatory Set II, No. 1 Attachment A.

Met-Ed

	Residential Customers				Commercial Customers				Industrial Customers			
Month	Shopping	Default Service	Total	Percent Shopping	Shopping	Default Service	Total	Percent Shopping	Shopping	Default Service	Total	Percent Shopping
Jan-17	174,145	323,930	498,075	34.96%	31,278	35,409	66,687	46.90%	805	64	869	92.64%
Feb-17	175,357	323,156	498,513	35.18%	31,397	35,308	66,705	47.07%	802	63	865	92.72%
Mar-17	177,090	321,981	499,071	35.48%	31,371	35,321	66,692	47.04%	799	66	865	92.37%
Apr-17	177,421	321,178	498,599	35.58%	31,292	35,380	66,672	46.93%	800	64	864	92.59%
May-17	177,883	320,775	498,658	35.67%	31,344	35,344	66,688	47.00%	804	57	861	93.38%
Jun-17	176,495	322,277	498,772	35.39%	31,266	35,435	66,701	46.87%	806	55	861	93.61%
Jul-17	174,506	324,353	498,859	34.98%	31,228	35,452	66,680	46.83%	816	54	870	93.79%
Aug-17	171,980	327,102	499,082	34.46%	31,064	35,608	66,672	46.59%	839	65	904	92.81%
Sep-17	169,842	329,272	499,114	34.03%	30,949	35,710	66,659	46.43%	833	66	899	92.66%
Oct-17	167,911	331,916	499,827	33.59%	30,854	35,868	66,722	46.24%	836	66	902	92.68%
Nov-17	166,295	334,318	500,613	33.22%	30,758	36,015	66,773	46.06%	829	69	898	92.32%
Dec-17	164,908	336,241	501,149	32.91%	30,591	36,247	66,838	45.77%	824	72	896	91.96%
Jan-18	163,379	338,339	501,718	32.56%	30,453	36,428	66,881	45.53%	821	70	891	92.14%
Feb-18	161,934	339,936	501,870	32.27%	30,310	36,619	66,929	45.29%	821	70	891	92.14%
Mar-18	160,129	341,743	501,872	31.91%	30,265	36,720	66,985	45.18%	820	71	891	92.03%
Apr-18	158,858	342,998	501,856	31.65%	30,230	36,775	67,005	45.12%	825	70	895	92.18%
May-18	156,926	344,691	501,617	31.28%	30,162	36,832	66,994	45.02%	831	68	899	92.44%
Jun-18	155,290	346,155	501,445	30.97%	30,036	36,997	67,033	44.81%	832	66	898	92.65%
Jul-18	154,016	347,846	501,862	30.69%	29,893	37,163	67,056	44.58%	826	68	894	92.39%
Aug-18	152,675	349,458	502,133	30.41%	29,756	37,356	67,112	44.34%	824	69	893	92.27%
Sep-18	151,178	350,760	501,938	30.12%	29,610	37,490	67,100	44.13%	831	69	900	92.33%
Oct-18	149,838	352,708	502,546	29.82%	29,566	37,631	67,197	44.00%	811	70	881	92.05%
Nov-18	149,026	353,956	502,982	29.63%	29,570	37,664	67,234	43.98%	807	71	878	91.91%
Dec-18	147,680	355,819	503,499	29.33%	29,436	37,841	67,277	43.75%	803	72	875	91.77%
Jan-19	146,827	357,135	503,962	29.13%	29,437	37,849	67,286	43.75%	818	75	893	91.60%
Feb-19	145,874	358,273	504,147	28.93%	29,599	37,698	67,297	43.98%	821	69	890	92.25%
Mar-19	144,934	359,200	504,134	28.75%	29,671	37,624	67,295	44.09%	824	68	892	92.38%
Apr-19	144,326	359,772	504,098	28.63%	29,723	37,608	67,331	44.14%	825	68	893	92.39%
May-19	143,074	360,875	503,949	28.39%	29,706	37,656	67,362	44.10%	825	69	894	92.28%
Jun-19	142,370	361,558	503,928	28.25%	28,820	37,641	66,461	43.36%	1,672	148	1,820	91.87%
Jul-19	141,434	362,837	504,271	28.05%	28,756	37,738	66,494	43.25%	1,670	146	1,816	91.96%
Aug-19	140,245	364,127	504,372	27.81%	28,666	37,869	66,535	43.08%	1,668	145	1,813	92.00%
Sep-19	139,809	365,184	504,993	27.69%	28,612	37,911	66,523	43.01%	1,667	148	1,815	91.85%
Oct-19	139,322	366,134	505,456	27.56%	28,450	38,156	66,606	42.71%	1,658	153	1,811	91.55%
Nov-19	138,917	367,268	506,185	27.44%	28,363	38,319	66,682	42.53%	1,667	151	1,818	91.69%
Dec-19	138,828	367,911	506,739	27.40%	28,360	38,375	66,735	42.50%	1,661	152	1,813	91.62%
Jan-20	138,443	368,776	507,219	27.29%	28,363	38,443	66,806	42.46%	1,658	162	1,820	91.10%
Feb-20	138,226	369,006	507,232	27.25%	28,695	38,148	66,843	42.93%	1,665	158	1,823	91.33%
Mar-20	138,333	369,416	507,749	27.24%	28,695	38,212	66,907	42.89%	1,661	154	1,815	91.52%
Apr-20	137,509	370,313	507,822	27.08%	28,698	38,198	66,896	42.90%	1,667	153	1,820	91.59%
May-20	136,856	371,091	507,947	26.94%	28,729	38,177	66,906	42.94%	1,666	154	1,820	91.54%
Jun-20	136,234	372,194	508,428	26.80%	28,717	38,149	66,866	42.95%	1,771	183	1,954	90.63%
Jul-20	135,140	373,665	508,805	26.56%	28,662	38,257	66,919	42.83%	1,767	184	1,951	90.57%
Aug-20	134,100	375,015	509,115	26.34%	28,891	38,204	67,095	43.06%	1,592	167	1,759	90.51%
Sep-20	133,007	376,580	509,587	26.10%	28,926	38,233	67,159	43.07%	1,602	161	1,763	90.87%
Oct-20	131,837	377,995	509,832	25.86%	28,873	38,334	67,207	42.96%	1,607	160	1,767	90.95%
Nov-20	130,821	379,680	510,501	25.63%	28,836	38,427	67,263	42.87%	1,607	158	1,765	91.05%
Dec-20	129,567	381,267	510,834	25.36%	28,802	38,500	67,302	42.80%	1,592	167	1,759	90.51%
Jan-21	128,174	382,951	511,125	25.08%	28,867	38,508	67,375	42.85%	1,595	161	1,756	90.83%
Feb-21	127,378	383,967	511,345	24.91%	28,229	39,093	67,322	41.93%	1,590	175	1,765	90.08%
Mar-21	126,297	385,413	511,710	24.68%	28,107	39,248	67,355	41.73%	1,585	178	1,763	89.90%
Apr-21	125,303	386,664	511,967	24.47%	28,227	39,178	67,405	41.88%	1,590	180	1,770	89.83%
May-21	124,165	387,474	511,639	24.27%	28,276	39,148	67,424	41.94%	1,591	174	1,765	90.14%
Jun-21	122,994	388,955	511,949	24.02%	28,371	39,240	67,611	41.96%	1,502	161	1,663	90.32%
Jul-21	121,650	390,310	511,960	23.76%	28,207	39,380	67,587	41.73%	1,493	167	1,660	89.94%
Aug-21	120,812	391,653	512,465	23.57%	28,160	39,437	67,597	41.66%	1,486	174	1,660	89.52%
Sep-21	120,179	392,473	512,652	23.44%	28,160	39,720	67,880	41.48%	1,487	172	1,659	89.63%
Oct-21	119,140	393,508	512,648	23.24%	28,146	39,780	67,926	41.44%	1,495	169	1,664	89.84%
Nov-21	118,210	395,213	513,423	23.02%	28,036	39,918	67,954	41.26%	1,492	172	1,664	89.66%
Dec-21	115,960	397,786	513,746	22.57%	27,512	40,405	67,917	40.51%	1,476	194	1,670	88.38%
Jan-22	113,908	400,525	514,433	22.14%	27,703	40,241	67,944	40.77%	1,476	200	1,676	88.07%

Penelec

	Residential Customers				Commercial Customers				Industrial Customers			
Month	**Shopping**	**Default Service**	**Total**	**Percent Shopping**	**Shopping**	**Default Service**	**Total**	**Percent Shopping**	**Shopping**	**Default Service**	**Total**	**Percent Shopping**
Jan-17	155,527	346,792	502,319	30.96%	36,072	49,038	85,110	42.38%	762	89	851	89.54%
Feb-17	156,322	346,035	502,357	31.12%	36,280	48,838	85,118	42.62%	756	91	847	89.26%
Mar-17	157,435	345,032	502,467	31.33%	36,240	48,845	85,085	42.59%	757	86	843	89.80%
Apr-17	157,508	344,471	501,979	31.38%	36,161	48,852	85,013	42.54%	765	88	853	89.68%
May-17	156,634	344,586	501,220	31.25%	36,268	48,815	85,083	42.63%	766	77	843	90.87%
Jun-17	154,280	346,745	501,025	30.79%	36,219	48,895	85,114	42.55%	763	80	843	90.51%
Jul-17	152,157	348,632	500,789	30.38%	36,200	48,923	85,123	42.53%	776	78	854	90.87%
Aug-17	150,280	350,544	500,824	30.01%	36,042	49,100	85,142	42.33%	745	76	821	90.74%
Sep-17	147,877	352,820	500,697	29.53%	35,822	49,138	84,960	42.16%	752	78	830	90.60%
Oct-17	145,637	355,486	501,123	29.06%	35,684	49,337	85,021	41.97%	751	77	828	90.70%
Nov-17	143,829	357,892	501,721	28.67%	35,603	49,400	85,003	41.88%	749	80	829	90.35%
Dec-17	142,441	359,524	501,965	28.38%	35,406	49,621	85,027	41.64%	750	82	832	90.14%
Jan-18	141,122	361,140	502,262	28.10%	35,232	49,749	84,981	41.46%	757	79	836	90.55%
Feb-18	140,147	362,180	502,327	27.90%	35,183	49,770	84,953	41.41%	751	77	828	90.70%
Mar-18	138,798	363,434	502,232	27.64%	34,881	50,019	84,900	41.08%	750	76	826	90.80%
Apr-18	138,323	363,687	502,010	27.55%	34,835	50,155	84,990	40.99%	751	72	823	91.25%
May-18	136,595	364,428	501,023	27.26%	34,898	50,130	85,028	41.04%	750	81	831	90.25%
Jun-18	134,666	365,987	500,653	26.90%	34,782	50,275	85,057	40.89%	735	92	827	88.88%
Jul-18	132,983	367,756	500,739	26.56%	34,690	50,408	85,098	40.76%	734	86	820	89.51%
Aug-18	131,796	369,064	500,860	26.31%	34,578	50,541	85,119	40.62%	742	84	826	89.83%
Sep-18	130,396	370,313	500,709	26.04%	34,537	50,577	85,114	40.58%	741	82	823	90.04%
Oct-18	129,165	372,032	501,197	25.77%	34,411	50,776	85,187	40.39%	742	82	824	90.05%
Nov-18	128,384	373,343	501,727	25.59%	34,241	50,947	85,188	40.19%	747	80	827	90.33%
Dec-18	127,834	374,001	501,835	25.47%	34,186	50,947	85,133	40.16%	738	86	824	89.56%
Jan-19	126,855	375,195	502,050	25.27%	34,429	50,693	85,122	40.45%	742	87	829	89.51%
Feb-19	125,723	376,385	502,108	25.04%	34,599	50,499	85,098	40.66%	747	84	831	89.89%
Mar-19	125,019	376,975	501,994	24.90%	34,753	50,386	85,139	40.82%	741	78	819	90.48%
Apr-19	123,957	377,688	501,645	24.71%	34,476	50,707	85,183	40.47%	749	79	828	90.46%
May-19	122,454	378,243	500,697	24.46%	34,432	50,809	85,241	40.39%	750	77	827	90.69%
Jun-19	121,691	378,406	500,097	24.33%	33,551	50,619	84,170	39.86%	1,759	178	1,937	90.81%
Jul-19	121,235	378,925	500,160	24.24%	33,486	50,742	84,228	39.76%	1,761	173	1,934	91.05%
Aug-19	120,523	379,281	499,804	24.11%	33,365	50,864	84,229	39.61%	1,761	172	1,933	91.10%
Sep-19	120,295	379,756	500,051	24.06%	33,279	50,942	84,221	39.51%	1,772	171	1,943	91.20%
Oct-19	119,907	380,364	500,271	23.97%	33,174	51,107	84,281	39.36%	1,763	171	1,934	91.16%
Nov-19	119,685	381,079	500,764	23.90%	33,159	51,120	84,279	39.34%	1,769	168	1,937	91.33%
Dec-19	119,755	381,246	501,001	23.90%	33,140	51,148	84,288	39.32%	1,755	170	1,925	91.17%
Jan-20	119,210	381,946	501,156	23.79%	33,166	51,124	84,290	39.35%	1,758	176	1,934	90.90%
Feb-20	119,510	381,462	500,972	23.86%	33,360	50,939	84,299	39.57%	1,749	178	1,927	90.76%
Mar-20	119,661	381,468	501,129	23.88%	33,370	50,932	84,302	39.58%	1,751	174	1,925	90.96%
Apr-20	119,008	382,228	501,236	23.74%	33,392	50,927	84,319	39.60%	1,760	171	1,931	91.14%
May-20	118,384	382,664	501,048	23.63%	33,369	50,959	84,328	39.57%	1,766	179	1,945	90.80%
Jun-20	118,039	383,272	501,311	23.55%	33,342	50,984	84,326	39.54%	1,853	194	2,047	90.52%
Jul-20	117,401	384,278	501,679	23.40%	33,483	50,894	84,377	39.68%	1,836	196	2,032	90.35%
Aug-20	116,535	385,339	501,874	23.22%	33,690	50,889	84,579	39.83%	1,719	180	1,899	90.52%
Sep-20	116,111	386,001	502,112	23.12%	33,767	50,858	84,625	39.90%	1,723	175	1,898	90.78%
Oct-20	115,093	386,983	502,076	22.92%	33,723	50,891	84,614	39.86%	1,713	182	1,895	90.40%
Nov-20	114,100	388,365	502,465	22.71%	33,767	50,907	84,674	39.88%	1,714	179	1,893	90.54%
Dec-20	112,695	389,964	502,659	22.42%	33,978	50,772	84,750	40.09%	1,710	178	1,888	90.57%
Jan-21	111,514	391,043	502,557	22.19%	33,881	50,819	84,700	40.00%	1,708	178	1,886	90.56%
Feb-21	110,503	392,241	502,744	21.98%	33,253	51,498	84,751	39.24%	1,703	177	1,880	90.59%
Mar-21	109,460	393,197	502,657	21.78%	33,067	51,660	84,727	39.03%	1,707	186	1,893	90.17%
Apr-21	108,596	393,739	502,335	21.62%	33,167	51,608	84,775	39.12%	1,709	182	1,891	90.38%
May-21	107,507	394,177	501,684	21.43%	33,296	51,529	84,825	39.25%	1,700	187	1,887	90.09%
Jun-21	106,170	395,342	501,512	21.17%	33,473	51,538	85,011	39.37%	1,554	187	1,741	89.26%
Jul-21	105,109	396,229	501,338	20.97%	33,413	51,612	85,025	39.30%	1,542	193	1,735	88.88%
Aug-21	104,273	397,311	501,584	20.79%	33,342	51,744	85,086	39.19%	1,536	190	1,726	88.99%
Sep-21	103,174	397,965	501,139	20.59%	33,319	52,237	85,556	38.94%	1,540	192	1,732	88.91%
Oct-21	102,183	398,883	501,066	20.39%	33,210	52,383	85,593	38.80%	1,552	188	1,740	89.20%
Nov-21	100,987	400,627	501,614	20.13%	33,064	52,547	85,611	38.62%	1,540	203	1,743	88.35%
Dec-21	99,375	402,275	501,650	19.81%	33,011	52,616	85,627	38.55%	1,527	213	1,740	87.76%
Jan-22	97,746	404,232	501,978	19.47%	32,950	52,257	85,207	38.67%	1,533	204	1,737	88.26%

RESA/NRG Exhibit TK-6

ME/PN/PP/WP Response to RESA Interrogatory Set II, No. 1
Attachment A
Witness: J. M. Savage

Penn Power

	Residential Customers				Commercial Customers				Industrial Customers			
Month	Shopping	Default Service	Total	Percent Shopping	Shopping	Default Service	Total	Percent Shopping	Shopping	Default Service	Total	Percent Shopping
Jan-17	40,581	103,493	144,074	28.17%	9,207	11,517	20,724	44.43%	132	22	154	85.71%
Feb-17	41,080	103,094	144,174	28.49%	9,263	11,446	20,709	44.73%	129	23	152	84.87%
Mar-17	41,541	102,722	144,263	28.80%	9,286	11,423	20,709	44.84%	135	21	156	86.54%
Apr-17	41,333	102,810	144,143	28.67%	9,188	11,553	20,741	44.30%	131	20	151	86.75%
May-17	41,129	102,982	144,111	28.54%	9,198	11,540	20,738	44.35%	131	22	153	85.62%
Jun-17	40,668	103,505	144,173	28.21%	9,271	11,473	20,744	44.69%	132	21	153	86.27%
Jul-17	40,196	104,012	144,208	27.87%	9,274	11,498	20,772	44.65%	132	21	153	86.27%
Aug-17	39,516	104,679	144,195	27.40%	9,295	11,475	20,770	44.75%	136	18	154	88.31%
Sep-17	38,934	105,303	144,237	26.99%	9,213	11,482	20,695	44.52%	135	18	153	88.24%
Oct-17	38,229	106,210	144,439	26.47%	9,191	11,510	20,701	44.40%	135	16	151	89.40%
Nov-17	37,887	106,702	144,589	26.20%	9,198	11,526	20,724	44.38%	136	18	154	88.31%
Dec-17	37,636	107,209	144,845	25.98%	9,182	11,566	20,748	44.25%	136	18	154	88.31%
Jan-18	37,385	107,609	144,994	25.78%	9,166	11,554	20,720	44.24%	134	19	153	87.58%
Feb-18	37,015	108,070	145,085	25.51%	9,129	11,606	20,735	44.03%	136	18	154	88.31%
Mar-18	36,798	108,337	145,135	25.35%	9,140	11,621	20,761	44.02%	133	19	152	87.50%
Apr-18	36,550	108,610	145,160	25.18%	9,132	11,648	20,780	43.95%	133	22	155	85.81%
May-18	36,225	108,955	145,180	24.95%	9,126	11,642	20,768	43.94%	133	22	155	85.81%
Jun-18	35,970	109,125	145,095	24.79%	9,156	11,625	20,781	44.06%	135	22	157	85.99%
Jul-18	35,738	109,514	145,252	24.60%	9,156	11,643	20,799	44.02%	134	22	156	85.90%
Aug-18	35,431	109,904	145,335	24.38%	9,128	11,683	20,811	43.86%	133	22	155	85.81%
Sep-18	35,162	110,149	145,311	24.20%	9,103	11,704	20,807	43.75%	132	23	155	85.16%
Oct-18	35,014	110,512	145,526	24.06%	9,084	11,719	20,803	43.67%	132	25	157	84.08%
Nov-18	34,904	110,745	145,649	23.96%	9,054	11,771	20,825	43.48%	132	25	157	84.08%
Dec-18	34,727	110,999	145,726	23.83%	9,014	11,816	20,830	43.27%	132	25	157	84.08%
Jan-19	34,616	111,228	145,844	23.73%	9,231	11,658	20,889	44.19%	131	27	158	82.91%
Feb-19	34,570	111,328	145,898	23.69%	9,250	11,635	20,885	44.29%	132	26	158	83.54%
Mar-19	34,367	111,570	145,937	23.55%	9,287	11,597	20,884	44.47%	127	29	156	81.41%
Apr-19	34,128	111,832	145,960	23.38%	9,295	11,593	20,888	44.50%	129	31	160	80.63%
May-19	34,035	111,893	145,928	23.32%	9,311	11,602	20,913	44.52%	129	29	158	81.65%
Jun-19	33,982	111,930	145,912	23.29%	8,965	11,551	20,516	43.70%	497	70	567	87.65%
Jul-19	33,959	111,982	145,941	23.27%	8,935	11,553	20,488	43.61%	528	66	594	88.89%
Aug-19	33,747	112,186	145,933	23.12%	8,929	11,577	20,506	43.54%	524	69	593	88.36%
Sep-19	33,607	112,434	146,041	23.01%	8,935	11,576	20,511	43.56%	530	70	600	88.33%
Oct-19	33,447	112,679	146,126	22.89%	8,958	11,567	20,525	43.64%	525	70	595	88.24%
Nov-19	33,380	112,914	146,294	22.82%	8,934	11,581	20,515	43.55%	521	76	597	87.27%
Dec-19	33,517	112,903	146,420	22.89%	8,884	11,649	20,533	43.27%	522	74	596	87.58%
Jan-20	33,580	112,977	146,557	22.91%	8,945	11,585	20,530	43.57%	521	79	600	86.83%
Feb-20	33,829	112,779	146,608	23.07%	8,982	11,522	20,504	43.81%	523	76	599	87.31%
Mar-20	33,956	112,762	146,718	23.14%	8,987	11,505	20,492	43.86%	524	72	596	87.92%
Apr-20	33,801	112,981	146,782	23.03%	9,010	11,486	20,496	43.96%	531	65	596	89.09%
May-20	33,550	113,275	146,825	22.85%	9,044	11,473	20,517	44.08%	530	66	596	88.93%
Jun-20	33,463	113,486	146,949	22.77%	9,027	11,458	20,485	44.07%	556	76	632	87.97%
Jul-20	33,194	113,889	147,083	22.57%	8,987	11,510	20,497	43.85%	563	76	639	88.11%
Aug-20	32,987	114,181	147,168	22.41%	9,004	11,554	20,558	43.80%	535	68	603	88.72%
Sep-20	32,706	114,553	147,259	22.21%	9,002	11,555	20,557	43.79%	542	66	608	89.14%
Oct-20	32,414	114,878	147,292	22.01%	9,012	11,556	20,568	43.82%	534	68	602	88.70%
Nov-20	32,237	115,235	147,472	21.86%	9,043	11,526	20,569	43.96%	535	67	602	88.87%
Dec-20	31,914	115,635	147,549	21.63%	9,045	11,559	20,604	43.90%	537	67	604	88.91%
Jan-21	31,468	116,191	147,659	21.31%	9,022	11,585	20,607	43.78%	539	67	606	88.94%
Feb-21	31,131	116,694	147,825	21.06%	8,834	11,794	20,628	42.83%	537	69	606	88.61%
Mar-21	30,724	117,184	147,908	20.77%	8,770	11,866	20,636	42.50%	535	71	606	88.28%
Apr-21	30,438	117,523	147,961	20.57%	8,860	11,790	20,650	42.91%	532	69	601	88.52%
May-21	30,058	117,908	147,966	20.31%	8,821	11,843	20,664	42.69%	532	67	599	88.81%
Jun-21	29,701	118,370	148,071	20.06%	8,882	11,856	20,738	42.83%	466	73	539	86.46%
Jul-21	29,417	118,689	148,106	19.86%	8,877	11,861	20,738	42.81%	464	75	539	86.09%
Aug-21	28,858	119,384	148,242	19.47%	8,816	11,900	20,716	42.56%	470	76	546	86.08%
Sep-21	28,784	119,547	148,331	19.41%	8,740	12,015	20,755	42.11%	466	78	544	85.66%
Oct-21	28,707	119,658	148,365	19.35%	8,729	12,048	20,777	42.01%	463	77	540	85.74%
Nov-21	28,639	119,930	148,569	19.28%	8,722	12,053	20,775	41.98%	465	79	544	85.48%
Dec-21	28,307	120,367	148,674	19.04%	8,703	12,072	20,775	41.89%	469	78	547	85.74%
Jan-22	27,959	120,831	148,790	18.79%	8,816	11,912	20,728	42.53%	472	78	550	85.82%

West Penn

	Residential Customers				Commercial Customers				Industrial Customers			
Month	**Shopping**	**Default Service**	**Total**	**Percent Shopping**	**Shopping**	**Default Service**	**Total**	**Percent Shopping**	**Shopping**	**Default Service**	**Total**	**Percent Shopping**
Jan-17	175,074	447,050	622,124	28.14%	38,602	63,119	101,721	37.95%	580	58	638	90.91%
Feb-17	175,791	446,485	622,276	28.25%	38,806	62,828	101,634	38.18%	580	60	640	90.63%
Mar-17	176,320	446,086	622,406	28.33%	38,768	62,829	101,597	38.16%	580	58	638	90.91%
Apr-17	176,236	445,627	621,863	28.34%	38,909	62,659	101,568	38.31%	576	64	640	90.00%
May-17	176,217	445,173	621,390	28.36%	38,996	62,596	101,592	38.38%	572	73	645	88.68%
Jun-17	174,923	446,453	621,376	28.15%	39,118	62,486	101,604	38.50%	578	68	646	89.47%
Jul-17	172,767	448,553	621,320	27.81%	39,135	62,460	101,595	38.52%	578	69	647	89.34%
Aug-17	169,770	451,944	621,714	27.31%	39,137	62,476	101,613	38.52%	577	73	650	88.77%
Sep-17	168,784	452,824	621,608	27.15%	38,951	62,607	101,558	38.35%	584	65	649	89.98%
Oct-17	167,975	454,268	622,243	27.00%	38,968	62,675	101,643	38.34%	584	65	649	89.98%
Nov-17	167,270	455,584	622,854	26.86%	38,863	62,904	101,767	38.19%	589	60	649	90.76%
Dec-17	166,071	457,177	623,248	26.65%	38,703	63,021	101,724	38.05%	587	64	651	90.17%
Jan-18	164,670	462,193	626,863	26.27%	37,921	60,295	98,216	38.61%	943	347	1,290	73.10%
Feb-18	162,689	464,042	626,731	25.96%	37,610	60,751	98,361	38.24%	954	336	1,290	73.95%
Mar-18	161,510	465,086	626,596	25.78%	37,405	60,957	98,362	38.03%	955	339	1,294	73.80%
Apr-18	160,235	466,408	626,643	25.57%	37,329	61,177	98,506	37.90%	813	298	1,111	73.18%
May-18	158,489	467,515	626,004	25.32%	37,188	61,382	98,570	37.73%	814	285	1,099	74.07%
Jun-18	157,057	468,483	625,540	25.11%	37,081	61,504	98,585	37.61%	815	314	1,129	72.19%
Jul-18	156,454	469,376	625,830	25.00%	36,987	61,663	98,650	37.49%	800	296	1,096	72.99%
Aug-18	154,834	471,303	626,137	24.73%	36,789	61,896	98,685	37.28%	803	282	1,085	74.01%
Sep-18	154,039	471,995	626,034	24.61%	36,673	62,034	98,707	37.15%	789	286	1,075	73.40%
Oct-18	153,214	473,308	626,522	24.45%	36,471	62,335	98,806	36.91%	816	280	1,096	74.45%
Nov-18	152,870	474,246	627,116	24.38%	36,335	62,559	98,894	36.74%	824	303	1,127	73.11%
Dec-18	152,466	474,972	627,438	24.30%	36,204	62,716	98,920	36.60%	809	297	1,106	73.15%
Jan-19	151,571	476,255	627,826	24.14%	36,419	62,483	98,902	36.82%	804	280	1,084	74.17%
Feb-19	151,077	476,886	627,963	24.06%	36,357	62,533	98,890	36.77%	813	272	1,085	74.93%
Mar-19	150,201	477,777	627,978	23.92%	36,511	62,373	98,884	36.92%	810	287	1,097	73.84%
Apr-19	149,335	478,533	627,868	23.78%	36,360	62,613	98,973	36.74%	807	268	1,075	75.07%
May-19	148,263	478,818	627,081	23.64%	36,381	62,545	98,926	36.78%	834	256	1,090	76.51%
Jun-19	147,487	479,281	626,768	23.53%	35,181	62,334	97,515	36.08%	2,100	440	2,540	82.68%
Jul-19	146,490	480,328	626,818	23.37%	35,118	62,440	97,558	36.00%	2,092	439	2,531	82.66%
Aug-19	145,231	481,352	626,583	23.18%	35,194	62,487	97,681	36.03%	2,082	444	2,526	82.42%
Sep-19	144,712	482,467	627,179	23.07%	35,293	62,282	97,575	36.17%	2,108	444	2,552	82.60%
Oct-19	144,631	482,823	627,454	23.05%	35,412	62,293	97,705	36.24%	2,082	465	2,547	81.74%
Nov-19	144,769	483,318	628,087	23.05%	35,579	62,165	97,744	36.40%	2,106	452	2,558	82.33%
Dec-19	145,003	483,405	628,408	23.07%	35,678	62,078	97,756	36.50%	2,098	439	2,537	82.70%
Jan-20	144,705	484,084	628,789	23.01%	35,792	61,992	97,784	36.60%	2,053	447	2,500	82.12%
Feb-20	144,669	484,118	628,787	23.01%	35,863	61,900	97,763	36.68%	2,032	444	2,476	82.07%
Mar-20	144,541	484,481	629,022	22.98%	35,923	61,891	97,814	36.73%	2,041	456	2,497	81.74%
Apr-20	144,107	484,956	629,063	22.91%	35,977	61,879	97,856	36.77%	2,033	459	2,492	81.58%
May-20	143,537	485,599	629,136	22.81%	36,108	61,844	97,952	36.86%	2,007	460	2,467	81.35%
Jun-20	142,912	486,629	629,541	22.70%	35,827	62,018	97,845	36.62%	2,154	478	2,632	81.84%
Jul-20	141,729	488,166	629,895	22.50%	35,780	62,226	98,006	36.51%	2,130	481	2,611	81.58%
Aug-20	140,228	490,272	630,500	22.24%	35,698	62,288	97,986	36.43%	2,145	483	2,628	81.62%
Sep-20	139,624	491,277	630,901	22.13%	35,659	62,368	98,027	36.38%	2,141	487	2,628	81.47%
Oct-20	138,301	492,780	631,081	21.91%	35,589	62,531	98,120	36.27%	2,144	498	2,642	81.15%
Nov-20	136,729	494,979	631,708	21.64%	35,548	62,695	98,243	36.18%	2,138	518	2,656	80.50%
Dec-20	134,954	497,111	632,065	21.35%	35,662	62,670	98,332	36.27%	2,138	493	2,631	81.26%
Jan-21	133,410	498,753	632,163	21.10%	35,537	62,689	98,226	36.18%	2,128	501	2,629	80.94%
Feb-21	132,256	500,070	632,326	20.92%	34,921	63,413	98,334	35.51%	2,144	507	2,651	80.88%
Mar-21	131,050	501,477	632,527	20.72%	34,845	63,514	98,359	35.43%	2,127	517	2,644	80.45%
Apr-21	130,198	502,394	632,592	20.58%	34,987	63,521	98,508	35.52%	2,127	511	2,638	80.63%
May-21	129,192	503,057	632,249	20.43%	34,999	63,513	98,512	35.53%	2,138	502	2,640	80.98%
Jun-21	127,839	504,597	632,436	20.21%	35,331	63,585	98,916	35.72%	1,828	457	2,285	80.00%
Jul-21	126,150	505,802	631,952	19.96%	35,290	63,692	98,982	35.65%	1,833	459	2,292	79.97%
Aug-21	124,969	507,553	632,522	19.76%	35,304	63,743	99,047	35.64%	1,808	470	2,278	79.37%
Sep-21	123,850	508,450	632,300	19.59%	35,246	64,392	99,638	35.37%	1,818	457	2,275	79.91%
Oct-21	122,850	509,337	632,187	19.43%	35,095	64,573	99,668	35.21%	1,797	471	2,268	79.23%
Nov-21	121,586	511,235	632,821	19.21%	34,982	64,778	99,760	35.07%	1,811	474	2,285	79.26%
Dec-21	119,738	513,198	632,936	18.92%	34,784	65,049	99,833	34.84%	1,797	473	2,270	79.16%
Jan-22	117,834	515,662	633,496	18.60%	34,885	64,847	99,732	34.98%	1,806	473	2,279	79.25%

RESA/NRG EXHIBIT TK-7

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

OFFICE OF CONSUMER ADVOCATE Set I, No. 21

> "Has the Company prepared an analysis of the number of residential EV owners in each of its EDCs? If so, please provide such analysis. If not, on what basis does the Company conclude that sufficient EV owners would participate in its proposed TOU rate option?"

RESPONSE:

The Companies have not prepared an analysis of the number of residential EV owners. By Secretarial Letter issued on January 23, 2020 at Docket No. M-2019-3007101, the Commission directed electric distribution companies to explore TOU rates in the context of EV expansion in Pennsylvania. As explained by Ms. Larkin in her direct testimony (Met-Ed/Penelec/Penn Power/West Penn Statement No. 5, pp. 15, 17-18), the Companies responded by incorporating a super-off peak pricing period in their TOU rate design to provide cost savings to customers who elect the TOU Rider rate and charge their EVs during the overnight low-priced energy hours.

RESA/NRG EXHIBIT TK-8

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

OFFICE OF CONSUMER ADVOCATE Set I, No. 34

"Provide the number of residential customers enrolled in each EDC's current TOU rate option for each month since June 2019."

RESPONSE:

See ME/PN/PP/WP Response to OCA Interrogatory Set I, No. 034 Attachment A.

Residential Customers Enrolled in Rider K by Month

	ME	PN	PP	WP	TOTAL
June-19	19	24	0	1	44
July-19	19	24	0	1	44
August-19	19	24	0	1	44
September-19	19	24	0	1	44
October-19	19	24	0	1	44
November-19	19	24	0	1	44
December-19	19	24	0	1	44
January-20	54	32	1	6	93
February-20	54	32	1	6	93
March-20	54	32	1	6	93
April-20	54	32	1	6	93
May-20	54	32	1	6	93
June-20	54	32	2	6	94
July-20	54	32	2	6	94
August-20	54	32	2	6	94
September-20	54	32	2	6	94
October-20	54	32	2	6	94
November-20	54	32	2	6	94
December-20	54	32	2	6	94
January-21	54	32	2	6	94
February-21	54	32	3	6	95
March-21	54	32	4	6	96
April-21	54	32	4	6	96
May-21	54	32	5	6	97
June-21	54	32	5	6	97
July-21	54	32	5	6	97
August-21	54	32	5	6	97
September-21	54	31	5	6	96
October-21	54	31	5	6	96
November-21	54	31	5	6	96
December-21	54	30	5	6	95

RESA/NRG EXHIBIT TK-9

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

OFFICE OF CONSUMER ADVOCATE Set I, No. 31

"Has the Company estimated the number of residential customers who will enroll in the proposed TOU rate option? If so, provide the assumptions for such estimate."

RESPONSE:

The Companies have not estimated of the number of residential customers who will enroll in the proposed TOU Rider rate.

RESA/NRG EXHIBIT TK-10

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

OFFICE OF CONSUMER ADVOCATE Set I, No. 27

"Please provide the educational materials that FirstEnergy intends or has already developed to inform its customers about this TOU rate option. If not already developed, provide the marketing plan or educational outreach plan that describes the future implementation of this rate option."

RESPONSE:

The Companies will develop the educational materials, marketing plan and educational outreach plan referenced in this question after the Commission enters its Final Order in this proceeding.

RESA/NRG EXHIBIT TK-11

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

OFFICE OF CONSUMER ADVOCATE Set I, No. 32

"Please provide a proposed bill design for residential TOU customers under the Company's proposal that shows the TOU rate periods and prices."

RESPONSE:

The Companies will develop the bill design requested in this question after the Commission enters its Final Order in this proceeding.

RESA/NRG EXHIBIT TK-12

reliant
an NRG company

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

CARD PAYMENT Exhibit TK-12

Reliant Account:
Referral ID:

Billing Date:	Date Due:	Amount Due:
04/16/2020	**05/04/2020**	**$ 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**

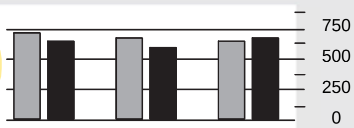
Chat online at **reliant.com**

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

Electricity Usage Summary

This Year's Usage
Last Year's Usage

33% of your usage was free this month!



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.**

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.

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.

Thank you for being our customer.

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

TX13

20008/40015

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.

Exhibit TK-12

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.

RESA/NRG EXHIBIT TK-13

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

OFFICE OF CONSUMER ADVOCATE Set I, No. 24

"Does the Companies' billing system allow an EGS to bill a different TOU rate structure other than the option proposed in this filing?"

RESPONSE:

Yes. The Companies' billing system does not limit the terms of EGS products and contracts, including time-varying generation rates, provided to customers that are not enrolled in the Companies' Customer Assistance Programs.

RESA/NRG EXHIBIT TK-14

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

OFFICE OF SMALL BUSINESS ADVOCATE Set I, No. 10

"Reference Companies' Statement No. 4, page 16, including footnote 10.

a. Please review why seasonal cost differentials were eliminated from the Companies' default service plans and explain whether that decision remains appropriate for this proceeding.
b. Please indicate whether the Companies' considered the seasonal nature of power costs in proposing to exclude seasonal cost differences for both regular and TOU default service rates.
c. Please provide the analysis referenced in footnote 10, in MS Excel electronic format if available."

RESPONSE:

a. Seasonal factors were traditionally included to account for the differential in the cost of default service supply during the summer months and the non-summer months. However, those factors were set to 1.0 in DSP III, meaning there was effectively no seasonal weighting. As the Companies' witness Reeping noted in DSP IV, non-summer month volatility had been much more pronounced in recent years, meaning that there was no longer a need to "summer-weight" prices paid to suppliers (a finding which is supported by the analysis presented in the Attachment referenced in response to part c of this question).[1] Seasonal factors were therefore eliminated in DSP IV.

   With respect to commercial customers, the inclusion of 3-month default service supply procurements naturally added some seasonal exposure into the default service generation costs paid by those customers. With 6-month default service supply procurements, some degree of seasonal exposure will still remain.

b. Ultimately, there is a tradeoff between exposing default service customers to seasonal cost differences, which more closely aligns customer payments for generation during a specific season with the cost of providing the power at that particular time of year, and the rate stability that customers typically prefer. The proposal in the default service plan to limit customers' exposure to seasonal cost differences is aimed at providing more cost stability to customers.

[1] See Docket Nos. P-2015-2511333, P-2015-2511351, _ P-2015-2511355, P-2015-2511356, Met-Ed/Penelec/Penn Power/West Penn Statement No. 1 at 21:12-22.

c. See ME/PN/PP/WP Response to OSBA Interrogatory Set I, No. 10 Attachment A.

RESA/NRG EXHIBIT TK-15

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

RETAIL ENERGY SUPPLY ASSOCIATION AND NRG ENERGY, INC. Set I, No. 3

"Reference Direct Testimony of James H. Catanach, pages 21-23.

A. As to the Companies' proposal to solicit up to 20 MWs of solar capacity for energy and SPAECs through PPAs with terms up to 10 years, please explain the justification for proposing a time period that exceeds the proposed four-year term of the default service program period.

B. Please explain how the Companies would handle the remaining years on such contracts if the Commission, in the interim, would approve a different entity to provide default service in the Companies' service territories."

RESPONSE:

A. As explained in the Direct Testimony of James H. Catanach, page 21, the proposed solar PPAs will serve as the long-term component of each Company's "prudent mix" of default service contracts and also provide support for solar projects in Pennsylvania. Under the Public Utility Code, 66 Pa.C.S. § 2807(e)(3.1), long-term contracts may have a term of more than four and not more than twenty years.

B. The Companies have not determined how the remaining years of the contracts will be handled if the Commission, in the interim, were to approve a different entity to provide default service in the Companies' service territories.

RESA/NRG EXHIBIT TK-16

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

SHIPLEY CHOICE, LLC D/B/A SHIPLEY ENERGY Set II, No. 5

"Reference the Direct Testimony of James H. Catanach, at pages 18, lines 19-21. For each AEPSA compliance year from 2022 to 2024, provide a schedule that shows the percentage of Solar Photovoltaic Alternative Energy Credits ("SPAEC") that Met-Ed, Penelec and Penn Power will procure on behalf of retail electricity suppliers."

RESPONSE:

The percentage of Solar Photovoltaic Alternative Energy Credits ("SPAEC") that Met-Ed, Penelec and Penn Power will procure on behalf of retail electricity suppliers for each AEPSA compliance year (2022-2024) is as follows:

2022 – 100%
2023 – 100%
2024 – 0%

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

SHIPLEY CHOICE, LLC D/B/A SHIPLEY ENERGY Set II, No. 6

"Are the costs of SPAEC's presently recovered through the default service rate? If not, explain why not."

RESPONSE:

The costs of SPAECs are presently recovered from all customers through Met-Ed, Penelec, and Penn Power's Solar Photovoltaic Requirements Charge ("SPVRC") Riders on a non-bypassable basis because the SPAECs are allocated to both Default Service suppliers and retail suppliers. West Penn's SPAEC costs are recovered in the Price to Compare Default Service Rider rates.

RESA/NRG EXHIBIT TK-17

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

RETAIL ENERGY SUPPLY ASSOCIATION AND NRG ENERGY, INC. Set I, No. 4

"Reference Direct Testimony of Patricia M. Larkin, page 4. Ms. Larkin describes the costs that the Companies currently recover through default service rates and includes a reference to "administrative costs, as contemplated by 52 Pa. Code § 69.1808."

A. Please indicate whether the Companies' current default service rates recover 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. Please provide a breakdown of the Companies' current default service rates for the residential, commercial and industrial classes. These breakdowns should note whether each cost is direct or indirect and identify the amount of each direct and indirect cost that is included in these rates. For purposes of this question, direct costs are directly attributable to default service, whereas indirect costs are overhead or shared costs incurred by each Company on a Company-wide basis, which are not directly attributable to default service."

RESPONSE:

A. See ME/PN/PP/WP Response to Shipley Interrogatory Set I, No. 8.

B. All costs included in the Companies' current default service rates identified in the Companies' response to ME/PN/PP/WP Response to RESA-NRG Interrogatory Set I, No. 008 are costs directly attributable to default service.

See ME/PN/PP/WP Response to RESA-NRG Interrogatory Set I, No. 004 Attachment A for the calculation of default service rates effective December 1, 2021 by class.

RESA/NRG Exhibit TK-17

Metropolitan Edison Company
Price to Compare Default Service Rate Calculation
Residential Class: For the Default Service Period December 1, 2021 through February 28, 2022

Line No.	Fixed Price Tranche Purchases ($ per MWh)	Number of Tranches	Clearing Price	Weighted Clearing Price		
1	April 2020 Auction (June 20 through May 22)	1	$ 52.12	$ 52.12		
2	November 2020 Auction (June 21 through May 22)	4	58.91	235.64		
3	January 2021 Auction (June 21 through May 22)	4	59.44	237.76		
4	April 2021 Auction (June 21 through May 22)	4	62.95	251.80		
5	November 2020 Auction (June 21 through May 23)	4	57.52	230.08		
6	January 2021 Auction (June 21 through May 23)	4	58.43	233.72		
7	April 2021 Auction (June 21 through May 23)	4	61.39	245.56		
8	Total	25		$ 1,486.68		
9	Total Average Fixed Price Tranche		$ 59.47			
10	Times Fixed Portion of Load		95%			
11	Total Fixed Price Cost (Line 9 X Line 10)			$ 56.49		
12	Average Variable Hourly Price Tranche		$ 61.30			
13	Capacity, Anc. Serv. and AEPS Adder ($20/MWh)		20.00			
14	Variable Hourly Priced Cost (Line 12 + Line 13)		$ 81.30			
15	Times Variable Portion of Load		5%			
16	Total Variable Hourly Priced Cost (Line 14 X Line 15)			$ 4.07		
17	Price to Compare Weighted Average Price ((Line 11 + Line 16) / 1000)			$ 0.06056		
18	Times PTC Loss $_{\text{Current}}$			1.0515		
19	Price to Compare Weighted Average Price, including line losses (Line 17 X Line 18)				$ 0.06368	*per kWh*
20	PTC $_{\text{Administrative Charge}}$				$ 0.00004	*per kWh*
21	PTC$_{\text{Current}}$ before PA Gross Receipts Tax (Line 19 + Line 20)				$ 0.06372	
22	PA Gross Receipt Gross-Up [1/(1-T) (5.9% Gross Receipts Tax)				1.062699	
23	**PTC $_{\text{Current}}$ Residential Class including PA Gross Receipts Tax (Line 21 X Line 22)**				**$ 0.06771**	*per kWh*
24	**E Reconciliation Rate, including PA Gross Receipts Tax (Page 2, Line 9)**				**$ 0.00643**	*per kWh*
25	**PTC $_{\text{Default}}$ Residential Class (Line 23 + Line 24)**				**$ 0.07414**	*per kWh*

(A) All Price to Compare computations will be pursuant to the terms of the Company's "Price to Compare Default Service Rate Rider".
(B) All Adders are subject to Quarterly Updates

RESA/NRG Exhibit TK-17

Metropolitan Edison Company
Price to Compare Default Service Rate Calculation
Commercial Class: For the Default Service Period December 1, 2021 through February 28, 2022

Line No.	Fixed Price Tranche Purchases ($ per MWh)	Number of Tranches	Clearing Price	Weighted Clearing Price		
1	April 2020 Auction (June 20 through May 22)	1	$ 50.80	$ 50.80		
2	November 2020 Auction (June 21 through May 22)	1	54.75	54.75		
3	January 2021 Auction (June 21 through May 22)	2	55.67	111.34		
4	April 2021 Auction (June 21 through May 22)	2	58.52	117.04		
5	November 2020 Auction (June 21 through May 23)	1	54.86	54.86		
6	January 2021 Auction (June 21through May 23)	1	54.40	54.40		
7	April 2021 Auction (June 21 through May 23)	1	57.72	57.72		
8	November 2021 Auction (Dec 21 through Feb 22)	4	120.51	482.04		
9	Total	13		$ 982.95		
10	Total Average Fixed Price Tranche		$ 75.61			
11	Times Fixed Portion of Load		100%			
12	Total Fixed Price Cost (Line 10 X Line 11)			$ 75.61		
13	Average Variable Hourly Price Tranche		$ -			
14	Capacity, Anc. Serv. and AEPS Adder ($20/MWh)		20.00			
15	Variable Priced Hourly Cost (Line 13 + Line 14)		$ 20.00			
16	Times Variable Portion of Load		0%			
17	Total Variable Hourly Priced Cost (Line 15 X Line 16)			$ -		
18	Price to Compare Weighted Average Price ((Line 12 + Line 17) / 1000)			$ 0.07561		
19	Times PTC Loss $_{Current}$			1.0515		
20	Price to Compare Weighted Average Price, including line losses (Line 18 X Line 19)				$ 0.07951	*per kWh*
21	PTC $_{Administrative\ Charge}$				$ 0.00004	*per kWh*
22	PTC$_{Current}$ before PA Gross Receipts Tax (Line 20 + Line 21)				$ 0.07955	
23	PA Gross Receipt Gross-Up [1/(1-T) (5.9% Gross Receipts Tax)				1.062699	
24	**PTC** $_{Current}$ Commercial Class including PA Gross Receipts Tax (Line 22 X Line 23)				**$ 0.08454**	*per kWh*
25	**E Reconciliation Rate, including PA Gross Receipts Tax (Page 2, Line 8)**				**$ 0.00253**	*per kWh*
26	**PTC** $_{Default}$ Commercial Class (Line 24 + Line 25)				**$ 0.08707**	*per kWh*

(A) All Price to Compare computations will be pursuant to the terms of the Company's "Price to Compare Default Service Rate Rider".
(B) All Adders are subject to Quarterly Updates

RESA/NRG Exhibit TK-17

Metropolitan Edison Company
Hourly Pricing Default Service Rate Calculation (for Illustrative Purposes Only)
Industrial Class: For the Default Service Period December 1, 2021 through February 28, 2022

Line No.		
	HP $_{\text{Energy Charge}}$ = ∑ (kWht x (LMPt + HPOth) x HP $_{\text{Loss Multiplier}}$	
1	∑ (kWh$_t$ x	kWh for each hour in billing period
2	(LMP$_t$ + HPOth)	LMP = Real Time PJM Load Weighted average LMP for ME Zone for each hour
3		HP$_{\text{Oth}}$ = \$.004 per kWh for Ancillary Services
4	HP $_{\text{Energy Charge}}$ (Line 1 x Line 2)	t = An hour in the Billing Period
5	x HP $_{\text{Loss Multiplier}}$	GS Small, Medium, Large = 1.0515 GP = 1.0171 TP = 1.0007
6	HP $_{\text{Energy Charge}}$ (Line 4 x Line 5)	
	HP $_{\text{Cap-AEPS-Other Purchases (\$/MWh)}}$	**Price**
7	January 2021 (June 21 through May 22)	\$ 21.49 *\$/MWh*
8		\$ 0.02149 *per kWh*
9	x HP $_{\text{Loss Multiplier}}$	GS Small, Medium, Large = 1.0515 GP = 1.0171 TP = 1.0007
10	HP $_{\text{Cap-AEPS-Other Purchases (\$/MWh)}}$ (Line 8 x Line 9)	
11	**HP** $_{\text{Administrative Charge}}$	\$ 0.00003 *per kWh*
12	**HP** $_{\text{Uncollectibles Charge}}$	\$ 0.00016 *per kWh*
13	**HP** $_{\text{Reconciliation Charge}}$	\$ 0.00613 *per kWh*
14	**Hourly Pricing Service Charge (Lines 6 + 10 + 11 + 12 + 13)**	**\$ x.xxxxx**

(A) All Hourly Pricing Service Charge computations will be pursuant to the terms of the Company's "Hourly Pricing Default Service Rider".
(B) All Adders are subject to Quarterly Updates

RESA/NRG Exhibit TK-17

Pennsylvania Electric Company
Price to Compare Default Service Rate Calculation
Residential Class: For the Default Service Period December 1, 2021 through February 28, 2022

Line No.	Fixed Price Tranche Purchases ($ per MWh)	Number of Tranches	Clearing Price	Weighted Clearing Price		
1	April 2020 Auction (June 20 through May 22)	1	$ 49.02	$ 49.02		
2	November 2020 Auction (June 21 through May 22)	3	54.80	164.40		
3	January 2021 Auction (June 21 through May 22)	3	55.53	166.59		
4	April 2021 Auction (June 21 through May 22)	3	60.04	180.12		
5	November 2020 Auction (June 21 through May 23)	2	53.86	107.72		
6	January 2021 Auction (June 21 through May 23)	2	54.59	109.18		
7	April 2021 Auction (June 21 through May 23)	3	58.12	174.36		
8	Total	17		$ 951.39		
9	Total Average Fixed Price Tranche		$ 55.96			
10	Times Fixed Portion of Load		95%			
11	Total Fixed Price Cost (Line 9 X Line 10)			$ 53.17		
12	Average Variable Hourly Price Tranche		$58.85			
13	Capacity, Anc. Serv. and AEPS Adder ($20/MWh)		20.00			
14	Variable Hourly Priced Cost (Line 12 + Line 13)		$78.85			
15	Times Variable Portion of Load		5%			
16	Total Variable Hourly Priced Cost (Line 14 X Line 15)			$ 3.94		
17	Price to Compare Weighted Average Price ((Line 11 + Line 16) / 1000)			$ 0.05711		
18	Times PTC Loss $_{Current}$			1.0573		
19	Price to Compare Weighted Average Price, including line losses (Line 17 X Line 18)				$ 0.06038	*per kWh*
20	PTC $_{Administrative\ Charge}$				$ 0.00004	*per kWh*
21	PTC$_{Current}$ before PA Gross Receipts Tax (Line 19 + Line 20)				$ 0.06042	
22	PA Gross Receipt Gross-Up [1/(1-T) (5.9% Gross Receipts Tax)				1.062699	
23	**PTC $_{Current}$ Residential Class including PA Gross Receipts Tax (Line 21 X Line 22)**				**$ 0.06421**	*per kWh*
24	**E Reconciliation Rate, including PA Gross Receipts Tax (Page 2, Line 9)**				**$ 0.00086**	*per kWh*
25	**PTC $_{Default}$ Residential Class (Line 23 + Line 24)**				**$ 0.06507**	*per kWh*

(A) All Price to Compare computations will be pursuant to the terms of the Company's "Price to Compare Default Service Rate Rider".
(B) All Adders are subject to Quarterly Updates

RESA/NRG Exhibit TK-17

Pennsylvania Electric Company
Price to Compare Default Service Rate Calculation
Commercial Class: For the Default Service Period December 1, 2021 through February 28, 2022

Line No.	Fixed Price Tranche Purchases ($ per MWh)	Number of Tranches	Clearing Price	Weighted Clearing Price		
1	April 2020 Auction (June 20 through May 22)	1	$ 49.45	$ 49.45		
2	November 2020 Auction (June 21 through May 22)	1	54.80	54.80		
3	January 2021 Auction (June 21 through May 22)	1	54.59	54.59		
4	April 2021 Auction (June 21 through May 22)	2	57.84	115.68		
5	November 2020 Auction (June 21 through May 23)	1	54.01	54.01		
6	January 2021 Auction (June 21 through May 23)	1	53.55	53.55		
7	April 2021 Auction (June 21 through May 23)	2	57.03	114.06		
8	November 2021 Auction (Dec 21 through Feb 22)	5	114.25	571.25		
9	Total	14		$ 1,067.39		
10	Total Average Fixed Price Tranche		$ 76.24			
11	Times Fixed Portion of Load		100%			
12	Total Fixed Price Cost (Line 10 X Line 11)			$ 76.24		
13	Average Variable Hourly Price Tranche		$ -			
14	Capacity, Anc. Serv. and AEPS Adder ($20/MWh)		20.00			
15	Variable Priced Hourly Cost (Line 13 + Line 14)		$ 20.00			
16	Times Variable Portion of Load		0%			
17	Total Variable Hourly Priced Cost (Line 16 X Line 17)			$ -		
18	Price to Compare Weighted Average Price ((Line 12 + Line 17) / 1000)			$ 0.07624		
19	Times PTC Loss $_{Current}$			1.0573		
20	Price to Compare Weighted Average Price, including line losses (Line 18 X Line 19)				$ 0.08061	*per kWh*
21	PTC $_{Administrative\ Charge}$				$ 0.00004	*per kWh*
22	PTC$_{Current}$ before PA Gross Receipts Tax (Line 20 + Line 21)				$ 0.08065	
23	PA Gross Receipt Gross-Up [1/(1-T) (5.9% Gross Receipts Tax)				1.062699	
24	**PTC $_{Current}$ Commercial Class including PA Gross Receipts Tax (Line 22 X Line 23)**				**$ 0.08571**	*per kWh*
25	**E Reconciliation Rate, including PA Gross Receipts Tax (Page 2, Line 8)**				**$ 0.00065**	*per kWh*
26	**PTC $_{Default}$ Commercial Class (Line 24 + Line 25)**				**$ 0.08636**	*per kWh*

(A) All Price to Compare computations will be pursuant to the terms of the Company's "Price to Compare Default Service Rate Rider".
(B) All Adders are subject to Quarterly Updates

Pennsylvania Electric Company
Hourly Pricing Default Service Rate Calculation (for Illustrative Purposes Only)
Industrial Class: For the Default Service Period December 1, 2021 through February 28, 2022

Line No.			
	HP $_{\text{Energy Charge}}$ = $\sum$ (kWht x (LMPt + HPOth) x	HP $_{\text{Loss Multiplier}}$	
1	$\sum$ (kWh$_t$ x	kWh for each hour in billing period	
2	(LMP$_t$ + HPOth)	LMP = Real Time PJM Load Weighted average LMP for PN Zone for each hour	
3		HP$_{\text{Oth}}$ = \$.004 per kWh for Ancillary Services	
4	HP $_{\text{Energy Charge}}$ (Line 1 x Line 2)	t = An hour in the Billing Period	
5	x HP $_{\text{Loss Multiplier}}$	GS Small, Medium, and Large = 1.0573 GP = 1.0234 LP = 1.0035	
6	HP $_{\text{Energy Charge}}$ (Line 4 x Line 5)		
	HP $_{\text{Cap-AEPS-Other Purchases (\$/MWh)}}$	**Price**	
7	January 2021 (June 21 through May 22)	$ 20.37	*$/MWh*
8		$ 0.02037	*per kWh*
9	x HP $_{\text{Loss Multiplier}}$	GS Small, Medium, and Large = 1.0573 GP = 1.0234 LP = 1.0035	
10	HP $_{\text{Cap-AEPS-Other Purchases (\$/MWh)}}$ (Line 8 x Line 9)		
11	**HP** $_{\text{Administrative Charge}}$	$ 0.00008	*per kWh*
12	**HP** $_{\text{Uncollectibles Charge}}$	$ 0.00100	*per kWh*
13	**HP** $_{\text{Reconciliation Charge}}$	$ 0.03158	*per kWh*
14	**Hourly Pricing Service Charge (Lines 6 + 10 + 11 + 12 + 13)**	**$ x.xxxxx**	

(A) All Hourly Pricing Service Charge computations will be pursuant to the terms of the Company's "Hourly Pricing Default Service Rider".
(B) All Adders are subject to Quarterly Updates

RESA/NRG Exhibit TK-17

Pennsylvania Power Company
Price to Compare Default Service Rate Calculation
Residential Class: For the Default Service Period December 1, 2021 through February 28, 2022

Line No.	Fixed Price Tranche Purchases ($ per MWh)	Number of Tranches	Clearing Price	Weighted Clearing Price		
1	April 2020 Auction (June 20 through May 22)	1	$ 57.09	$ 57.09		
2	November 2020 Auction (June 21 through May 22)	1	63.34	63.34		
3	January 2021 Auction (June 21 through May 22)	1	63.98	63.98		
4	April 2021 Auction (June 21 through May 22)	1	69.56	69.56		
5	November 2020 Auction (June 21 through May 23)	1	61.48	61.48		
6	January 2021 Auction (June 21 through May 23)	1	62.15	62.15		
7	April 2021 Auction (June 21 through May 23)	1	64.92	64.92		
8	Total	7		$ 442.52		
9	Total Average Fixed Price Tranche		$ 63.22			
10	Times Fixed Portion of Load		95%			
11	Total Fixed Price Cost (Line 9 X Line 10)			$ 60.06		
12	Average Variable Hourly Price Tranche		$ 57.15			
13	Capacity, Anc. Serv. and AEPS Adder ($20/MWh)		20.00			
14	Variable Hourly Priced Cost (Line 12 + Line 13)		$ 77.15			
15	Times Variable Portion of Load		5%			
16	Total Variable Hourly Priced Cost (Line 14 X Line 15)			$ 3.86		
17	Price to Compare Weighted Average Price ((Line 11 + Line 16) / 1000)			$ 0.06391	$ 0.00822	
18	Times PTC Loss $_{Current}$			1.0661		
19	Price to Compare Weighted Average Price, including line losses (Line 17 X Line 18)				$ 0.06814	*per kWh*
20	PTC $_{Administrative\ Charge}$				$ 0.00004	*per kWh*
21	PTC$_{Current}$ before PA Gross Receipts Tax(Line 19 + Line 20)				$ 0.06818	
22	PA Gross Receipt Gross-Up [1/(1-T) (5.9% Gross Receipts Tax)				1.062699	
23	**PTC $_{Current}$ Residential Class including PA Gross Receipts Tax (Line 21 X Line 22)**				**$ 0.07245**	*per kWh*
24	**E Reconciliation Rate, including PA Gross Receipts Tax (Page 2, Line 9)**				**$ 0.00348**	*per kWh*
25	**PTC $_{Default}$ Residential Class (Line 23 + Line 24)**				**$ 0.07593**	*per kWh*

(A) All Price to Compare computations will be pursuant to the terms of the Company's "Price to Compare Default Service Rate Rider".
(B) All Adders are subject to Quarterly Updates

RESA/NRG Exhibit TK-17

Pennsylvania Power Company
Price to Compare Default Service Rate Calculation
Commercial Class: For the Default Service Period December 1, 2021 through February 28, 2022

Line No.	Fixed Price Tranche Purchases ($ per MWh)	Number of Tranches	Clearing Price	Weighted Clearing Price			
1	April 2020 Auction (June 20 through May 22)	1	58.90	58.90			
2	January 2021 Auction (June 21 through May 22)	1	63.34	63.34			
3	April 2021 Auction (June 21 through May 22)	1	67.22	67.22			
4	April 2021 Auction (June 21 through May 23)	1	64.80	64.80			
5	November 2021 Auction (Dec 21 through Feb 22)	2	121.21	242.42			
6	Total	6		$ 496.68			
7	Total Average Fixed Price Tranche		$ 82.78				
8	Times Fixed Portion of Load		100%				
9	Total Fixed Price Cost (Line 8 X Line 9)			$ 82.78			
10	Average Variable Hourly Price Tranche		$ -				
11	Capacity, Anc. Serv. and AEPS Adder ($20/MWh)		20.00				
12	Variable Priced Hourly Cost (Line 10 + Line 11)		$ 20.00				
13	Times Variable Portion of Load		0%				
14	Total Variable Hourly Priced Cost (Line 12 X Line 13)			$ -			
15	Price to Compare Weighted Average Price ((Line 9 + Line 14) / 1000)			$ 0.08278			
16	Times PTC Loss $_{\text{Current}}$			1.0661			
17	Price to Compare Weighted Average Price, including line losses (Line 15 X Line 16)				$	0.08825	*per kWh*
18	PTC $_{\text{Administrative Charge}}$				$	0.00005	*per kWh*
19	PTC$_{\text{Current}}$ before PA Gross Receipts Tax (Line 17 + Line 18)				$	0.08830	
20	PA Gross Receipt Gross-Up [1/(1-T) (5.9% Gross Receipts Tax)					1.062699	
21	**PTC $_{\text{Current}}$ Commercial Class including PA Gross Receipts Tax (Line 19 X Line 20)**				**$**	**0.09383**	*per kWh*
22	**E Reconciliation Rate, including PA Gross Receipts Tax (Page 2, Line 8)**				**$**	**0.00682**	*per kWh*
23	**PTC $_{\text{Default}}$ Commercial Class (Line 21 + Line 22)**				**$**	**0.10065**	*per kWh*

(A) All Price to Compare computations will be pursuant to the terms of the Company's "Price to Compare Default Service Rate Rider".
(B) All Adders are subject to Quarterly Updates

RESA/NRG Exhibit TK-17

Pennsylvania Power Company
Hourly Pricing Default Service Rate Calculation (for Illustrative Purposes Only)
Industrial Class: For the Default Service Period December 1, 2021 through February 28, 2022

Line No.		
	$\underline{\textbf{HP}}_{\textbf{Energy Charge}}$ = $\sum$ (kWht x (LMPt + HPOth) x	$HP_{\text{Loss Multiplier}}$
1	$\sum$ (kWh_t x	kWh for each hour in billing period
2	(LMP_t + HPOth)	LMP = Real Time PJM Load Weighted average LMP for ATSI Zone for each hour
3		HP_{Oth} = \$.004 per kWh for Ancillary Services
4	$HP_{\text{Energy Charge}}$ (Line 1 x Line 2)	t = An hour in the Billing Period
5	x $HP_{\text{Loss Multiplier}}$	GS Small, Medium, Large = 1.0515 GP = 1.0171 TP = 1.0007
6	$HP_{\text{Energy Charge}}$ (Line 4 x Line 5)	
	$\underline{\textbf{HP}}_{\textbf{Cap-AEPS-Other Purchases (\$/MWh)}}$	**Price**
7	January 2021 (June 21 through May 22)	\$ 29.61 *\$/MWh*
8		\$ 0.02961 *per kWh*
9	x $HP_{\text{Loss Multiplier}}$	GS Small, Medium, Large = 1.0515 GP = 1.0171 TP = 1.0007
10	$\underline{HP}_{\text{Cap-AEPS-Other Purchases (\$/MWh)}}$ (Line 8 x Line 9)	
11	$\underline{\textbf{HP}}_{\textbf{Administrative Charge}}$	\$ 0.00051 *per kWh*
12	$\underline{\textbf{HP}}_{\textbf{Uncollectibles Charge}}$	\$ 0.00002 *per kWh*
13	$\underline{\textbf{HP}}_{\textbf{Reconciliation Charge}}$	\$ 0.00535 *per kWh*
14	**Hourly Pricing Service Charge (Lines 6 + 10 + 11 + 12 + 13)**	**\$ x.xxxxx**

(A) All Hourly Pricing Service Charge computations will be pursuant to the terms of the Company's "Hourly Pricing Default Service Rider".
(B) All Adders are subject to Quarterly Updates

RESA/NRG Exhibit TK-17

West Penn Power Company
Price to Compare Default Service Rate Calculation
Residential Class: For the Default Service Period December 1, 2021 through February 28, 2022

Line No.	Fixed Price Tranche Purchases ($ per MWh)	Number of Tranches	Clearing Price	Weighted Clearing Price		
1	January 2020 Auction (June 20 through May 22)	2	$ 44.07	$ 88.14		
2	April 2020 Auction (June 20 through May 22)	2	45.39	90.78		
3	November 2020 Auction (June 21 through May 22)	5	49.48	247.40		
4	January 2021 Auction (June 21 through May 22)	5	49.82	249.10		
5	April 2021 Auction (June 21 through May 22)	5	53.16	265.80		
6	November 2020 Auction (June 21 through May 23)	3	47.76	143.28		
7	January 2021 Auction (June 21 through May 23)	4	48.29	193.16		
8	April 2021 Auction (June 21 through May 23)	4	50.73	202.92		
9	Total	30		$ 1,480.58		
10	Total Average Fixed Price Tranche		$ 49.35			
11	Times Fixed Portion of Load		95%			
12	Total Fixed Price Cost (Line 10 X Line 11)			$ 46.89		
13	Average Variable Hourly Price Tranche		$60.02			
14	Capacity, Anc. Serv. and AEPS Adder ($20/MWh)		20.00			
15	Variable Hourly Priced Cost (Line 13 + Line 14)		$80.02			
16	Times Variable Portion of Load		5%			
17	Total Variable Hourly Priced Cost (Line 15 X Line 16)			$ 4.00		
18	Price to Compare Weighted Average Price ((Line 12 + Line 17) / 1000)			$ 0.05089		
19	Times PTC Loss $_{Current}$			1.0910		
20	Price to Compare Weighted Average Price, including line losses (Line 18 X Line 19)				$ 0.05552	*per kWh*
21	PTC $_{Administrative\ Charge}$				$ 0.00004	*per kWh*
22	PTC$_{Current}$ before PA Gross Receipts Tax (Line 20 + Line 21)				$ 0.05556	
23	PA Gross Receipt Gross-Up [1/(1-T) (5.9% Gross Receipts Tax)				1.062699	
24	**PTC $_{Current}$ Residential Class including PA Gross Receipts Tax (Line 22 X Line 23)**				**$ 0.05904**	*per kWh*
25	**E Reconciliation Rate, including PA Gross Receipts Tax (Page 2, Line 9)**				**$ (0.00206)**	*per kWh*
26	**PTC $_{Default}$ Residential Class (Line 24 + Line 25)**				**$ 0.05698**	*per kWh*

(A) All Price to Compare computations will be pursuant to the terms of the Company's "Price to Compare Default Service Rate Rider".
(B) All Adders are subject to Quarterly Updates

RESA/NRG Exhibit TK-17

West Penn Power Company
Price to Compare Default Service Rate Calculation
Commercial Class: For the Default Service Period December 1, 2021 through February 28, 2022

Line No.	Fixed Price Tranche Purchases ($ per MWh)	Number of Tranches	Clearing Price	Weighted Clearing Price		
1	April 2020 Auction (June 20 through May 22)	1	44.88	44.88		
2	November 2020 Auction (June 21 through May 22)	2	45.88	91.76		
3	January 2021 Auction (June 21 through May 22)	2	46.25	92.50		
4	April 2021 Auction (June 21 through May 22)	2	49.38	98.76		
5	November 2020 Auction (June 21 through May 23)	1	45.01	45.01		
6	January 2021 Auction (June 21 through May 23)	2	44.98	89.96		
7	April 2021 Auction (June 21 through May 23)	2	47.76	95.52		
8	November 2021 Auction (Dec 21 through Feb 22)	5	108.27	541.35		
9	Total	17		$ 1,099.74		
10	Total Average Fixed Price Tranche		$ 64.69			
11	Times Fixed Portion of Load		100%			
12	Total Fixed Price Cost (Line 10 X Line 11)			$ 64.69		
13	Average Variable Hourly Price Tranche		$ -			
14	Capacity, Anc. Serv. and AEPS Adder ($20/MWh)		20.00			
15	Variable Priced Hourly Cost (Line 13 + Line 14)		$ 20.00			
16	Times Variable Portion of Load		0%			
17	Total Variable Hourly Priced Cost (Line 15 X Line 16)			$ -		
18	Price to Compare Weighted Average Price ((Line 12 + Line 17) / 1000)			$ 0.06469		
19	Times PTC Loss $_{Current}$			1.0899		
20	Price to Compare Weighted Average Price, including line losses (Line 18 X Line 19)				$ 0.07051	*per kWh*
21	PTC $_{Administrative\ Charge}$				$ 0.00004	*per kWh*
22	PTC$_{Current}$ before PA Gross Receipts Tax (Line 20 + Line 21)				$ 0.07055	
23	PA Gross Receipt Gross-Up [1/(1-T) (5.9% Gross Receipts Tax)				1.062699	
24	**PTC $_{Current}$ Commercial Class including PA Gross Receipts Tax (Line 22 X Line 23)**				**$ 0.07497**	*per kWh*
25	**E Reconciliation Rate, including PA Gross Receipts Tax (Page 2, Line 8)**				**$ 0.00112**	*per kWh*
26	**PTC $_{Default}$ Commercial Class (Line 24 + Line 25)**				**$ 0.07609**	*per kWh*

(A) All Price to Compare computations will be pursuant to the terms of the Company's "Price to Compare Default Service Rate Rider".
(B) All Adders are subject to Quarterly Updates

RESA/NRG Exhibit TK-17

West Penn Power Company
Hourly Pricing Default Service Rate Calculation (for Illustrative Purposes Only)
Industrial Class: For the Default Service Period December 1, 2021 through February 28, 2022

Line No.				
	HP $_{\text{Energy Charge}}$ = $\sum$ (kWht x (LMPt + HPOth) x HP $_{\text{Loss Multiplier}}$			
1	$\sum$ (kWh$_t$ x	kWh for each hour in billing period		
2	(LMP$_t$ + HPOth)	LMP = Real Time PJM Load Weighted average LMP for APS Zone for each hour		
3		HP$_{Oth}$ = \$.004 per kWh for Ancillary Services		
4	HP $_{\text{Energy Charge}}$ (Line 1 x Line 2)	t = An hour in the Billing Period		
5	x HP $_{\text{Loss Multiplier}}$	Rates 20 and 30 = 1.0899 Rate 35 = 1.0678 Rates 40, 44, 46, and PSU = 1.0356		
6	HP $_{\text{Energy Charge}}$ (Line 4 x Line 5)			
	HP $_{\text{Cap-AEPS-Other Purchases (\$/MWh)}}$	**Price**		
7	January 2021 (June 21 through May 22)	\$10.71 *\$/MWh*		
8		\$ 0.01071 *per kWh*		
9	x HP $_{\text{Loss Multiplier}}$	Rates 20 and 30 = 1.0899 Rate 35 = 1.0678 Rates 40, 44, 46, and PSU = 1.0356		
10	HP $_{\text{Cap-AEPS-Other Purchases (\$/MWh)}}$ (Line 8 x Line 9)			
11	**HP** $_{\text{Administrative Charge}}$		\$ 0.00009	*per kWh*
12	**HP** $_{\text{Uncollectibles Charge}}$		\$ 0.00012	*per kWh*
13	**HP** $_{\text{Reconciliation Charge}}$		\$ (0.00083)	*per kWh*
14	**Hourly Pricing Service Charge (Lines 6 + 10 + 11 + 12 + 13)**		**\$ x.xxxxx**	

(A) All Hourly Pricing Service Charge computations will be pursuant to the terms of the Company's "Hourly Pricing Default Service Rider".
(B) All Adders are subject to Quarterly Updates

RESA/NRG EXHIBIT TK-18

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

SHIPLEY CHOICE, LLC D/B/A SHIPLEY ENERGY Set I, No. 8

"Identify each and every cost or expense element that is recovered, in whole or in part, in the default service rate (also known as the "Price to Compare" or "PTC"). If a cost/expense element is not recovered in full, explain what portion of the cost is recovered in the default service rate and explain why it is recovered in that manner."

RESPONSE:

The following costs are recovered in whole in default service rates through the Companies' Price to Compare Default Service Rate ("PTC") Riders and the Hourly Pricing Default Service ("HP") Riders:

- Wholesale energy, capacity, ancillary, applicable RTO or ISO administrative and transmission costs, except for Non-Market Based Services Transmission Charges ("NMB Charges"). For a list of those NMB charges that are recovered through the Companies' Default Service Support ("DSS") Riders on a non-bypassable basis, see Met-Ed/Penelec/Penn Power/West Penn Statement No. 5, page 11, footnote 7. NMB Charges are provided by the Companies to shopping and non-shopping customers. Default service suppliers under contract with the Companies for wholesale power are responsible for any costs they incur for supply management (e.g., hedging, risk management and similar activities), as well as any congestion and congestion management costs incurred to meet their default supply responsibilities. The Companies therefore expect default service suppliers to include such costs in their wholesale power contract prices, which are recovered through the Companies' PTC and HP Riders. See also Met-Ed/Penelec/Penn Power/West Penn Statement No. 3, pages 4-5 for a detailed description of the costs included in the Companies' payments to default service suppliers under their Supply Master Agreements.
- Administrative and general costs directly attributable to default service, such as the costs to conduct procurements, a default service independent evaluator to oversee the procurement process, as well as regulatory filing and litigation costs associated with the Companies' default service programs. Costs related to billing, collections, education, tariff filings, working capital, information system and associated administrative and general expenses are incurred to serve all distribution customers and are therefore collected in base rates. However, default service-related uncollectible accounts expense for large commercial and industrial customers is recovered through the Companies' HP Riders.

- Taxes applicable to default service, including Pennsylvania's 5.9% Gross Receipts Tax, imposed on gross sales of electric energy within Pennsylvania.
- Costs for compliance with Pennsylvania's Alternative Energy Portfolio Standard ("AEPS") Act for the Companies' default service load, except for solar requirements for Met-Ed, Penelec, and Penn Power, which are collected through the Solar Photovoltaic Requirements Charge Riders on a non-bypassable basis.
- The cost of compensating customers taking service under a Company's net metering rider for excess generation in accordance with the AEPS Act.

RESA/NRG EXHIBIT TK-19

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

RETAIL ENERGY SUPPLY ASSOCIATION AND NRG ENERGY, INC. Set I, No. 6

"Please confirm that the Companies are not including any indirect costs of providing default service in its default service rates. If this is not confirmed, please explain."

RESPONSE:

The Companies confirm that no indirect costs of providing default service are included in their default service rates.

RESA/NRG EXHIBIT TK-20

Retail Energy Supply Association

Energy Market Savings Report

Pennsylvania

By shopping for the best deal for electricity, Pennsylvania consumers could have saved more than **$37.9 million** in December and benefited from a wide range of value-added products and services by switching to competitive suppliers.

Savings Over	
Duquesne:	$5,352,211
MetEd:	($3,770,178)
PECO:	$11,105,722
Penelec PA:	$60,379
Penn Power:	$948,129
PPL:	$27,083,485
West Penn Power:	$918,112
December Potential Market Savings:	**$37,927,681**

December Notable Offers:

One year of free Amazon Prime

National Park Pass

$50 contribution to the Children's Hospital of Philadelphia

Source: www.papowerswitch.com

RESA/NRG EXHIBIT TK-21

Standard Offer Program

Before you begin taking calls, you need a good understanding of how the Standard Offer program works. This course will introduce you to the Standard Offer program and prepare you to add these calls to your skill set.

Compliance Information

Lesson 1 of 8

The Rundown

In this course, you'll learn everything you need to know about the Standard Offer program. The course will cover:

1. Program basics like terminology, offer details, and customer benefits
2. How it looks in Concert
3. Frequently Asked Questions and best responses

Let's Get Started!

Common Terminology

Before we get into the details of the Standard Offer Program (SOP), let's review some common terminology you'll need to know.

Click each item below to learn common terms and definitions.

Deregulation

Most utility markets are Regulated - governed by a regulatory or government body which controls all energy-providing processes including generation, transmission, distribution, as well as pricing. In Regulated markets only the local utility is able to sell directly to consumers.

In **Deregulated** markets, customers are allowed to choose the supplier for the electric generation portion of their services. Retailers are competitive in these markets, offering customers innovative features, pricing plans, and options that would otherwise have not been available.

Supplier

The Supplier generates electricity, establishes the usage rates, and makes the electricity available to use by the customer.

A **Default Supplier** is automatically chosen for a customer when they set up electricity services. Typically the default supplier of the customer's electricity is the utility itself.

In deregulated markets, customers can choose an **Alternate Supplier** to take advantage of the Standard Offer Program discount. On SimpleChoice calls you will be educating customers about their ability to shop for an alternate supplier.

Distributor

The Distributor is the company that owns the poles, lines, and equipment necessary to electric delivery (i.e. FirstEnergy). The distributor is responsible for billing the customer; maintaining poles, lines, meter boxes and other components required for electric delivery; and serves as the default supplier if the customer does not choose an alternate supplier. Customers will continue to contact their distributor for billing issues, maintenance concerns, and power outages when they enroll in SOP.

Price-to-Compare (PTC)

The Price-to-Compare is the price per kilowatt hour (kWh) charged by the utility company for the customer's electricity services. This is the price that is discounted through the Standard Offer Program. The PTC changes quarterly and may be higher or lower than the discounted rate throughout the 12-month enrollment period.

View ALL content before moving on.

Lesson 3 of 8

What is the Standard Offer?

Did you know that electric utilities in the state of Pennsylvania are **deregulated**? Energy deregulation makes utility company monopolies a thing of the past. Customers who live in deregulated states have the power to choose their energy supplier, although many customers are unaware they have this choice. The Pennsylvania Public Utilities Commission created the Standard Offer Program to encourage customers to take advantage of this choice by shopping around for an alternate supplier.

Watch the video to learn more.

Watch the video before moving on.

First Energy chose to work with Allconnect to create SimpleChoice – a program designed to get the word out about the Standard Offer Program in Pennsylvania and provide unbiased education and support to customers looking for more information about Standard Offer.

Keep reading to learn more about the details of SOP.

1

7% Discount

The Standard Offer Program provides customers with a discount on the electricity generation portion of their utility bill simply for switching to a competitive supplier. The customer will get 7% off the utility's current Price-to-Compare rate.

2

Fixed Rate

The customer's new discounted Price-to-Compare rate is locked in for 12 months, so even when the Price-to-Compare changes the customer's rate stays the same. If the Price-to-Compare drops below their discounted rate, the customer can choose to cancel or re-enroll in the program.

3

Low Risk

Customers who choose to participate in the Standard Offer Program can take comfort in knowing that they can make changes to their enrollment at any time without penalties or fees. This includes changing their supplier, canceling their enrollment, or re-enrolling to take advantage of a lower discounted rate.

CONTINUE

Lesson 4 of 8

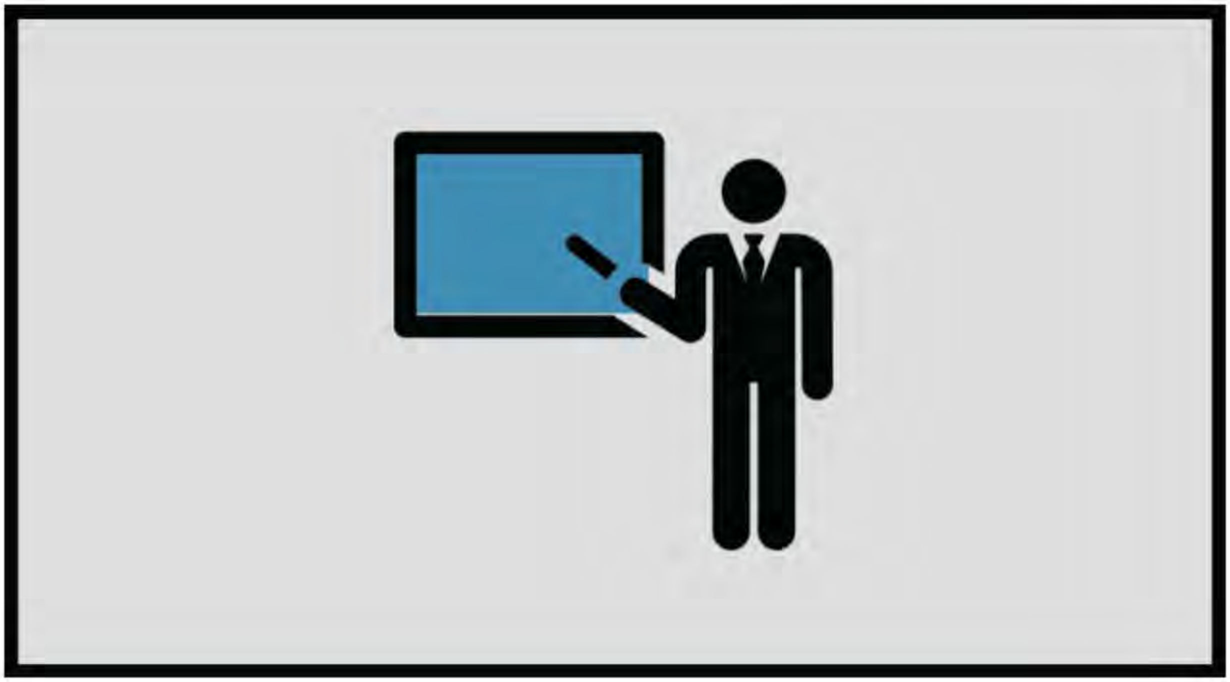
Agent Role

SimpleChoice calls are different from the other calls you take in many ways. The most important difference in these calls is that you're not actually SELLING the customer on the Standard Offer Program. Your role is to EDUCATE the customer on their ability to choose an alternate supplier.

Click each tab below to learn more about your role in SimpleChoice.

1. EDUCATE	2. SELL THE BENEFITS	3. ENCOURAGE PARTICIPATION	4. SIGN THEM UP!

The SimpleChoice program was created to educate customers about the benefits of the Standard Offer Program. FirstEnergy is indifferent about the customer's decision to enroll in SOP - their goal is not to increase participation in the program, but rather to increase awareness of the program and provide information about SOP to their customers. Help your customer understand what the Standard Offer is and why it's being offered. If you've done your job correctly, the customer should understand that they have a choice in who provides their electricity.



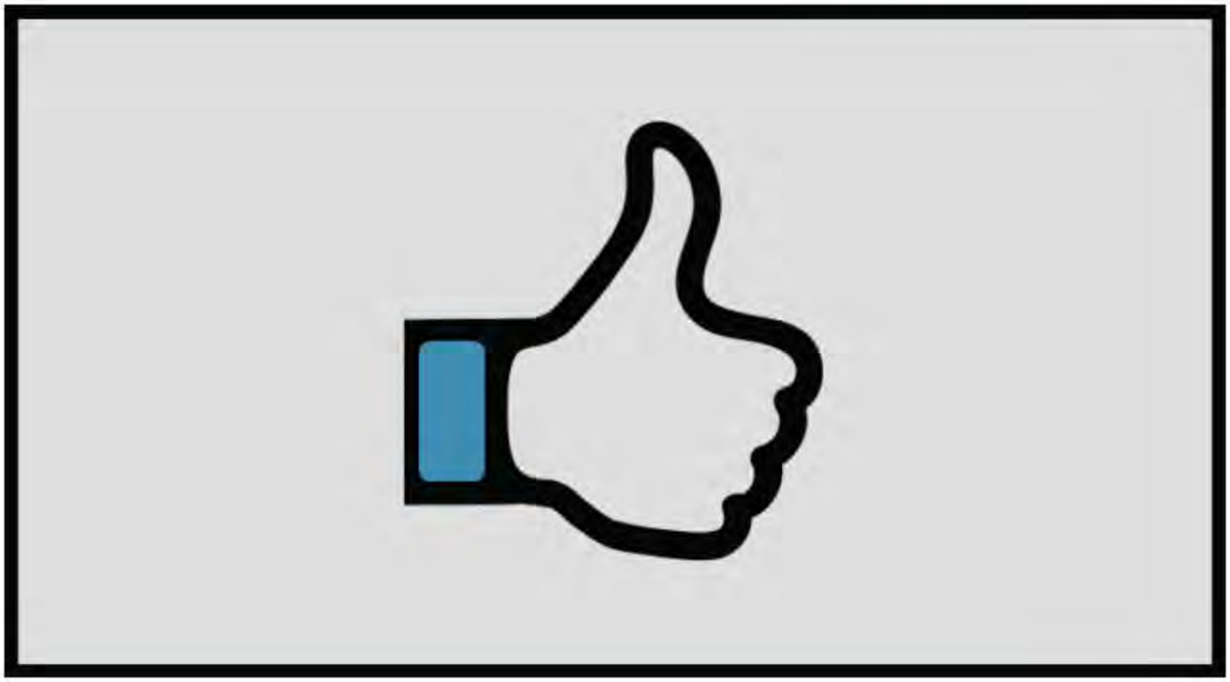
1. EDUCATE	2. SELL THE BENEFITS	3. ENCOURAGE PARTICIPATION	4. SIGN THEM UP!

Agents are responsible for explaining the benefits of SOP to the customer. Most customers are unaware that SOP even exists, so agents need to have a good understanding of the program and why it is beneficial to the customer. Scripting in Concert covers all the benefits of the program! If your customer still seems hesitant, remind them:

- the program will help them save money
- they can re-enroll any time to further increase savings
- the discounted rate they receive through SOP is fixed for 12 months and protected against fluctuating PTC rates
- the program presents almost no risk to the customer since they can opt out or change their enrollment at any time with no penalties or fees

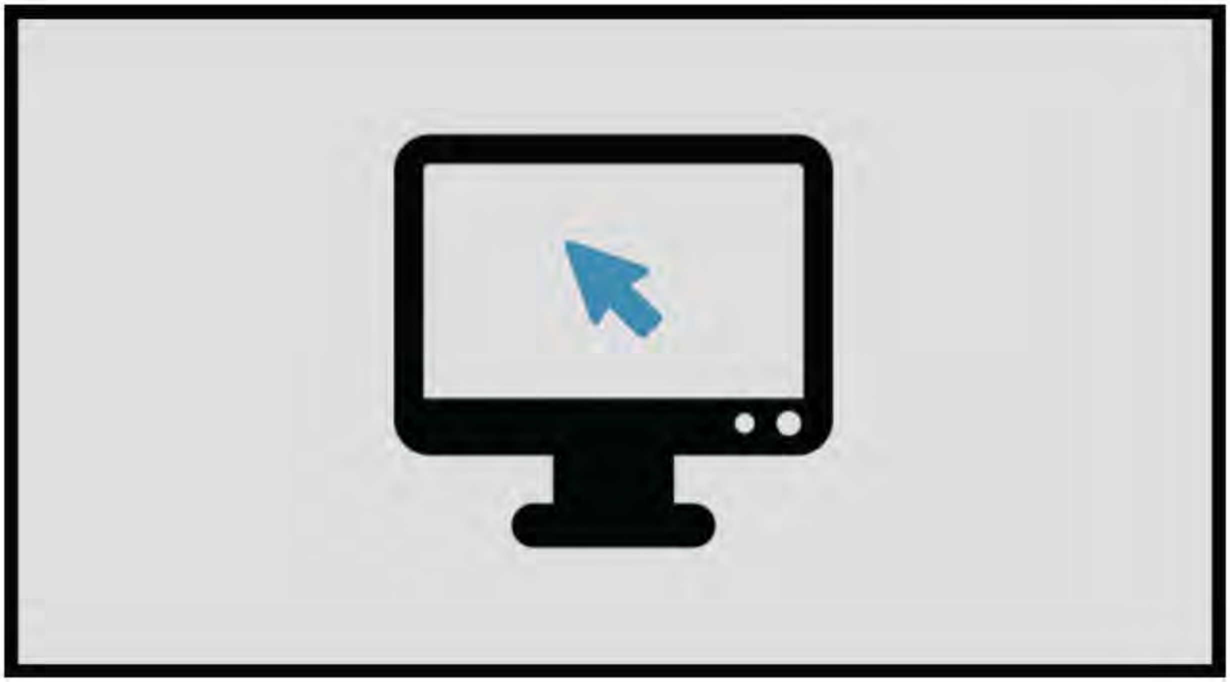
1. EDUCATE	2. SELL THE BENEFITS	3. ENCOURAGE PARTICIPATION	4. SIGN THEM UP!

Remember, your job is not to SELL the customer on the program or push them into choosing an alternate supplier. Your job is to educate customers about the program and encourage them to enroll by explaining the benefits of participation. **Agents must remain unbiased when offering the program and not recommend specific suppliers.** In addition, agents should not push customers to enroll in the program. If the customer does not want to enroll, make sure they understand the program and keep the call moving.



1. EDUCATE	2. SELL THE BENEFITS	3. ENCOURAGE PARTICIPATION	4. SIGN THEM UP!

If you've educated the customer correctly by following scripting in Concert, the SOP basically sells itself. Follow Concert to complete the enrollment process, taking care to read all disclosures verbatim and verify all necessary customer information. Your customer may still have questions during the enrollment process, so take your time and listen carefully. After completing the customer's enrollment, proceed with the call as normal.



Click ALL tabs before moving on.

Lesson 5 of 8

Order Flow - FE Movers

The Standard Offer order flow for FirstEnergy isn't very different from a standard utility call. You'll start the call the same way, by collecting and/or verifying basic customer information and offering Savers Program. Then, you'll talk about SOP.

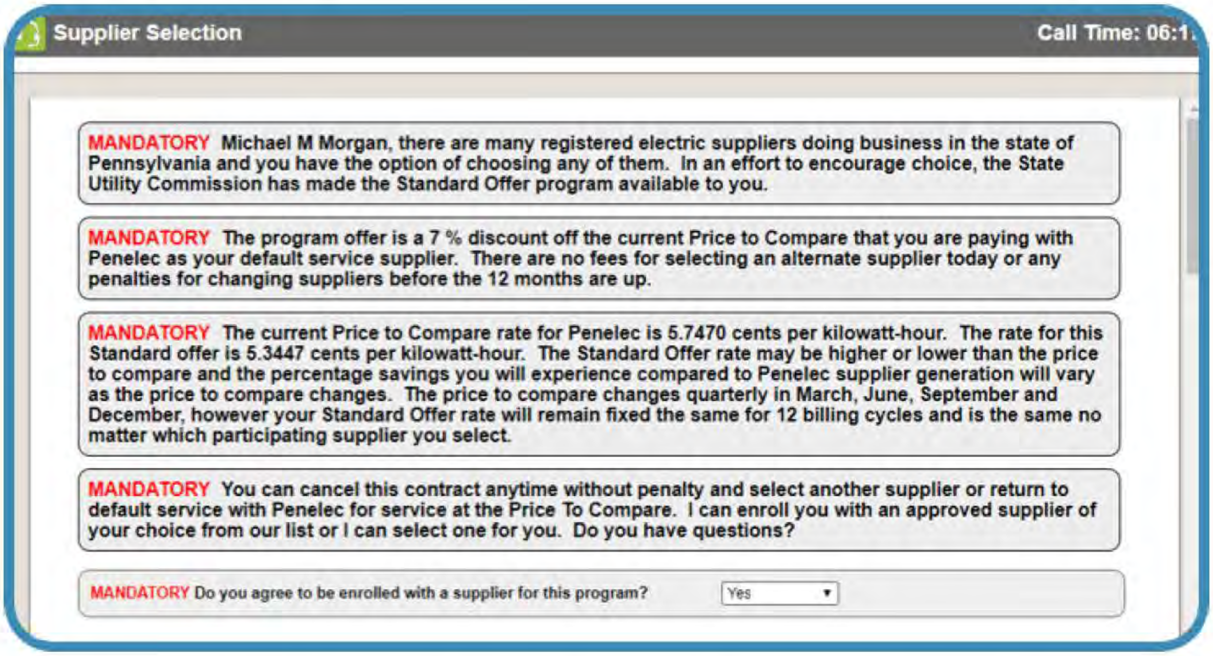
Click through the slideshow to see what the process looks like in Concert.

SOP Concert Flow - FirstEnergy

Selling SOP on FirstEnergy calls is easy. Just follow Concert! Click START to view the Concert Flow slideshow.

Step 1

Explain the Program


Supplier Selection

Call Time: 06:1

MANDATORY Michael M Morgan, there are many registered electric suppliers doing business in the state of Pennsylvania and you have the option of choosing any of them. In an effort to encourage choice, the State Utility Commission has made the Standard Offer program available to you.

MANDATORY The program offer is a 7 % discount off the current Price to Compare that you are paying with Penelec as your default service supplier. There are no fees for selecting an alternate supplier today or any penalties for changing suppliers before the 12 months are up.

MANDATORY The current Price to Compare rate for Penelec is 5.7470 cents per kilowatt-hour. The rate for this Standard offer is 5.3447 cents per kilowatt-hour. The Standard Offer rate may be higher or lower than the price to compare and the percentage savings you will experience compared to Penelec supplier generation will vary as the price to compare changes. The price to compare changes quarterly in March, June, September and December, however your Standard Offer rate will remain fixed the same for 12 billing cycles and is the same no matter which participating supplier you select.

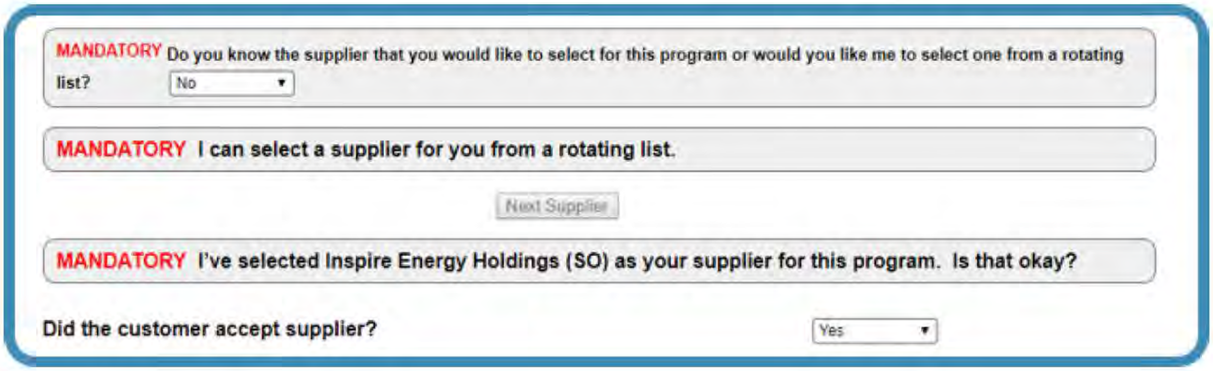
MANDATORY You can cancel this contract anytime without penalty and select another supplier or return to default service with Penelec for service at the Price To Compare. I can enroll you with an approved supplier of your choice from our list or I can select one for you. Do you have questions?

MANDATORY Do you agree to be enrolled with a supplier for this program? Yes

Follow Mandatory Disclosures in Concert to explain the Standard Offer Program to the customer. Keep in mind that your customer may know FirstEnergy by another name (ex: West Penn Power). Read the disclosures word for word at a steady pace. When reading pricing information (like the PTC) you need to read the entire number as it appears. If the customer interrupts with a question, answer the question and then pick up where you left off just as you would with other disclosures.

Step 2

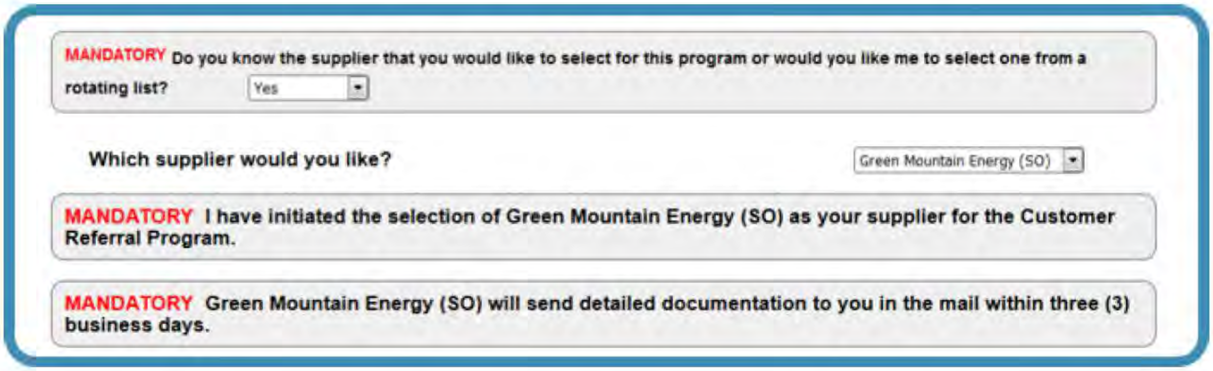
Supplier Selection - When They Don't Know



Typically the customer won't have a particular supplier in mind. When the customer agrees to choose a supplier but doesn't have a preference, you MUST use the round robin function in Concert to select a supplier for the customer. Click the "Next Supplier" button to select a supplier at random, then follow scripting in Concert to ask for their acceptance of that supplier before continuing with enrollment.

Step 3

Supplier Selection - When They Know


MANDATORY Do you know the supplier that you would like to select for this program or would you like me to select one from a rotating list? Yes

Which supplier would you like? Green Mountain Energy (SO)

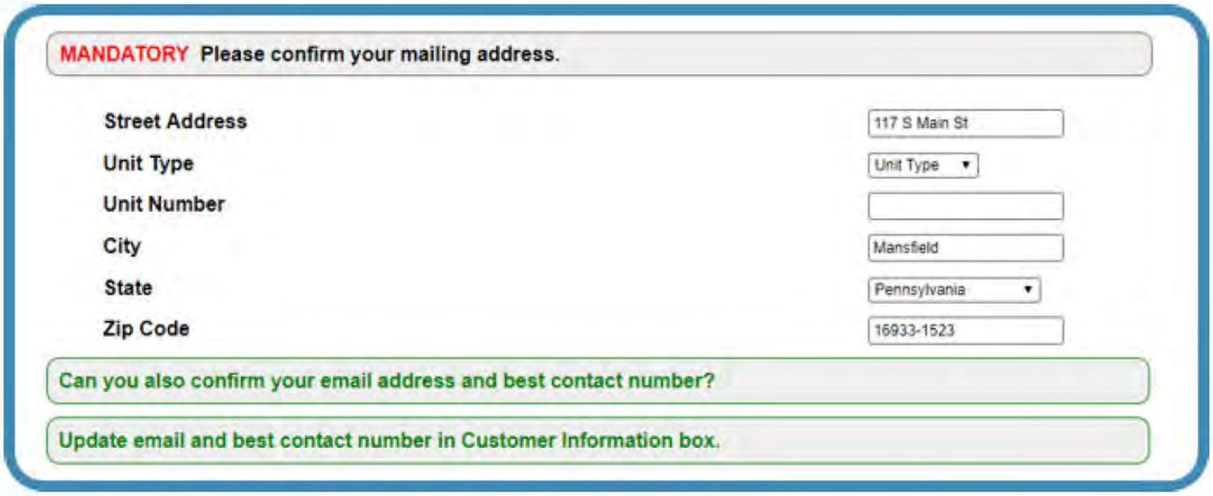
MANDATORY I have initiated the selection of Green Mountain Energy (SO) as your supplier for the Customer Referral Program.

MANDATORY Green Mountain Energy (SO) will send detailed documentation to you in the mail within three (3) business days.

If the customer is familiar with Standard Offer Program or otherwise knows which supplier they'd like to choose, simply select the supplier from the drop down menu. Don't see the supplier in the list? Inform the customer that supplier is not currently participating and offer to select a different supplier at random for them. Remind the customer they can change suppliers any time without penalties. They can research suppliers at papowerswitch.com - for FirstEnergy the list is updated every three months.

Step 4

Verify Customer Information


MANDATORY Please confirm your mailing address.

Street Address	117 S Main St
Unit Type	Unit Type
Unit Number	
City	Mansfield
State	Pennsylvania
Zip Code	16933-1523

Can you also confirm your email address and best contact number?

Update email and best contact number in Customer Information box.

Even though you've already verified the customer's information at this point in the call, when you're enrolling them in SOP you need to do it again. Verify complete address including ZIP code, email address, and best contact number.

Step 5

Next Steps

MANDATORY Depending on your billing cycle, the supplier will begin to show on your Penelec bill within 1 billing cycle.

MANDATORY Please remember that you should continue to contact Penelec for any questions related to your electric service, regardless of who you chose as a supplier.

MANDATORY Also, you can make changes to your supplier selection any time you want to.

After choosing a supplier and gaining the customer's agreement to use that supplier, simply follow Concert to explain next steps to the customer and give a few final reminders.

Step 6

Frequently Asked Questions

- The customer can always make their choice – go to www.papowerswitch.com for additional information.
- The Customer Referral Program is the same for all participating suppliers.
- If customer asks, "What is changing", tell him that the only items changing will be the supplier of the customer's electricity and a lower price per kilowatt-hour on the bill for 12 months. Everything else will remain the same.
- The Commission wants customers to choose suppliers and believes it will lower costs for consumers over time.
- The participating suppliers are licensed and accredited to be doing business as electric suppliers within the state of Pennsylvania.
- The rate per kilowatt-hour will be the same for 12 billing cycles. The price to compare could fluctuate over time.
- The customer can select another supplier or return to default service at any time – even if the supplier is not participating in the Customer Referral Program.
- There is no cost to switch out of the Customer Referral Program.

Does your customer have a question about the Standard Offer Program? Answer carefully! The green section at the bottom of the order page in Concert includes approved scripting you can use to answer questions and further explain the program to your customer (if needed).

That's All!

Keep it simple! Follow Concert, get permission, and use the FAQs section when you get stuck.

View the entire slideshow before moving on.

Lesson 6 of 8

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Step 2

[redacted]

[redacted]

[redacted]

Step 3

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Step 5

[redacted]

[redacted]

Step 6

[redacted]

Step 7

[redacted]

[redacted]

[redacted]

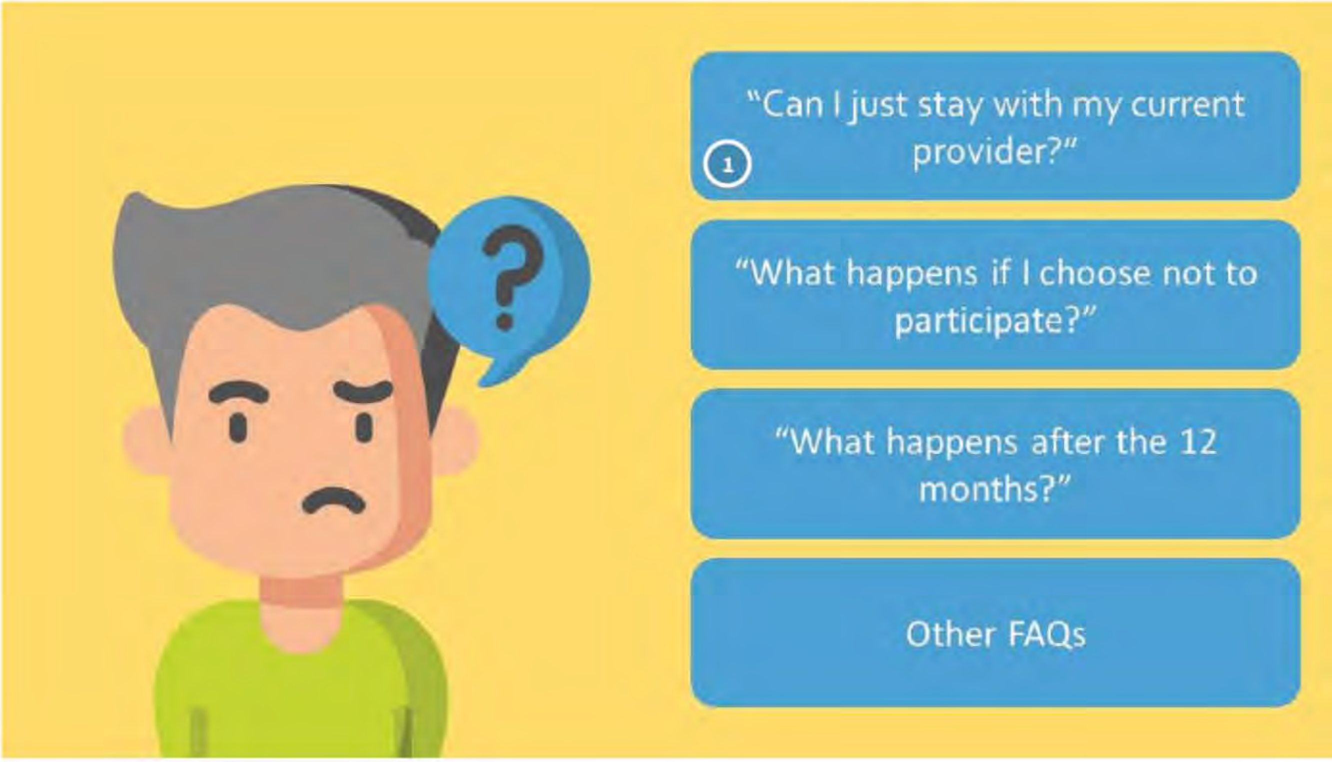
That's All!

Keep it simple! Follow Concert, get permission, and use the FAQs section when you get stuck.

FAQs and Customer Objections

Customers may find the Standard Offer Program a bit confusing even after you've done a great job explaining how it all works. When customers have questions, it's important to answer those questions accurately.

Click each point on the graphic to learn more about the most frequent customer questions and how best to respond to them.

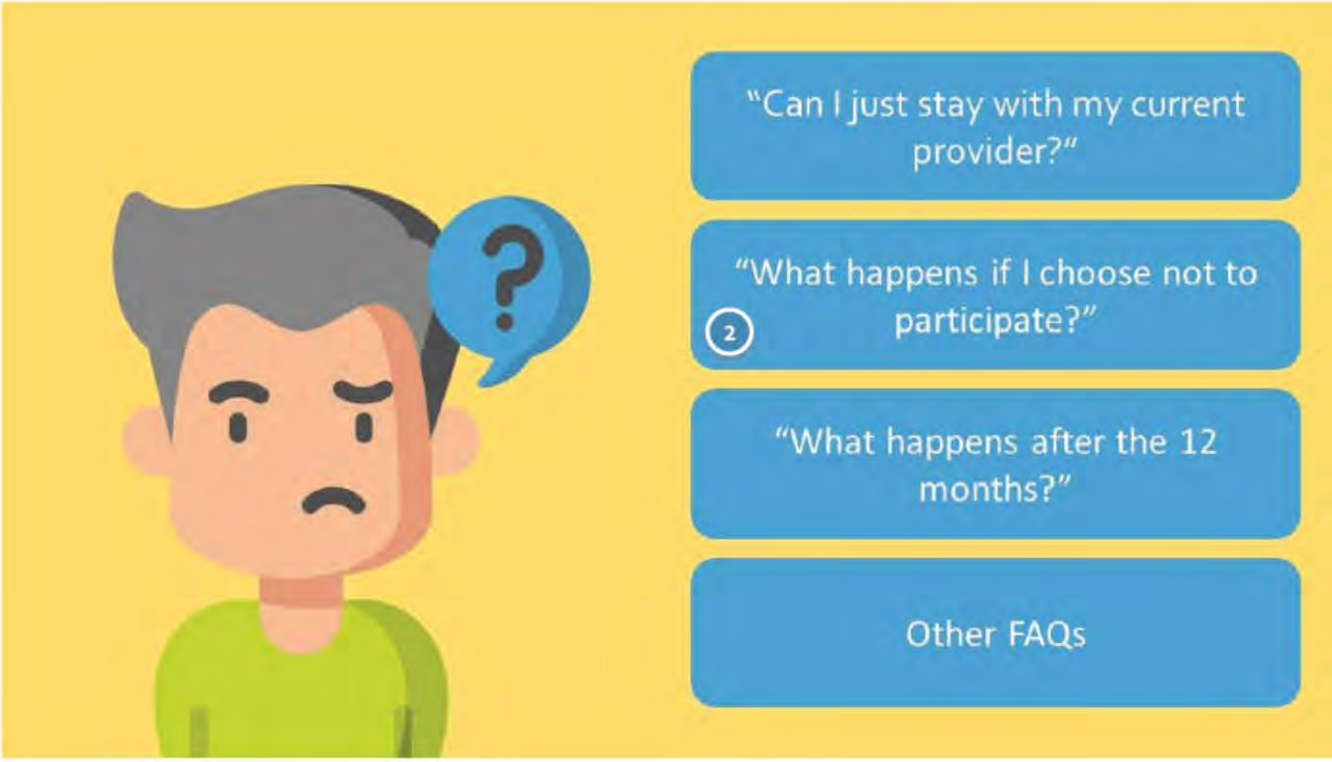


"Can I just stay with my current provider?"

▶ 00:21

This is the most common question you'll hear when offering SOP. You may also hear "I just want to stay with who I have now." Remember to acknowledge the customer's question, educate them on the program, and encourage them to participate.

Play the clip to hear an example of how best to respond to this question.

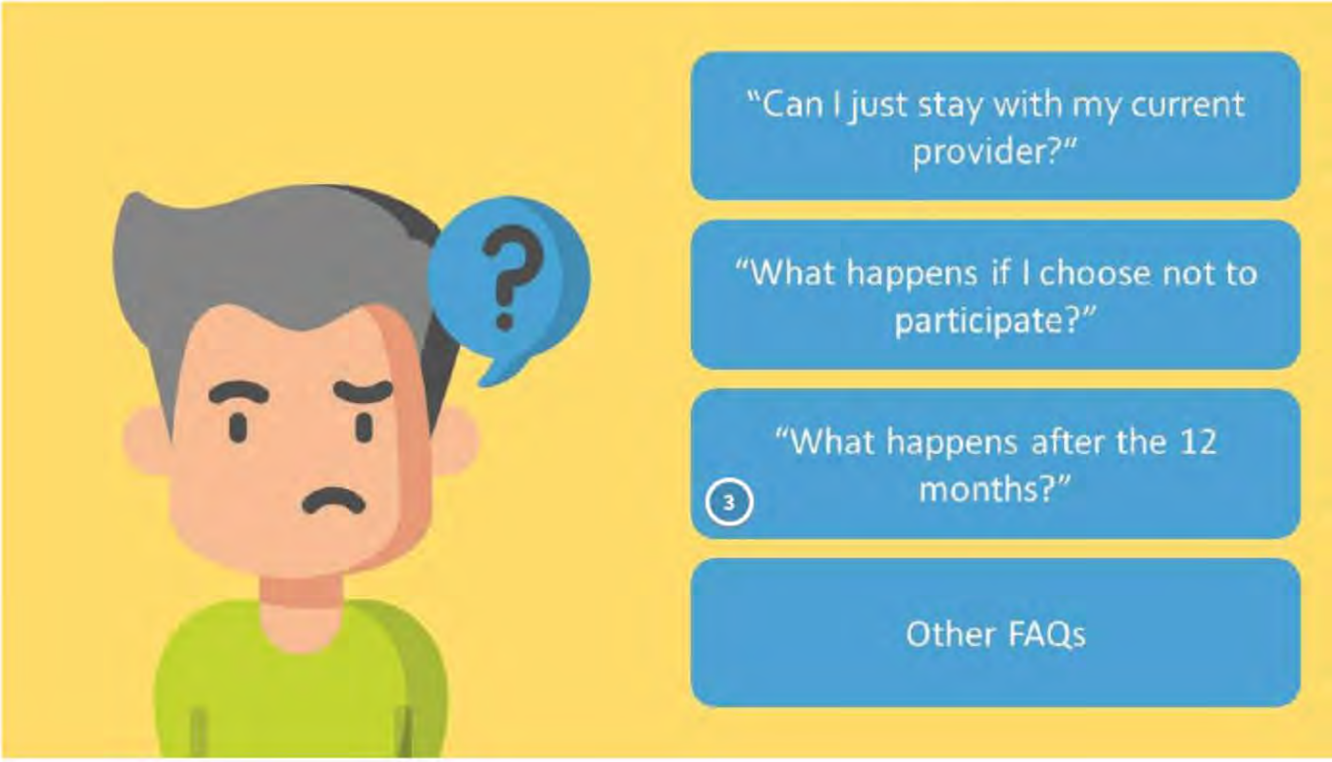


"What happens if I choose not to participate?"

00:15

Participation in the program is completely optional. Remind the customer of the benefits of the program and leave the choice to the customer.

Play the clip to hear an example of how best to respond to this question.

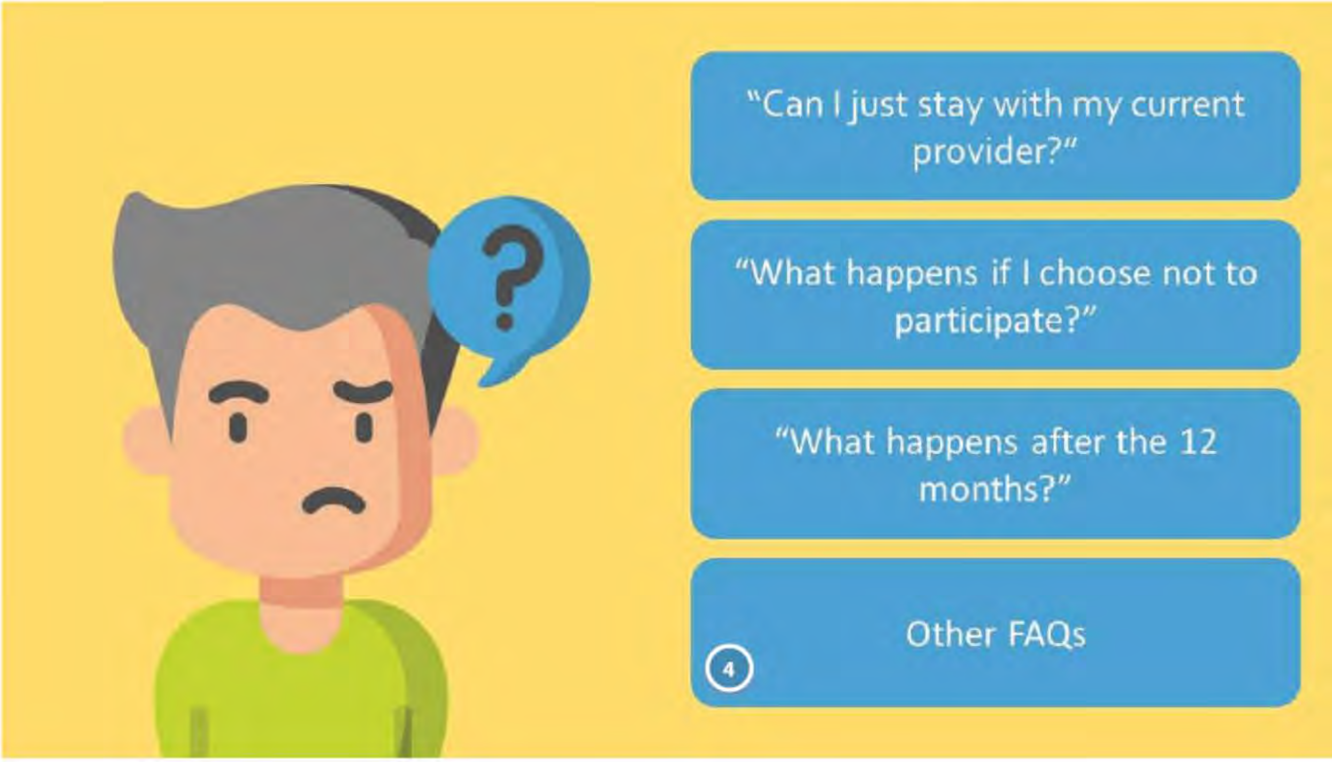


"What happens after the 12 months are up?"

00:22

Sometimes customers need some reassurance before they agree to enroll in a program like SOP. Keep things simple – explain next steps to the customer and assure them that the program is low risk and high benefit.

Play the clip to hear an example of how best to respond to this question.



Other FAQs

You have additional resources to help you answer questions about Standard Offer Program! Besides the information in Concert, you can also use the Standard Offer FAQs document. Find the document HERE.

Click ALL points on the graphic before moving on.

Lesson 8 of 8

Compliance Information

For the most part, you should follow the same compliance guidelines for Standard Offer Program as you do for all other products and services. Check out the information below to learn more about Compliance Do's and Don'ts for Standard Offer Program.

1

DON'T Recommend a Supplier

Making a recommendation or otherwise influencing the customer's decision in selecting a supplier is an Elevated Risk occurrence. Examples include:

- Telling the customer not to use a specific supplier

- Failing to use the round-robin process if the customer chooses to have a supplier randomly selected
- Qualifying a supplier (i.e. "This supplier is greenest/least popular/most popular, etc.)
- Giving an opinion on which supplier most customers choose

?

What if a customer ASKS you which supplier they should go with? When this happens, you still have to remain unbiased and not recommend a specific supplier. You can say something like:

"All suppliers honor the same rate. More research can be found at www.papowerswitch.com . I can randomly select a supplier now, and you can change suppliers at any time with no penalties."

2

DO Follow the Script

Going off script is the number one cause for customer confusion about the Standard Offer Program, and customer confusion presents more opportunities for mistakes to creep into your calls. Use information in Concert or the FAQs document to answer customer questions and educate the customer about SOP. If you're not sure what to say or how to answer a question, ASK.

3

DON'T Force It

Participation in the Standard Offer Program is completely optional. The customer is not required to participate and will not be penalized in any way for choosing not to enroll. Take care not to mislead the customer into thinking they are required to participate in the program.

4

DO Get Permission

You'll need to get the customer's express permission to enroll them in SOP. You also need their agreement when selecting a supplier. Best practice is to follow the prompts in Concert – READ the mandatory scripting verbatim and WAIT for the customer's response.

CONTINUE

There Isn't Any More

That's all there is to it! Standard Offer Program is a different beast for sure, but it doesn't have to be difficult. If you have any questions or concerns, please feel free to reach out to your training team.

Questions? Comments? Concerns?

Let us know! Click the button to email your Allconnect training team!

EMAIL US!

RESA/NRG EXHIBIT TK-22

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

OFFICE OF CONSUMER ADVOCATE Set I, No. 10

"With regard to the Referral Program, please provide the following data for each EDC for each month since June 2019 and for each month during the pendency of this proceeding:

a. Number of referrals made by FirstEnergy's customer service representatives;
b. Number of calls handled by the Customer Referral Program Team;
c. Number of customers by customer class who enrolled in the Referral program;
d. The applicable PTC and Referral contract price; and
e. Number of participating EGSs;"

RESPONSE:

a. See ME/PN/PP/WP Response to OCA Interrogatory Set 1, No. 10 Attachment A for the number of referrals made by the Companies' customer service representatives for each month since June 2019.

b. See ME/PN/PP/WP Response to OCA Interrogatory Set 1, No. 10 Attachment B for the number of calls handled by the Customer Referral Program Team for each month since June 2019. The difference in the number of referrals made by the Companies' customer service representatives and calls handled by the Customer Referral Program Team is attributable to customer disconnections after the transfer of the call.

c., d. and e. See ME/PN/PP/WP Response to OCA Interrogatory Set 1, No. 10 Attachment C for the number of customers by customer class who enrolled in the Referral program, the applicable PTC and Referral contract price, and the number of participating EGSs for each month since June 2019.

West Penn Power Customer Referral Program Information 2019

	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
# Residential Enrollments	812	911	900	701	765	519	535
# Small Comm. Enrollments	0	0	1	0	0	6	7
# EGSs Serving Residential	5	5	5	6	6	6	9
# EGSs Serving Small Comm.	3	3	3	3	3	3	3
Residential Standard Offer Rate (¢/kWh)	$0.05131	$0.05131	$0.05131	$0.04964	$0.04964	$0.04964	$0.05357
Small Comm. Standard Offer Rate (¢/kWh)	$0.05148	$0.05148	$0.05148	$0.05320	$0.05320	$0.05320	$0.05321

West Penn Power Customer Referral Program Information 2020

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
# Residential Enrollments	568	545	606	447	464	497	681	943	538	402	282	278
# Small Comm. Enrollments	9	5	10	6	5	7	7	1	1	1	3	2
# EGSs Serving Residential	9	9	11	11	11	10	10	10	9	9	9	7
# EGSs Serving Small Comm.	3	3	3	3	3	5	5	5	2	2	2	1
Residential Standard Offer Rate (¢/kWh)	$0.05357	$0.05357	$0.05242	$0.05242	$0.05242	$0.04766	$0.04766	$0.04766	$0.04549	$0.04549	$0.04549	$0.04834
Small Comm. Standard Offer Rate (¢/kWh)	$0.05321	$0.05321	$0.05440	$0.05440	$0.05440	$0.05210	$0.05210	$0.05210	$0.04877	$0.04877	$0.04877	$0.05304

West Penn Power Customer Referral Program Information 2021

	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
# Residential Enrollments	319	368	207	460	545	298	353	645	372	363	288	259
# Small Comm. Enrollments	0	0	0	13	6	13	9	8	8	2	2	6
# EGSs Serving Residential	7	7	4	4	4	7	7	7	7	7	7	2
# EGSs Serving Small Comm.	1	1	2	2	2	2	2	2	1	1	1	1
Residential Standard Offer Rate (¢/kWh)	$0.04834	$0.04834	$0.04793	$0.04793	$0.04793	$0.05308	$0.05308	$0.05308	$0.05066	$0.05066	$0.05066	$0.05299
Small Comm. Standard Offer Rate (¢/kWh)	$0.05304	$0.05304	$0.04532	$0.04532	$0.04532	$0.05699	$0.05699	$0.05699	$0.05264	$0.05264	$0.05264	$0.07076

ME Customer Referral Program Information 2017

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
# Residential Enrollments	2,000	1,918	2,556	2,068	2,338	619	286	287	272	287	219	232
# Small Comm. Enrollments	22	22	24	19	23	5	3	6	1	2	2	4

PN Customer Referral Program Information 2017

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
# Residential Enrollments	2,056	1,880	2,406	2,174	2,667	618	224	302	234	232	173	135
# Small Comm. Enrollments	22	17	21	13	29	6	2	2	2	5	5	1

PP Customer Referral Program Information 2017

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
# Residential Enrollments	514	466	592	584	723	227	80	82	64	77	53	41
# Small Comm. Enrollments	8	5	10	9	9	1	2	0	1	1	0	1

WP Customer Referral Program Information 2017

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
# Residential Enrollments	1,993	1,960	2,292	2,218	2,743	728	241	452	287	240	170	132
# Small Comm. Enrollments	26	29	22	15	21	6	13	21	2	3	8	3

ME Customer Referral Program Information 2018

	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
# Residential Enrollments	286	223	240	207	248	225	262	263	192	185	144	138
# Small Comm. Enrollments	2	6	9	2	5	3	6	5	3	1	0	0

PN Customer Referral Program Information 2018

	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
# Residential Enrollments	175	157	167	160	179	192	188	231	146	168	112	80
# Small Comm. Enrollments	2	1	5	6	4	4	0	0	1	1	0	0

PP Customer Referral Program Information 2018

	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
# Residential Enrollments	50	44	55	64	54	61	73	67	43	40	25	19
# Small Comm. Enrollments	0	0	0	0	3	3	0	2	0	0	0	0

WP Customer Referral Program Information 2018

	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
# Residential Enrollments	173	171	215	198	200	203	204	320	202	148	128	75
# Small Comm. Enrollments	1	4	5	4	3	4	3	1	0	1	0	0

ME Customer Referral Program Information 2019

	Jan-19	Feb-19	Mar-19	Apr-19	May-19
# Residential Enrollments	106	125	152	313	804
# Small Comm. Enrollments	0	2	1	1	0

PN Customer Referral Program Information 2019

	Jan-19	Feb-19	Mar-19	Apr-19	May-19
# Residential Enrollments	83	78	88	256	738
# Small Comm. Enrollments	0	0	0	0	1

PP Customer Referral Program Information 2019

	Jan-19	Feb-19	Mar-19	Apr-19	May-19
# Residential Enrollments	27	24	17	83	198
# Small Comm. Enrollments	0	0	0	0	0

WP Customer Referral Program Information 2019

	Jan-19	Feb-19	Mar-19	Apr-19	May-19
# Residential Enrollments	93	109	115	256	812
# Small Comm. Enrollments	0	0	0	0	0

RESA/NRG EXHIBIT TK-23

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

SHIPLEY CHOICE, LLC D/B/A SHIPLEY ENERGY Set I, No. 1

"How many customers, by month, has each Company enrolled in residential service for each of the past five years? For the customers reported, for each month quantify the number of customers by the method used to enroll them, using categories such as: telephone, online, and other."

RESPONSE:

See ME/PN/PP/WP Response to SHIPLEY ENERGY Interrogatory Set 1, No. 1 Attachment A which shows all residential service enrollments, regardless of shopping status, from 2017 to 2021, including a breakdown of enrollments by web process, telephone during a contact with a customer service representative, and manual enrollment by an agent following a request for service on the Companies' websites.

Residential Service Applications Completed - 2017						
	Month	PN	ME	PP	WP	Total
January	Total	5394	5942	1454	5965	18755
	Manual Agent	127	260	45	188	620
	Web process	26	44	15	38	123
	Live Agents	5241	5638	1394	5739	18012
February	Total	5375	6224	1486	5989	19074
	Manual Agent	176	271	56	176	679
	Web process	57	42	13	57	169
	Live Agents	5142	5911	1417	5756	18226
March	Total	7048	8163	1905	7503	24619
	Manual Agent	162	305	52	221	740
	Web process	39	55	19	49	162
	Live Agents	6847	7803	1834	7233	23717
April	Total	6065	7099	1771	6781	21716
	Manual Agent	168	299	67	227	761
	Web process	43	61	19	72	195
	Live Agents	5854	6739	1685	6482	20760
May	Total	8700	7869	2156	8408	27133
	Manual Agent	232	373	90	317	1012
	Web process	45	56	21	87	209
	Live Agents	8423	7440	2045	8004	25912
June	Total	9058	8923	2536	9257	29774
	Manual Agent	230	399	80	330	1039
	Web process	66	93	17	93	269
	Live Agents	8762	8431	2439	8834	28466
July	Total	8056	7827	2065	8964	26912
	Manual Agent	233	370	77	514	1194
	Web process	65	72	20	132	289
	Live Agents	7758	7385	1968	8318	25429
August	Total	10292	8920	2365	15231	36808
	Manual Agent	351	432	93	684	1560
	Web process	64	90	29	159	342
	Live Agents	9877	8398	2243	14388	34906
September	Total	8150	8443	2174	8826	27593
	Manual Agent	226	364	81	335	1006
	Web process	47	60	21	52	180
	Live Agents	7877	8019	2072	8439	26407
October	Total	7954	8139	2158	8181	26432
	Manual Agent	181	340	60	260	841
	Web process	32	55	15	48	150
	Live Agents	7741	7744	2083	7873	25441
November	Total	7453	7939	1969	7671	25032
	Manual Agent	207	320	51	269	847
	Web process	50	46	16	74	186
	Live Agents	7196	7573	1902	7328	23999
December	Total	6373	7329	1929	7052	22683
	Manual Agent	148	264	66	250	728
	Web process	37	41	14	44	136
	Live Agents	6188	7024	1849	6758	21819
2017	Total	89918	92817	23968	99828	306531
	Manual Agent	2441	3997	818	3771	11027
	Web process	571	715	219	905	2410
	Live Agents	86906	88105	22931	95152	293094

Residential Service Applications Completed - 2018						
	Month	PN	ME	PP	WP	Total
January	Total	5669	5901	1477	6193	19240
	Manual Agent	172	259	53	216	700
	Web process	27	37	20	57	141
	Live Agents	5470	5605	1404	5920	18399
February	Total	5291	5905	1567	5693	18456
	Manual Agent	142	235	54	199	630
	Web process	34	53	11	46	144
	Live Agents	5115	5617	1502	5448	17682
March	Total	6723	7335	2018	7126	23202
	Manual Agent	172	333	90	279	874
	Web process	390	60	19	66	535
	Live Agents	6161	6942	1909	6781	21793
April	Total	6312	6910	1871	7063	22156
	Manual Agent	221	379	96	303	999
	Web process	40	63	20	74	197
	Live Agents	6051	6468	1755	6686	20960
May	Total	8465	8003	2238	8546	27252
	Manual Agent	289	417	82	403	1191
	Web process	71	77	15	100	263
	Live Agents	8105	7509	2141	8043	25798
June	Total	8804	8729	2335	9336	29204
	Manual Agent	249	446	99	414	1208
	Web process	66	91	29	97	283
	Live Agents	8489	8192	2207	8825	27713
July	Total	8106	8104	2306	9269	27785
	Manual Agent	315	478	105	635	1533
	Web process	73	70	30	175	348
	Live Agents	7718	7556	2171	8459	25904
August	Total	10385	9203	2671	15306	37565
	Manual Agent	346	460	99	681	1586
	Web process	61	84	24	148	317
	Live Agents	9978	8659	2548	14477	35662
September	Total	7370	7252	1975	7936	24533
	Manual Agent	225	347	84	408	1064
	Web process	44	69	14	70	197
	Live Agents	7101	6836	1877	7458	23272
October	Total	8503	8302	2181	8598	27584
	Manual Agent	251	412	86	311	1060
	Web process	48	61	19	81	209
	Live Agents	8204	7829	2076	8206	26315
November	Total	7560	7706	1913	7723	24902
	Manual Agent	220	355	69	263	907
	Web process	51	62	21	84	218
	Live Agents	7289	7289	1823	7376	23777
December	Total	5531	6417	1519	6279	19746
	Manual Agent	36	46	47	58	187
	Web process	168	266	10	230	674
	Live Agents	5327	6105	1462	5991	18885
2018	Total	88719	89767	24071	99068	301625
	Manual Agent	2638	4167	964	4170	11939
	Web process	1073	993	232	1228	3526
	Live Agents	85008	84607	22875	93670	286160

Residential Service Applications Completed - 2019						
	Month	PN	ME	PP	WP	Total
January	Total	5814	6017	1529	6127	19487
	Manual Agent	169	245	68	235	717
	Web process	31	47	9	50	137
	Live Agents	5614	5725	1452	5842	18633
February	Total	5219	5634	1354	5529	17736
	Manual Agent	146	253	50	175	624
	Web process	100	148	37	116	401
	Live Agents	4973	5233	1267	5238	16711
March	Total	6157	6831	1819	6828	21635
	Manual Agent	63	115	28	67	273
	Web process	251	366	105	311	1033
	Live Agents	5843	6350	1686	6450	20329
April	Total	6895	7095	1963	7334	23287
	iWd Agent	267	407	35	331	1040
	Web process	66	128	101	84	379
	Live Agents	6562	6560	1827	6919	21868
May	Total	8855	8118	2154	8772	27899
	Manual Agent	73	142	27	97	339
	Web process	330	461	102	451	1344
	Live Agents	8452	7515	2025	8224	26216
June	Total	7494	7739	2077	7937	25247
	Manual Agent	81	147	35	109	372
	Web process	351	469	143	545	1508
	Live Agents	7062	7123	1899	7283	23367
July	Total	8543	8207	2169	9626	28545
	Manual Agent	92	164	35	165	456
	Web process	390	547	115	799	1851
	Live Agents	8061	7496	2019	8662	26238
August	Total	9777	9028	2464	14740	36009
	Manual Agent	406	551	115	820	1892
	Web process	161	165	34	161	521
	Live Agents	9210	8312	2315	13759	33596
September	Total	7329	7398	1978	7837	24542
	Manual Agent	89	139	29	100	357
	Web process	332	534	97	332	1295
	Live Agents	6908	6725	1852	7405	22890
October	Total	8281	8276	2211	8655	27423
	Manual Agent	78	139	23	105	345
	Web process	322	482	92	417	1313
	Live Agents	7881	7655	2096	8133	25765
November	Total	7291	7668	1940	7796	24695
	Manual Agent	77	156	28	101	362
	Web process	315	461	82	404	1262
	Live Agents	6899	7051	1830	7291	23071
December	Total	6264	6799	1742	6699	21504
	Manual Agent	62	110	22	76	270
	Web process	242	388	84	324	1038
	Live Agents	5960	6301	1636	6299	20196
2019	Total	87919	88810	23400	97880	298009
	Manual Agent	1603	2568	495	2381	7047
	Web process	2891	4196	1001	3994	12082
	Live Agents	83425	82046	21904	91505	278880

Residential Service Applications Completed - 2020						
	Month	PN	ME	PP	WP	Total
January	Total	5826	6276	1600	6400	20102
	Manual Agent	54	94	30	68	246
	Web process	244	367	70	344	1025
	Live Agents	5528	5815	1500	5988	18831
February	Total	5317	6166	1614	5855	18952
	Manual Agent	259	402	23	376	1060
	Web process	79	107	91	74	351
	Live Agents	4979	5657	1500	5405	17541
March	Total	5934	6800	1673	6491	20898
	iWd Agent	49	113	44	81	287
	Web process	254	473	70	405	1202
	Live Agents	5631	6214	1559	6005	19409
April	Total	5075	5087	1440	5379	16981
	Manual Agent	79	97	20	94	290
	Web process	248	366	80	372	1066
	Live Agents	4748	4624	1340	4913	15625
May	Total	5663	5239	1452	5946	18300
	Manual Agent	88	121	30	79	318
	Web process	290	415	82	410	1197
	Live Agents	5285	4703	1340	5457	16785
June	Total	6557	6075	1733	6842	21207
	Manual Agent	70	156	36	135	397
	Web process	323	494	125	535	1477
	Live Agents	6164	5425	1572	6172	19333
July	Total	8080	7770	2308	9953	28111
	Manual Agent	124	206	37	269	636
	Web process	463	620	140	899	2122
	Live Agents	7493	6944	2131	8785	25353
August	Total	7515	7286	2050	12753	29604
	Manual Agent	128	195	62	249	634
	Web process	466	635	149	945	2195
	Live Agents	6921	6456	1839	11559	26775
September	Total	7008	7580	1969	8146	24703
	Manual Agent	122	218	45	151	536
	Web process	438	705	130	623	1896
	Live Agents	6448	6657	1794	7372	22271
October	Total	7504	8001	2104	8337	25946
	Manual Agent	89	160	31	118	398
	Web process	354	589	125	488	1556
	Live Agents	7061	7252	1948	7731	23992
November	Total	5890	6578	1610	6409	20487
	Manual Agent	146	477	45	135	803
	Web process	375	663	109	577	1724
	Live Agents	5369	5438	1456	5697	17960
December	Total	6197	7216	1826	6889	22128
	Manual Agent	100	169	40	129	438
	Web process	283	495	109	453	1340
	Live Agents	5814	6552	1677	6307	20350
2020	Total	76566	80074	21379	89400	267419
	Manual Agent	1308	2408	443	1884	6043
	Web process	3817	5929	1280	6125	17151
	Live Agents	71441	71737	19656	81391	244225

Residential Service Applications Completed - 2021						
	Month	PN	ME	PP	WP	Total
January	Total	5167	5891	1429	5814	18301
	Manual Agent	86	153	34	111	384
	Web process	326	523	104	436	1389
	Live Agents	4755	5215	1291	5267	16528
February	Total	4823	5173	1445	5304	16745
	Manual Agent	60	110	29	99	298
	Web process	251	447	77	350	1125
	Live Agents	4512	4616	1339	4855	15322
March	Total	5870	6645	1684	6678	20877
	Manual Agent	73	141	36	92	342
	Web process	335	508	102	505	1450
	Live Agents	5462	5996	1546	6081	19085
April	Total	6506	6997	1869	7039	22411
	Manual Agent	68	142	35	107	352
	Web process	325	523	132	467	1447
	Live Agents	6113	6332	1702	6465	20612
May	Total	6647	6599	1755	7045	22046
	Manual Agent	95	186	48	145	474
	Web process	354	601	109	592	1656
	Live Agents	6198	5812	1598	6308	19916
June	Total	7389	7696	2056	8205	25346
	Manual Agent	105	198	49	166	518
	Web process	444	692	143	736	2015
	Live Agents	6840	6806	1864	7303	22813
July	Total	7748	7960	2260	10196	28164
	Manual Agent	115	191	54	208	568
	Web process	403	714	148	921	2186
	Live Agents	7230	7055	2058	9067	25410
August	Total	7566	7636	2106	12506	29814
	Manual Agent	221	192	58	221	692
	Web process	480	730	192	1106	2508
	Live Agents	6865	6714	1856	11179	26614
September	Total	6815	6909	1988	7548	23260
	Manual Agent	90	179	41	136	446
	Web process	469	607	174	593	1843
	Live Agents	6256	6123	1773	6819	20971
October	Total	6587	6816	1961	7160	22524
	Manual Agent	95	150	39	106	390
	Web process	407	660	151	586	1804
	Live Agents	6085	6006	1771	6468	20330
November	Total	6482	6767	1848	6947	22044
	Manual Agent	117	251	57	166	591
	Web process	486	768	172	707	2133
	Live Agents	5879	5748	1619	6074	19320
December	Total	5801	7062	1760	6746	21369
	Manual Agent	75	149	30	112	366
	Web process	333	578	107	489	1507
	Live Agents	5393	6335	1623	6145	19496
2021	Total	77401	82151	22161	91188	272901
	Manual Agent	1200	2042	510	1669	5421
	Web process	4613	7351	1611	7488	21063
	Live Agents	71588	72758	20040	82031	246417

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

SHIPLEY CHOICE, LLC D/B/A SHIPLEY ENERGY Set I, No. 4

"Does First Energy currently allow customers to enroll in the Customer Referral Program Online? If not, why not?"

RESPONSE:

No. The Companies' current Customer Referral Programs have evolved over the course of their last four default service proceedings and are consistent with the parameters approved by the Commission in those proceedings. Those parameters do not require the Companies to offer self-service web enrollment for the CRP.

RESA/NRG EXHIBIT TK-24

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

SHIPLEY CHOICE, LLC D/B/A SHIPLEY ENERGY Set I, No. 5

"Does First Energy offer a discounted rate, such as that provided through the Customer Referral Program, to customers who contact the Companies for reasons other than just setting up new service? For example: a) if a customer calls about high bill complaint; b) a general billing question; c) to set up automatic billing, etc."

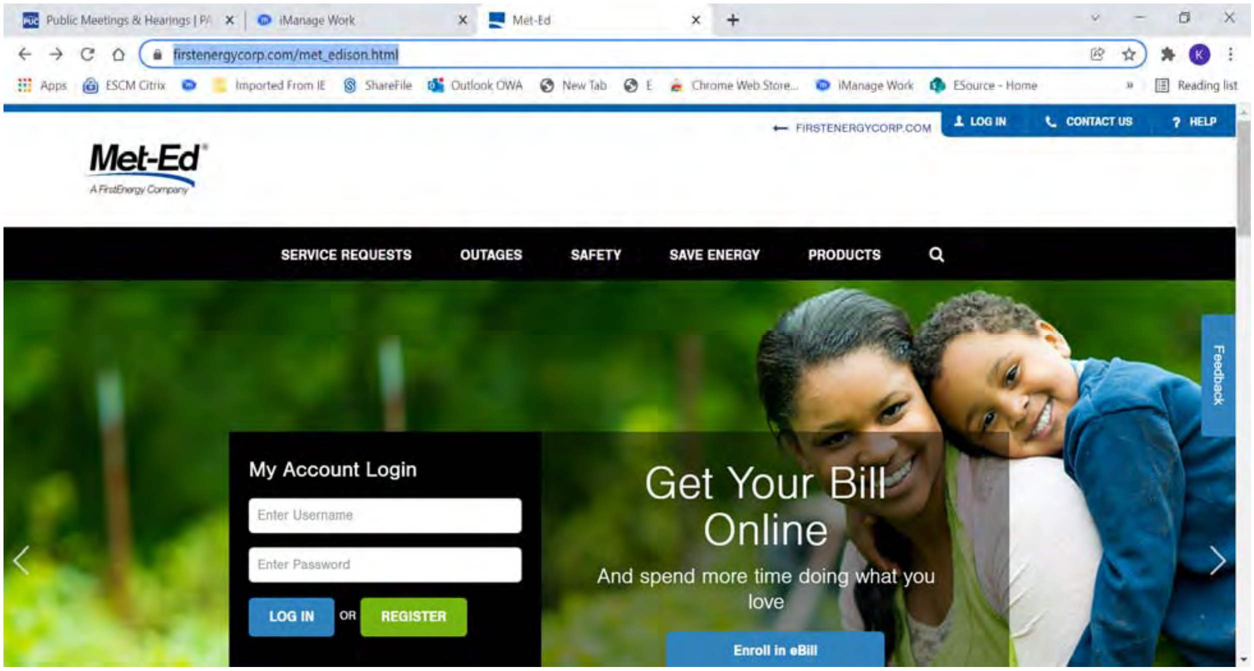
RESPONSE:

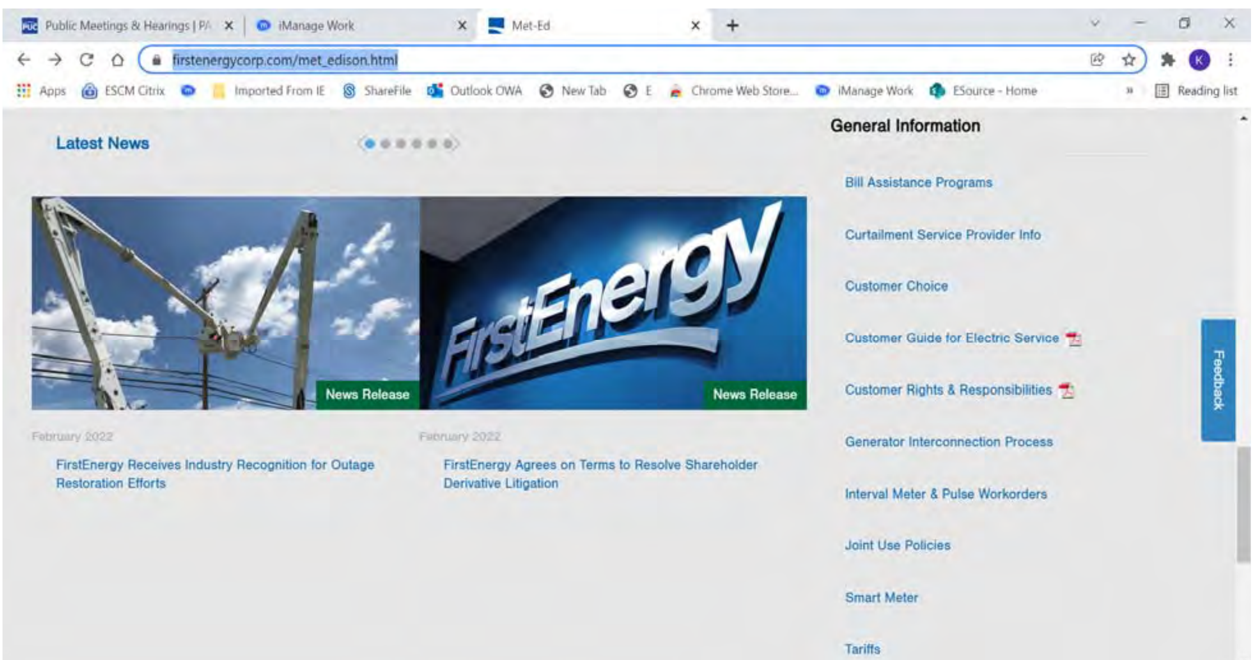
Yes. The following call types trigger an offer of the Customer Referral Program to the Companies' residential and small commercial customers: a billing inquiry, customer choice calls, or during a move-in, for new customers or existing customer for transfers of service.

RESA/NRG EXHIBIT TK-25

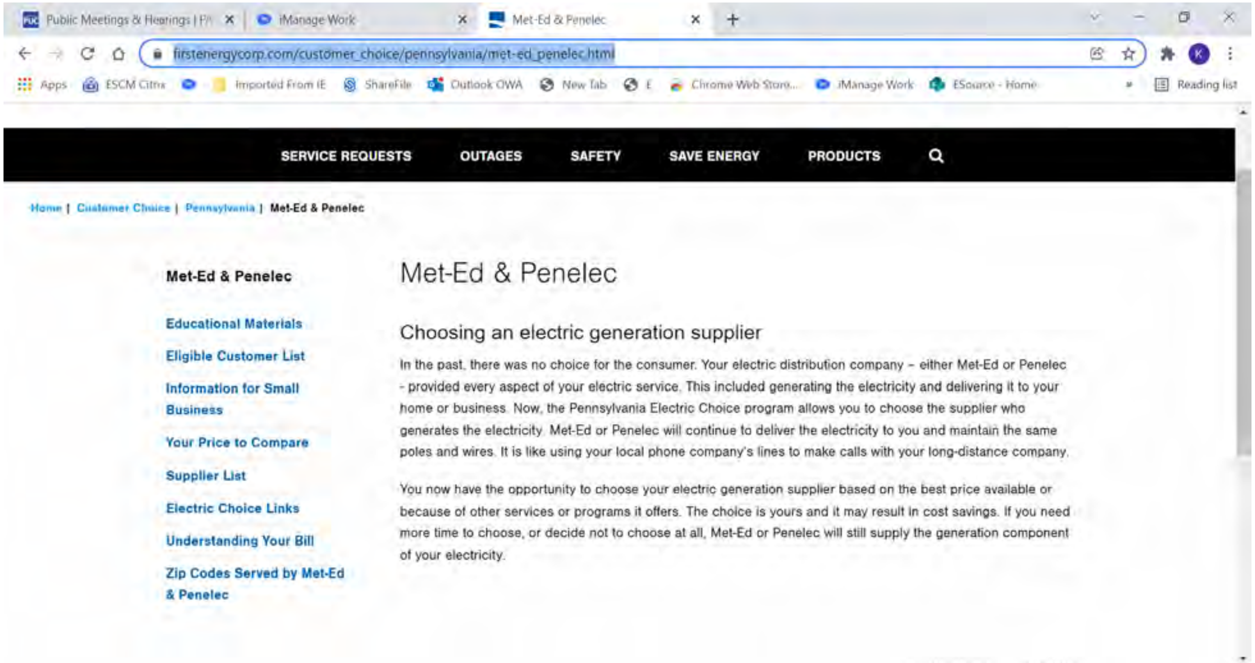
RESA/NRG Exhibit TK-25

Excerpts of Met-Ed's Home Page





RESA/NRG Exhibit TK-25
Excerpt of Customer Choice Page



firstenergycorp.com/customer_choice/pennsylvania/met-ed_penelec.html

SERVICE REQUESTS | OUTAGES | SAFETY | SAVE ENERGY | PRODUCTS

Home | Customer Choice | Pennsylvania | Met-Ed & Penelec

Met-Ed & Penelec

- Educational Materials
- Eligible Customer List
- Information for Small Business
- Your Price to Compare
- Supplier List
- Electric Choice Links
- Understanding Your Bill
- Zip Codes Served by Met-Ed & Penelec

Met-Ed & Penelec

Choosing an electric generation supplier

In the past, there was no choice for the consumer. Your electric distribution company – either Met-Ed or Penelec - provided every aspect of your electric service. This included generating the electricity and delivering it to your home or business. Now, the Pennsylvania Electric Choice program allows you to choose the supplier who generates the electricity. Met-Ed or Penelec will continue to deliver the electricity to you and maintain the same poles and wires. It is like using your local phone company's lines to make calls with your long-distance company.

You now have the opportunity to choose your electric generation supplier based on the best price available or because of other services or programs it offers. The choice is yours and it may result in cost savings. If you need more time to choose, or decide not to choose at all, Met-Ed or Penelec will still supply the generation component of your electricity.

RESA/NRG Exhibit TK-25

Excerpt of Pennsylvania Page

Public Meetings & Hearings | P | iManage Work | Pennsylvania

firstenergycorp.com/customer_choice/pennsylvania.html

Apps | ESCM Citrix | Imported From IE | ShareFile | Outlook OWA | New Tab | E | Chrome Web Store... | iManage Work | ESource - Home | Reading list

SERVICE REQUESTS | OUTAGES | SAFETY | SAVE ENERGY | PRODUCTS

Home | Customer Choice | Pennsylvania

Customer Choice

- Ohio
- Pennsylvania
  - Met-Ed & Penelec
  - Penn Power
  - West Penn Power
  - Eligible Customer List
  - Pennsylvania Tariffs
  - Customer Referral Program
- New Jersey
- West Virginia

Pennsylvania

Competition Brings Changes

There are three basic changes as a result of competition. First, electricity is being split into separate services. Before retail competition, your electric company generated or bought the electricity and delivered it to you. Now, under Electric Choice, you choose the supplier who provides the electricity and an electric company delivers the electricity to you. The image below illustrates the separation of services resulting from competition.

RESA/NRG EXHIBIT TK-26

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

RETAIL ENERGY SUPPLY ASSOCIATION AND NRG ENERGY, INC. Set II, No. 6

"Reference Direct Testimony of Patricia M. Larkin, page 12. You refer to the Companies' Supplier Tariffs.

A. Please confirm that in the Companies' Supplier Tariffs, they commit to supplying data that is reasonably required by an EGS in a thorough and timely manner. For example, see Metropolitan Edison Company's Electric Pa. P.U.C. No. S-1, Original Page No. 16, 4.10 (Supply of Data). If you do not confirm, please explain.

B. Please confirm that the Companies' Supplier Tariffs obligate them to make available to an EGS daily files containing meter readings, total kWh usage and other information for each of an EGS's customers as it becomes available by billing route. For example, see Metropolitan Edison Company's Electric Pa. P.U.C. No. S-1, Original Page No. 30, 10.7 (Meter Data Provided by the Company to an EGS). If you do not confirm, please explain.

C. Please confirm that when the Companies are billing for the EGS, the Companies' Supplier Tariffs obligate them to provide the EGS with sufficient meter data on a timely basis. For example, see Metropolitan Edison Company's Electric Pa. P.U.C. No. S-1, Original Page No. 30, 12.1 (Customer Billing by the Company). If you do not confirm, please explain.

D. Please confirm that the Companies are experiencing delays, sometimes more than 90 days, in transmitting customer usage data to EGSs that is needed for billing. If this is confirmed, please provide an explanation for the delays. If this is not confirmed, please explain."

RESPONSE:

A. Confirmed, to the extent such data is reasonably required by the EGS in connection with the provision of Coordination Services. Met-Ed's, Penelec's and Penn Power's Electric Generation Supplier Coordination Tariffs ("Supplier Tariffs") at Page No. 6 define "Coordination Services" as:

> [T]hose services that permit the type of interface and coordination between EGSs and the Company in connection with the delivery of Competitive Energy Supply to serve Customers located within the Company's service territory including, but not limited to, the provision of metering information to PJM. Coordination Services do not include Network Integration Transmission Service and ancillary services which are offered under the PJM Tariff.

West Penn's Supplier Tariff at Page No. 5 defines "Coordination Services as:

> [T]hose services that provide the required interface and coordination between a Registered EGS and the Company in order to effect the delivery of Competitive Generation Service to service Customers located within the Company's service territory. Coordination Services may include Load Forecasting, scheduling activities, and energy imbalance services.

B. Confirmed, so long as the "other information" referred to in this question is specifically identified in the applicable Company's Supplier Tariff or was mutually agreed upon by the applicable Company and EGS.

C. Confirmed, but the Companies note that the "Company Billing for EGS" provision of Met-Ed's, Penelec's and Penn Power's Supplier Tariffs only requires the Company to provide the meter data referenced in this question in those situations where the Company's billing system is unable to calculate the EGS charges under the pricing format being used by the EGS. West Penn's Supplier Tariff provides that West Penn will normally provide EGSs with actual or estimated meter read data within three days of the meter read date that would allow EGS using "bill-ready" consolidated billing to calculate its generation charges. West Penn's billing system calculates the EGS charges under the "rate-ready" consolidated billing option.

D. The Companies confirm that they have experienced delays in transmitting customer usage data to EGSs since the first quarter of 2021. An issue was identified with some smart meters that caused the meter to go into an error state that stopped the meter from sending reads and therefore required an unexpected increase in meter read validations. This problem was amplified by an increased volume and workload for the smart meter billing team related to impacts from the COVID-19 emergency. The Companies have added staff to the smart meter billing team to reduce delays in customer usage data transmission to EGSs and are exploring solutions to address the technical issue driving delays related to the need for increased meter read validation.

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-2021-3030012, P-2021-3030013, P-2021-3030014, and P-2021-3030021

RETAIL ENERGY SUPPLY ASSOCIATION AND NRG ENERGY, INC. Set II, No. 7

"Please refer to the Commission's Secretarial Letter dated April 4, 2013 issued at Docket Nos. P-2011-2273650, P-2011-2273668, P-2011-2273669 and P-2011-2273670 in the Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company for Approval of Their Default Service Programs. By that Secretarial Letter, the Commission directed the Companies to provide a status report to the Office of Competitive Market Oversight ("OCMO") on March 13, 2014 regarding, among other things, the implementation of a web-based solution for customer interval usage data. Please provide a copy of the status report that the Companies submitted to OCMO."

RESPONSE:

After a discussion between RESA and the Companies on 2/14/22, RESA has agreed to strike the question above and replace it with the following:

"Please explain the reason for the delay in providing customer interval usage to EGSs' referenced in RESA Set II, No. 6 and explain when the Companies expect the issue to be remedied."

See ME/PN/PP/WP Response to RESA-NRG Interrogatory Set II, No. 6 subpart D. The Companies are working to expeditiously resolve the issues driving the delays with the goal of substantially reducing delays in customer interval usage data transmission by mid-March.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company for Approval of Their Default Service Programs for the Period From June 1, 2023 Through May 31, 2027	:	Docket Nos. P-2021-3030012 P-2021-3030013 P-2021-3030014 P-2021-3030021

REBUTTAL TESTIMONY OF

TRAVIS KAVULLA

ON BEHALF OF
RETAIL ENERGY SUPPLY ASSOCIATION
AND NRG ENERGY, INC.

TOPICS:

Competitive Market Issues

MARCH 24, 2022

Table of Contents

Page

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 1825 K. St. NW, Suite 1203, Washington, D.C. 20006.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

A. Yes. On February 25, 2022, I submitted Direct Testimony on behalf of the Retail Energy Supply Association[1] ("RESA") and NRG.

Q. HAVE YOU REVIEWED DIRECT TESTIMONY SUBMITTED BY OTHER PARTIES IN THIS PROCEEDING?

A. Yes.

Q. BASED UPON YOUR REVIEW OF THE OTHER PARTIES' DIRECT TESTIMONY, HAVE YOU CHANGED YOUR POSITION ON ANY OF THE ISSUES ADDRESSED BY YOUR DIRECT TESTIMONY?

A. No. I stand behind my Direct Testimony, including the observations and recommendations set forth therein. Merely because I am electing to not respond to all of the other parties' testimony that addresses issues affecting the competitive electric retail market that are of interest to RESA and NRG should be not be viewed as acceptance of their positions on those topics. To the contrary, I continue to believe that Pennsylvania is at a point that the Commission needs to assume its prior national leadership role to

---

[1] The comments expressed in this filing represent the position of the Retail Energy Supply Association (RESA) as an organization but may not represent the views of any particular member of the Association. Founded in 1990, RESA is a broad and diverse group of retail energy suppliers dedicated to promoting efficient, sustainable and customer-oriented competitive retail energy markets. RESA members operate throughout the United States delivering value-added electricity and natural gas at retail to residential, commercial and industrial energy customers. More information on RESA can be found at www.resausa.org.

address the flaws that are preventing customers from realizing the benefits of a properly functioning retail electric market.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to briefly respond to the Direct Testimony of Harry Geller on behalf of the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA")[2] and the Direct Testimony of Barbara R. Alexander on behalf of the Office of Consumer Advocate ("OCA").[3]

II. RESPONSES TO CAUSE-PA AND OCA WITNESSES

Q. PLEASE IDENTIFY AN ISSUE RAISED BY MR. GELLER TO WHICH YOU ARE RESPONDING THROUGH THIS TESTIMONY.

A. Mr. Geller refers to data obtained by CAUSE-PA through discovery in this proceeding to compare electric supply prices paid to electric generation suppliers ("EGSs") by the distribution customers of the Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company (collectively, "the Companies") to the prices that those consumers would have paid the Companies for default supply service.[4] I disagree fundamentally with the methodology that Mr. Geller uses, which omits essential considerations that would be necessary to arrive at a proper cost-benefit analysis.

Q. DO YOU DISAGREE WITH OTHER ASPECTS OF MR. GELLER'S TESTIMONY?

A. Yes. Mr. Geller makes a series of recommendations designed to deprive customers of choices in the marketplace. I disagree with at least three of the proposals he makes:

---

2 CAUSE-PA Statement No. 1.

3 OCA Statement No. 2.

4 CAUSE-PA Statement No. 1 at 7-13.

1. Preventing low-income customers enrolled in the Customer Assistance Program ("CAP") from being allowed to shop in the market, regardless of their reasons for finding this approach beneficial to them or their families;[5]
2. Preventing these same customers from selecting the time-of-use rate ("TOU") offered as a default service, despite a desire they may have to shift usage in a way that saves money on their monthly electric bills; and
3. Terminating the customer referral program, even though it gives consumers an opportunity to lock in a fixed generation price for 12 months that is *less* than the default service pricing at time of contracting.[6]

Q. HOW DO YOU RESPOND TO MR. GELLER'S COMPARISONS OF DEFAULT SERVICE RATES AND EGS SUPPLY CHARGES?

A. Comparisons between the Companies' default service rates and prices charged for electric supply in the competitive market are misleading. This exercise fails to take into account a number of real-life issues for consumers, including their preferences to purchase renewable energy products at a premium, to opt for the certainty of a long-term fixed price being offered by EGSs, and to obtain value-added services from EGSs, such as donations to charitable organizations, free subscriptions to Amazon Prime and rewards for energy conservation. Mr. Geller has not attempted to impute a value for even a single of these value-added products, which are widely present in the EGS market. Without an imputation of value for these considerations, his cost-benefit analysis is missing an essential element that renders a comparison meaningless.

---

[5] Ms. Alexander's Direct Testimony also seeks to prevent low-income customers from participating in the electric retail market. OCA Statement No. 2 at 12-13.

[6] Ms. Alexander's Direct Testimony offers the same proposal. OCA Statement No. 2 at 7-9.

Q. YOU HAVE STATED THAT MR. GELLER'S ANALYSIS IGNORES CERTAIN VALUES THAT WOULD ADD TO A CALCULATION OF THE BENEFITS OF EGS SERVICE, RELATIVE TO THEIR COST. DOES HE ALSO IGNORE CERTAIN COSTS OF DEFAULT SERVICE?

A. Yes. As I noted in my earlier testimony, the Companies' default service rates do not account for all the costs incurred to provide default service.[7] Mr. Geller appears satisfied to let all customers, including those who made a decision to shop, to pay those costs through distribution rates. However, these costs have to be added to any credible cost-benefit analysis, like the one Mr. Geller has attempted. He has not attempted a quantification of those costs of default supply service, just as he has not attempted a quantification of the additional value of EGSs' products.

Q. PLEASE ADDRESS MR. GELLER'S RECOMMENDATIONS AIMED AT LOW-INCOME CUSTOMERS.

A. None of his recommendations take into consideration what the consumer wants. Pennsylvania has a competitive retail electric market established by the General Assembly, which is premised on customer choice. Yet, Mr. Geller prefers that low-income customers have <u>no</u> choices. Because they are low-income, Mr. Geller believes that: (i) they should not have the ability to choose an EGS that is offering a product that would benefit them; (ii) they should not have access to a TOU rate that would give them the power to reduce energy costs by shifting usage to off-peak times; and (iii) they should be deprived of an opportunity to obtain a 7% discount off the Companies' prevailing default service rate through a utility-led program that reduces the transaction costs and other marketing of EGS contracting. I do not see how any of these recommendations are

[7] RESA/NRG Statement No. 1 at 42-53.

consistent with the underlying premise of customer choice, and I recommend that they be rejected.

Q. MR. GELLER SPECIFICALLY SUGGESTS THAT TIME-OF-USE RATES MAY DISADVANTAGE LOW-INCOME CUSTOMERS. HOW DO YOU RESPOND?

A. I disagree. Let's first be clear about what Mr. Geller is proposing. In arguing both that low-income customers in the CAP program *not* be allowed to shop for service through an EGS and also that these customers *not* be allowed to be served under a default-service TOU tariff, Mr. Geller is proposing that customers have no ability whatsoever to select a time-varying rate plan that may better correspond to their usage. His approach would deny agency to ordinary consumers on the basis of their socioeconomic status. Indeed, although Mr. Geller has selectively chosen to cite one of the authorities he relies upon for his recommendation, it is worth heeding what else the report in question concludes about the benefits of a time-varying rate plan: "Research in most jurisdictions has shown that on average lower income customers use less electricity, and use proportionately less electricity during peak periods. Such lower usage customers would thus benefit from a change in rate design from a flat rate to either an inverted tier rate or a TOU rate."[8] Under either my proposed approach or the Companies' approach to TOU, consumers would have a choice for a TOU rate. Under Mr. Geller's approach, they would not.

8 Colgan, John T. *et al.* "Guidance for Utilities Commissions on Time of Use Rates: A Shared Perspective from Consumer and Clean Energy Advocates" (July 15, 2017) at 27. Available at: https://uspirg.org/sites/pirg/files/reports/TOU-Paper-7.17.17.pdf (accessed March 24, 2022). *Compare to* Cause-PA Statement No. 1 at 41.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS ABOUT MR. GELLER'S TESTIMONY?

A. Yes. In some ways, it seems both Mr. Geller and I agree that the status quo about the competitive retail market is *not* working as it should, albeit for very different reasons. I believe the mutual dissatisfaction provides support for my position in Direct Testimony that the Commission undertake a statewide investigation that examines whether the structure of the default service provider role, and its provision through electric distribution companies, is appropriate.[9]

III. <u>CONCLUSION</u>

Q. DOES THAT COMPLETE YOUR REBUTTAL TESTIMONY?

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

---

9 RESA/NRG Statement No. 1 at 12-16.

Verification

I, Travis Kavulla**,** state that I am Vice President, Regulatory Affairs for NRG Energy, Inc. and providing the foregoing Rebuttal Testimony of the Retail Energy Supply Association and NRG Energy, Inc. I hereby state that the facts contained in the foregoing Rebuttal Testimony are true and correct to the best of my knowledge, information and belief. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

March 24, 2022

/Travis Kavulla/
Travis Kavulla, Vice President
Regulatory Affairs, NRG Energy, Inc.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company for Approval of Their Default Service Programs for the Period From June 1, 2023 Through May 31, 2027	:	Docket Nos. P-2021-3030012 P-2021-3030013 P-2021-3030014 P-2021-3030021

SURREBUTTAL TESTIMONY OF

TRAVIS KAVULLA

ON BEHALF OF
RETAIL ENERGY SUPPLY ASSOCIATION
AND NRG ENERGY, INC.

TOPICS:

Competitive Market Issues
Default Service Investigation
Proposed TOU Rate
Long-Term Solar Procurement
Default Service Rate
Customer Referral Programs
Operational Issues

APRIL 7, 2022

Table of Contents

Page

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 1825 K. St. NW, Suite 1203, Washington, D.C. 20006.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

A. Yes. On February 25, 2022, I submitted Direct Testimony on behalf of the Retail Energy Supply Association[1] ("RESA") and NRG, and on March 24, 2022, I submitted Rebuttal Testimony on behalf of RESA and NRG.

Q. HAVE YOU REVIEWED REBUTTAL TESTIMONY SUBMITTED BY OTHER PARTIES IN THIS PROCEEDING?

A. Yes.

Q. BASED UPON YOUR REVIEW OF THE OTHER PARTIES' REBUTTAL TESTIMONY, HAVE YOU CHANGED YOUR POSITION ON ANY OF THE ISSUES ADDRESSED BY YOUR DIRECT AND REBUTTAL TESTIMONIES?

A. No. I stand behind my Direct Testimony and Rebuttal Testimony, including the observations and recommendations set forth therein. Merely because I am electing to not respond to all of the other parties' testimony that addresses issues affecting the competitive electric retail market should not be viewed as acceptance of their positions on those topics. To the contrary, I continue to believe that Pennsylvania is at a point when the Commission needs to assume its prior national leadership role to address the

---

1 The comments expressed in this filing represent the position of the Retail Energy Supply Association (RESA) as an organization but may not represent the views of any particular member of the Association. Founded in 1990, RESA is a broad and diverse group of retail energy suppliers dedicated to promoting efficient, sustainable and customer-oriented competitive retail energy markets. RESA members operate throughout the United States delivering value-added electricity and natural gas at retail to residential, commercial and industrial energy customers. More information on RESA can be found at www.resausa.org.

flaws that are preventing customers from realizing the benefits of a properly functioning retail electric market.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my Surrebuttal Testimony is to respond to the Rebuttal Testimonies of several witnesses presented by Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company (collectively, the "Companies"), including: Joanne M. Savage,[2] James H. Catanach,[3] James D. Reitzes/Nicholas E. Powers,[4] Patricia M. Larkin,[5] and Kenneth Strah.[6] In addition, I am responding to the Rebuttal Testimonies of: (i) the Office of Consumer Advocate ("OCA") presented by Serhan Ogur[7] and Barbara R. Alexander;[8] (ii) the Office of Small Business Advocate ("OSBA") submitted by Robert Knecht;[9] and (iii) Harry Geller, testifying on behalf of the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA").[10]

Q. GIVEN THE NUMBER OF WITNESSES YOU ARE RESPONDING TO BY THIS SURREBUTTAL TESTIMONY, IT APPEARS THAT SEVERAL PARTIES DISAGREE WITH YOUR RECOMMENDATIONS. DO YOU HAVE ANY COMMENTS ABOUT THAT?

---

2 Companies' Statement No. 1R.

3 Companies' Statement No. 2R.

4 Companies' Statement No. 4R.

5 Companies' Statement No. 5R.

6 Companies' Statement No. 7R.

7 OCA Statement No. 1R.

8 OCA Statement No. 2R.

9 OSBA Statement No. 1-R.

10 CAUSE-PA Statement No. 1R.

A. Yes. I recognize that several parties, including the Companies, OCA, OSBA and CAUSE-PA, disagree with most of the recommendations that I have advanced on behalf of RESA and NRG. It is important to emphasize that RESA and NRG are focused on making proposals that help to promote development of the competitive market, which Pennsylvania's General Assembly mandated through passage of the Electricity Generation Customer Choice and Competition Act ("Customer Choice Act")[11] more than 25 years ago. Of note, the Commission's own Bureau of Investigation and Enforcement ("I&E") did not submit Rebuttal Testimony refuting any of the recommendations that RESA and NRG have offered.

In launching Phase II of the Retail Markets Investigation ("RMI") in July 2011, the Commission found that 22% of the customers shopping shows that "consumers are not moving in the retail market place at a rate that we would expect in a well-functioning market."[12] Notably, more than a decade later, the Companies' shopping statistics throughout their serve territories are very similar to the statewide percentage in 2011 and the statewide statistics today are only slightly better at 26%.[13]

Just as the Commission has not been satisfied with shopping levels in the past, the Commission should take steps to improve the status of participation in the market today. Of note, even when Pennsylvania hit the milestone of 2 million customers participating in the electric choice program in February 2013, only 35% of customers were shopping for

---

[11] 66 Pa. C.S. §§ 2801 *et seq.*

[12] *Investigation of Pennsylvania's Retail Electricity Market,* Docket No. I-2011-2237952 (Order entered July 28, 2011, at 6) ("*RMI Phase II Order*").

[13] https://www.papowerswitch.com/media/31ob5hkc/paps_numbers022822.pdf

competitive supply.[14] About the only area in life where that percentage is considered successful is in a baseball batting average. While the Commission celebrated the achievement, the Commission was understandably not satisfied with that level of success for the retail market and continued pressing forward with the RMI it had launched less than two years before. Vice Chairman Coleman declared: "This celebration of 2 million shopping customers is not the end of our story. The PUC is in the final stages of an investigation intended to ensure the state's regulatory framework is one that encourages a market where consumers have continued choices for electric supply."[15]

Today, Pennsylvania's retail market is at a crossroads. Shopping statistics have significantly declined over the past five years and fewer than 1.6 million customers are currently purchasing electricity from electric generation suppliers ("EGSs"). Continuing to do nothing to foster the development of the retail market disregards the fundamental premise of the Customer Choice Act and undermines the Commission's prior efforts to remove "impediments to a fully functioning, robust retail market."[16] It is imperative for the Commission to examine the framework on which the electric choice program is based and make changes, where feasible and necessary. I urge the Commission to keep that in mind as it adjudicates the issues we have raised in an effort to bring the benefits of competition to Pennsylvania consumers.

II. SUMMARY OF RESA/NRG RECOMMENDATIONS

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS YOU PRESENT IN YOUR DIRECT TESTIMONY ON BEHALF OF RESA/NRG.

---

14 https://www.puc.pa.gov/press-release/2013/puc-marks-2-million-electric-customers-shopping-emphasizes-more-work-ahead-to-ensure-robust-market-continues

15 *Id.*

16 *RMI Phase II Order* at 5.

A. My recommendations can be summarized as follows:[17]

- 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 open one or more proceedings following the entry of an Order on the Companies' DSP VI Petition to:

  (1) reexamine the current structure of default service and consider whether it should be modified so that it is truly a back-stop option that is supplied by EGSs; and

  (2) revisit the default service regulations and policy statement and determine whether revisions should be made to ensure that electric distribution companies ("EDCs") are recovering all default service costs through the default service rates.
- In tandem with allowing the Companies to offer a time-of-use ("TOU") rate, the Commission should approve the TOU rate as the standard default rate;
- The Commission should dispense with the misnomer of "Price to Compare" when referring to default service rates;
- The Commission should not permit the Companies to transition from quarterly to semi-annual adjustments of their default service rates;
- The Commission should reject the Companies' 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 modify certain aspects of the existing Customer Referral Program to increase participation by consumers; and
- The Commission should require the Companies to make changes to the Supplier Tariff to address recent issues affecting EGSs' ability to bill for supply services and get paid.

[17] RESA/NRG Statement No. 1 at 4-5.

III. COMPETITIVE RETAIL MARKET

Q. PLEASE BRIEFLY YOUR OBSERVATIONS ABOUT THE COMPETITIVE RETAIL MARKET.

A. When I led the National Association of Regulatory Utility Commissioners ("NARUC") as president of NARUC, Pennsylvania's reputation as being a national leader in opening its market to competition, for the benefit of consumers, was well-known. In my Direct Testimony, I refer to the significant decline in the percentage of customer participation in the retail market over the past five years and describe Pennsylvania's electric market as stagnating. At the crux of this stagnation is the presence of a domineering default service provider ("DSP") – also, the monopoly EDC – and a persistently unlevel playing field between the DSP and electric generation suppliers EGSs. Without structural changes to improve the market, it is not realistic to expect competitive retail offerings to flourish, drive significant investment or result in innovative product development. For that reason, I recommend in Direct Testimony that the Commission launch a separate proceeding that focuses on transitioning the DSP role from the EDCs to EGSs.[18]

Q. HOW DO OTHER PARTIES RESPOND TO YOUR CONCLUSIONS THAT THE RETAIL MARKET IS STAGNATING?

A. Testifying for the Companies, Drs. Reitzes and Powers disagree that the market is stagnating. Their view is based upon comparisons between the total load that is served by EDCs and EGSs and the number of active EGSs in the market.[19]

Q. PLEASE RESPOND.

---

[18] RESA/NRG Statement No. 1 at 7-17.

[19] Companies' Statement No. 4R at 6-8.

A. While EGSs are serving a large amount of the load of industrial and large commercial customers, the fact remains that the percentage of mass market customers (*i.e.*, residential and small commercial customers) shopping for electricity declined significantly between January 2017 and January 2022 – a reality that the Companies' witnesses do not refute. The number of EGSs actively participating in the market is also of no particular consequence since they are clearly not serving a high number of residential and small commercial customers and are serving far fewer mass market customers than they were five years ago. With the EDCs serving 74% of the statewide residential load, this means that the remaining 137 licensed EGSs serve only one quarter of the residential market, with an average market share per EGS of 0.175%.[20] This level of retail competition is inconsistent with the Customer Choice Act and demonstrates the need for the Commission to act now in reviewing the current status of competition and the proper functioning of the market.

The Commission has previously evaluated competition in a retail market by considering participation in the market by many buyers and sellers, the lack of substantial barriers to market entry for suppliers, the lack of substantial barriers that would discourage customer participation, and the presence of sellers offering buyers a variety of products and services.[21] Yet, based on the shopping statistics alone, which were in line with where they are today in the Companies' service areas, the Commission found a compelling need to launch the RMI. In doing so, the Commission highlighted its

[20] https://www.puc.pa.gov/electricity/electric-companies-suppliers/licensed-suppliers/ (137 EGSs excludes brokers and marketers).

[21] *RMI Phase II Order* at 4.

dissatisfaction with the lack of innovative products that are available to retail customers in a truly competitive market.[22]

Q. WHAT ARE THE VIEWS OF OTHER PARTIES AS TO WHY THE SHOPPING STATISTICS HAVE DECLINED?

A. Testifying for the Companies, Drs. Reitzes and Powers suggest that EGSs are not making attractive offers to residential and small commercial customers in terms of pricing and other retail product attributes. They also opine that residential customers have smaller loads, which may make it less valuable for them to invest effort in comparing the various options available to them. In addition, Drs. Reitzes and Powers testify that residential and small commercial customers do not have the time, sophistication or resources to choose an EGS and therefore stay on default service. The Companies' witnesses further claim that the primary factor in determining whether residential customers remain with an EGS is whether they will see savings on their electric bills. Referring to the higher prices paid by residential shopping customers over what they would have paid the Companies, as presented by CAUSE-PA witness Geller, Drs. Reitzes and Powers contend that the value of shopping is decreasing over time.[23]

On behalf of OCA, Ms. Alexander refers to studies from other restructured states showing that on average retail electric suppliers charge more than the applicable default service over a reasonable period of time.[24] OCA witness Ogur presents shopping statistics from neighboring states to show that the decline in residential shopping levels compared to five years ago is not unique to the Companies' service territories. Mr. Ogur

---

[22] *RMI Phase II Order* at 6.

[23] Companies' Statement No. 4R at 9-12.

[24] OCA Statement No. 2R at 13-14.

also suggests that shopping statistics may be lower because customers have failed to see the savings and product innovations than were expected with the implementation of electric choice.[25] Likewise, CAUSE-PA witness Geller describes the decline in residential shopping rates as the natural consequence of EGS pricing and other alleged practices.[26]

Q. PLEASE RESPOND.

A. Importantly, shopping consumers are not always and exclusively focused on savings on the monthly electric bill, especially if other products of value are included in the offer. In the Pennsylvania market, these products include 100% renewable energy, one year of free Amazon Prime, a National Park Pass, or a charitable contribution. Indeed, the Commission's own reporting shows that one-third of residential shopping customers chose renewable energy products in 2020, which was an increase over prior years.[27] Additionally, customers may pay a premium for the insurance that a long-term, fixed-price product provides through price stability over a period of two or three years.

Further, I do not agree with the Companies' testimony suggesting that residential and smaller commercial customers are not sophisticated enough to make choices or lack the time and resources to do so. Pennsylvania's shopping website, PaPowerSwitch.com, is very user-friendly, making it easy for customers to compare products being offered in the market without requiring a significant investment of time. Rather, a key reason for

[25] OCA Statement No. 1R at 11-13.

[26] CAUSE-PA Statement No. 1R at 3-4. I note that Mr. Geller does not point to any evidence regarding other alleged practices of EGSs. His citation refers to I&E settlements with EGSs where no wrongdoing was admitted or found, except for adjudicating proceedings from 2014 and 2016, which precede the recent significant decline that I have addressed.

[27] Retail Electricity Choice Activity Report released in October 2021 at 1 and 29. In 2020, 457,867 of 1,741,095 residential shopping customers chose renewable energy products. https://www.puc.pa.gov/media/1787/retail_elec_choice_report2020v2.pdf

low participation in the market is the simple behavioral economics that has led default service to be a product of first resort, which former Commissioner James Cawley observed 10 years ago when he 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."[28] (One of the reasons I propose to make the Customer Referral Program more easy-to-use and visible is to ensure a structure where customers are presented with a simple and clear choice to participate in the competitive market at times when they are actively thinking about their energy supply.) Commissioner Cawley pointed to the lack of shopping 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, concluding that "mass market customers, including residential and small commercial customers, often will not make affirmative choices for their supplier unless they are required to."[29]

Other reasons for the stagnation of Pennsylvania's retail market include having the EDCs in the DSP roles, artificially low default service rates, and the inability of EGSs to issue consolidated bills to customers that contain both the EDC's distribution charges and the EGS's supply charges – which is known as supplier consolidated billing ("SCB"). Many product innovations and larger investment in the Pennsylvania market are possible only if the EGS is able to offer SCB. SCB enables suppliers to establish relationships with customers; be seen as offering something more than just a commodity; communicate

---

[28] *Investigation of Pennsylvania's Retail Electricity Market*, Docket No. I-2011-2237952 (Concurring and Dissenting Statement dated September 27, 2012) at 1.

[29] *Id.* at 2.

more effectively with customers; and be more accountable to customers – all things that make the market flourish.

IV. DEFAULT SERVICE INVESTIGATION

Q. PLEASE DESCRIBE THE REBUTTAL TESTIMONY OF OTHER PARTIES REGARDING YOUR RECOMMENDATION FOR A DEFAULT SERVICE INVESTIGATION.

A. Ms. Savage, on behalf of the Companies, disagrees with this recommendation, citing the Commission's past consideration of the issue during the RMI and the outcome of the inquiry at that time which was to retain EDCs in this role.[30] OCA witness Alexander describes the proposal of RESA/NRG for structural changes to the market as "radical" and based on the unique market structure of Texas.[31] Mr. Geller, on behalf of CAUSE-PA, testifies that there is no need for any further investigation into the default service model.[32] Although Mr. Knecht, testifying for OSBA, does not oppose a default service investigation and opines that higher prices from EGSs may be justified in part by the nature of the product or value-added services, he suggests that any investigation should include a broader agenda. He would have the Commission also examine whether EGS prices in excess of the default service rate are accompanied by valuable services for shopping customers, whether customer referral programs ("CRPs") should be terminated, whether EGSs have taken advantage of smart metering, etc.[33]

Q. HOW DO YOU RESPOND?

---

30 Companies' Statement No. 1R at 16-17.

31 OCA Statement No. 2R at 3-4.

32 CAUSE-PA Statement No. 1-R at 6.

33 OSBA Statement No. 1-R at 4-5.

A. At the outset, the Commission's consideration of the default service model in the RMI should not be relied upon a decade later as a reason to forgo a review of this framework, particularly given the reverse path that Pennsylvania's electric choice program is currently on. Ten years have passed since the Commission held the *en banc* hearing during the RMI, which was focused specifically on various models for placing EGSs in the DSP role.[34] Even though the Commission declined to transition the DSP role from EDCs to EGSs at the conclusion of the RMI, the Commission certainly did not close down any further discussions regarding this issue. To the contrary, the Commission referred to other retail market enhancements that were being implemented as a "reasonable step in the evolution of Pennsylvania's retail electric market" and acknowledged that it may revisit the merits of adopting alternative DSP or DSPs in the future.

Recognizing that having the EDCs in the DSP role presents a structural barrier to a robust market, and the need for EDCs to focus on their core competencies, the Commission concluded that "at this time, it would be prudent to be patient" and allow the other changes to be implemented. The Commission's expectation was that the retail market enhancements would permit the market "to continue its fairly steady progress of organic growth while providing the Commission with the ability to take further action in the future, if necessary.[35]

---

[34] *Investigation of Pennsylvania's Retail Electricity Market*, Docket No. I-2011-2237952 (Secretarial Letter dated March 2, 2012).

[35] *Investigation of Pennsylvania's Retail Electricity Market,* Docket No. I-2011-2237952 (Order entered February 15, 2013 at 20) ("*RMI End State Order*").

The steady progress envisioned by the Commission in 2013 has not occurred. Particularly in view of the steady and significant declines in shopping over the past five years, which is contrary to the growth that the Commission expected, now is the time for the Commission to revisit this model. Markets do not continue to evolve if issues are not periodically examined. The retail electric market in Pennsylvania must continue to evolve to keep up with technology advancements, the roll-out of advanced metering infrastructure ("AMI") since the RMI, a trend toward net zero/carbon reduction, growth of electric vehicles and interest in community solar. All of these changes have occurred in the last 10 years and it means that consumer behavior is changing; more information is available to help consumers understand their usage better and be better informed in general; the past is not a predictor of the future; customer expectations are evolving; and the Commission needs to evolve this market or risk being unprepared for the changes that are coming.

I further note that RESA and NRG's proposals are neither radical nor Texas-based. We are not suggesting that the Commission eliminate default service. Simply, RESA and NRG view the time as being now for the Commission to revisit the default service model in Pennsylvania While we are not necessarily opposed to a default service investigation including a broader agenda, we believe that the default service framework which has the EDC in the DSP role is an important topic that deserves its own focus.

V. TIME-OF-USE RATES

A. Time-of-Use Rate as Default Service Rate

Q. PLEASE BRIEFLY DESCRIBE THE RESA/NRG PROPOSAL REGARDING THE COMPANIES' PROPOSED TIME-OF-USE RATE.

A. RESA and NRG do not oppose the Companies' proposal to offer time-of-use ("TOU") rates. However, the Companies and, if their proposal is accepted, the Commission are setting themselves up for failure if this DSP rate is offered only on an opt-in rather than a default basis. As I describe in my Direct Testimony, the recent history of the Companies demonstrates that an opt-in program will not result in substantial enrollment in or visibility for the TOU rate. Enrollment in the Companies' current TOU rate has been abysmal, and there is no reason to believe that participation would increase under the Companies' proposal in this proceeding. As a result, consumers will continue *not* to have a default retail rate that is based in the opportunity that smart meters provide, and which was heralded as a benefit when this investment was approved. This is a textbook example of a massive increase to utilities' rate base having been approved, earning a generous return for the utilities in question, while not subsequently being operationalized to the investment's full advantage. No party has disputed the reasonableness of the utilities' cost-based TOU rate in this proceeding. Therefore, in my Direct Testimony, I recommend that the TOU Rate be the default service rate available to non-shopping customers.[36]

Q. HOW DO OTHER PARTIES RESPOND TO THIS RECOMMENDATION?

A. On behalf of the Companies, Ms. Larkin testifies that an EDC's TOU program should be optional for default service customers.[37] Testifying for OSBA, Mr. Knecht raises a question about the legality of using the TOU rate as the default rate.[38] Similarly, Ms. Alexander sets forth OCA's position that Pennsylvania law contemplates that TOU rates

---

[36] RESA/NRG Statement No. 1 at 18-20.

[37] Companies' Statement No. 5R at 10.

[38] OSBA Statement No. 1-R at 2-3.

are optional. Ms. Alexander also questions how a mandatory TOU Rate could be obtained in the wholesale market while also meeting the default service mandate of acquiring a prudent mix of contracts to assure that the portfolio will result in a least cost over time. Further, Ms. Alexander points to a provision in the Commission's regulations, which she claims stands for the proposition that default service be structured as a single rate and displayed as a single line item on the bill.[39] Ms. Alexander also attempts to differentiate Pennsylvania from other jurisdictions, including California and Michigan, which have adopted a TOU rate design for default service.[40] Finally, OCA witness Alexander claims that Massachusetts and Maryland explicitly rejected reliance on TOU rates for residential customers to justify smart meter investments.[41]

Q. HOW DO YOU RESPOND?

A. Although I understand that this issue involves a legal interpretation of Act 129 of 2008, which I will defer to counsel to address during the briefing phase, I note that the RESA and NRG proposal does make an EDC's TOU program optional for customers. Any customer who does not wish to risk the uncertainty of time-varying charges is free to select the price structure of their choosing in the competitive market.

In addition, the competitive procurement process mandated by the Customer Choice Act and the rate design that is implemented by the Companies for default service are separate issues. Indeed, the TOU Rate, by pricing the peak time period around marginal costs, appropriately unifies two goals of ratemaking: the recovery of costs incurred by the EDC acting as DSPs and the conveyance of appropriate price signals to

[39] OCA Statement No. 2R at 5-6; 52 Pa. Code § 187.

[40] OCA Statement No. 2R at 6.

[41] OCA Statement No. 2R at 6-7.

consumers that will help avoid those costs that are related to demand, such as transmission and capacity costs, as well as energy costs during the interval. As I testified before, the Company has done a good job designing the TOU Rate to include avoidable costs as a marginal price signal within the peak price, and this price signal should be the default, not an option, because it is a rate that more closely adheres to the economic principles of utility ratemaking, especially now that we are blessed with the technological innovation of advanced metering that allows such rates to be widespread.[42]

Regarding the regulation cited by Ms. Alexander providing for default service customers to be offered a single rate option, that requirement is consistent with the RESA/NRG proposal to make TOU the default service rate—the single option. Ms. Alexander's position is, indeed, an unwitting recognition that the Companies' proposal to have multiple, different default service rates is essentially incompatible with the concept of default service. I have no real competence to make declarations about the law, like Ms. Alexander does, but I agree with her that there should be a single rate option as a default service option, rather than a confusing bouquet of options, which is why I advocate selecting TOU as a default rather than an "opt-in" offering. Further, the provision requiring the PTC to be displayed as a separate line item does not preclude use of TOU as the default service rate.[43] Regardless of the rate design that is implemented for default service, including the TOU rate, it would be displayed as its own line item on the monthly bill.

---

42 RESA/NRG Statement No. 1 at 20.

43 52 Pa. Code § 187(c).

Ms. Alexander also testifies that Michigan and California, which have both adopted a TOU rate, have not adopted a retail energy market for residential customers that allows them to choose their own provider, like Pennsylvania.[44] She points to this as a reason not to support an opt-out TOU rate in Pennsylvania. This is a perplexing assertion, and simple reasoning should lead an observer to the opposite conclusion of Ms. Alexander: Because Pennsylvania consumers, unlike Californians and Michiganders, have a far wider variety of options to select an alternative retail product from the Pennsylvania competitive retail market, including a non-time-varying-rate product, there is no compelling reason not to have the default product defined by utility regulators be something other than a product that more closely aligns to cost—in other words, the TOU product.

Finally, Ms. Alexander's reliance on decisions by regulators in Maryland and Massachusetts is misleading. Neither jurisdiction has yet to have been presented with a proposal, upon smart meter deployment, to use the TOU rate as the default service rate. The Maryland Public Service Commission ("MD PSC") rejected the entire 2010 AMI deployment proposal of Baltimore Gas and Electric Company ("BGE").[45] BGE had sought authorization to deploy a smart grid initiative and to establish a surcharge mechanism for the recovery of costs. The MD PSC was "not persuaded that this bargain is cost-effective or serves the public interest, at least not in its current form."[46] The MD PSC did not reach the merits of whether a default TOU rate was appropriate or not.

---

44 OCA Statement No. 2R at 7.

45 *In the Matter of the Application of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge for the Recovery of Cost*, Case No. 9208, Order No. 83410 dated June 21, 2010 at 1.

46 *Id.*

Similarly, the Massachusetts Department of Public Utilities ("DPU") rejected AMI in its entirety, including the argument that having time-varying charges available to residential customers justified smart meter investment.[47] The Massachusetts Commissioners' judgment did not hinge on whether or not TOU ought to be the default rate for consumers. By contrast, in Pennsylvania, AMI was approved with a transformation in consumer rate design in mind.[48]

Put simply, Pennsylvania regulators approved, and consumers are paying for, a smart grid that remains very dumb, at least as far as retail ratemaking is concerned.

B. Inability of EGSs to Display Savings on Bill

Q. EVEN IF CUSTOMERS DO NOT EMBRACE THE COMPANIES' TOU RATE, COULDN'T THEY STILL BENEFIT FROM THE SMART METER INVESTMENT BY CHOOSING TOU RATES FROM EGSS?

A. Yes, but only if EGSs have the same option that is available to EDCs of issuing a consolidated bill to customers that includes both the utility's distribution charges and the EGS's supply charges.[49] With the significant investments in smart meters of over $2 billion that Pennsylvania has made and the extensive work that has been done to develop protocols for sharing that information with EGSs, the Commission cannot stop there. To not take advantage of this large infrastructure investment would be a waste of ratepayer's capital. Now that EGSs finally have access to smart meter data that enables them to develop customized energy solutions for existing and prospective customers, it is

---

[47] *Petition of Massachusetts Electric Company and Nantucket Electric Company, d/b/a National Grid for Approval by the Department of Public Utilities of its Grid Modernization Plan*, D.P.U. 15-120, Order dated May 10, 2018 at 1-2.

[48] RESA/NRG Statement No. 1 at 19-20.

[49] Attached to my Direct Testimony as RESA/NRG Exhibit TK-12 is an example of a supplier consolidated bill showing the impact of time-varying charges on the customer's monthly energy costs.

essential that the Commission press forward to allow EGSs to issue consolidated bills to those customers.

Although consumers rely on mobile applications ("apps") and other mechanisms to pay for other products and services they purchase, EDCs in Pennsylvania continue to hold monopoly status as the only entity that can provide consolidated bills to consumers. The ability to offer innovative products and services is meaningless if EGSs are unable to properly bill for them and show the customer on a consolidated bill the benefits of choosing those options. Once EGSs have established direct relationships with their supply customers, learned what those customers want and are able to show those customers on the monthly bills the benefits of choosing a particular product or service, the possibilities are endless for the types of innovative products that EGSs can and will offer. If consumers desire to choose any product or service from an EGS other than a "plain-vanilla" per kWh price, their only choice is to receive dual bills from the EDC and EGS, which consumers find unacceptable.

Q. WHAT HAVE OTHER PARTIES CLAIMED REGARDING THE ADEQUACY OF UTILITY CONSOLIDATED BILLING TO ACCOMMODATE TOU RATES OFFERED BY EGSS?

A. Testifying for the Companies, Ms. Larkin claims that the utility consolidated billing ("UCB") option provides ample space for EGSs to display their TOU pricing, with seven lines and 80 characters per line to describe their pricing in the supply charges section of the consolidated bill.[50] Likewise, witnesses for OCA and CAUSE-PA suggest that UCB enables an EGS to convey time-varying rates.[51]

---

[50] Companies' Statement No. 5R at 11.

[51] OCA Statement No. 2R at 7; CAUSE-PA Statement No. 1R at 15-17.

Q. WHY IS THE UCB OPTION INADEQUATE FOR EGSS IN CONVEYING THE EFFECTS OF TIME-VARYING CHARGES?

A. It is not only about the amount of space that is available on the bill. The larger issue is the lack of flexibility of UCB to accommodate the many different variations of time-varying charges that EGSs would offer (and do offer in other jurisdictions) if they could effectively show the customer the savings they realized from shifting their usage. For example, Ms. Larkin's illustration in her testimony of how an EGS could use this space to present the effects of a customer shifting usage to a lower cost period only has two different charges, peak and off-peak, with no seasonal variations. An EGS may have different time periods, or critical peak times when a rebate is triggered for using less, or troughs when usage is encouraged, for a customer. EGSs should not be required to use the limited space on the EDC bill to include a display and description of how the customer benefited from a time-varying usage price. SCB is a critical path forward for EGSs to establish direct relationships with customers, provide them products that are intended to encourage flexible demand through understandable and visually catching appeals, and customize products customers demand based on their own unique needs. This kind of retail product differentiation takes advantage of the smart meter investment, while a "text box" on the utility's bill does not.

C. <u>Eligibility for TOU Rate</u>

Q. AS TO ELIGIBILITY FOR THE TOU RATE, WHAT IS THE RESA/NRG POSITION?

A. In my Direct Testimony, I describe the opposition of RESA and NRG to the Companies' proposal to make customers ineligible for the TOU Rate if they participate in the Companies' Customer Assistance Programs ("CAPs"). My understanding of Pennsylvania law is that all customers with a smart meter are entitled to select a TOU

Rate. This mandate makes no exceptions and is consistent with the fundamental feature of the Customer Choice Act – being choice for customers.

Q. WHAT POSITION DO OTHER PARTIES TAKE ON THIS RECOMMENDATION?

A. Ms. Larkin claims that the Companies' CAP customers may be charged a TOU Rate that is above the average default service rate if the customer is unable to shift usage to off peak hours.[52]

Q. HOW DO YOU RESPOND?

A. I do not see any link between a customer being on a CAP and being unable to shift usage to off peak hours. Frankly, I view the Companies' attempt to make such a link as underestimating the sophistication of low-income customers to manage their energy consumption. Indeed, in the PC44 Time of Use Pilots: End-of-Pilot Evaluation prepared by the Brattle Group for the MD PSC in 2021, one of the issues examined was to separately measure the impact of TOU rates on low and moderate income ("LMI") customers and non-LMI customers. Notably, one of the Companies' own witnesses in this proceeding, Dr. Powers, was a consultant on the study for the MD PSC. These two groups were allocated to separate treatment cells, allowing their responses to be measured in parallel. A key result from the analysis was that "the PC44 pilots conclusively showed that LMI customers respond to the price signals just like the non-LMI customers, and in most cases in similar magnitudes.[53]

---

[52] Companies' Statement No. 5R at 13-14.

[53] https://www.brattle.com/wp-content/uploads/2021/12/PC44-Time-of-Use-Pilots-End-of-Pilot-Evaluation.pdf at i and 52.

VI. LONG-TERM SOLAR PROCUREMENT

Q. PLEASE DESCRIBE THE POSITION OF RESA AND NRG ON LONG-TERM SOLAR PROCUREMENT.

A. In my Direct Testimony, RESA and NRG oppose the Companies' proposal to enter into power purchase agreements ("PPAs") to procure solar energy and solar photovoltaic alternative energy credits ("SPAECS") for terms of up to 10 years. The rationale for our opposition includes the following: (i) entering into contract that extend six years beyond the DSP program plan period is not reasonable since this would impede the ability of the Commission to approve an alternative DSP; (ii) the use of long-term contracts places the Companies' 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; and (iii) when DSPs 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.[54] Therefore, I recommend that wholesale default service suppliers should be required to deliver the full amount of their solar requirements and not pursue the proposed long-term solar procurement. Alternatively, the Commission should direct the Companies to modify solar procurement to four years to match the proposed DSP VI program period.[55]

Q. HOW DO THE OTHER PARTIES RESPOND?

A. Through Rebuttal Testimony of Mr. Catanach, the Companies indicate that RESA and NRG have not provided any evidence to show that the Companies' procurement proposal

---

[54] RESA/NRG Statement No. 1 at 37-41.

[55] RESA/NRG Statement No. 1 at 38.

will harm solar development in Pennsylvania.[56] On behalf of OCA, Mr. Ogur describes my concern about the Commission's approval of an alternative DSP as speculative and suggests that any contractual obligations incurred by the Companies can be transferred to the DSP.[57]

Q. WHAT IS YOUR RESPONSE?

A. In response to Mr. Catanach, my Direct Testimony, which is evidence offered by RESA/NRG, I explain that when default supply utilities are allowed to use the promotion of solar development as a reason for them to enter the market with a supply agreement to support it, it hampers the willingness and ability of EGSs to undertake these projects themselves. It also hampers the willingness of solar developers to enter into contracts with EGSs when they know they can contract with the utility on a long-term basis and interferes with the ability of EGSs in the market to procure SPAECs.[58] In this regard, I rely on my own expertise as someone who has personally regulated industries where firms that enjoy a guarantee of cost recovery compete against those firms that do not have that guarantee. I also cite to other experts' study of the issue. [59]Simply put, it does not require any especially deep quantitative analysis to conclude the following: 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 competition is a rate-regulated utility with the ability to recover all its costs, even on bad deals.

---

56 Companies' Statement No. 2R at 7.

57 OCA Statement No. 1R at 7-8.

58 RESA/NRG Statement No. 1 at 38-39.

59 RESA/NRG Statement No. 1 at 6, footnote 11.

As to Mr. Ogur's description of my concern about the Commission's approval of an alternative DSP as speculative, I believe the opposite is true. The only thing presently before the Commission is this DSP plan, which expires well before the Companies' proposed solar contracts. It is speculative to assume that the EDC will continue to be in the DSP role after expiration of the pending DSP plan, should it be approved. The Customer Choice Act expressly authorizes the Commission to approve an alternative DSP, and it would not be appropriate for the Commission to prejudge the outcome of a future DSP proceeding.[60] It essentially does so when it approves contractual arrangements that extend beyond the term of the proposed DSP. If the Commission adopts the Companies' proposal, it should include a requirement that the contracts can be voided by a change made in another DSP proceeding, including either a change in the DSP entity or the approval of an alternative procurement strategy. Holding a future DSP responsible for the bad deal negotiated by the EDC is not a reasonable outcome.

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. In the approach I propose, the DSP will obtain sufficient SPAECs through their wholesalers, who like EGSs are competitive actors that must manage their risk and costs. That ensures a substantially more level playing field than what the Companies are recommending in this proceeding.[61]

[60] 66 Pa.C.S. § 2807(e)(3.1).

[61] RESA/NRG Statement No. 1 at 40-41.

VII. DEFAULT SERVICE RATES

A. Allocation of Indirect or Overhead Costs to Default Service

Q. PLEASE BRIEFLY DESCRIBE THE CONCERN THAT HAS BEEN RAISED BY RESA AND NRG REGARDING THE ALLOCATION OF OVERHEAD COSTS TO DEFAULT SERVICE.

A. Although the Companies incur substantial costs in providing default service, they have regulated distribution businesses that absorb many of those costs, effectively cross-subsidizing their default service offerings. Today, the Companies are recovering no overhead or indirect costs that each of them incurs on a Company-wide basis to provide distribution service as an EDC and default service as a DSP through the rate for default service. All of these costs are recovered through their monopoly distribution rates. If EDCs remain in the DSP role, it is critical that the default service rate actually reflects the costs that an EDC is incurring to provide default service so that the competitive market functions properly and delivers the benefits of a robust market to consumers. Therefore, I recommend that the Commission pursue these issues through a statewide proceeding and require EDCs in future proceedings to propose the allocation of indirect costs to the default service rate.[62]

Q. WHAT ARE THE OTHER PARTIES' POSITIONS ON THIS RECOMMENDATION?

A. Through Rebuttal Testimony of Ms. Larkin, the Companies oppose the proposal of RESA and NRG for the examination of the allocation of overhead costs between default service and distribution service. In support of this view, Ms. Larkin suggests that: (i) the Commission has previously approved the Companies' default service rate design; (ii) default service and distribution service are not two separate businesses; (iii) when costs

[62] RESA/NRG Statement No. 1 at 42-43, 45.

are incurred to directly fulfill default service obligations, they are recovered through the default service rate; (iv) the Companies' default service is not competing with EGSs; and (v) NARUC guidelines are inapplicable.[63] Other parties likewise disagree with the need for an examination of this issue, although Mr. Knecht on behalf of OSBA acknowledges the importance of an honest accounting of the EDC's costs of providing default service.[64]

Q. PLEASE RESPOND.

A. The Commission's prior approval of the Companies' default service rate design does not mean that the approved components should remain in place indefinitely. In fact, the elements of default services have been adjusted on several occasions over the past decade or so.[65] Moreover, as explained by Frank Lacey in articles published in *Public Utilities Fortnightly* and *Electricity Journal*, regulators have been inappropriately permitting utilities for decades to omit indirect or overhead costs from default service pricing. One of the challenges is that default service rate design is established in DSP proceedings, while the cost of service data needed to correctly allocate indirect costs to the default service rate is available in the utilities' base rate proceedings. RESA and NRG are not aware of a prior default service proceeding in which any parties raised an issue about the proper allocation of indirect costs. Therefore, Commission approval of default service rate design has not considered whether any of the indirect costs incurred by the Companies were recovered through default service rates.

---

63 Companies' Statement No. 5R at 2-8.

64 OCA Statement No. 2R at 4; OSBA Statement No. 1-R at 4; CAUSE-PA Statement No. 1R at 7-9.

65 *See, e.g.*, *Petition of Metropolitan Edison Company for Approval of a Default Service Program for the Period Beginning June 1, 2019 through May 31, 2023*, Docket No. P-2017-2637855 (Order entered September 4, 2018).

As to Ms. Larkin's contention that distribution and default service are not separate businesses operated by the Companies, the construct of the Customer Choice Act places two separate and distinct responsibilities on the Companies – of *delivering* electricity to all customers on their distribution systems and of *supplying* electricity to customers on their distribution systems who do not purchase generation services from EGSs. These two duties fulfilled by the Companies are subject to different regulatory requirements. The Customer Choice Act preserves the regulation of distribution service "as a natural monopoly subject to the jurisdiction and active supervision" of the Commission.[66] As such, in their role as EDCs, the Companies are required to comply with various portions of the Public Utility Code, including Chapters 11 (authority to provide service), 13 (just and reasonable rates) and 15 (adequacy of service). By contrast, the law provides that the generation of electricity will no longer be regulated as a public utility function except for specified limited exceptions.[67] In addition, the Customer Choice Act establishes the EDCs' obligations to provide default service and sets forth the various requirements that must be followed.[68]

With respect to Ms. Larkin's testimony concerning the recovery of costs that are incurred to directly fulfill default service obligations through the default service rate, this statement misses the point. RESA and NRG understand that when costs, such as information technology costs, are incurred in connection with a change to the default service program, the Companies recover them through the default service rate. Our point is that the Companies incur indirect costs everyday across their businesses that are not

[66] 66 Pa.C.S. § 2802(16).

[67] 66 Pa.C.S. § 2802(14).

[68] 66 Pa.C.S. § 2807(e).

directly attributable to either distribution or default service but are allocated wholly to distribution service.

Further, I disagree with Mr. Larkin's claim that the Companies' default service is not competing with EGSs' generation supply services. To the contrary, PaPowerSwitch.com, utility bills and Commission decisions consistently compare EGS pricing to EDC default service rates.[69] This shows that EGSs are competing against default service when in a truly competitive market, they should be competing against each other.

As to Ms. Larkin's contention that the NARUC Guidelines are not applicable to default service, my Direct Testimony recognizes their applicability to affiliate transactions. The NARUC Guidelines are relevant because the default service businesses operate like an affiliate in the market, even if the Companies have not chosen to formally structure them as separate corporate affiliates. That is especially the case because, in defining distribution service as a "natural monopoly," the legislature cannot simultaneously have meant that an electric generation service like DSP was part and parcel of that monopoly; clearly it was not by dint of the legislature's declaration that it should be competitive. The fundamental premise of the NARUC Guidelines is to ensure the competitiveness of markets and to prevent subsidization between different businesses of utilities.[70]

---

[69] *See, e.g.*, Investigation of Pennsylvania's Retail Electricity Market: Intermediate Work Plan, Docket No. I-2011-2237952 (Order entered March 2, 2012, at 6, 14, 20, 31); https://www.papowerswitch.com/about-switching-electricity/how-to-choose-a-supplier/#

[70] RESA/NRG Statement No. 1 at 52-53.

B. Use of Misnomer "Price to Compare"

Q. PLEASE DESCRIBE THE RESA AND NRG PROPOSAL CONCERNING THE CONTINUED USE OF THE TERM "PRICE TO COMPARE".

A. Unless or until the accurate pricing of default service is addressed the Commission should dispense with the misnomer – "Price to Compare" or PTC.[71]

Q. WHAT ARE THE OTHER PARTIES' POSITIONS ON THIS RECOMMENDATION?

A. On behalf of OCA, Mr. Ogur advocates for continuing to use the term "PTC" because it is a logical starting place for judging the value of an EGS product.[72]

Q. HOW DO YOU RESPOND?

A. Comparisons between the EDC's default service rate and EGS supply prices in the market are meaningless for reasons noted above. Mr. Ogur's testimony actually makes my point that EGSs are competing with the EDC's default service. Therefore, the Commission should discontinue use of the nomenclature "Price to Compare" and seek to ensure that the competitive market is structured in a way that promotes competition among EGSs. The price charged by the EDC, acting as DSP, for electricity should simply be referred to as the "default service rate."

C. Semi-Annual Adjustments

Q. PLEASE DESCRIBE THE POSITION ADVANCED BY RESA AND NRG IN RESPONSE TO THE COMPANIES' PROPOSAL TO TRANSITION FROM QUARTERLY ADJUSTMENTS TO SEMI-ANNUAL ADJUSTMENTS IN THE DEFAULT SERVICE RATE.

A. RESA and NRG oppose the Companies' proposal to shift from quarterly to semi-annual adjustments in the default service rate. The Companies' rationale for this proposed

---

71 RESA/NRG Statement No. 1 at 54.

72 OCA Statement No. 2R at 9-10.

change is to smooth out fluctuations in default service rates and send clearer price signals to customers and EGSs. As I explain in my Direct Testimony, neither of these justifications warrants the Companies' proposal to transition from quarterly to semi-annual adjustments. To the contrary, a quarterly adjustment in default service rates results in more reflective rate, and customers seeking price stability are free to opt for an EGS product. Therefore, I recommend that the proposal be rejected.[73]

Q. HOW DID PARTIES RESPOND TO THIS RECOMMENDATION?

A. On behalf of the Companies, Dr. Reitzes and Powers disagree that quarterly adjustment of default service rates would better reflect markets. The basis for their view is that in three of four quarters, changes to each Company's residential default service rate are determined almost entirely by the E-Factor, which reconciles the differences between default service supply costs and billed revenue. Therefore, they believe that quarterly adjustments are largely exposing residential customers to fluctuations in the E-Factor rather than providing clear pricing signals. Dr. Reitzes and Powers opine that if these fluctuations are smoothed out, the default service rate would be more reflective of the projected cost of supply.[74]

Q. DO YOU AGREE?

Let me first say that if Dr. Reitzes and Powers' argument here is accepted, then the argument I propound above about discarding "Price to Compare" as a misnomer *should* certainly be adopted. If the "Price to Compare" is not actually a measure of the market's price, but really a reconciliation of unrecovered expenses from the past (or unrebated

---

[73] RESA/NRG Statement No. 1 at 55-56.

[74] RESA/NRG Statement No. 4R at 3-5.

collections from the past), then there is seriously something wrong with the way in which default service rates are established. Importantly, the concept of reconciliation runs contrary to the robust functioning of a competitive market. Indeed, the Commission has previously recognized that default service rates inherently pass along false or misleading price signals due to reconciliation.[75]

I do not see how, given the reconciliation mechanism already results in a market price signal distortion, that spreading the cost recovery over a 6-month period will make things any better. It will indeed simply further abstract the default service price signal from the time period during which the costs were incurred. This results in giving customers the false impression that the EDC's default service costs are stable. They are not, and the Commission should not engage in the trickery of the cook who puts the frog in slowly warming water.

The Companies' proposal is also inconsistent with the Commission's prior directives that EDC's default service rate should be market based and accurately reflect all costs of providing default service.[76]

Finally, realizing that parts of this proceeding interact with one another, were the underlying rate design TOU Rates, RESA and NRG would not have a problem with less frequent adjustments since they would inherently be more reflective of market prices at the margin. But a proposal that simply serves to further dampen retail price signals, and alienate them from the actual cost drivers, is simply not appropriate in a construct like Pennsylvania has adopted.

---

[75] *RMI End State Order* at 12.

[76] *RMI End State Order* at 41; 52 Pa. Code § 54.187(b).

VIII. CUSTOMER REFERRAL PROGRAMS

Q. PLEASE DESCRIBE THE PROPOSALS SET FORTH BY RESA AND NRG REGARDING THE COMPANIES' CUSTOMER REFERRAL PROGRAMS ("CRPS").

A. Noting the steady decline in enrollment in the CRP over the past years, I offer several recommendations in my Direct Testimony to enhance customer participation, including that: (i) all new customers (who have not already made an affirmative choice of an EGS) be automatically enrolled in the CRP; (ii) the Companies be required to allow online enrollments in the CRP; and (iii) the Companies be required to revisit the situations in which the CRP is mentioned, particularly to default service customers who contact the call center, and to otherwise engage in periodic communications, such as when changes to the default service rates occur, promoting CRP to all customers on default service.[77]

Q. DO THE COMPANIES ACCEPT ANY OF THESE RECOMMENDATIONS?

A. Through the Rebuttal Testimony of Ms. Savage, the Companies indicate that they do not oppose the proposal for online enrollments in the CRP, but note that they would incur an estimated $500,000 to make this change, which would need to be recovered from customers through the default service support riders.[78] As to expanding the scope of calls in which CRP is presented and the automatic enrollment of new or moving customers in CRP, the Companies oppose these recommendations.[79]

Q. PLEASE RESPOND.

A. Particularly given that the Companies do not oppose the proposal for online enrollments in the CRP, this recommendation should be implemented for the reasons I explain in my

---

77 RESA/NRG Statement No. 1 at 57-58.

78 Companies' Statement No. 1R at 10.

79 Companies' Statement No. 1R at 9-10.

Direct Testimony. Customers can currently sign up electronically for new service from the Companies and the Companies have proposed in this proceeding that customers be able to enroll online in the proposed TOU Rate. 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 online for the CRP. An added benefit of website enrollments is that since no third-party verification is required, the CRP fee should be waived or reduced.[80] Regarding the Companies' resistance to expanding the scope of calls during which the CRP is raised, RESA and NRG believe that a minimum, the Companies should commit to enhanced communication with customers about the availability of CRP, such as through bill inserts, and by making the link to CRP directly accessible on its their Customer Choice pages.[81]

With respect to automatically enrolling new and moving customers in the CRP, the Companies offered little by way of justification for opposing this proposal.[82] While the Commission may have previously viewed the CRP as being voluntary for both customers and EGSs, the data today suggests that greater participation in the CRP is warranted. Since the CRP has been designed to give customers a 7 percent discount off the Companies' rate for default service, while also introducing customers to participation in the retail market,[83] no reason exists to initially place a customer on 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 has

[80] RESA/NRG Statement No. 1 at 59.

[81] RESA/NRG Statement No. 1 at 59-60.

[82] Companies' Statement No. 1R at 9.

[83] *Investigation of Pennsylvania's Retail Electricity Market: Intermediate Work Plan*, Docket No. I-2011-2237952 (Order entered March 2, 2012 at 20-32).

been successful in promoting consumer participation in the market. Importantly, automatically placing these new customers on the CRP also eliminates the notion of the Companies' default service as the "first" service in which consumers enroll. Of note, the Commission has recognized the CRP as an effective way for consumers to participate in the market, while providing them with valuable information about the electric choice program.[84]

IX. OPERATIONAL ISSUES

Q. PLEASE SUMMARIZE THE OPERATIONAL ISSUES RAISED BY RESA AND NRG IN THIS PROCEEDING.

A. EGSs have been experiencing significant delays in receiving customer usage data (of more than 90 days) from the Companies that is needed to prepare and send billing information to the Companies. Under the bill ready approach, EGSs send the supply charges to the Companies for inclusion on bills, which reflect both the EGS prices and the customer's usage. Due to the delays that are occurring, EGSs are unable to send the bill ready supply charges for inclusion on the bills and are not getting timely paid. Although the Companies are exploring solutions to these delays, I recommend in my Direct Testimony that the Companies be directed to revise their Supplier Tariffs to provide a specific timeframe, such as 15 days, for providing usage data to EGSs since it is readily available to the Companies and is needed by EGSs to be paid for the supply service they provide.[85]

---

[84] Companies' Statement No. 1R at 5.

[85] RESA/NRG Statement No. 1 at 61-62.

Q. HOW DO THE COMPANIES RESPOND?

A. Through the Rebuttal Testimony of Mr. Strah, the Companies explain the reasons for the delays in transmitting usage data and the actions taken by the Companies to address those delays. However, the Companies disagree with the proposal for revisions to their Supplier Tariffs because of their efforts to resolve these problems.[86]

Q. IS THIS AN ACCEPTABLE RESOLUTION TO RESA AND NRG?

A. No. Because the timely transmission of usage data is critical to the issuance of bills and the receipt of money owed to EGSs for supply service, the Companies' commitment to a resolution of the issue should include a revision to their Supplier Tariffs, such as 15 days unless the circumstances are beyond the Companies' control.

X. CONCLUSION

Q. DOES THAT COMPLETE YOUR SURREBUTTAL TESTIMONY?

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

---

[86] Companies' Statement No. 7R at 3-4.

Verification

I, Travis Kavulla, state that I am Vice President, Regulatory Affairs for NRG Energy, Inc. and providing the foregoing Surrebuttal Testimony of the Retail Energy Supply Association and NRG Energy, Inc. I hereby state that the facts contained in the foregoing Surrebuttal Testimony are true and correct to the best of my knowledge, information and belief. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

April 7, 2022

/Travis Kavulla/

Travis Kavulla, Vice President
Regulatory Affairs, NRG Energy, Inc.