PENNSYLVANIA PUBLIC UTILITY COMMISSION
HARRISBURG, PENNSYLVANIA 17120

Alternative Ratemaking Methodologies

Public Meeting: March 2, 2017
2518883-LAW
Docket No. M-2015-2518883

STATEMENT OF VICE CHAIRMAN ANDREW G. PLACE

In December 2015, the Commission issued a Secretarial Letter announcing its intention to hold an *en banc* hearing to seek information from experts regarding the efficacy and appropriateness of alternative ratemaking methodologies that remove the disincentives that may currently exist for energy utilities to pursue aggressive energy conservation and efficiency measures. In the Secretarial Letter, the Commission identified a list of issues and questions to be discussed at the hearing and subsequently, invited participants to present testimony at the *en banc* hearing addressing those issues. On March 3, 2016, panel presentations were made by alternative ratemaking and energy efficiency experts as well as public utility and consumer perspective experts. Various exhibits and statements from the participants were entered into the record on March 3, 2016.

In addition to the information presented at the *en banc*, the Commission requested that additional written comments on this topic be submitted by March 16, 2016. Interested parties provided additional comments, including the issue of decoupling of revenues and more advanced demand-based rate designs.

After review of all testimony and comments received, I am proposing additional questions and issues for comment as the Commission further examines alternative ratemaking methodologies. In this discussion, I believe that it is important to provide strong incentives that minimize the long term costs of electricity service – whether it be for self-supply, efficiency, or demand side management programs. Simultaneously, I also recognize that electric distribution companies (EDCs) must have tools to minimize necessary investments to safely and reliably provide electric service and have a reasonable opportunity to earn a fair return on their capital investments in light of impacts from the advancement of distributed energy resources and energy efficient technologies. Further, one key issue is the impact of alternative ratemaking proposals on low-income customers as is articulated in my directed questions set forth below.

In order to further the debate, I am presenting separate advanced rate design and decoupling methodologies for electric distribution companies (EDCs) and natural gas distribution companies (NGDCs) for comment by interested parties.

Based on the comments received at this docket for the electricity sector,[1] I have developed a proposal based on a 3-part rate, including a customer charge, a demand charge based on coincident peak hours, and a volumetric charge, all of which can be phased in over time. I request that stakeholders comment on this proposal so that further guidance can be provided to the Commission on this important topic.

Advanced Rate Design Consideration for EDCs:

- 3-part rate – Existing customer charge, demand charge, and volumetric charge
    - Customer charge recovers metering and service line extension costs, based on size of service drop or service meter provided.
    - Coincident Demand Charge covers basic distribution grid capital and fixed grid operating costs.
    - Volumetric charge covers other variable costs and operating expenses.
- Gradualism – move to full rate structure, as approved by the Commission, over 9 years in 3-year increments. [a third every three years]
- Demand charge determinant, based on coincident peak usage intervals during the day, month, season or year.
- Cost allocation between rate classes is unaffected - no change in policy implemented through base rate proceedings.
- Demand charges would be "net metered" to the extent they reduce coincident peak demand usage.

I recognize that as a prerequisite for transitioning to a coincident demand charge rate design, EDCs must have fully deployed smart meters and the associated back-office systems to measure, communicate, store and process at least hourly usage data. Furthermore, education programs would be necessary to help customers understand any such final advanced rate structures approved by the Commission.

Another ratemaking option for the electric industry not specifically addressed in the Commission's March 3, 2016 *en banc* proceeding is a reliability performance-based mechanism. The Commission presently evaluates EDC reliability via a set of objective metrics. These metrics include the system average interruption duration index (SAIDI), the system average interruption frequency index (SAIFI), and the customer average interruption duration index (CAIDI). Reliability performance metrics such as those can be tied to rates in an effort to incentivize increased reliability. Various versions of reliability-based ratemaking mechanisms exist in states including New York, Illinois, California, and Hawaii. Such mechanisms vary in form and fashion and, for example, include an increase in the utility's authorized

[1] See PECO comments at 5, PPL comments at 3-4, First Energy Comments at 20.

return on equity (ROE) based on that utility's performance in relation to the identified metric or a penalty for not meeting the metric. In Pennsylvania, a potential concept could be to give consideration to the electric companies' reliability results in determining its authorized distribution system improvement charge or rate base ROE. The effective use of reliability performance metrics for ratemaking could influence EDC performance in areas where historic performance was inadequate. However, such ratemaking may also come with unintended consequences of shifting utility attention from areas of need to areas of financial opportunity. I welcome additional comments on reliability performance-based mechanisms.

At the same time, I note that natural gas distribution companies (NGDCs) operate under a somewhat different economic environment. I believe that the existing rate design provides significant customer rewards for using natural gas more efficiently, further assisting a carbon constrained regulatory environment. However, while it is important to continue to achieve the efficient use of natural gas, trends of declining use per customer related to efficiency gains can challenge NGDCs ability to simultaneously achieve profitability by serving new and existing customers. This is particularly necessary to support infrastructure replacement programs in order to maintain safe and reliable service as prescribed by the Public Utility Code.

Therefore, for the natural gas sector, I propose consideration of a "revenue per customer" model, which would adjust the NGDCs volumetric rates in a manner that more closely enables the recovery of the cost of service authorized in a base rate case for those rate schedules subject to the rate adjustment mechanism. A mechanism which adjusts overall volumetric rates to compensate for changes in average use per customer, both up and down, may continue to provide individual customer incentives to reduce usage. At the same time, adjustments to volumetric rates may provide more stable revenues for the utility, more stable annual distribution charges to customers, and maintain revenue opportunities for the growth and expansion to new customers, thereby enhancing the long term efficiency of the energy system. The possible disadvantage of such a proposal is that volumetric rate volatility would increase.

<u>NGDC Decoupling Consideration</u>

- Maintain current customer charge and volumetric rate designs for residential and small commercial customers.
- Adjust volumetric charges to allow NGDCs to recover their cost of service, using the "revenue per customer" model - calculated, for example, by dividing the revenue requirement, as determined in the utility's most recent §1308

base rate case[2], by the number of customers in each rate class as articulated in the same §1308 base rate case. Volumetric rates would be adjusted, to maintain the amount of revenue per customer calculated.

- Cost allocation between rate classes is unaffected - no change in policy.
- Maintain existing DSIC mechanism to assist in infrastructure replacement.

I wish to emphasize, however, that I encourage interested parties to provide suggestions for alternatives to the proposals herein, to the extent they believe these suggested models are unworkable, or inferior to other alternative ratemaking concepts. The sole objective of this work is to thoroughly consider all concepts that have the potential to optimize utility economics and customer affordability. In that vein, the Commission can review all of the comments submitted and determine the next steps, including possibly a Proposed Policy Statement, which would provide for an optional rate design or decoupling mechanism to encourage a more efficient energy sector in the future.

<u>Directed Questions for Electric Distribution Company Proposal</u>

1. Provide overall supportive or critical comments on the outlined advanced rate design structure.
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?
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?
4. How should peak demand be measured? Should each measurement be based, for example, on a 15 minute, 30 minute, or 1 hour period?
5. Should tiered demand rates be used?
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?
7. What other "rate gradualism" mechanism should be employed?
8. What revenue streams should be excluded (e.g. § 1307 automatic adjustment revenues)?
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?

[2] 66 Pa. C.S. §1308.

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

<u>Directed Questions for Natural Gas Distribution Company Proposal</u>

1. Provide overall supportive or critical comments to the outlined NGDC decoupling structure.
2. Has this proposal been successfully or unsuccessfully implemented in other jurisdictions?
3. Are there any statutory and regulatory barriers in Pennsylvania to a revenue-per-customer decoupling for NGDCs?
4. What are the general potential bill impacts associated with this form of decoupling?
5. Should the use of decoupling be limited to NGDCs that are offering conservation and efficiency programs and, if so, what should be the required types and scope of such programs?
6. Should measures of success be included in the implementation and how should the Commission ensure that incremental conservation and efficiency program benefits exceed costs?
7. Should the Commission undertake periodic evaluations as a means for establishing the overall impacts, as well as the effectiveness of design and administration?
8. How should the Commission design the mechanism to true-up forecast and actual utility delivery service revenues?
9. To what rate classes should decoupling apply?
10. What revenues streams should be excluded (e.g. § 1307 automatic adjustment revenues)?
11. How should a "usage-per-customer" parameter be developed during the implementation of a revenue-per customer decoupling mechanism, and how should this parameter be used to adjust future rates? Should there be separate usage per customer values for new and existing customers?
12. What should be the frequency of the rate adjustment?
13. Should the Commission incorporate caps on rate adjustments?
14. How soon after the conclusion of the future test year should the Commission allow adjustments?
15. Should the Commission periodically require a complete review of costs, sales, and revenues (i.e., a general rate case or equivalent)? Please describe the suggested review process and necessary time period.

16. Should there be carrying charges (interest) calculated on rate adjustments, both upward and downward? If so, how should these carrying charges be calculated?
17. What would the range of cost impacts be, if any, for low income customers? Under a given model, what modifications should be made to Low Income/Customer Assistance Program participants to maintain affordability and ratepayer equity?
18. What type of consumer education programs should be provided to customers when implementing a decoupling methodology?

DATED: March 2, 2017

Andrew G. Place

Andrew G. Place, Vice Chairman