FirstEnergy

2800 Pottsville Pike
PO Box 16001
Reading, PA 19612-6001

Tori L. Giesler, Esq.
(610) 921-6658
(330) 315-9263 (Fax)

May 31, 2017

VIA ELECTRONIC FILING

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

Re: ***Alternative Ratemaking Methodologies***
Docket No. M-2015-2518883

Dear Secretary Chiavetta:

Pursuant to the Commission's Tentative Order entered March 2, 2017 in the above-referenced proceeding, enclosed herewith for filing are the Comments of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company.

Please contact me if you have any questions regarding this matter.

Very truly yours,

Tori L. Giesler /dm

Tori L. Giesler

dlm
Enclosures

c: As Per Certificate of Service

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Alternative Ratemaking Methodologies	:	**Docket No. M-2015-2518883**

COMMENTS OF METROPOLITAN EDISON COMPANY, PENNSYLVANIA ELECTRIC COMPANY, PENNSYLVANIA POWER COMPANY AND WEST PENN POWER COMPANY

I. INTRODUCTION

On December 31, 2015, the Pennsylvania Public Utility Commission ("Commission") issued a secretarial letter announcing that it was opening the above-captioned docket ("December 2015 Secretarial Letter") in order to begin gathering "information from experts regarding the efficacy and appropriateness of alternative ratemaking methodologies, such as revenue decoupling, that remove disincentives that might presently exist for energy utilities to pursue aggressive energy conservation and efficiency initiatives." December 2015 Secretarial Letter at 1. It further went on to notify that it would hold an *en banc* to be held on March 3, 2016, with testimony requested on the following rate issues: (1) whether revenue decoupling or other similar rate mechanisms encourage energy utilities to better implement energy efficiency and conservation ("EE&C") programs; (2) whether such rate mechanisms are just and reasonable and in the public interest; and (3) whether the benefits of implementing such rate mechanisms outweigh any costs associated with implementing the rate mechanisms ("March 3 *en banc*"). In addition, the December 2015 Secretarial Letter enclosed a series of twenty-two topics intended to guide the discussion.

On March 3, 2016, testimony was provided at that *en banc* by representatives of the Natural Resources Defense Council ("NRDC"), the Regulatory Assistance Project, the Edison Electric Institute ("EEI"), H. Gil Peach & Associates ("Peach"), the Keystone Energy Efficiency Alliance ("KEEA") in coordination with the Clean Air Council and NRDC, PPL Electric Utilities Corporation ("PPL"), Columbia Gas of Pennsylvania, Inc., the Office of Consumer Advocate ("OCA"), and Alcoa, Inc. on behalf of the Industrial Energy Consumers of Pennsylvania ("IECPA").

The December 2015 Secretarial Letter provided that written comments could be submitted by all interested parties on these topics and in response to the testimony offered at the March 3 *en banc*, to be filed no later than March 16, 2016. Metropolitan Edison Company ("Met-Ed"), Pennsylvania Electric Company ("Penelec"), Pennsylvania Power Company ("Penn Power") and West Penn Power Company ("West Penn") (individually a "Company" and in any combination, the "Companies") collectively filed comments in response to the December 2015 Secretarial Letter. In addition, comments were filed by American Association of Retired People, Duquesne Light Company, National Association of Water Companies Pennsylvania chapter, Pennsylvania Law Project, Office of Small Business Advocate, Citizen Power, Sierra Club, Environmental Defense Fund, UGI Distribution Company, the Energy Freedom Coalition of America, PPL, The Penn State University, the Energy Association of Pennsylvania, PECO Energy Company, Northeast Energy Efficiency Partnership ("NEEP"), Citizens for Pennsylvania's Future, OCA, IECPA, Citizens' Electric Company and Wellsboro Electric Company, and KEEA.

On March 2, 2017, the Commission issued a Tentative Order which requested comments from interested Parties in response to specific questions ("March 2017 Tentative Order"). At the public meeting during which the March 2017 Tentative Order was adopted, statements were also offered on this topic by each of Vice Chairman Place, Commissioner Powelson, and Commissioner Sweet. Per the March 2017 Tentative Order, comments were to be filed by April 16, 2017, with reply comments to be filed by May 16, 2017. On March 23, 2017, the Commission issued a Secretarial Letter extending the deadline for comments to May 31, 2017 and reply comments to July 31, 2017. The Companies submit these comments in response to the questions posed by the March 2017 Tentative Order and those considerations and questions outlined in the statements offered at the time of its adoption.

II. COMMENTS

In its March 2017 Tentative Order, the Commission outlined various approaches to adopting "alternative ratemaking" mechanisms, recognizing that there are differing factors that may inform which mechanism is most appropriate to a particular type of utility. To that end, the questions it posed were directed to several categories of utility types, including separate categories for each of electric, natural gas, and water and wastewater utilities. In addition to those targeted sets of questions, the Commission also encouraged feedback with respect to: a) whether the Commission should proceed with the adoption of policy statements offering guidelines for preferred methodologies to be adopted by type of utility; b) whether the Commission should initiate rulemakings to address this issue; and c) what options are available to the Commission under its existing statutory authority. Meanwhile, each of the statements issued on March 2, 2017 at the above-referenced docket identify areas of interest and/or specific questions seeking comment. Specifically, Vice Chairman Place's statement outlined an advanced rate design for consideration by electric distribution companies ("EDCs"), as well as eleven directed questions associated with that proposed design. Commissioner Powelson specifically questioned what actions the Commission is able to implement through either policy statement or rulemaking that would increase the use of alternative ratemaking mechanisms to the benefit of all stakeholders. And finally, Commissioner Sweet specifically encouraged comments regarding the impact of any proposed methodologies on all customers, but in particular low income and income-challenged customers, as well as the impact of such methodologies on the replacement of infrastructure and the operation of distribution system improvement charges. In response to these calls for feedback, the Companies focus these comments on the specific questions directed to the electric utilities, as well as their response to each of the broader questions within the context of their response to those directed questions, as applicable.

March 2017 Tentative Order – A. Electric Utilities

1. Identify the alternative rate methodology(ies) each EDC is currently using, including the number and types of automatic adjustment clauses, cost trackers, and separate cost recovery mechanisms. Also identify, as a percentage of total costs or revenues, the costs or revenues each separate mechanism recovers.

Each of the Companies actively employ both cost trackers (also referred to as automatic adjustment clauses or "riders"), as well as the fully projected future test year for the setting of new base distribution rates. Specifically, the Companies each have the following riders that recover cost on a dollar for dollar basis: Default Service Support ("DSS"),[1] Universal Service Charge ("USC"),[2] Energy Efficiency and Conservation ("EE&C"),[3] Non-Utility Generation ("NUG"),[4] Solar Photovoltaic Requirements Charge ("SPVRC"),[5] Smart Meter Technologies Charge ("SMT-

[1] The DSS Riders recover non-market based costs associated with the provision of default service.
[2] The USC Riders recover the costs of universal service programs from residential customers.
[3] The EE&C Riders recover the costs of statutorily required EE&C programs.
[4] Met-Ed and Penelec's NUG Riders recover the costs of long term power purchase agreements entered into by Met-Ed and Penelec and approved by the Commission. Penn Power and West Penn do not have such costs and therefore do not have NUG riders.
[5] Met-Ed, Penelec and Penn Power each recover the costs of procurement of solar photovoltaic credits as required by Pennsylvania's Alternative Energy Portfolio Standards Act, 73 P.S. §§ 1648.2 – 1648.9, through their SPVRC Riders. West Penn does not procure solar photovoltaic credits in the same manner as its sister Pennsylvania companies and does not have a SPVRC Rider.

C"),[6] and Distribution System Improvement Charge ("DSIC").[7] These riders account for between fifteen and twenty-two percent of an average residential customer's[8] distribution service bill. Each Company also has bypassable Price to Compare Default Service and Time of Use Default Service Riders, which provide the generation component of a customer's bill for those who do not shop, bringing the total percentage of an average non-shopping residential customers' total monthly bill attributed to cost trackers, including generation charges, to between fifty-two and sixty-two percent.

Meanwhile, for distribution base rates - i.e., those rates are not recovered through a cost tracking mechanism – the Companies in recent years have taken advantage of their ability to request rates be set based upon fully projected future test years. The fully projected future test year, when normalized as appropriate for lost sales as a result of statutorily-mandated EE&C plans, offers EDCs a tool to help reduce the negative revenue impacts that are presented by such mandates.

2. If any, what alternative rate methodology(ies) could and should be used by EDCs? Regarding the proposed methodology(ies), please provide specific comments on:

- **a. The potential advantages**
- **b. The potential disadvantages;**
- **c. The effects on all rate classes, with a specific focus on small volume, low-income, income-challenged and large C&I customers, as well as a discussion regarding any potential inter- or intra-class cost shifting;**
- **d. The effects on existing energy efficiency and peak demand reduction programs; and**
- **e. The effects on the number and/or frequency of base rate case filings, as well as possible rate increases or decreases.**

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[6] The Companies recover any costs associated with the installation of smart meters in excess of those built into base distribution rates, as well as refund any savings associated with smart meters back to customers as appropriate, through their SMT-C Riders.

[7] The Companies' DSIC Riders are mechanisms which permit the Companies to recover the costs of Commission-approved long term infrastructure improvement plans ("LTIIPs") once specific criteria are met.

[8] The Companies assumed an average usage of 1,000 kilowatt hours ("kWh") per month in determining what the average residential customer's bill may look like.

There are several mechanisms either currently available to the Commission and EDCs or which could be pursued through legislative changes to help address the issues pertaining to an EDC's lost distribution revenue attributable to the implementation of EE&C programs, which the Commission summarized in its March 2017 Tentative Order. While the Companies don't offer any alternative methodologies to those already itemized by the Commission, several are more effective than others in achieving the goals of implementing alternative ratemaking methodologies while minimizing any negative effects of doing so. Those that would be most effective in reaching these goals are discussed in further detail below. However, it's first important to underscore the particular goals that must be strived towards in implementing any new methodology.

Alternative rate mechanisms, if properly designed, present minimal risk of interclass shifting, with the alternative rate mechanisms determined by each rate schedules respective cost of service. However, intraclass cost shifting could be realized under certain models. For instance, by implementing a properly structured straight fixed variable ("SFV") rate design methodology, intraclass cost shifting would be consistent with cost causation principals, resulting in a customer's fixed costs increasing, while their kWh charges decrease. Thus, those who use the least amount will see the largest effect on their bills, and will also be picking up a higher percentage of costs allocated to the class. Under other alternative rate mechanisms, intraclass cost shifting occurs without the benefit of being consistent with cost causation principals, which the Companies do not advocate.

In his testimony, Mr. Peach of H. Gil Peach & Associates discussed potential concerns with alternative ratemaking mechanisms – specifically, those related to the impact to low income customers. He cited the fact that federal low-income payment assistance is important but erratic as to amount and timing, as well as the fact that federal assistance levels can decline, creating a need for modification to low-income assistance programs when an alternative ratemaking mechanism is applied. While valid points, these events would happen under a normal change in rates under today's ratemaking construct. Unfortunately, the reality is that some low-income customers have high energy use. Under a model that put more emphasis on a fixed charge, the higher the use, the lower the impact on the bill – which in turn would benefit these users.

In general, and regardless of which mechanisms are employed, it is important to ensure consistent application of any selected mechanism across the various customer classes. Properly structured, the alternative ratemaking mechanisms discussed within these comments and testified to at the March 3, 2016 *en banc* should not result in interclass subsidies. While both the IECPA and EEI suggest excluding the industrial class for fear of intra-class subsidies, those arguments ignore the fact that such concerns apply equally to the residential and commercial classes. For instance, IECPA provided feedback suggesting that alternative ratemaking mechanisms provide incentives to large commercial and industrial customers to engage in the EE&C measures that they have voluntarily adopted over many years – a fact that is equally true for all other commercial and residential customers.

Of the various alternative ratemaking methodologies, among those that are most effective in managing to each of these considerations include lost revenue adjustment mechanisms ("LRAMs"), straight fixed variable ("SFV") rate design, and the use of fully projected future test years ("FPFTY"). While individually effective in meeting specific goals, pairing the three methods as a comprehensive rate strategy would maximize the benefits of using these models – both to the utility and the customer.

Lost Revenue Adjustment Mechanisms

LRAMs offer value by eliminating the risk to an EDC of resulting lost revenue due to declining sales following implementation of EE&C programs by providing certainty of revenue through a reconcilable rider. This mechanism assures timely cost recovery tied specifically to an individual utility's EE&C efforts, without the downside of interclass cost shifting, assuming proper design is used. In addition, a LRAM could reduce the frequency of rate cases by eliminating one significant driving force behind an EDC's need to file a base rate case. Meanwhile, the mechanism ensures that an individual customer's incentive to participate in utility sponsored EE&C programs is not reduced due to the fact that the utility's pricing structure remains unchanged other than the addition of the LRAM.

Unfortunately, this type of mechanism is presently not permissible under Pennsylvania law and, in fact, is explicitly prohibited. In addition, if permitted, some jurisdictions have adopted models which effectively account for customer-initiated EE&C activities that many not otherwise be counted as part of an EDC's mandated plan. Any LRAM should be based on class-specific cost recovery, thereby eliminating inter-class cost shifting. However, customers would experience a limited degree of intra-class cost shifting, as energy-based prices would increase for those customers not participating in utility-sponsored EE&C programs. By increasing the maximum CAP credit by an amount which corresponds to residential LRAM charges, the Commission would be able to effectively assure that low-income customers that elected not to participate in EE&C programs would not end up with increased costs that resulted purely as a function of the implementation of the LRAM.

Straight Fixed Variable Rate Design

SFV rate design allows the utility to take a more aggressive approach with respect to implementing EE&C programs, with reduced risk to the utility's bottom line. Meanwhile, the model follows cost causation principles widely recognized (albeit not fully implemented) by the industry today. Under this method, a utility's rate design recognizes that most of its distribution cost is fixed and does not vary based on consumption. This is accomplished by increasing the customer charge and decreasing energy charges to align with cost of service. The SFV approach assures no inter- or intra-class cost shifting other than that which is consistent with cost causation.

From the utility perspective, a stronger reliance upon a rate structure that is fixed in nature will increase a utility's incentive, or at the very least, remove any existing disincentives, to initiate additional EE&C efforts. And, given that Pennsylvania customers can shop for generation in Pennsylvania today, customers would still have the ability to manage their costs with respect to the variable portion of their bills in a meaningful way by participating in energy efficiency programs and shopping for that component of their bill which represents the biggest proportion of charges. As a point of illustration, even if the Companies were to establish a 100% fixed rate for their commercial and industrial classes, those customers would still see a large percentage of their bill charged under a variable rate due to the proportion of the generation piece of their bills. The same holds true for the residential classes, where approximately 51 to 63% of the total charges for electricity would remain variable in nature if 100% of base distribution charges were collected on a customer charge basis. Implementation of a SFV design could be fairly simply completed as part of a filing of a distribution base rate case as part of the overall rate design portion of the case, or could be implemented more gradually in a series of such cases. In a declining sales environment, it is likely that the frequency of rate cases would decrease where SFV design is implemented as compared to continued reliance volumetric pricing.

The downside to this model, however, is to limit a utility's growth potential due to the fact that most of its revenue will be fixed. Furthermore, consumer advocates and customers have shown a reluctance to accept this type of rate design, in part because low usage customers may be adversely affected as compared to existing rate design, despite the fact that such a methodology is consistent with well-established cost causation principles. This concern could be addressed by establishing different levels of customer charges based on factors such as the size of a customer's service entrance or historic usage.

On the residential side, SFV rate design would give customers only slightly less incentive to participate in EE&C programs than exists under today's rate design. Further, this type of design would have very little, if any, impact on low-income customers. In fact, a recent study performed by the Companies showed that the average monthly usage for CAP customers exceeded that of non-CAP customers by approximately 100 kWh per month. Therefore, it is expected that the fixed portion of a CAP customer's bill under SFV design would produce more favorable monthly bills when compared to a non-CAP customer given the fact that the Companies' average CAP customer has higher usage than non-CAP and the fact that higher usage customers in general benefit from SFV design.

<u>Fully Projected Future Test Years</u>

Consumer Advocate Tanya J. McCloskey and Eric Ackerman, Director of Alternative Regulation at EEI, both testified at the March 3, 2017 *en banc* to the importance of Pennsylvania's introduction of the FPFTY as a form of alternative ratemaking and an effective tool for utilities in managing the potential declines in sales that result from the implementation of EE&C measures, while allowing utilities to recoup the investments necessary to rebuild infrastructure. The disadvantage to this method is the EDC must file a full distribution base rate case to realize the benefits of this forward-looking method. The Companies appreciate that this methodology has been adopted in Pennsylvania and have availed themselves of its benefits in their two most recent sets of distribution base rate proceedings. In general, the use of the FPFTY eliminates the disincentive of EE&C programs by allowing an EDC to recover lost distribution revenue resulting from statutorily mandated reductions. Meanwhile, the impact to low-income customers is proportional to other customers within the same class, and does not differ significantly from the impact that would result if the alternative were using a traditional historical or future test year. In fact, modification to maximum CAP credit could be completed as part of an overall distribution rate case.

3. How would the particular alternative rate methodology(ies) interact with existing mechanisms or traditional ratemaking principles currently in use or available to EDCs (*e.g.*, the distribution system improvement charge (DSIC) or FPFTY, etc.)?

Most of the outlined mechanisms would work relatively seamlessly within the context of today's rate design, particularly considering the continuing use of a FPFTY or DSIC mechanism. For example, cost trackers – including LRAMs, if permitted – are already in use today and could be further implemented in a way that sterilizes a particular set of costs from the calculation of base distribution rates, and would not in any way impact DSIC mechanisms in place today, except that the revenue from a particular tracker would be included as part of base rates and part of the prescribed five percent cap when evaluating the implementation or renewal of a DSIC. All other existing cost trackers or riders should be otherwise unaffected. Specific to the DSM performance incentive mechanism, any such program would integrate with existing trackers associated with EE&C programs, and therefore would not drive changes to the use of today's tools.

Similarly, a SFV rate design is a type of alternative ratemaking methodology can be easily implemented as part of a base distribution rate case proceeding under today's construct without negative impact to the use of a FPFTY, DSIC mechanism, or other cost trackers. Much of a distribution company's costs are fixed, so it makes sense to align existing distribution charges in a way that matches the fixed/variable nature of costs. Recent cost of service studies performed as part of the Companies' latest distribution base rate cases produced results that establish that most of the Companies' distribution function is fixed. In fact, in the National Association of Regulatory Utility Commissioners' ("NARUC") Cost of Service Manual ("NARUC manual"), it states that an EDC's distribution-related facilities are, from a design and operational perspective, sized to meet the maximum kW load (demand) requirements of customers. Therefore, the NARUC manual concludes that all distribution costs should be classified as either customer or demand-related. Today, almost all of the Companies' commercial and industrial class rate schedules (except for commercial customers with less than 1500 kWh per month usage) have established rate design which includes a customer charge and a demand charge consistent with this principle. A move to SFV rate design (and similarly, demand based rates) for residential and small commercial customers could be implemented seamlessly under today's construct by simply adding a demand component to the rate design without adverse impact to today's existing ratemaking tools.

Meanwhile, integration of a multiyear rate plan into the existing rate design would be very similar to the implementation of base distribution rate case using a FPFTY today, except that it would be done with a tiered approach. However, use of this type of approach adds layers of complication and could potentially result in inaccurate cost of service outcomes and difficulty in determining billing determinants for each year included in the plan. For that reason, the use of a FPFTY on a single-year basis is more efficient than this approach as it takes into account all factors into one future test year. Likewise, any impact to the DSIC would be similar to the impact of a FPFTY, except that it would be applicable on a multi-year basis, with the DSIC not implemented until after the multiyear rate plan has concluded. The other cost trackers and riders would not be affected.

4. How would such a methodology be implemented? Specifically, in what timeframe? Is there a need for a gradual implementation or phasing-in process?

The implementation of alternative ratemaking mechanisms, however helpful, within the context of an EDC's existing rate design raises a number of potential concerns. For several of the mechanisms, including the use of SFV design, choice of test year, revenue decoupling and implementation of or increased use of standby, backup, and demand charges, changes in legislation may not be necessary. However, it may be challenging to implement many changes to an EDC's distribution rates outside of a distribution rate case given the provisions of 66 Pa.C.S. § 1308, which requires that unless the Commission otherwise orders, no public utility shall make any change in any existing and duly established rate without a sixty days' notice. This timeline has traditionally also led to suspended tariffs and long investigation periods to litigate such changes. However, should the Commission issue an order offering guidance or a policy regarding alternative ratemaking mechanism implementation, it is technically feasible that companies could file tariff changes on 60 days' notice be considered and placed into service within the context of that guidance without a procedural schedule that is associated with a traditional distribution base rate case should the Commission determine that suspension for the full duration is not necessary. However, given that current distribution rates are established using this defined procedural and evidentiary process, including the filing of very specific information as required by the Commission's regulations, such changes to existing rates that were already established pursuant to a distribution base rate case proceeding may likely have to be part of a base rate proceeding –

particularly where all affected parties may not be in agreement with the proposed changes. This would lead to the implementation process for many new mechanisms to take between twelve and eighteen months, following potentially protracted litigation. In the case of certain of the mechanisms, SFV rates being an excellent example, it may take several such cases before the rate structure is fully moved to the new model due to concerns that such changes take place gradually to give customers time to adjust usage behaviors.

Meanwhile, mechanisms such as a new cost tracker are most likely to be initiated and implemented as part of another filing, for instance an EDC's default service plan or distribution base rate case, each of which follow the defined procedural schedule of that specific plan to which the tracker would be related. Once the cost tracker is implemented, the rider or automatic adjustment clause, which recovers costs dollar-for-dollar, would be updated periodically (quarterly, semiannually, or yearly) to include a new cost period and reconciliation balances from prior periods.

Finally, there are certain types of alternative ratemaking mechanisms which would likely, or necessarily, require legislative changes to begin their use in Pennsylvania. Examples of these include LRAMs, multi-year rate plans, revenue decoupling, and demand side management performance incentive mechanisms. Without knowing what such legislative changes would require procedurally, it is likely that the implementation of any resulting mechanisms would take nine to twelve months at minimum to implement following the effective date of new legislation.

<u>Statement of Vice Chairman Place – Directed Questions for EDC Proposal</u>

Vice Chairman Place's Statement outlined an advanced rate design proposal and sought responses to certain questions from EDCs in order to evaluate the merits of Commissioner Place's proposal and how it would compare with the EDC's existing distribution rate structure. The

Companies' responses to the specific questions directed to EDCs by the Statement are outlined in the numbered questions below. In his statement, Vice Chairman Place also suggested as an alternative the use of a reliability performance-based ratemaking mechanism under which reliability results are considered for purposes of determining the rate base return on equity ("ROE") or authorized DSIC to be awarded to EDCs. In fact, the Commission already has the ability to make positive or negative adjustments to the requested ROE in distribution base rate cases as it sees appropriate to effectively incent performance. Given the way in which a DSIC is determined, the ROE set in a base distribution case will automatically also be used in the DSIC calculation for an EDC where such adjustments are made. Any further adjustments to the DSIC may run afoul of the goals of the DSIC mechanism in funding the system enhancements often needed by EDCs to be able to maintain strong reliability.

1. Provide overall supportive or critical comments on the outlined advanced rate design structure.

The general concept behind the advanced rate design proposal is reasonable, but the design does raise certain concerns. First, setting the demand charge kW billing determinants based on the coincident peak usage interval is inconsistent with traditional cost of service principles and the Companies' actual cost of serving a particular customer, as discussed in further detail in response to the following question. Another point that should be considered is the set of costs that the advanced rate design proposal has allocated to customer versus demand charges. The proposal inappropriately limits the customer charge to only those costs associated with metering and service line extensions. However, the allocation recommended by the NARUC and commonly accepted within the industry more broadly includes costs defined to be customer-related, and appropriately classified to be included in the customer charge. Specifically, in addition to metering expense, NARUC also classifies customer accounting, customer information (e.g., call center operations, etc.), administrative and general expense, and general maintenance as customer-related to be included in the calculation of the customer charge. In addition, the Commission itself established a precedent related to the treatment of customer-related costs in PPL's 2012 distribution base rate case, where a customer cost analysis was performed and adopted by the Commission to allocate the NARUC-recommended costs to the customer charge.

2. For a demand-based rate design, what system peak should be used? For example, RTO peak hours, EDC peak hours, rate class peak hours?

For purposes of allocating distribution revenue requirements to demand-based rates, the single non-coincident peak ("NCP") demand allocation method should be utilized. This method is based on the theory that distribution facilities are sized to meet the maximum demands of a customer. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are in turn designed to meet the maximum load from the distribution feeders from the substation. Further, distribution facilities must be sized to meet maximum demands that can be, and often are, imposed on them at any time of the year, not just at the time of the system coincident peak. Therefore, matching the peak capacity, represented by NCP, with the maximum load from the distribution feeders would establish a basis of proper cost causation upon which to charge customers. In the NARUC Cost Allocation Manual, it states:

> Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class noncoincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities.

The closer distribution facilities are physically located to the customer, the lower the load diversity becomes. Because of this, the use of the customer's maximum demands provides the most accurate calculation of capacity that should be allocated to the customer for ratemaking purposes. With the advent of more accurate load data that will be available to EDCs as a result of smart meter implementation, it is becoming increasingly possible to identify with reasonable accuracy the maximum non-coincident peak demands for each individual customer. Conversely, the use of system coincident demands, as suggested in the proposal, may not accurately represent the distribution capacity that is devoted to a specific customer. This may lead to under recovery of costs and misallocation of demand-based distribution costs across rate schedules.

3. How many hours should be used to calculate the demand billing determinant? Should there be periodic demand ratchets? Should this be measured, for example, over 1 hour, 5 hours, 10 hours, or perhaps 20 hours per billing period? Should the demand determinate change annually, seasonally, monthly? Should a daily hourly time range be established in which coincident peak will be measured?

For a monthly billing period, the maximum measured load in kilowatts ("kW") should be determined by metering the maximum metered kW over all of the hours within a billing month. This allows the EDC to properly allocate the amount of capacity to a specific customer for a billing month at the customer's single non-coincident peak. In each billing month, the billing kW for a customer should be equal to the greater of the maximum metered load in kW or the highest kW billing demand for the past year (or some other defined time) multiplied by a percentage. Because distribution investments are designed to meet a customer's maximum capacity, a periodic ratchet allows the EDC to recover part of that investment through the demand charge.

The demand determinant should be measured monthly, with a periodic ratchet looking back at the maximum measured demand over a defined period of time (typically at least one year and up to five years). The measured kW demand should not include a time-of-use component, because the distribution assets are sized to meet the maximum measured load rather than the measured load during a certain period of time. The Companies's rates continue to maintain an off-peak demand provision as part of the calculation of a customer's billing demand in order to minimize the impact (or grandfather) customers that have utilized this provision in the past. To provide a benefit to customers who used capacity during off-peak hours would result in intraclass subsidization by those that do not use capacity during off-peak hours. For example, if the distribution assets serving a customer are sized to meet load of 100 kW and the measurement accounts for a discounted off-peak capacity measured at 60 kW despite the maximum measurement of 100 kW, then 40 kW of capacity would not be billed, resulting in an undercollection of demand revenues that would ultimately be paid for by non-off peak customers. This outcome would create a subsidization that runs counter to traditional cost of service principles.

4. How should peak demand be measured? Should each measurement be based, for example, on a 15 minute, 30 minute, or 1 hour period?

In general, the Companies measure demand at fifteen minute intervals, with some rate schedules measured at thirty minutes.[9] The use of fifteen minute intervals would account for most intermittent usage within an hour, thereby providing a more accurate determination of kW demand than less granular measurements allow.

5. Should tiered demand rates be used?

No. Declining block or tier demand rates provide disincentives to conserve energy and have historically been discouraged by the Commission for that reason.

6. What costs should be recovered under the coincident demand charge? Which cost "bucket" should information systems, billing systems, customer service systems, customer service costs, operational expenses, or other costs (please specify) be allocated under such a new rate design?

The cost of information, billing, and customer service systems should be allocated to the customer charge because these costs are generally incurred by the utility on a per customer basis. Conversely, most operating expenses are fixed and are based on the size of an EDC's distribution system, and should therefore be classified as demand-related. For example, costs that would be

[9] Differences in the Companies' applied measurements are primarily a function of legacy tariff provisions and metering equipment which has restricted a wholesale change to their measurement criteria.

considered demand-related would include such costs as operation dispatch and substation operation and maintenance expense. Most costs of an EDC could be separated into two categories based upon this general theory of cost-causation.

7. What other "rate gradualism" mechanism should be employed?

The rate gradualism suggested in Commissioner Place's statement is sufficient to allow for the impact to residential customers, including low-income customers, to be scaled in a manageable way over time. Any additional gradualism measures would unnecessarily delay the implementation of this type of rate design.

8. What revenue streams should be excluded (e.g. § 1307 automatic adjustment revenues)?

The overall advanced rate design should include all distribution-related revenues, but exclude any § 1307 automatic adjustment rider revenues. Those riders are established and should not be part of the revenue allocation process of this advanced rate design.

9. While large customers generally have demand-based non-coincident peak charges, should large customer demand charges be modified to incorporate coincident peak-based charges?

No. Demand charges and associated billing determinants are established to account for an industrial customer's distribution system investment at the maximum measured kW load. To calculate rates based on other criteria would create an under recovery of investment and could eventually lead to intra-class or inter-class cross subsidization.

10. What would the range of cost impacts be, if any, for low income customers? Under a given model, what modifications should be considered to Low-Income/Customer Assistance Program participants to maintain affordability and ratepayer equity?

Because distribution charges represent only approximately one-third of a customer's total bill, the impact of imposing more fixed or demand-based charges is expected to have a minimal impact to all customers, including those who are considered low income or income-challenged.

Even so, one effective tool available to the Commission in mitigating the impact of any rate mechanism, regardless of type, is changing or increasing the maximum CAP credit that is established as part of an EDC's universal service plans to allow low income customers to better adapt to a new rate design. Such an approach must be implanted, however, by striking an appropriate balance to ensure that while low income customer bills maintain a level of affordability, such efforts do not inadvertently distort cost allocation amongst rate classes, creating unintended subsidies.

11. What type of consumer education programs should be provided to customers when implementing alternative ratemaking methodologies?

When any alternative ratemaking methodology is implemented, consumer education should be targeted to affected customers identifying the changes that are being made to their rates, why it is being made, and potential tools available to the customer to help them understand how their usage behavior affects their rates under the new methodology so that they are able to best mitigate the impact of these behaviors on the customer's bill. Of course, the specific message to customers would need to be tailored to the type of alternative methodology implemented.

III. CONCLUSION

Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company appreciate the opportunity to provide comments in response to the Commission's Tentative Order dated March 2, 2017 and the associated statements issued contemporaneously with its adoption. The Companies are not opposed to alternative ratemaking methodologies. However, the specific details associated with each alternate methodology must be studied carefully to ensure that, as the Commission has already pointed out, the methodology employed meets the standards set forth in existing statute and regulation. The

Companies look forward to continued collaboration with the Commission and interested stakeholders on this very important topic.

Respectfully submitted,

Dated: May 31, 2017

Tori L. Giesler /dm

Tori L. Giesler
Attorney No. 207742
FirstEnergy Service Company
2800 Pottsville Pike
P.O. Box 16001
Reading, PA 19612-6001
Phone: (610) 921-6658
Fax: (330) 315-9263
Email: tgiesler@firstenergycorp.com

Counsel for:
Metropolitan Edison Company,
Pennsylvania Electric Company,
Pennsylvania Power Company and
West Penn Power Company

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Alternative Ratemaking Methodologies : Docket No. M-2015-2518883

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a true and correct copy of the foregoing document upon the individuals listed below, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

Service by first class mail, as follows:

John R. Evans
Office of Small Business Advocate
Suite 1102, Commerce Building
300 North Second Street
Harrisburg, PA 17101

Tanya J. McCloskey
Office of Consumer Advocate
555 Walnut Street, 5th Floor Forum Place
Harrisburg, PA 17101

Richard Kanaskie
Bureau of Investigation and Enforcement
Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105-3265

Dated: May 31, 2017

Tori L. Giesler/dm

Tori L. Giesler
Attorney No. 207742
FirstEnergy Service Company
2800 Pottsville Pike
P.O. Box 16001
Reading, Pennsylvania 19612-6001
(610) 921-6658
tgiesler@firstenergycorp.com