

Pennsylvania Public Utilities Commission  
Alternative Ratemaking Methodologies

M-2015-2518883

**Advanced Energy Economy Institute - Comments on Alternative Ratemaking  
Methodologies in Response to Pennsylvania Public Utility Commission Tentative Order,  
Dated March 2, 2017**

**Preface**

On March 2, 2017, the Pennsylvania Public Utility Commission (“PUC” or “Commission”) issued a Tentative Order requesting comment on alternative ratemaking methodologies that may address issues currently facing Pennsylvania’s regulated public utilities, as well as processes for advancing said methodologies. The Advanced Energy Economy Institute (AEE Institute) is pleased to provide these Initial Comments in response to the Tentative Order.

The AEE Institute is a 501(c)(3) charitable organization whose mission is to raise awareness of the public benefits and opportunities of advanced energy. AEE Institute provides critical data to drive the policy discussion on key issues through commissioned research and reports, data aggregation and analytic tools. AEE Institute also provides a forum where leaders can address energy challenges and opportunities facing the United States. AEE Institute is affiliated with Advanced Energy Economy (AEE), a 501(c)(6) business association, whose purpose is to advance and promote the common business interests of its members and the advanced energy industry as a whole.

AEE Institute has substantial experience in participating in regulatory reform, grid modernization and “utility-of-the-future” discussions and proceedings across the country. Through its *21st Century Electricity System* initiative, Advanced Energy Economy is helping to accelerate the transition to a high-performing, customer-focused electricity system that is secure, clean, and affordable. AEE Institute has been very active in the New York Reforming the Energy Vision proceeding for the past three years, and has participated in other proceedings in California, Minnesota, Ohio, Michigan, the District of Columbia, and Maryland. As an organization with stakeholders that provide a range of technologies and services, we balance a wide variety of interests and address issues with a technology-neutral perspective.

AEE Institute has also been active in Pennsylvania. On March 29, 2017, AEE Institute released a white paper titled, *Performance-Based Regulation for Pennsylvania*. The paper was a follow-on activity to a CEO Forum hosted by AEE Institute on April 12, 2016, that brought together CEOs and senior executives from a diverse group of advanced energy companies, the state's electric and natural gas utilities, and key policymakers and regulators. Our comments here are based largely on that whitepaper, and focus on answering Question 2 in the Tentative Order.

## **Introduction**

AEE Institute commends the Commission for deliberating the efficacy and appropriateness of alternatives to traditional ratemaking principles for public utilities. AEE Institute appreciates the opportunity to provide this input as the "Commission continues the investigation by seeking comments on, and potential processes to advance, alternative rate methodologies that address issues each utility industry is facing." This is a timely effort, as regulatory commissions across the country are proactively engaging stakeholders to address the substantial changes taking place within the utility industry.

As noted above, the focus of our comments are on Performance-based regulation (PBR), but we also address several supportive ratemaking approaches. PBR is a regulatory framework that attempts to align the behavior and financial interests of regulated utilities with public interest objectives and consumer benefits. It does so by rewarding utilities for achieving well-defined outcomes (performance metrics), as opposed to solely providing financial incentives tied to capital investment (inputs). In our whitepaper, the Working Group proposes clear areas. In the context of alternative ratemaking options, PBR should be seen as an evolution of existing frameworks, not a wholesale replacement for traditional regulatory approaches.

## **Responses to Specific Questions on 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.*
- 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[1] 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.*

### **Performance-Based Regulation as a Framework for Utility Regulation in Pennsylvania**

Performance is the heart of the PBR model and it is managed through established qualitative and quantitative metrics. These metrics provide a basis of establishing revenue to utilities.

#### *a. Potential Advantages*

A PBR approach has many advantages. PBR represents a regulatory shift toward a wider range of potential values, including customer-oriented outcomes and environmentally sustainable utility service. A system of PBR complements long-held regulatory values, while linking performance objectives to emerging values. PBR provides an exciting opportunity to maintain reasonable costs, meet policy objectives, and craft a market structure to deliver an array of consumer benefits while offering utilities a financial incentive structure that is better aligned with the changing nature of utility service, including greater customer engagement and the use of non-wires alternatives.

AEE Institute strongly supports implementing broad performance incentive mechanisms (PIMs) that tie designated financial rewards and penalties to specific performance metrics. PIMs shift the focus of the utility from static cost minimization to enhancement of value as utilities are incented to improve performance that leads to an increased return on investment. Metrics also greatly enhance transparency and accountability on the part of the utility, which directly addresses regulatory concerns regarding the prudence and value of capital investment.

PBR also offers the potential for less frequent rate cases, and could reduce the need for detailed Commission oversight of utility planning, instead focusing on whether the utility is achieving the desired outcomes.

*b. Potential Disadvantages*

A potential disadvantage of switching to a performance based regulatory framework is that there may be need for workforce training and development for Commission staff. This appears to be common in the limited implementations of PBR. As mentioned at page 29 of our whitepaper, “moving forward on PBR in Pennsylvania will require reexamining elements of the regulatory framework and ratemaking process, including regulatory oversight, benefit-cost analysis, ratemaking and cost recovery, and rate design.” However, AEE Institute believes an incremental strategy for implementation of PBR will provide stakeholders and Commission staff with opportunities to gain experience and expertise.

*c. Effects on different rate classes*

AEE Institute, like many stakeholders, is sensitive to the impact of ratemaking changes on low and moderate income (LMI) customers. AEE Institute believes that ratemaking changes can and should benefit low and moderate income (LMI) customers. Well-designed PBR would deliver cost savings for all customers, aimed at making utility capital budgets more efficient while increasing shareholder value. We recommend the inclusion of specific metrics to focus on outcomes related to LMI customers.

In principal, strategies that avoid or defer larger capital expenditures, will deliver significant cost savings. An effective PBR model should incentivize utilities to empower customers, resulting in improved customer engagement and satisfaction and increased energy efficiency and conservation, all while maintaining affordability. While utilities may earn additional revenue for engaging their customers and improving customer satisfaction through PBR, customers must have access to tools to keep their utility bills affordable.

As part of implementing PBR, the Commission could direct the development of metrics specifically to address LMI customers, which could be constructed to address barriers that LMI customers face with respect to participation in beneficial utility programs or more broadly with participating in opportunities to deploy DER. As such, AEE Institute believes that PBR can help ensure LMI participation in programs, such as energy efficiency and demand reduction/response. Energy efficiency and demand response programs empower customers to better understand and manage and/or reduce their energy usage. Tools such as high bill alerts – where customers receive a notification if they are on track to receive a high bill, paired with energy saving tips to help them avoid a high bill – time-varying rates, energy efficiency incentives, smart thermostats,

and demand response programs all enable customers to manage their energy usage to lower their bills.

More generally, existing LMI program and protections should continue, while energy efficiency and demand reduction strategies can be strengthened.

*d. Effects on existing energy efficiency and peak demand reduction programs*

AEE Institute strongly supports the development and implementation of robust energy efficiency (EE) and peak demand reduction (DR) programs and commends the Commonwealth for its success with Act 129.

Although specific design issues would need to be worked out, existing EE and DR programs could be modified to fit within the broader PBR framework. We would expect that energy efficiency and peak load reduction would be core metrics in any PBR implementation in Pennsylvania. For example, Massachusetts and Michigan have a nation-leading energy efficiency programs that include performance incentives for achieving certain levels of EE deployment. PBR should also allow utilities to earn on voluntary EE and DR programs which go beyond compliance with Act 129 goals. For those activities that are cost beneficial, utilities can receive a share of benefits as an incentive, while still providing savings to customers.

*e. The effects on the number and/or frequency of base rate case filings, as well as possible rate increases or decreases.*

The PBR framework proposed here is envisioned as an enhancement to current ratemaking whereby revenues and earnings are adjusted for quality of performance. Utilities are expected to develop capital spending and asset improvement plans directly linked to stated policy goals, system condition and customer demands. Base rates are projected forward based on the approved capital plan, but are reconciled annually with actual investment.

Our paper outlines rate filing and proceedings under the section “Ratemaking and Cost Recovery” (at pg. 9). Our paper considers one option for structuring the ratemaking and cost recovery component of a PBR framework. Projected investment costs (depreciation and return on net plant in-service components) would enter base rates beginning in the initial year of the plan and reflect the planned timing of investments over the approved plan timeline. Each year an annual review process would be held in which the utility must report and explain to the Commission any

variances between planned and actual capital expenditures. The difference in revenue requirements between planned and actual capital expenditures would be reflected in a Capital Reconciliation Mechanism, which would be used to adjust future annual base rates, including carrying costs based on the utility's approved pre-tax weighted average cost of capital, to reflect Commission-approved variances in capital spending. Operational expenditures would be recovered through base rates that are set at the time of approval of the utility's multi-year rate case. This portion of base rates would then be adjusted on an annual basis over the term of the plan based upon a formula that considers the rate of inflation adjusted for productivity gains. Further, base rates would be adjusted annually pursuant to Commission review of utility performance and service quality metrics.

PBR should decrease the number and frequency of rate base filings because it would make use of multi-year (three to five year) rate plans to provide stability for utilities, cut down on the cost of administrative oversight and process, and play an important part in providing utilities with the right incentives to meet state policy objectives. Having a predetermined rate case period provides a financial incentive for the utility to increase operational efficiency and reduce costs because they prohibit the utility from filing a new rate case to recover their costs if they aren't operating efficiently, therefore benefitting all customers. In addition, because multi-year plans replace annual or ad hoc rate cases, less time will be spent in the hearing room, with more time spent enhancing the system and serving customers.

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.)?*

As a general matter, PBR and the other ratemaking methodologies discussed above would be complementary to existing mechanisms such as the DSIC. A PBR framework would make use of a forward looking multi-year rate plan and as such is consistent with the current use of the FPFTY in Pennsylvania.

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

As highlighted in our paper, we believe authority already exists in Pennsylvania statute to implement some elements of PBR. In defining categories of desired utility

performance, the Commission will need to act consistent with statutory authority and policy mandates. The building blocks are in place to put Pennsylvania at the forefront of 21st century energy system development. For example, Act 129, passed in 2008, is advancing the Commonwealth's goal of ensuring the availability of adequate, reliable, affordable, efficient, and environmentally sustainable electric service at least cost. The legislation also expanded sections of Title 66, including responsibilities of electric distribution companies in the Commonwealth, and the role of the Public Utility Commission (PUC) in meeting those responsibilities.

We support careful and thoughtful implementation of PBR, with appropriate stakeholder engagement. From our experience in other contexts, we believe it is important to gather input from a wide range of stakeholders when drafting a PBR framework and developing metrics. In general, we foresee that the Commission may need 12-18 months to build the record necessary with the stakeholder community. Given that the Commission has been considering this matter for some time, a shorter implementation timeline may be appropriate. Stakeholders and utilities would need opportunities to gain experience and test both the application of, and the adequacy of revenues from, performance based regulation. In line with experience, we could imagine PBR as phased-in over next 2-3 years, starting with priority metrics. This provides utilities time to adjust internal processes and submit the necessary rate plans.

It is also important to note that over the past decade, Pennsylvania has taken a number of actions that have laid the foundation for implementing PBR. Using its broad grant of authority from the Public Utility Code, the PUC has the ability to facilitate a number of required PBR elements, including data tracking, smart metering infrastructure, energy efficiency, distributed energy resources, and others.

#### *Shared Savings Mechanisms as a Complement to PBR*

If utilities implement solutions that result in lower usage, customer savings, and other outcome, may lead to lower utility revenue and earnings opportunities. 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, 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 non-bulk power level seen by the utility (such as deferred or avoided investment). Allocating some of the benefits to the utility via a shared savings model will better align the interests of the utility with the customer and with the state's goals.

Shared savings can also form a basis for establishing utility incentives levels in a PBR approach - savings could be divided in such a way as to ensure that customers receive substantial net benefits but that the utility also receives a sufficiently large reward to pursue cost-beneficial programs and solutions in line with policy objectives.

### **AEE Institute's Comments on Other Alternative Ratemaking Methodologies**

Whereas PBR can be considered an evolution of the overall regulatory framework, there are a number of other enhancements that can be made that support the transition to an outcomes-oriented regulatory approach. These are generally geared towards removing the utility bias towards making capital investments to grow its rate base in favor of actions that lower costs for customers and improve system efficiency. In addition to the specific questions addressed above, the Tentative Order described a series of alternative ratemaking methodologies. We would note that the following methodologies are designed to address concerns with revenue, as opposed to earnings. Many of these methodologies are aimed to manage risk to utility revenues, but do not address the bias toward capital investments. We provide below our perspectives on each.

#### **A. Revenue Decoupling**

AEE Institute believes that revenue decoupling can be a foundational part of modern ratemaking. As noted in the citation of Mr. Miller's testimony included in the Tentative Order related to performance incentive mechanisms, removing financial incentives to pursue certain technologies over others does not equate to rewarding utilities for valued outputs. 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 doesn't leave the utility neutral to achieving outputs if achieving those outputs puts current input incentives (return on capital expenditures) at risk. More plainly, revenue decoupling removes the threat of lowered revenue, but falls short of rewarding outputs. A gradual approach to revenue decoupling, combined with a PBR framework, could provide a transition toward rewarding outputs, rather than incentivizing investments in specific inputs.

#### **B. Lost Revenue Adjustment Mechanisms (LRAMs)**

Much like revenue decoupling, LRAMs can be used to remove disincentives that are in conflict with certain outputs, such as increased energy efficiency. Conservation and energy efficiency programs should not be at odds with utility behavior, as Pennsylvania



clearly values such programs. However, the utility in this case would be “made whole” for its efforts, as compared to the revenue it would have received through conducting business as usual. Again, this removes counterproductive incentives, but does not align utility behavior and motivate utility action toward such programs.

Given the choice between revenue decoupling and LRAM, we prefer the former as it is a more comprehensive approach. LRAMs are primarily focused on recovering lost revenues for certain programs, while revenue decoupling will allow for revenue stability despite lower kWh sales from efficiency and customer distributed generation that take place outside of utility programs. The utility should be in a position to encourage efficiency and distributed generation that occurs outside of its direct control rather than view them as a threat.

#### C. Straight Fixed / Variable (SFV) Pricing

We agree with the assessment of SFV presented in the Tentative Order. We are particularly concerned about the risk of decoupling bills from consumption, as this acts as a disincentive to use electricity efficiently. We believe that linking consumer values to utility earnings in a performance-based framework provides opportunities to align behavior for both utilities and consumers in ways superior to the incentives of SFV designs.

#### D. Cost Trackers (also known as Surcharges or Riders)

Cost trackers have a long history in utility regulatory proceedings and rate designs. AEE Institute understands that there are appropriate applications to manage volatility in prices for utilities and rate risks for consumers. For utilities, managing these costs well is directly related to performance categories outlined in our whitepaper, including affordability, and operational and system efficiency.

#### E. DSM Performance Incentive Mechanism

As mentioned earlier, AEE strongly supports implementing broad performance incentive mechanisms (PIMs) that tie designated financial rewards and penalties to specific performance metrics. PIMs shift the focus of the utility from static cost minimization to enhancement of value as utilities are incented to improve performance that leads to an increased return on investment. Metrics also greatly enhance transparency and accountability on the part of the utility, which directly addresses regulatory concerns regarding the prudence and value of capital investment.

#### F. Choice of Test Years

As mentioned above in our description of PBR, we support using future test years, along with multi-year rate plans.

#### G. Multiyear Rate Plans

As previously mentioned, PBR should decrease the number of and frequency of rate base filings because it would make use of multi-year (three to five year) rate plans. Such a plan can provide stability for utilities, cut down on the cost of administrative oversight and process, and play an important part in providing utilities with the right incentives to meet state policy objectives. In addition, because multi-year plans replace annual or ad hoc rate cases, less time will be spent in the hearing room, with more time spent enhancing the system and serving customers.

#### H. Demand Charges

Demand charges are intended to better align revenue collection with costs, because costs borne by the utility are largely based on peak capacity. The argument is that by charging customers for the maximum amount of instantaneous demand (kW) as well as total consumption over time (kWh) customers will be incented to spread out their usage and reduce the capacity needs of the system, which helps reduce system costs overall. Demand charges can be structured either as an individual non-coincident peak charge or as a system coincident peak charge.

Non-coincident demand charges are typically based on a customer's highest usage (e.g. hourly or daily) during each billing cycle. However, unlike fixed charges, non-coincident demand charges better align costs to those customers who are driving up system costs. System costs, however, are rarely driven by any individual customer's non-coincident demand, and are instead dependent on aggregate peak demand. Coincident peak demand charges both better align cost recovery with cost causation and send customers price signals to avoid usage during times that drive new system costs.

Mass-market customer in particular are likely to be unfairly treated by non-coincident peak demand charges, because their peak demand rarely matches up with the system peak. Residential customers have a wide variety of load profiles, such that residential usage overall tends to have a smoothing effect on the demand curve. As a result, the

non-coincident peak demand of a typical residential customer tends to unfairly allocate costs to customers with erratic loads and is not a good indicator of that customer's contribution to utility costs. Also, residential customers with high non-coincident peak demand usually have lower coincident peak demand than customers with low non-coincident peak demand. The relationship is inverse.

System coincident demand charges on the other hand align closely with system costs and directly incent customers to reduce their usage during the system peak. Coincident charges are based on an individual customer's demand during the system peak regardless of their individual peak. However, coincident demand charges are impossible to implement without advanced metering infrastructure and a robust customer communication and education program. With this said, coincident demand charges are superior to both non-coincident demand charges and higher fixed charges if structured properly. However, there are various other consequences that mirror those imposed on customers from higher fixed charges.

Demand charges take away predictability in residential consumer rates, and they may be difficult to control if customers do not know when their usage peaks (if structured as a non-coincident demand charge) or if utilities do not to notify customers when the system is peaking so that they can adjust their usage (if structured as a coincident demand charge). Additionally, demand charges undermine the incentive for energy efficiency by reducing the volumetric rate and shift bill savings opportunities toward peak management at the expense of overall kWh reduction. Finally, demand charges hurt the value proposition for non-dispatchable DG (e.g. rooftop solar) as customers would have to pay based on their maximum usage when their solar panels are not generating, even if they are meeting their electricity needs under net metering. Conversely, coincident peak demand charges can encourage non-dispatchable DG to pair with storage to provide energy when the system needs it most.

#### I. Standby and Backup Charges

While the motivation for standby and backup charges is to ensure the utility maintains adequate capacity for customers that provide all or some portion of their own energy needs, these charges must be handled with care. As noted by Stanton "Excessive standby charges can have a chilling effect, deterring DG system developers from focusing efforts in those areas and discouraging customers from investigating DG options." (at pg 33) In our comments to a proceeding at the New York Public Service Commission we supported a design of a standby rate that also accounts for potential overcharges. Under this rate, customers that have a track record of good reliability

during peak demand hours would be eligible for rebates for the value of the demand that they pay for in their contract, but do not actually use. The proposed rebate was equal to contracted demand less the customer's actual maximum demand in two consecutive summer periods during peak hours. Such a rate ensures that customers only pay for the capacity needed to serve them, increasing rate equity.

### **Response to Three Part Rate Proposal of Vice Chair Place**

AEE Institute believes that valuing performance and fostering innovation must be part of thoughtful rate designs. To that end, we support the creation of programs, products, services and rates that will ultimately transform how customers, utilities, and third party service providers interact with the modern grid. Determining the benefits and costs of services is vital for designing rates that align with performance objectives. Regulators have a toolbox outside of traditional rate designs to address issues with performance. There are widespread examples of alternative rate designs already being implemented or considered.

Generally, AEE Institute supports a transition to more precise and granular rate designs, provided that customers are given the tools, education and information necessary to respond to the price signals they are receiving, including deployment of different types of DER. For mass-market customers, various types of time varying rates (TVRs) can be appropriate.

We generally do not support the use of mandatory or opt-out demand charges with mass-market customers, as these can be particularly difficult for these customers to manage. We also do not support increases in fixed charges beyond actual customer-specific costs, such as the cost of interconnection to the grid, metering and customer service, which are used to establish monthly customer charges. Applying fixed charges beyond these cost components reduces the incentive to deploy energy efficiency and unfairly penalizes customers with onsite distributed generation. Further, they provide no signal to customers to reduce consumption at critical times to avoid future utility costs. Customers, through rate design, can be empowered to reduce their own cost of service over the long run. Fixed charges remove the ability to send these price signals.

Given the foregoing general remarks on rate design, AEE Institute does not support the proposed three-part rate contained in the Statement of Vice Chair Place, in particular, the demand charge component. Although demand charges may be appropriate for large, sophisticated customers, their benefits are not easily transferable to mass-market (residential and small commercial) customers. Other options, such as

well-designed time-of-use rates, or critical peak pricing or peak-time rebate programs, are better options.

### **Responses to Specific Questions on Natural Gas Utilities and Water and Wastewater Utilities**

In the comments above and in our whitepaper, we speak mostly to PBR for electric utilities. We believe our comments on rate methodologies above apply across other regulated industries. Further, our working group did incorporate concerns of gas utilities. We would note that the approach to PBR outlined in our report would work well for other public utility regulatory domains. Statutes that govern these other domains would guide appropriate areas of performance that the Commission may use to drive alternative rate designs.

ATTACHMENT

AEE Institute Whitepaper *Performance-Based Regulation for Pennsylvania: An Opportunity for Pennsylvania to Drive Innovation in the Utility Sector*