AEE INSTITUTE

October 22, 2018

VIA ELECTRONIC FILING

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

Re: Docket M-2015-2518883, En Banc Hearing Re Alternative Ratemaking Methodologies

Dear Secretary Chiavetta:

In the above-referenced alternative ratemaking docket ("Docket"), Advanced Energy Economy Institute (AEE Institute) respectfully submits these comments in response to the Commission's May 3, 2018, *Proposed Policy Statement Order* on Fixed Utility Distribution Rates. These comments also respond to the Commission's August 14, 2018, order extending the time to file comments. In particular, in its August 14 order, the Commission agreed with AEE Institute and other parties that the passage of Act 58 earlier this year, which concerns the ability of regulated utilities to file alternative ratemaking proposals, has important implications for the Proposed Policy Statement Order, and more generally for the broader investigation of the Commission in the above-referenced Docket.

As such, these comments are divided into two parts. First, we provide specific feedback on the Proposed Policy Statement, which concerns the issue of rate design. We also offer as part of that, comments on rate design issues as they relate to electric vehicle charging. Second, we provide some general comments on the related issue of alternative ratemaking. In particular, we strongly encourage the Commission to use this Docket to develop and issue guidance to utilities on the types of alternative ratemaking proposals that the Commission would like to see the utilities put forward. While Act 58 appears to put the onus on utilities to come forward with alternative ratemaking proposals, we believe that the Commonwealth will be better served if the Commission can put forth guidelines on the types of proposals it would like to see - guidelines that are consistent with the state's policy objectives and with the goals of the Commission.

Given the extensive record on these and related issues in this Docket, AEE Institute believes that it remains the best venue for the Commission to address implementation of Act 58 and to articulate its policy goals in greater detail. We also note that it is common practice for commissions to provide guidance to utilities under their regulatory purview, especially on new issues. This can provide for a more consistent market evolution within a jurisdiction, which can help lower costs and provide larger, more predictable markets for companies and result in greater access for customers to products and services. While waiting for individual utilities to file rate cases is another option, we assert that a more proactive approach by the Commission will allow for a broader range of stakeholders to provide meaningful input that will help surface the best ideas and foster a collaborative environment that will ultimately benefit customers.

In opening this Docket, the Commission recognized that the utility business model is evolving, and we commend the Commission for continuing this investigation. We view the issuance of guidance to utilities on ratemaking and rate design and the natural next step after investigating the issues, and one that can be beneficial prior to utilities making specific proposals in general rate cases. To that end, we provide some recommendations below on alternative ratemaking concepts that we believe will serve the Commonwealth.

Respectfully Submitted,

Ryan Katofsky

Vice President, Industry Analysis

Ratemaking vs. Rate Design

We view ratemaking and rate design as distinct but related concepts. We use the term ratemaking to describe the process for deciding a utility's revenue requirement while we use rate design to describe the methods by which the revenue requirement is collected from customers (i.e., tariffs). The role of ratemaking and rate design is significantly more important than merely deciding how much revenue should be collected and in what way. Rate design is widely understood as the method by which customers receive signals to manage consumption and behavior in beneficial ways, but likewise ratemaking, the construction of the revenue requirement, is an important way to send signals to utilities and influence their behavior and decision-making.

Both ratemaking and rate design will incent utilities and customers to engage in certain behaviors, regardless of whether those incentives were purposeful and intentional. We support the Commission's effort to re-evaluate these embedded incentives and investigate whether they support behavior on the part of both utilities and customers that is consistent with providing a low cost, reliable, and low emissions electricity system, particularly in light of the technology and market changes that have been recognized by the Legislature in Act 58 and by the Commission in this Docket. Given the complexity and expansiveness of both ratemaking and rate design, we have decided to focus mainly on rate design in these comments, since the majority of the Proposed Policy Statement is focused on rate design topics. However, we also believe that re-evaluating ratemaking and the utility business model is equally as important and is a substantial topic that deserves its own focus and opportunity for stakeholder engagement.

While separate consideration of ratemaking and rate design is warranted given the breadth of each topic, identifying the linkages between each topic can result in better coordinated policy and outcomes. The Proposed Policy Statement already identifies revenue decoupling as one of these linkages, which mitigates the risk to a utility's full recovery of its revenue requirement when rate design encourages conservation. In addition to revenue recovery, the Commission should also consider how rate design can impact utility earnings. For example, if a rate design is successful at driving down consumption at peak, new capacity additions can be avoided. This represents a loss of an investment opportunity for the utility and associated return on that capital investment. This opportunity cost to the utility may stand in the way of successful implementation of more advanced rate designs which target peak demand reductions. In order to have a utility that is motivated to recruit and educate customers about more advanced rates that promote efficient usage and other benefits, utilities may need performance incentives that counterbalance the opportunity cost embedded in cost of service ratemaking.

Rate Design Considerations

We largely support, with a few exceptions, the proposed list of Distribution Rate Considerations (§69.3302 of the Proposed Policy Statement). While each principle may have individual merit, when combined, they may not all be simultaneously achievable, or at least, some trade-offs will need to be made. It will be necessary to prioritize based on the Commission's policy priorities, and preference some principles over others where there are conflicts. Thus, to the extent that the Commission can articulate what its policy priorities are, it will likely receive rate design proposals that are more in line with its priorities. Below we have some recommendations on prioritization.

Consideration 1: "(1) How the rates align revenues with cost causation principles as to both fixed and variable costs."

AEE Institute agrees with a focus on cost causation principles, however, we suggest that the principle should focus on encouraging appropriate customer behavior rather than focus on utility revenues. Regulated utilities should always have the opportunity to recover their revenue requirements, subject to established regulatory review processes as to prudency, and there are multiple avenues of affording them the opportunity to do so, such as revenue decoupling. Rates can be designed in multiple ways while ensuring that the revenue requirement is recovered. Instead, rate design should focus on customer charges, and how those customer charges encourage beneficial customer behavior. Customers should be encouraged to consume power in ways that avoid creating new system costs, which will over time hold down the growth of a utility's revenue requirement.

We are also concerned that the way the first principle is written implies that cost causation principles should only be considered in determining the breakdown in sources of revenue so that charges are aligned with fixed and variable costs. Cost causation principles have much broader applicability and should be focused on creating tariffs that encourage efficient customer usage that minimizes fixed and variable costs. Cost causation principles should be applied broadly, and we have recommended a change that should allow their broader application.

Recommended change: "(1) How the rates align ~~revenues~~ **charges** with cost causation principles **and encourage efficient customer usage that minimizes both fixed and variable costs** ~~as to both fixed and variable costs.~~"

Consideration 2: "(2) How the rates impact the fixed utility's capacity utilization."

AEE Institute believes that focusing on capacity utilization may not actually achieve the Commission's goals. Capacity utilization is a composite metric that describes average demand relative to peak demand and can be improved in a number of different ways, some of which may not actually be beneficial to the system or customers.

Current distribution capacity is a result of past investments which need to be paid for, regardless of whether they are fully utilized. Ideally, investments are right-sized to meet customer demand before they are made, but once they are made, no savings result from utilizing more of the available capacity.

Arguments are often made that increasing capacity utilization through "valley filling" is a benefit because higher energy sales will spread the burden of sunk costs across more kilowatt-hours, lowering the distribution rate for each kilowatt-hour. While it is true that the distribution rate is lowered, the same amount of revenue still needs to be collected across all customers, and whether or not an individual customer saves is dependent on their own usage patterns. In addition to resulting in no distribution savings to customers overall, the increased distribution sales can only come with increased supply charges, resulting in higher total bills for customers.

With that said, organic and economically beneficial energy growth at off-peak times can be beneficial in its own right (e.g., greater economic activity, fuel switching, or EV charging), and can also be a benefit to existing customers. While total distribution costs are not lowered, they are *reallocated* to the new consumption, lowering costs for existing consumption. Any new consumption should only take place when it is needed for economically beneficial purposes. Conversely, valley filling that is pursued merely to improve capacity utilization will result in larger total bills due to higher supply charges and reduced customer benefits.

For this reason, we recommend that the Commission focus on peak demand reduction and relieving system constraints, instead of capacity utilization. All of the benefits that can be achieved through better capacity utilization can be better achieved through peak demand reduction while avoiding counterproductive methods for increasing capacity utilization. Instead of encouraging potentially counterproductive "valley filling," a focus on peak demand reduction can help shift growth in consumption that occurs naturally to off peak hours. This avoids creating new distribution peaks and associated distribution cost and also results in lower distribution rates for customers when consumption grows or is shifted off-peak.

With that said, efforts to address peak demand should not reduce overall efforts to promote energy efficiency (Factors 5 and 6 in the Proposed Policy Statement).[1] To the extent that energy efficiency measures can help reduce congestion and peak demand, then the two objectives are aligned. But increased

[1] See §69.3302 of the Proposed Policy Statement; Annex A at page 1.

energy efficiency during valleys should also be encouraged as it results in reductions in emissions and customer energy bill savings.

Recommended Change: "(2) How the rates impact the fixed utility's ~~capacity utilization~~ **peak demand**."

Consideration 3: "(3) Whether the rates reflect the level of demand associated with the customer's anticipated consumption levels."

AEE Institute believes that design consideration #3 regarding customer demand is unnecessary if there is already a principle on cost causation. Aligning a customer's charges with their demand is one way of incorporating cost causation into rate design, but it is not the only method. Additionally, a customer's individual, non-coincident demand is not the only measure of system costs, nor may it be the most accurate. A customer's usage during distribution, transmission, and generation peaks is often a greater driver of system costs than the customer's highest non-coincident demand, and so rates that minimize usage coincident with the network/system peaks may have better alignment with cost causation. This principle is too prescriptive on how cost causation principles should be implemented, and instead the principles should retain their focus on the primary goal, alignment with cost causation.

Recommended deletion: "~~(3) Whether the rates reflect the level of demand associated with the customer's anticipated consumption levels.~~"

Considerations 5 and 6: "(5) How the rates limit or eliminate disincentives for the promotion of efficiency programs. (6) How the rates impact customer incentives to employ efficiency measures and distributed energy resources."

As the Commission recognized in its Proposed Policy Statement Order, rate design has important implications for the adoption of distributed energy resources.[2] As we discuss below in the section on ratemaking, it is important to align the financial interests of the utility with customer benefits and policy objectives. DER deployment by customers and third parties is an important aspect of this, and rate design for DER will play an important role in either encouraging or erecting barriers to DER deployment. Moreover, rate design can be used to encourage DER deployment that provides not only benefits to participating customers, but to the system as a whole. This goes beyond simply "limiting or eliminating disincentives". Advanced Energy Economy's issue brief on rate design provides a comprehensive look at rate designs for a DER future.[3]

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[2] We define DER broadly to include distributed generation of all types, energy efficiency, demand response, energy storage, electric vehicles, and microgrids. DER thus includes options for both generating and managing energy use.
[3] Available for download at https://info.aee.net/21ces-issue-briefs.

Recommended change: "(5) How the rates limit or eliminate **current** disincentives **and provide incentives** for the promotion of efficiency programs."

Consideration 13: "(13) Whether the alternative rate mechanism is understandable and acceptable to consumers and comports with Pennsylvania law."

This consideration addresses an important concept—that a rate should be understandable and acceptable to customers—however, designing an understandable rate is necessary but not sufficient to achieve greater customer benefits from rate design reform. Significant customer outreach and education, accompanied by tools they can use to act on the information, is required for customers to understand rate design changes and to know how to respond to them. Absent this education, most customers will not know that a change took place, will not understand the changes that took place, and will be unable to change their behavior to take advantage of new rates. As a result, potential benefits to customers and the utility system will be left on the table.

Experience from around the country has shown that robust outreach efforts are necessary to achieve meaningful levels of participation in voluntary time-varying rates. And regardless of whether a rate is voluntary or mandatory, education is necessary for customer response.

In order for a new rate design to be effective at saving customers money and decreasing system costs, we recommend adding an additional paragraph that focuses on customer outreach and education. We recommend that this be added as item (c) in §69.3302 of the Proposed Policy Statement, as follows:

(c) In any distribution rate filing by a fixed utility under 66 Pa. C.S. § 1308, the fixed utility shall include a customer outreach and education plan that the Commission, following a review and opportunity for stakeholder input, deems is sufficient to encourage high levels of customer participation and beneficial changes in usage patterns among participating customers.

Rate Design for Electric Vehicles

As the Commission continues to develop general principles for rate design, we recommend that it also consider issues that affect the emerging transportation electrification opportunity. The greatest benefits from plug-in electric vehicle (PEV) deployment will be achieved if charging is done in such a way as to minimize the need for building additional infrastructure, including generation, transmission, and distribution. It is important that utilities implement well-designed rates for PEV charging before adoption is too high because studies have shown that consumers are creatures of habit. San Diego Gas & Electric conducted a multi-year PEV pricing and technology study that concluded there is a learning curve for PEV customers on new rates and that in order to optimize charging, utilities should develop well-designed tariffs before customers adopt poor charging habits.[4] Moreover, if done right and as noted above, the additional load from PEV charging can improve the utilization of existing utility assets and drive down rates for all customers. These benefits can be achieved by incenting charging behaviors by addressing a few areas of rate design as outlined below.

PEV-only tariffs

In general, rate designs should align with utility cost causation, incent charging behaviors that optimize the use of the grid, and ensure that customers have the ability to manage their energy usage and energy costs. Rates for PEV charging should also align with cost causation but should be available as "PEV-only" tariffs. This means that the tariffs can be applied to the PEV load only, as opposed to the whole home or business. This is important, because many PEV owners like time-varying rates for their PEVs but do not want the rates for their entire home.

One mechanism for moving in this direction is establishing PEV-only rates that can be implemented by installing a second utility meter or by utilizing a billing-quality sub-meter built into the electric vehicle supply equipment (EVSE). While the accuracy of the sub-meters needs to be ensured, the latter approach can be significantly less expensive as demonstrated through San Diego Gas & Electric's (SDG&E) program.[5] Importantly, national standards for such sub-metering already exist, including the NIST PC-44 standard.[6]

As of 2017, over 25 utilities offered PEV tariffs; most of them incent charging during off-peak hours, with rate reductions of up to 95%.[7] Over time tariffs that rely on on-/off-peak hours should be revisited regularly as the power production profile of the grid changes. For example, in some regions, PEV tariff design is likely to change with an increase in solar power penetration, allowing for lower rates during midday hours that coincide with peak solar production. In this case, PEV loads become valuable in that they provide demand for renewable energy that might otherwise be curtailed.

It should be noted that the design of PEV-only rates will differ by sector. A rate design that may work for home chargers may not be suitable for public charging or fleet infrastructure. For example, customers who primarily rely on home chargers or workplace chargers have a greater ability to manage their charging because their cars will usually be sitting idle for a longer period of time and are therefore more likely to be responsive to rates that vary throughout the day. On the other hand, customers charging

[4] https://www.sdge.com/sites/default/files/SDGE%20EV%20%20Pricing%20%26%20Tech%20Study.pdf
[5] https://www.sdge.com/residential/electric-vehicles/choosing-rate
[6] https://www.nist.gov/pml/weights-and-measures/nist-handbook-44-2018-current-edition
[7] https://about.bnef.com/blog/u-s-utilities-offer-multiple-electric-car-charging-rates/

at a public DCFC have a much smaller window during which to charge and therefore less ability to adjust their charging habits in response to price signals.

Time-varying rates

A key aspect of helping to align charging behavior with system needs is offering appropriately designed, optional time-varying rates (TVR). Well-designed TVR can encourage charging during off-peak hours (even if not a PEV-specific rate), aid with grid reliability, and prevent expensive transmission and distribution upgrades, which will benefit all utility customers. TVR encompasses a range of tariff design options, from simple time-of-use (TOU) rates with predefined peak and off-peak periods, to fully dynamic pricing, where rates vary by the hour (or more frequently) based on the actual market price for electricity. Dynamic rates based on day-ahead price forecasts are another option that can provide customers information in advance, allowing them to plan around times of high pricing.

Research has shown that TVRs are effective at changing charging behavior and can provide significant ratepayer benefits. An Idaho National Laboratory study found that 78% to 85% of owners on a PEV-specific TOU rate set their car to charge during off peak hours (usually in the middle of the night).[8] TOU rates have also been shown to save PEV customers and all ratepayers money. A study of the top five cities for PEV sales in the United States (Los Angeles, San Francisco, Atlanta, San Diego, and Portland, Oregon) found that TOU PEV rates saved PEV customers between $116 and $237 per year.[9] Another analysis concluded that PEV TOU rates would save California customers $1.2 billion compared to a traditional flat-rate from 2015 to 2030.[10]

Given their effectiveness in managing PEV charging, the Commission should pursue well-designed TOU rates for residential, workplace, and fleet charging and explore more granular TVR options over time that include dynamic pricing elements. When coupled with smart, networked EVSE, TOU rates allow customers to respond automatically via pre-defined “set it and forget it” preferences. These capabilities may also facilitate an eventual move to bi-directional flow of electricity where PEVs could export electricity to the grid at times when it is most valuable to the electricity system.

In terms of specific design considerations, research shows that larger differentials between on-peak and off-peak rates, increase the likelihood of changing customer charging habits. A recent study by The PEV

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[8] https://pluginamerica.org/wp-content/uploads/2017/03/PIA-Incentive-Survey-Paper-Final-Oct.-2016.pdf
[9] http://www.raponline.org/wp-content/uploads/2017/06/RAP-regulatory-considerations-transportation-electrification-2017-may.pdf
[10] http://www.raponline.org/wp-content/uploads/2017/06/RAP-regulatory-considerations-transportation-electrification-2017-may.pdf

Project and SDG&E found that a 2:1 price ratio between the peak and off-peak shifted 78% of charging to the off-peak period and a 6:1 price ratio shifted 85% to the off-peak period.[11]

Some utilities have also implemented more sophisticated real-time pricing (RTP) rates – prices that vary by the hour as determined by day-ahead market prices or real-time spot market prices for electricity. For example, a study of an hourly PEV charging program offered by Commonwealth Edison in Illinois found that participants reduced their energy supply costs by 45% when compared with a standard rate and 38% when compared with a TOU rate.[12] In a pilot in Washington D.C., low-income customers also achieved bill savings on RTP, with satisfaction levels of approximately 90%.[13] RTP has proven to be effective, compared to other, simpler TVRs, and smart, networked EVSE allows even the average customer to respond to such price signals easily and automatically.

Demand charges

Demand charges, which usually apply to large commercial and industrial (C&I) customers (but not residential and small commercial customers, so-called "mass-market" customers), are an important consideration when it comes to PEV rate design (as well as for other types of DERs). Demand charges are based on the highest level of electricity usage on a per kW basis for a certain time period (typically the highest 15 minutes) during each billing cycle. Generally speaking, demand charges are intended to better align revenue collection with utility costs, because the electricity system is designed, built, and maintained to meet peak demands at the customer, local, and wholesale system levels. Demand charges provide a price signal to incentivize customers to adjust their usage decisions to account for their impacts on the grid.

Demand charges for mass-market customers can be problematic for a variety of reasons (and not just for customers with PEVs). Instead, time varying rates can accomplish similar objectives for these customers. However, for EVSE that, based on its electricity load (e.g., public DC fast charging stations), would be subject to rates with demand charges, depending on its design and magnitude, a demand charge can significantly undermine the economics of PEV and charging station ownership, as we describe below.

Although demand charges are common for large C&I customers, which often have the tools for managing them, they present some unique challenges when it comes to PEVs, especially for charging station owners and operators. Demand charges, which can account for over 90% of a public charging station's electricity costs, can significantly increase costs for companies trying to establish PEV charging

[11] https://www.rmi.org/wp-content/uploads/2017/10/RMI-From-Gas-To-Grid.pdf
[12] http://www.elevateenergy.org/wp/wp-content/uploads/Hourly-Pricing-and-EVs-050714.pdf
[13] https://www.energy.gov/oe/downloads/powercentsdc-program-final-report

businesses.[14] The impact is especially pronounced at the current, early stages of PEV adoption when EVSE utilization rates (i.e., the time spent charging as a percentage of total time in a day) are quite low for public applications. As a result, demand charges translate into very high average per kWh rates and can stifle infrastructure investment, which is already lagging PEV deployment in many parts of the country and suppressing PEV adoption.

While there are tools like smart charging and energy storage available to help mitigate some of these costs (discussed more below), at this stage of the market's development in 2018, it is important to reduce the burden of demand charges on public charging retail accounts in the near-term, especially DCFC, and to evaluate appropriate rate design for public chargers in the long-term.

With respect to what types of installations should be eligible for demand charge relief, the Commission should distinguish between public charging-dedicated retail accounts (i.e., PEV-only applications) and accounts where public charging demand is combined with the overall demand of the customer premises. Balancing general rate design principles with the needs of the nascent PEV industry, it is reasonable to grant relief for PEV-only retail accounts, while the applicability of such relief to standard retail accounts with behind-the-meter public charging is unclear.

Several utilities have begun experimenting with alternative demand charge approaches. The programs and proposals identified in the box below provide some examples of demand charge relief that are being explored.

- In April 2017, PacifiCorp in Oregon received approval in their transportation electrification proposal to implement a transitional demand charge approach for DCFC.[15] The tariff offers an initial 100% discount on demand charges that steps down to 0% by the end of the 10-year program to reduce barriers to DCFC deployment.
- Southern California Edison, in their 2017 transportation electrification program, implemented a moratorium on demand charges for their commercial rate program for the first five years, with a subsequent five-year phase-back. The demand charge at the end of the ten-year period will only be 60% of the current demand charge.[16]

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[14] https://d231jw5ce53gcq.cloudfront.net/wp-content/uploads/2017/04/eLab_EVgo_Fleet_and_Tariff_Analysis_2017.pdf
[15] Docket UM 1810. http://apps.puc.state.or.us/edockets/docket.asp?DocketID=20572
[16] Application 17-01-021. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M215/K380/215380424.PDF

- In June 2014, Connecticut's Public Utilities Regulatory Authority approved a five-year PEV rate rider pilot for Connecticut Light & Power that replaces a demand charge with a higher per kWh charge.[17]
- In July 2013, the Hawaiian Electric Co.'s received approval to implement a five-year PEV charging pilot, Schedule EV-F, where the demand charge is replaced with a higher TOU per kWh charge.[18]
- In April 2018, the New York Power Authority proposed to move DCFCs to rates without demand charges in the short-term and requested a longer-term plan for DCFC rate modifications that align with their low load factors and sporadic usage.[19]

Role of technology in PEV rate design

Smart EVSE & Sub-metering: One element of tariff design that can facilitate PEV adoption is allowing for the use of two meters - one for the premise at which the EVSE is located and a separate meter for the EVSE – each with its own tariff. This approach enhances the ability of utilities and regulators to address PEVs via the types of PEV-only tariffs described above. Sub-metering to allow for separate treatment and billing can be achieved through the installation of a separate meter as part of the EVSE service upgrade and installation or through the built-in meter in a smart, networked EVSE charger, which is the method that SDG&E's effort is utilizing in its aforementioned pilot. The cost of a separate meter installed in front of the charger ranges between $500 and $1,500 (all in) as of 2018, while meters built into smart, networked EVSE can reduce that cost to less than $50 for volume deployment. In order for the utility to apply separate tariffs through the separate meter, three technological capabilities are necessary:

- The reading of the EVSE and premise meters must be synchronized,
- All of the meter data must be delivered to the utility's software system, and
- The meter readings must be disaggregated from the premise consumption for billing purposes.

As discussed previously, the use of smart, networked EVSE, which can support billing with embedded sub-meters, also provides a technological platform to support a variety of advanced rate structures, and managed charging programs and functionality. Deploying managed charging technology-

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[17] Docket 13-12-11. http://www.dpuc.state.ct.us/dockhistpost2000.nsf/8e6fc37a54110e3e852576190052b64d/0fdcd8bddffdbfdc8525829c0073540c/$FILE/FINAL131211.docx
[18] http://energy.hawaii.gov/hawaiian-electric-companies-offer-new-rates-for-public-ev-charging
[19] Docket 18-E-0239. http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=56376&MNO=18-00932

enabled EVSE is therefore a key consideration and program design element to maximize the benefits of transportation electrification.

Metering requirements should not be used as a reason to slow down the adoption of PEV-only rates and therefore should be optional. Other programs can also be developed that allow customers to earn rewards for optimal charging behavior (e.g., charging during off-peak hours) in the absence of a separate meter for billing purposes. For example, Con Edison's Smart Charge New York program offers participants a module that plugs into the PEV's diagnostic port that provides valuable information to the driver via an online portal, including battery health and driving efficiency.[20] The module also tracks charging behavior – and this data can be sent to the utility for verification and rewards.

DERs, especially energy storage, are also an option (instead of, or in addition to, altering rate design), either behind the meter to mitigate demand charges, or in front of the meter to help integrate charging station load. Onsite energy storage at public charging stations, particularly DCFC, would allow EVSE operators to ensure a consistent charging price for customers and help to reduce peak loads as seen by the utility. Onsite distributed generation coupled with storage would have the added benefit of ensuring power availability even during grid-wide power outages.[21]

As noted previously, managed charging with smart, networked EVSE can enable a PEV to act as a DER, and aggregated managed charging can be a resource for grid operators. In the California market, such aggregated PEV charging is already providing peak load reduction services.[22]

Alternative Ratemaking Considerations

As we described earlier, ratemaking and determining the amount of revenue and earnings to be collected through rates is a separate question from rate design and how revenue is collected within rates. Ratemaking and how the revenue requirement is determined provides financial signals to the utility to act in certain ways while rate design and how the revenue is collected sends signals to customers. In our comments filed in docket M-2018-3003269, *Implementation of Act 58 of Alternative Ratemaking for Utilities,* we noted that the growth of DER markets, as well as other technology changes, such as grid modernization, have important implications for the types of alternative ratemaking mechanisms utilities may file, as well

[20] https://www.coned.com/en/save-money/rebates-incentives-tax-credits/rebates-incentives-tax-credits-for-residential-customers/electric-vehicle-rewards
[21] https://www.cleanegroup.org/wp-content/uploads/Jump-Start-Energy-Storage.pdf
[22] https://emotorwerks.com/about/enewsso/press-releases/269-emwdram

as the types of utility investments that will be made under any future rate plans approved by the Commission. Utilities should make investments and take actions that facilitate customer use of DERs that benefit not only those customers but the system as a whole. Thus, ratemaking mechanisms should align utility financial incentives with customer benefits and customer opportunities to manage their energy usage, energy costs, and energy sources. Moreover, utilities should be making investments consistent with the evolving nature of the grid, and the regulatory framework should support such forward-looking efforts. Also, ratemaking mechanisms should recognize that some distribution utility functions that have traditionally been met by utilities investing capital in their own assets and systems can increasingly be cost-effectively met by utilities procuring services.

Utilities should be encouraged to explore the full range of regulatory options that can further align their financial interests with the interests of their customers and with state policy objectives, such as economic growth, while making the most out of the technology and service innovations coming from the advanced energy industry. Below we offer some recommendations on these types of ratemaking mechanisms, many of which were included in the Commission's Discussion section within the Proposed Policy Statement Order.

Revenue Decoupling

AEE Institute supports the use of revenue decoupling as a foundational element of modern ratemaking. Revenue decoupling is an important way to remove financial disincentives -- lost revenue from erosion in unit (kWh or other) sales. However, removing disincentives from lost throughput does not leave the utility entirely neutral if reduced throughput puts the primary utility earning opportunity (i.e., return on capital expenditures) at risk since energy efficiency is effective at reducing peak demand and future investments that would be needed to serve it. More plainly, revenue decoupling removes the threat of lowered revenue in the near term, but puts future earnings at risk by potentially lowering future capital investment requirements. Thus, while revenue decoupling is a valuable and worthwhile ratemaking change, is should be viewed as a first step toward more comprehensive regulatory reforms, as discussed below.

Performance Incentive Mechanisms (PIMs) and Performance-Based Regulation (PBR)

AEE Institute has filed comments previously in this Docket on PIMs and PBR and has previously published a white paper on PBR in the Pennsylvania context.[23] Rather than review those extensive comments here, we simply note that PIMs and PBR, along with multi-year rate plans, can further align the financial interests of utilities with desired policy outcomes and customer benefits. In particular, as customers continue to adopt DER, PIMs and PBR can reward utilities for helping customers and their designated third-party providers deploy DER in a way that benefits not just those customers but the system as a whole. To the extent that this changes—and potentially decreases—future utility capital investment, PIMs and PBR offer an important complement to revenue decoupling that can incent desirable utility activities. Examples of PIMs that the Commission could consider include:

- Safety & Reliability: SAIDI, SAIFI, or other reliability indices, if not already subject to performance requirements.
- Data access: Consumer access to standardized and actionable energy consumption data; third-party access to system data.
- Energy efficiency: Quantifiable reductions in total electricity usage, in particular, reductions above any baselines that the utility is subject to.
- Peak load reduction: Targeted demand reductions during peak periods – a primary driver of utility costs.
- Third-party resource deployment: DER deployments by third parties (including on behalf of customers) and/or the effectiveness of the utility at optimizing the use of third-party DER.
- Interconnection: Volume and processing speed of filling requests to connect resources to the electricity system.

When considering PBR, the Commission should consider various complementary policies that can make PBR more effective:

- Revenue decoupling, which removes the disincentive for utilities to reduce volumetric sales.
- Multi-year forward looking rate plans, in which base rates are set based on an approved multi-year investment plan but are reconciled annually with actual investment.
- Comprehensive benefit-cost analysis, which is used as a basis for developing multi-year rate plans, and which considers societal benefits.

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[23] *Performance-Based Regulation for Pennsylvania: An Opportunity for Pennsylvania to Drive Innovation in the Utility Sector*, Advanced Energy Economy Institute. Filed in PA PUC Docket M-2015-2518883 on May 31, 2017.

Shared Savings Arrangements

If utilities implement solutions that that result in lower usage and demand, customer savings, and other desired outcomes, this may lead to lower utility revenue and earnings opportunities. This can occur, for example, when utilities help customers deploy DER, whether via programs or targeted solicitations, as with non-wires solutions projects. Shared savings mechanisms can counteract this disincentive. For example, with energy efficiency, when a utility-run program helps a customer reduce his/her energy consumption and demand, many of the benefits will flow to the customer. Some of these benefits may be based upon the indirect impact of energy efficiency on wholesale energy and capacity market prices, and others based upon incremental savings resulting from benefits at the distribution system level seen by the utility (such as deferred or avoided investment). Allocating some of the benefits to the utility via a shared savings model can better align the interests of the utility with the customer and with the state's goals. However, developing a robust, transparent methodology for determining the savings to be shared is important for this to work.

Optimizing between Capital Expenditures and Certain Service Expenses

Throughout the economy, companies are finding efficiencies and operational benefits by meeting their needs through services provided by third parties rather than investing in physical assets that they own and manage. Utilities are no different. However, the trend toward services has faced some unique barriers in the investor-owned utility industry, as utilities have an issue in their underlying business model, imposed by regulation, that most other businesses do not.

In the current cost-of-service regulatory model, capital investments are a large driver of returns to utility shareholders. In contrast, operating costs (such as fuel, labor, maintenance, and service expenses) are generally passed through to customers in electric rates without the utility making any direct profits on them, although utilities remain incented to manage operating costs to reduce overall cost to customers, and also to manage profits between regulatory rate reviews.

Over the long term, however, services that can improve the utilization of, defer, or replace capital investments may have the effect of reducing opportunities for utilities to generate earnings. Because many new technologies are offered only as a service, utilities may be discouraged from using them. Realizing that both customers and utilities stand to benefit from equalizing the earnings opportunities between traditional capital solutions and service solutions that reduce capital investment needs, several state commissions have explored or implemented mechanisms to compensate for the bias toward capital investments that is inherent in cost-of-service regulation.[24]

Some of these mechanisms, such as capitalization of a service contract or the use of regulatory assets, are often used today without any changes in regulation. These mechanisms allow utilities to place "service assets" in the rate base and amortize them like capital investments. Other possible regulatory mechanisms could provide additional motivation, such as allowing the utility to retain a share of the cost savings from service-based solutions.

Cloud computing is a prime example of a service that could benefit from these types of regulatory treatment. For decades, utilities have deployed their own IT resources and servers, purchased software, and hired staff to manage and operate the systems. This requires a significant investment in onsite computing capacity and internal staff development to make all of the resources function properly. If the utility were to purchase cloud computing services, with all of the security and IT infrastructure supplied by the service provider and its own network of partners and vendors, the utility could leverage the specialization and expertise of the provider and benefit from cost efficiencies through use of shared infrastructure (the provider's data center). Cloud computing also allows utilities to scale capacity up or down on demand, providing much greater flexibility than a system that is owned and operated by the utility. Making use of cloud computing also ensures that the systems are always up to date, will not become obsolete, and are easier to keep secure. However, for regulated utilities, if cloud computing is treated as a service expense, it replaces an earnings opportunity – the capital expenses related to IT infrastructure and software upon which a utility can earn its regulated rate of return – with a service expense that earns the utility no return.

These principles that apply to cloud computing – scalability, flexibility, security, resource efficiency – often apply to other parts of the utility business. Various forms of non-wires alternatives (NWAs) rely on services - often provided by customer- or third-party-owned DER - that, in many cases, can effectively replace utility capital expenditures.

AEE Institute has published an in-depth paper on these and other mechanisms that models their impact on customers and utilities.[25]

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[24] National Association of Regulatory Utility Commissioner's Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements, adopted November 16, 2016. See: https://pubs.naruc.org/pub.cfm?id=2E54C6FF-FEE9-5368-21AB-638C00554476

Visibility at the "grid edge"

With respect to both rate design and ratemaking, there is a greater need for the utility to improve its visibility as to what is happening at the "grid edge". As more DER is adopted, if the utility cannot understand how they are performing or know where they are, then the risk is that utilities will continue to invest in traditional solutions, thus leading to investments that are not necessary and not consistent with the direction of grid evolution and customer energy use. Conversely, with increased grid-edge visibility, and the ability to either control or influence how DER is used, then the potential exists to lower customer costs while improving the customer experience and enhancing grid performance and reliability.

Conclusion

AEE Institute appreciates the opportunity to submit these comments and commends the Commission for its continued leadership on alternative ratemaking and rate design. We look forward to our continued participation in this important proceeding.

[25] https://info.aee.net/aee_institute_utility_report